



2025 Distributed System Implementation Plan

June 27, 2025



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Acronyms and Abbreviations

Acronyms and abbreviations are used extensively throughout this report and are presented here for ease of reference.

ACRONYM	DEFINITION
ADMS	Advanced Distribution Management System
ALT	Automatic Load Transfer
AMI	Advanced Metering Infrastructure
ASHP	Air-Source Heat Pump
ATWG	Advanced Technical Working Group
BCA	Benefit Cost Analysis
BE	Building Electrification
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BTU	British Thermal Unit
CBC	Customer Benefit Contribution
CCA	Community Choice Aggregators
CDG	Community Distributed Generation/Community Solar
CENTRAL HUDSON (COMPANY)	Central Hudson Gas & Electric Corporation
CEII	Critical Energy Infrastructure Information
CESIR	Coordinated Electric System Interconnection Review
CFF	Common File Format
CGPP	Coordinated Grid Planning Process
CIS	Customer Information System
CLCPA	Climate Leadership and Community Protection Act
COMMISSION OR PSC	Public Service Commission
CTO	Connecting Transmission Owner
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DAC	Disadvantaged Communities
DAF	Data Access Framework
DCFC	Direct Current Fast Charger
DEC	Department of Environmental Conservation
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DMS	Distribution Management System
DPS	Department of Public Service
DR	Demand Response
DRV	Demand Reduction Value
DSCADA	Distribution Supervisory Control and Data Acquisition

ACRONYM	DEFINITION
DSIP	Distributed System Implementation Plan
DSO	Distribution System Operations
DSP	Distributed System Platform
DTT	Direct Transfer Trip
EAM	Earnings Adjustment Mechanism
EE	Energy Efficiency
EIAT	Energy Infrastructure Assessment Tool
EJ	Environmental Justice
EMS	Energy Management System
EPPAC	Energy Policy Planning Advisory Council
EPRI	Electric Power Research Institute
ESCO	Energy Service Companies
ESRI	Environmental Systems Research Group, Inc.
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAT	Factory Acceptance Testing
FERC	Federal Energy Regulatory Commission
FISR	Fault, Isolation, and Service Restoration
GBC	Green Button Connect
GHG	Greenhouse Gas
GIS	Geographic Information System
GOF	Grid of the Future Proceeding
GSHP	Ground Source Heat Pump
HCCF	Hosting Capacity
HVAC	Heating, Ventilation, and Air Conditioning
IEDR	Integrated Energy Data Resource
IEEE	Institute of Electric and Electronics Engineers
IOAP	Interconnection Online Application Portal
IPV	Initial Public Version
IPWG	Interconnection Policy Working Group
ITWG	Interconnection Technical Working Group
JU	Joint Utilities
JUNY	Joint Utilities of New York
KW	Kilowatts
L2	Level 2 electric vehicle chargers
LDV	Light Duty Vehicle
ERV	Load Serving Capabilities
LMI	Low-to-Moderate-Income
LSRV	Locational System Relief Value
M&C	Monitoring and Control
M&V	Measurement & Verification
MOCS	Marginal Cost of Service
MDM	Meter Data Management
MHDV	Medium-Heavy Duty Vehicle

ACRONYM	DEFINITION
MVA	Mega Volt-Amperes
MVP	Minimum Viable Product
MW	Megawatts
NEM	Net Energy Metering
NENY	New Efficiency New York
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NMS	Network Monitoring System
NOPR	Notice of Proposed Rulemaking
NREL	National Renewable Energy Laboratory
NWA/NWS	Non-wire Alternative/Non-wire Solution
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research & Development Authority
NYSSIR	New York State Standardized Interconnection Requirements
NYTO	New York Transmission Owner
O&M	Operations and Maintenance
OMS	Outage Management System
PCC	Primary Control Center
PCIP	Participating Contractor and Industry Partners
PDS	Program Development System
PHEV	Plug-in Hybrid Electric Vehicle
PSC	Public Service Commission
PV	Photovoltaic
QA/QAS	Quality Assurance / Quality Assurance System
REV	Reforming the Energy Vision
RFP	Request for Proposal
RMC	Residential Managed Charging
SCADA	Supervisory Control and Data Acquisition
SEEP	System Energy Efficiency Plan
SGS	Smarter Grid Solutions
SIR	Standardized Interconnection Requirements
SME	Subject Matter Expert
TO	Transmission Owner
TOU	Time of Use
T&D	Transmission and Distribution
UCG	Utility Coordination Group
UER	Utility Energy Registry
UTEN	Utility Thermal Energy Network
V2G	Vehicle-to-Grid
VDER	Value of Distributed Energy Resources
VVO	Volt/VAr Optimization
VPP	Virtual Power Plant
ZEV	Zero Emissions Vehicle

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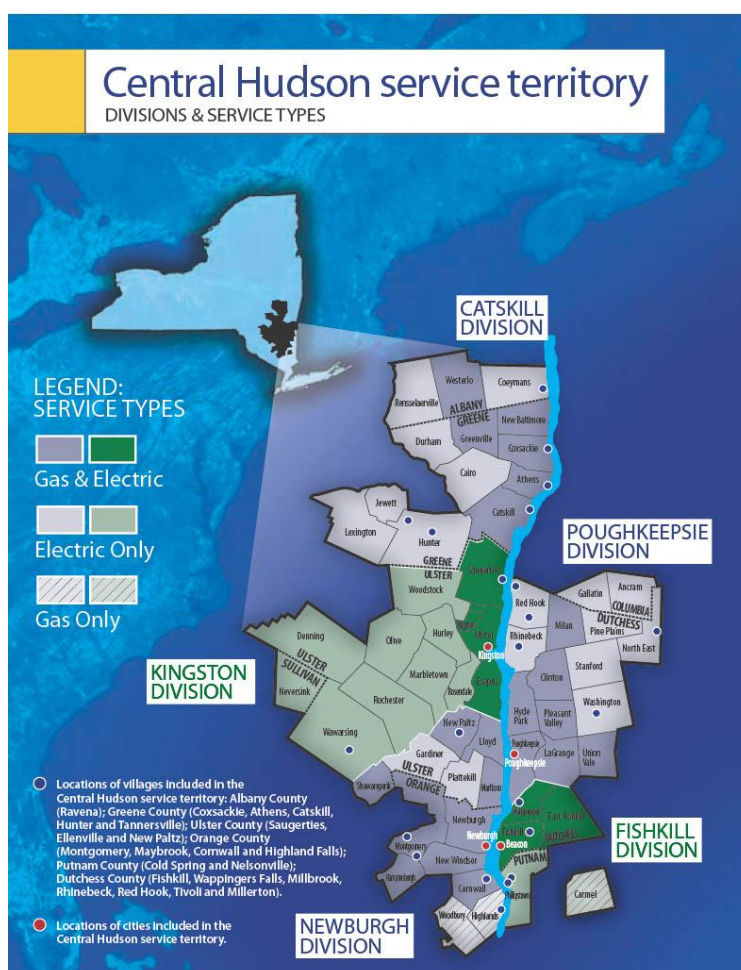
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I. EXECUTIVE SUMMARY

This is Central Hudson’s fifth Distributed System Implementation Plan (DSIP) filing since 2016. This DSIP presents the company’s progress and plan to enhance Distributed System Platform (DSP) capabilities in accordance with New York State Public Service Commission (PSC or Commission) requirements.

Central Hudson Gas & Electric Corporation (Central Hudson or Company) is a regulated gas and electric utility serving the Mid-Hudson Valley of New York State. The Company provides electricity and gas transmission and distribution (T&D) services to approximately 315,000 electric customers and 90,000 natural gas customers. Figure 1 illustrates the Central Hudson territory, which extends from the suburbs of metropolitan New York City north to the Capital District at Albany, covering approximately 2,600 square miles. The electric system comprises approximately 9,400 miles of transmission and distribution lines.

Figure 1: Central Hudson Service Territory



As a result of regional and state economic factors, energy efficiency (EE) programs, and the integration of large amounts of small-scale photovoltaic (PV) systems, Central Hudson’s electric system peak has remained flat or declining in recent years despite continued growth in the number of customers.

Central Hudson is committed to a cleaner energy future by supporting the Climate Leadership and Community Protection Act (CLCPA) targets and Reforming the Energy Vision (REV) policies, which are reshaping the state’s energy landscape toward a more distributed, less carbon-intensive system. Central Hudson continues to strongly believe that maintaining affordability must be part of the clean energy solution.

Central Hudson’s actual system peak in 2024 was 1,103 MW.¹ The electric peak forecast for 2030 is projected to be a summer peak of 1,087 MW. Overall, per-customer summer peak demand in Central Hudson has declined at a rate of -0.84% per year, likely due to a mixture of energy efficiency, codes and standards, and other changes in end-use loads. Winter peak demand has declined at a rate of -1.17% per year. For comparison, Central Hudson’s all-time electric system peak demand of 1,295 MW was set in 2006.

KEY FACTS

2024 customers ~316,950	2024 Summer Net Peak 1,103 MW	2024 Summer Gross Peak (Weather Adj.) 1,185 MW
2010-2024 Customer Growth Rate 0.61%	2010-2024 Summer Peak Demand Per Customer Growth Rate -0.84%	2010-2024 Non-Summer Peak Demand Per Customer Growth Rate -1.17%
Transmission areas 10	Distribution substations 66	Primary Feeders 272

As a result of the observed and forecasted demand growth, the Company’s electric capital expenditures relate primarily to replacing existing infrastructure based on condition assessments, and on Grid Modernization efforts. However, there are pockets of peak demand growth as well as pockets of Distributed Energy Resources (DERs) adoption which may result in the need for investments or non-wire alternatives to meet local demand.

A. SIGNIFICANT PROGRESS MADE

Since the 2023 DSIP filing, Central Hudson has progressed several efforts primarily completing the implementation of several large-scale transformational projects designed to improve the intelligence of its system, provide tangible benefits to customers, and improve the system’s ability to incorporate DER. These efforts include the installation of a Distribution Management System (DMS), substantially completing the Distribution Automation (DA) and Geographic Information System (GIS) projects, and significant completion of an enterprise Network Strategy communication system that allows field devices to communicate with corporate operational technology assets, including the DMS and the Energy Management System (EMS).

¹ The value includes loads and net metered distribution connected solar and storage, which is used for revenue requirements. For distribution planning, the loads used also include non-net metered distribution connected solar (e.g., community solar and storage). Gross Peak (Weather Adjusted) includes net loads, net metered solar production, and community-distributed generation solar production.

The Company has also completed the Distribution System Operation Center as part of its new Primary Control Center and has begun the transition to become fully operational as staffing, and the DA and DMS efforts are completed.

Since the last DSIP filing, the Company has made tremendous strides in the transformation of its Customer Information System (CIS) and in billing stabilization. Customers are being billed timely and accurately, with significantly decreased amounts of billing exceptions generated daily that require manual intervention. This can be attributed to lower numbers of estimated readings created by both system enhancements and monthly meter readings. Key billing metrics are very strong, with over 99% of invoices being issued on a timely basis. With this success, Central Hudson looks towards enhanced customer service to restore trust and provide customers with a positive experience. Current billing system development is focused on the regulatory Value of Distributed Energy Resources (VDER) and Distributed Energy Resources programs. These programming efforts are large system enhancements and will require a considerable amount of time, resources, and testing to complete.

B. THIS DSIP DOCUMENT

The *Order Adopting Distributed System Implementation Plan Guidance* (April 2016 Order), issued on April 20, 2016, describes the need to develop a more transactional, distributed electric grid that meets the demands of the modern economy and includes improvements in system efficiency, resilience, and carbon emissions reductions. In response to the transitioning utility model, the Commission defined a set of functions of the modern utility that are called the Distributed System Platform. The DSP functions combine planning and operations with the enabling of the markets. The process by which improved planning and operations are defined and implemented is the DSIP.

Since the April 2016 Order, New York State has set forth the boldest clean energy policies in the nation aimed at reducing carbon emissions to address climate change. One of the foundational elements of the State's REV initiative is increasing the amount of distributed energy resources (DERs) – such as wind, solar, and battery storage – and increasing energy efficiency. In July 2019, New York passed the nation-leading CLCPA, which includes: an 85% reduction of all greenhouse gas emissions by 2050, achieving 70 percent of all electric generation produced by renewable resources by 2030, and a carbon-neutral electric generating sector by 2040.

In 2024, the Commission initiated a Grid of the Future (GOF) proceeding. Although it is not the current focus of this DSIP filing, it will be a focus in subsequent DSIP filings as the electric market continues to evolve into a more active and dynamic state. The objective of the GOF proceeding, as described in the Instituting Order, is “to unlock innovation and investment to deploy flexible resources—such as distributed energy resources and virtual power plants (“VPPs”)—to achieve our clean energy goals at a manageable cost and at the highest levels of reliability.”² Central Hudson is looking forward to this next phase in DSP development as we meet the system's needs through the most efficient means. The investments that Central Hudson has made to date will serve our customers during this next

² Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Order Instituting Proceeding, p.3 (Issued April 18, 2024).

transformation, allowing for a seamless transition from traditional supply to flexible load in meeting electric system demand.

Central Hudson continues to put significant effort into progressing the DSP as outlined in its initial DSIP filing. In addition to establishing an internal team of subject matter experts and consultants to develop the filing, the Company works collaboratively with various stakeholder groups as well as the state's jurisdictional electric utilities. As such, this DSIP Update benefits from a collaborative process with the Joint Utilities of New York (JUNY), Department of Public Service (DPS) Staff, and stakeholders. The Joint Utilities (JU) are working collaboratively to progress the DSPs as consistently as possible across the state while recognizing the inherent differences of each utility system. To facilitate the review of each utility's DSIP Update, the Joint Utilities continue to present their plans in alignment with a standard table of contents and leveraging common language and figures. Where appropriate, the language and figures may be adapted to reflect the progress and plans of a specific utility.

The filing is segregated into four main sections:

- **Section II Progressing the Distributed System Platform:** This section provides a high-level summary of the Central Hudson vision of the DSP and the progress made in the DSP through the Joint Utility efforts and by Central Hudson in the areas of DER Integration, Market Services, and Information Sharing. The progress Central Hudson has made in its transformation efforts, including investments in Grid Modernization, Billing and Compensation, and various research programs related to Forecasting, Storage, and Distribution Energy Resources Management System (DERMS).
- **Section III DSIP Update Topical Sections:** This section provides updates on various topical sections, including Integrated Planning, Advanced Forecasting, Grid Operations, Energy Storage Integration, Electric Vehicle Integration, Clean Heat Integration, Energy Efficiency (EE) Integration and Innovation, Data Sharing, Hosting Capacity, Billing and Compensation, DER Interconnections, Advanced Metering Infrastructure, and Beneficial Locations for DERs and Non-Wires Alternatives.
- **Section IV Other DSIP Information:** This section provides an overview of the DSIP governance, which details how the plans and actions from the DSIP are implemented through the Company, the summary of the Marginal Cost of Service Study, and the Benefit-Cost Analysis Manual.
- **Section V Appendices:** This section includes detailed subsections that provide further information and support for our efforts and direction, including Load and DER forecasting, the Beneficial Cost Analysis (BCA) Handbook, Central Hudson Long Range System Plan, and Tools and Other Resources for customers and developers.

C. HIGHLIGHTS OF PROGRESS

1. FORECASTING AND PLANNING WITH DER

As outlined in the prior DSIP filings, Central Hudson has progressed its Integrated System Planning Process from the more traditional deterministic peak load forecasting and planning process to a more probabilistic granular hourly load forecasting and planning process. The forecasts are produced for distribution feeders, substations, and local transmission areas and include electric vehicles (EVs), building

electrification, solar, battery storage, and energy efficiency. In 2023, Central Hudson engaged a vendor to deliver a robust probabilistic load forecasting tool (see Advanced Forecasting) that can be utilized by both the external consultant as well as internal Central Hudson employees. The T&D Forecasting Tool has been fully developed and operating on Central Hudson servers since the fall of 2024. It is accessible to all Central Hudson transmission and distribution planners and additional staff as needed. This in-house tool was utilized for the development of this 2025 DSIP filing.

Central Hudson is currently developing changes to its design criteria to provide increased utilization of existing assets at both the distribution feeder and the substation. The increased visibility into the distribution system via intelligent electronic devices and the Advanced Distribution Management System (ADMS) will allow for improved feeder management on the distribution circuits as well as increased distribution substation loading. The ability to move load during normal and contingency scenarios while maintaining system reliability will improve the utilization factors associated with the distribution assets. The modifications will also incorporate winter ratings for the distribution assets to help manage the expected shift from a summer peaking to a winter peaking system. These modifications, along with new supporting planning documentation, are expected to be completed no later than Q2 2026.

2. SATISFYING THE DEVELOPERS' DATA NEEDS

Central Hudson maintains a robust data sharing program, which has continued to grow and evolve since the last DSIP was filed in 2023. Significant emphasis remains on the role of system data in facilitating market development and greater DER adoption as well as customer data in support of the development of new energy products and services, while also protecting customers' privacy. Thus, the information that Central Hudson published through the data sharing program is made available to all key stakeholder groups, which include customers, DER developers, communities engaged in clean energy planning, government officials, and others, in compliance with requirements and customer privacy considerations.

Central Hudson makes system and customer energy usage data available through several channels. Customers can access their usage information through their online customer accounts. Central Hudson publishes over a dozen other data sets and key reports relevant to the DER market, making these available on the Central Hudson website, the Joint Utilities of NY website, and regulatory filings on the NYS DPS website.

In addition to those resources shared directly by Central Hudson, stakeholders can access an increasing level of Central Hudson service territory information through platforms administered by the New York State Energy Research & Development Authority (NYSERDA), specifically the Integrated Energy Data Resource (IEDR) and the Utility Energy Registry (UER). These platforms allow stakeholders to see information on a statewide basis, across utility service territories. Since the last DSIP, Central Hudson has established an IEDR data sourcing program to supply its relevant information to the IEDR, working closely in support of NYSERDA as it has launched use cases and as it plans more for future release.

Central Hudson remains committed to maintaining its data sharing program and incorporating new requirements and feedback from stakeholders as needs and conditions change over time. Central Hudson intends to build upon progress already institutionalized as part of the DSIP and other processes and continue evolving its data sharing program as advancements in the digitization of information are implemented.

3. IMPROVING THE INTERCONNECTION OF DER

Central Hudson continues to enhance the transparency and utility of its Hosting Capacity Maps to support clean energy developers, policymakers, and other stakeholders. Our solar and energy storage maps are mature and widely used, offering actionable insights that help developers make informed interconnection decisions. A significant development since the 2023 DSIP is the launch of the first version of our electrification maps in January 2024, as directed by the Public Service Commission. These maps now include voltage information for various segments of each feeder, providing a more granular understanding of grid conditions and supporting beneficial electrification planning.

One of our key accomplishments over the past year has been the implementation of a new enterprise-grade Environmental Systems Research Institute (ESRI) GIS platform and the deployment of CYME load flow analysis software. In June 2024, the Electric Planning and Interconnection team implemented new load flow software, CYME, to meet the needs of increased modeling complexity related to DERs, hosting capacity analysis, as well as future electrification requirements. Additionally, Central Hudson plans to implement an integration with the Company's Interconnection Online Application Portal (IOAP), with scoping anticipated to commence in the second half of 2025 and implementation in 2026. With the Company's move to CYME load flow software, Central Hudson hopes to find ways to improve processes using features within CYME that did not exist within the load flow software previously used. This marks a substantial step forward in our analytical capabilities, enabling a more streamlined and robust hosting capacity mapping process. These tools support more accurate assessments of grid capacity and improve our maps' overall quality and usability. While our experience with standalone or hybrid energy storage systems above 50 kW remains limited, we continue to gather feedback and explore improvements, particularly in how storage is modeled based on charge/discharge schedules and operational use cases.

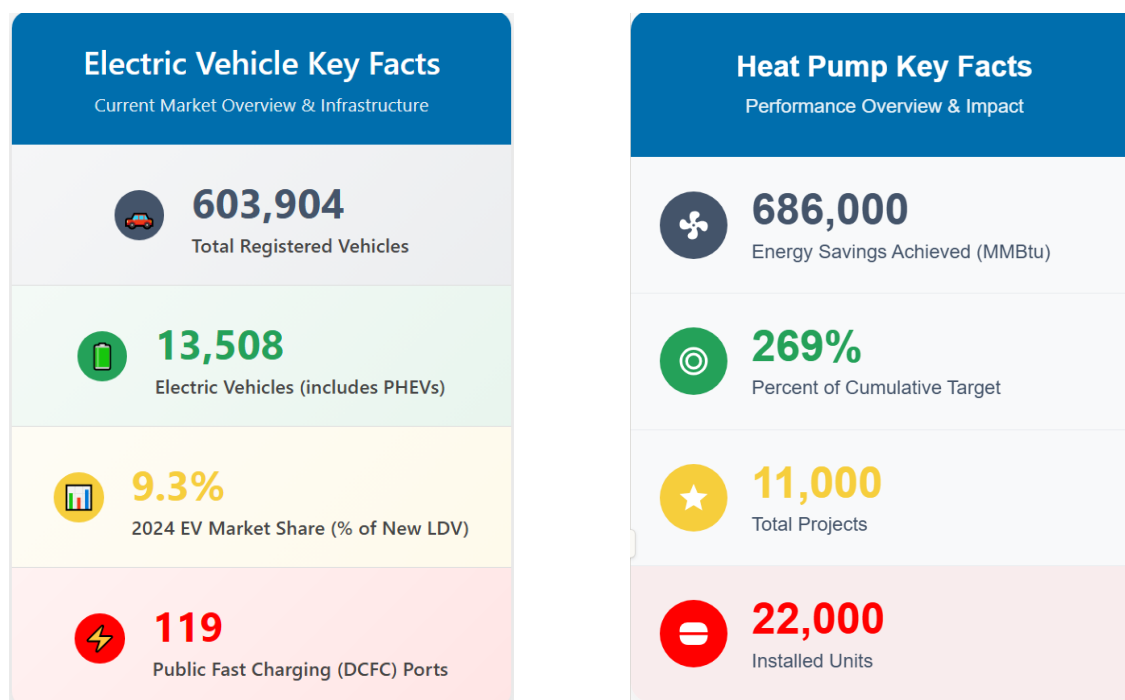
Central Hudson continues to see significant interconnection activity on both the distribution and transmission systems. With the recent New York Independent System Operator (NYISO) interconnection reform as required by Federal Energy Regulatory Commission (FERC) Order No. 2023, Central Hudson has seen a record number of projects as the Connecting Transmission Owner (CTO) compared to prior years, as part of the initial transition cluster study process. Improvements to our process and modeling allow us to meet all regulatory timelines, as well as provide flexibility to developers/applicants where possible, to support the integration of DER. Some examples of this include utilizing substation transformer 24-hour load cycles versus nameplate, which allows for higher thermal ratings, providing low-cost solutions such as low-cost direct transfer trip (DTT) versus substation transformer upgrades due to N-1 conditions or volt-var and volt-watt smart inverter settings, proactively providing multiple options within studies such as system downsizing options where high infrastructure upgrade costs may be identified, etc.

4. ADVANCING NEW FORMS OF BENEFICIAL ELECTRIFICATION AND DER

Central Hudson is a leader in New York State in advancing the electric grid, offering clean energy solutions and reducing greenhouse gas emissions. Central Hudson has taken a proactive role in preparing for the future of transportation electrification. Transportation electrification is poised to accelerate rapidly in the coming years to meet policy goals of lower greenhouse gas emissions and electrification targets. Central Hudson has also made significant strides in advancing clean heat technologies across its service territory, exceeding statewide targets and laying the groundwork for long-term electrification of building heating. With over 11,000 projects and 22,000 installed units, Central Hudson has achieved the

highest market penetration rate among all utility territories in the Clean Heat Program. This success was driven by leveraging a robust trade ally network, implementing targeted marketing and education campaigns, and collaborating with NYSEDA and the Joint Utilities to expand contractor training and consumer awareness.

Figure 2: Beneficial Electrification Key Facts



Central Hudson has achieved several key wins in supporting transportation electrification as well. The share of new model year light-duty vehicles in Central Hudson that are electric has grown from 1.3% in 2019 to 9.3% in 2024, indicating a growing EV presence in the market. Of the new electric vehicles, roughly 70% are full battery electric vehicles and 30% are Plug-in Hybrid Electric Vehicles (PHEV) in the two most recent years. Central Hudson's electric vehicle (EV) Portfolio of Programs empowers communities through hands-on education, outreach, and advisory services—positioning Central Hudson as a trusted EV advisor. With what has been learned over the past few years and this new strategic focus, Central Hudson is poised to progress in both aspects of the DER market at a rapid pace.

5. INVESTING IN INFRASTRUCTURE

Central Hudson plans its distribution system on a five-year forward timeframe and its transmission systems on a 10-year timeframe. Central Hudson's service territory continues to show an overall reduction in system peak, with only few areas showing load growth. Many circuits, substations, and local transmission areas are experiencing declining loads or have ample room for growth. However, there are some areas where traditional investment or non-wires alternative investment should be made to address load growth. With continuing low load growth, Central Hudson's Capital Investment Plans remain primarily focused on addressing infrastructure issues related to needed equipment replacement

or upgrades and on grid modernization efforts. In doing so, Central Hudson can leverage these investments to improve system reliability and resiliency, hosting capacity, and operating flexibility, all of which will enhance the functionality of the distribution system and position the Company for the continued growth of DERs in the service territory.

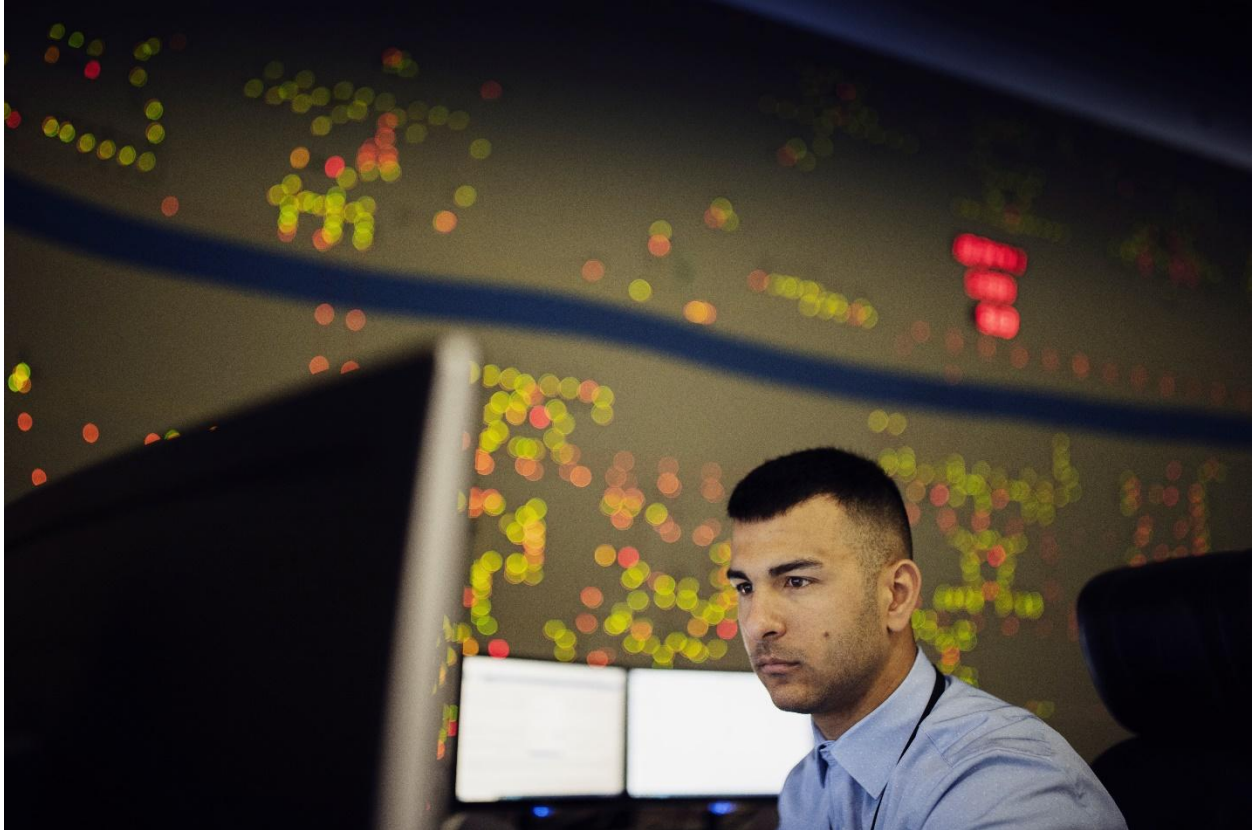
Finally, Central Hudson has completed an Advanced Metering Infrastructure (AMI) Benefit Cost Analysis and will be developing an AMI implementation plan, as discussed within this DSIP. The AMI BCA is included in this DSIP as Appendix B. It demonstrates cost-effectiveness utilizing the societal cost test.

6. ADVANCING NON-WIRE ALTERNATIVES

As for the areas where Central Hudson has seen system growth, these are being addressed by the implementation of Non-Wire Alternatives (NWA) as required by our Long-Range System Planning Process. Since the inception of its Non-Wire Alternative program, Central Hudson has identified and/or implemented three Non-Wire Alternative projects covering approximately 15% of load areas. Central Hudson currently has three NWA projects, located within Fishkill Plains/Shenandoah, the Northwest Corridor (i.e., Northwest 115/69, Northwest 69), and Merritt Park. As a result, T&D projects have been deferred for five, seven, and seven years, respectively, to date. However, Central Hudson is now quickly approaching a point where upgrades in these areas cannot be deferred for much longer. Moreover, this year's analysis shows one (1) new transmission area and four (4) new substation areas where DER may allow for the deferral of infrastructure investment. Central Hudson follows its standard process to model future loads and identifies potential candidates for non-wire alternatives based on the risk of potential overloads.

D. SUMMARY

In summary, since 2023, Central Hudson has made significant progress in the DSP through its individual efforts as well as the collective efforts of the Joint Utilities and in collaboration with DPS Staff and NYSERDA. The Company remains fully supportive of working with the stakeholders, the Commission, and the other utilities on improving data sharing through the Integrated Energy Data Resource and Data Access Framework. Additionally, Central Hudson strives to meet the objectives of the REV and the CLCPA in a cost-effective manner for all customers and with full transparency of all costs, including both supply and delivery.



II. PROGRESSING THE DISTRIBUTED SYSTEM PLATFORM

A. INTRODUCTION

This section provides a high-level summary of Central Hudson’s vision of the DSP, and the progress made in the areas of DER Integration, Market Services, and Information Sharing. This section also provides background information on the DSIP, and it describes actions and results from Central Hudson’s work with the Joint Utilities of New York,³ which is focused on establishing a robust and consistent state-wide DSP to integrate DERs in support of the state’s clean energy goals.

B. REGULATORY BACKGROUND

In its 2015 Reforming the Energy Vision Track One Order, the Public Service Commission began a transition from the model of a unidirectional electric system serving inelastic demand, to a new model of a grid that encompasses both sides of the utility meter and relies increasingly on distributed resources

³ The Joint Utilities include Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation.

and dynamic load management.⁴ To guide this transition of the utility model, the PSC defined a set of functions that are collectively called the Distributed System Platform. DSP functioning combines planning and operations with enabling markets.⁵ The Distributed System Implementation Plan is a vehicle by which Central Hudson and other utilities report progress toward implementing the DSP.

This is Central Hudson's fifth DSIP filing. It presents the Company's progress and plan to enhance the DSP's capabilities and responds to the 2023 DSIP whitepaper (2023 DSIP Guidance).⁶ Furthermore, this DSIP is enhanced by applying the findings and recommendations of the Retrospective DSIP Assessment contained in the March 31, 2025, First Iteration of the New York Grid of the Future Plan.⁷

As stated in the 2023 DSIP Guidance, the purpose of the DSIP filing is to:

1. Report on the utility's DSP implementation progress.
2. Describe in detail the utility's plans for implementing DSP-related policies, processes, resources, and standards, including any plans from the Coordinated Grid Planning Process (CGPP) that may be relevant to the DSP.
3. Identify and describe how to access the tools and information, including the new statewide IEDR Platform, that can be used by DER developers and other third parties to help them understand utility system needs and potential business opportunities.
4. Describe how the utility's DSP implementation efforts are organized and managed.⁸

Central Hudson developed this DSIP with these objectives in mind, which build from a set of goals that were established by the Commission when it defined the initial set of DSP-related objectives when it issued the Reforming the Energy Vision Track I Order in May of 2016. The six core REV goals were:

- Enhance Customer Knowledge and Tools;
- Animate the Marketplace;
- Improve System-Wide Efficiency;
- Increase Fuel and Resource Diversity;
- Enhance System Reliability and Resiliency; and
- Reduce Carbon Emissions.

Subsequent laws and regulatory initiatives built upon those goals. The Clean Energy Standard established a goal of achieving 50% clean energy by 2030 (later revised upward to 70%) and was followed by the

⁴ Case 14-M-0101, Proceeding on Motion of the PSC in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order).

⁵ Case 14-M-0101, *supra*, Track One Order, pp. 26-30.

⁶ Case 16-M-0411, In the Matter of Distributed System Implementation Plans ("DSIP Proceeding"), DPS Staff Whitepaper: Proposed PSC Guidance for the Electric Utilities' 2023 DSIP Update Filings ("2023 DSIP Guidance") (issued January 10, 2023).

⁷ Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, NYSEDA and DPS First Iteration of the Grid of the Future Plan (issued March 31, 2025).

⁸ *Ibid.*, p. 5.

2019 Climate Leadership & Community Protection Act which expanded upon state climate goals. In the case of the CLCPA, those expanded goals included an 85% reduction in Green House Gas (GHG) Emissions by 2050, 100% carbon-free electricity by 2040, and procurement of 3,000 MW of energy storage (later expanded to 6,000 MW)⁹ and 6,000 MW of solar (later expanded to 10,000 MW).¹⁰

The PSC’s introduction of the 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 integrating Local Transmission and Distribution studies with NYSEDA’s renewable generation and storage procurements.

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, starting with the 2023 DSIP, a greater emphasis has been placed on electrification and the identification of enabling investments and programs.

In April of 2024, the Commission initiated the Grid of the Future proceeding. The objective of the GOF proceeding, as described in the Instituting Order, is “to unlock innovation and investment to deploy flexible resources—such as distributed energy resources and virtual power plants (VPPs)—to achieve our clean energy goals at a manageable cost and at the highest levels of reliability.”¹¹

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

C. VISION

Central Hudson’s vision of the DSP is to facilitate the development of distributed energy resources through the three core DSP functions of DER integration, market services, and information sharing, so that its ongoing investments in grid technologies, advanced planning, and grid operations methods can empower communities and customers to actively manage their energy needs and participate in the marketplace, thus promoting affordability and the achievement of state policy goals.

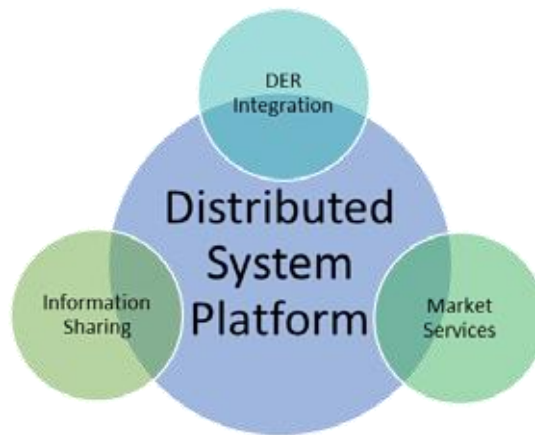
**Our Vision Remains Consistent
While DSP Functions Are Evolving**

⁹ This goal is now 6,000 MW after the June 20, 2024 Order Establishing Updated Energy Storage Goal and Deployment Policy.

¹⁰ In April 14, 2022, Governor Kathy Hochul announced that the Public Service Commission had approved a framework for the State to achieve at least 10,000 MW of distributed solar by 2030.

¹¹ Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Order Instituting Proceeding, p.3 (Issued April 18, 2024).

Figure 3: Core DSP Functions



While that overall vision remains the same since the 2023 DSIP, there have been changes in state and federal policy that will impact the way Central Hudson performs the core DSP functions. Accordingly, Central Hudson has incorporated those changes into its vision.

This kind of adjustment has been a continuous process for the Company. Starting with REV and through subsequent state policy initiatives, the Commission has been advancing an evolving set of goals for New York’s energy future that include enhancements to system efficiency, reliability and resilience, market animation, utility business models, customer empowerment, and greenhouse gas (GHG) emissions reduction. Central Hudson has continually strived to maintain a complementary vision for its role as DSP.

Central Hudson’s updated vision now incorporates four areas of greater focus that reflect such new or expanded initiatives – one in each of the core DSP functions of DER integration, market services, and information sharing, and a fourth reflecting a new, broader policy emphasis on how to facilitate electrification through investments in enabling technologies and utility capacities. The four areas are further elaborated within the table below.

Table 1: Core DSIP Functions and Vision

DSP Functions	Vision
DER Integration	Central Hudson’s long-term vision for the DSP is to achieve ever more seamless integration of DER into its system while continually evolving our planning process to preserve system safety and reliability and to maximize DER benefits for customers. As part of this, Central Hudson seeks to achieve greater integration with bulk system planning.
Information Sharing	Central Hudson’s vision for the information-sharing function of the DSP is to provide systems that measure, collect, analyze, manage, and display detailed customer energy usage and system data so that customers and other market participants can be empowered to make efficient, cost-effective market decisions.

DSP Functions	Vision
	Part of the information-sharing function is protecting customer privacy and security, which remains a core Company responsibility and an element of its vision. Central Hudson's vision in this area includes a focus on supporting NYERDA's implementation of its IEDR platform.
Market Services	As in years past, Central Hudson's DSP vision continues to be a future energy marketplace where competitive market signals play a greater role in achieving accurate pricing and compensation for distribution system value so that all participants can benefit from an efficient market. The objective is to incentivize the market to build and deliver resources at the right locations, in the right season, and at the right times. This vision includes supporting the NYISO in its efforts to provide new avenues for DER participation in wholesale markets.
Greater Focus on Electrification and Identification of Enabling Investments to Continue Progress on Clean Energy Goals Through Enhanced DSP Capabilities	While not directly related to one of the DSP's three core functions, our vision also includes an understanding that this company and all the utilities that function as DSPs have a critical role to play in achieving state policy goals by making enabling investments and delivering programs that help customers decarbonize their overall energy usage through distributed energy resources.

Given the expected growth across clean energy technologies, the Company has incorporated into its vision an understanding that enhanced flexibility in the distribution system – a longstanding focus of DSP enablement efforts – will be even more necessary to achieve CLCPA targets. In particular, the future grid will require enhanced flexibility to coordinate transmission system needs, given the likelihood that economic incentives will drive further bulk-level interconnections of utility-scale solar PV and wind and the continuing expansion of pathways for DER to participate in the wholesale market. As the link between the bulk power system and the end-user, the DSP will play a critical role in enabling the interconnection, integration, and reliable dispatch of all clean energy resources, with the goal of optimizing system and customer value. Future DSIPs will consider how the core DSP functions can best support the build-out of flexible services on a larger scale.

Core to Central Hudson's DSP vision is the goal of attaining clean energy targets at the lowest possible cost for customers. The long-term DSP vision is rooted in competitive market design that leverages the NYISO wholesale market and provides competitive pricing signals for distribution value. The sophistication and granularity of these distribution market pricing signals will grow as DER participation increases, technology advancements are adopted, and grid modernization technology is deployed. As these critical elements are implemented, the DSP market services will evolve from tariff- and procurement-based mechanisms to more competitive and cost-efficient market mechanisms.

D. DSP PROGRESS

This section presents the progress made toward implementing the DSP, firstly, through a discussion of Central Hudson's work in common with the Joint Utilities of New York and then later, through a discussion of recent progress specific to Central Hudson.

1. OVERALL PROGRESS IN COMMON WITH THE JOINT UTILITIES

The results of regulatory vision, state incentive support, stakeholder participation, and utility DSP enablement and program implementation are 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 of 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, the state has seen notable advances in all six original REV goals. The JU have, individually and collectively, through the IEDR Program, greatly enhanced customer knowledge and implemented programs that give customers more tools to control their bills. The profusion of DERs shows that New York has animated the market for advanced technologies and services. Enhanced planning across the transmission and distribution are growing in utility demand response, and other programs present opportunities to improve system-wide efficiency. The successes of the Clean Heat and EV programs are increasing fuel resource diversity. DSP-enabling grid management technologies like ADMS enhances system reliability and resiliency. And the growth of electrification and solar energy are reducing carbon emissions.

In summary, over the past ten years, Central Hudson has made significant progress in developing and enabling the DSP and, in tandem with its regulatory and market partners, have advanced toward its vision for New York's energy future. Central Hudson also recognizes that further work is needed to fully realize the goal of achieving an advanced DSP that empowers communities and customers, promotes affordability, supports the state's clean energy policy goals, and meets customers' and society's evolving needs.

¹² Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future ("Grid of the Future Order"), pp. 6-7, (Issued April 18, 2024).

2. RECENT PROGRESS ON DER INTEGRATION IN COMMON WITH THE JU

DER Integration encompasses the planning, operational, and infrastructural initiatives associated with implementing the DSP. This includes, but is not limited to, distribution system infrastructure upgrades, the evolution of planning methodologies, operational changes, and the general reduction of barriers to DER adoption. The goal of this aspect of the platform is to maintain safety and reliability in a higher DER penetration environment, enabling DERs to come onto the grid faster, cheaper, and with higher levels of visibility, allowing for greater provision of grid services and more access to value streams.

Prior to the outset of REV, utilities invested in technologies that could be considered foundational to the functioning of the DSP. At the time, planning methodologies and processes (including DER interconnection, forecasting, and capital investment planning) were calibrated to accommodate the prevailing level of DER market penetration and had not yet been aligned with REV goals regarding the enablement and management of a high-DER environment.

Since the 2023 DSIP, the Joint Utilities have continued to meet with stakeholders through numerous stakeholder engagement sessions. This includes, but is not limited to, the Interconnection Technical Working Group (ITWG), Interconnection Policy Working Group (IPWG), and Hosting Capacity Group. As these groups aim to streamline processes and enable higher DER deployment on the system, DSP enablement plans continue to evolve based on stakeholder priorities. From July 2023 through June 2025, Central Hudson with the Joint Utilities have implemented several key DER Integration initiatives, which are summarized in Table 2 below.

Table 2: JU Recent Actions and Results in DER Integration through June 2025

Actions		Results
Collaborated with members of the industry to provide a 2-year waiver for UL 1741 SB certification of EV chargers with vehicle-to-grid (V2G) capability.	→	Aligns certification timeline with market availability/ development of bi-directional EV chargers. The waiver expires in July 2025.
Collaborated with Electric Power Research Institute (EPRI) and inverter manufacturers to adopt the Common File Format (CFF). The JU initiated these conversations with EPRI in February 2023 and have had discussions with EPRI and Industry on this topic on an ongoing basis since then.	→	Adoption of the CFF will reduce the time required for utility engineers to review smart inverter settings for projects, which will in turn allow for faster DER interconnection times. Also, adoption of the CFF will make it easier for utilities and developers to share inverter settings with each other.
Provided developers with information on the JU's preferred charge and discharge schedules for battery storage in September 2023.	→	The alignment of the charge and discharge windows with the economic value streams and price signals will encourage greater adoption of Battery Energy Storage System (BESS) in the state.
Initiated discussions with Industry on the adoption of the UL 1741 CRD for Multimode systems in November 2023. The JU have had ongoing discussions with Industry on this topic and will add provisions relevant to the Certification Requirements Decision to the Standardized Interconnection Requirements (SIR) in the fall of 2025.	→	Clarifies the rules and interconnection procedures for DER systems capable of providing home backup (such as solar PV + storage and vehicle to grid (V2G) systems). The adoption of this rule will ensure that these systems do not pose a safety and reliability risk to utility personnel when there is a system outage.
Collaborated with Industry and DPS on updates to the NY SIR in 2023 and 2024.	→	Provides stakeholders with the latest guidance on UL 1741-SB certified inverters, storage schedules, and DER penetration screens, and will aid in improving the efficiency of the interconnection process.

3. RECENT PROGRESS ON MARKET SERVICES IN COMMON WITH THE JU

While the distributed system platform must perform multiple functions, a key focus of the Track One and Track Two Orders¹³ was evolving the New York market at the distribution level to allow DERs to bring value to the system and be compensated based on that value through enhanced market mechanisms. This has also been a major focus for the Joint Utilities over the past two years. In DSP 1.0, the goal of the market services aspect of the platform has been to provide DERs greater access to market value through

¹³ Case 14-M-0101, Proceeding on Motion of the PSC in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order).

Case 14-M-0101, Proceeding on Motion of the PSC in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (Track Two Order)

advances in the “3 P’s” (pricing, programs, and procurement), and the Joint Utilities have implemented steps in each of these areas to accomplish this goal.

Since the outset of REV, New York utilities have undertaken several key measures related to DER, including incorporating NWAs into distribution procurement processes, implementing VDER, and facilitating Community Distributed Generation programs. From July 2023 through June 2025, Central Hudson and the Joint Utilities have continued or expanded the implementation of several key market services initiatives, which are summarized in Table 3 below.

Table 3: Recent JU Actions and Results in Market Services through June 2025

Actions		Results
Continued implementation of non-wires alternatives projects. To date, Central Hudson’s active NWA projects account for approximately 25% of its service territory based on the percentage of load.	»»	Developing projects and portfolios of DER solutions that provide value to customers; streamlining the non-wires solicitation process across the Joint Utilities; more projects give opportunities to support/improve system reliability
Continued working closely with NYISO to develop and support the launch of the DER Market Participation Model, including refining the exchange of information related to registration, enrollment, operational coordination, and data exchanges providing input on draft NYISO manual revisions and resolving process concerns	»»	Provides opportunity for DER to access value for both distribution-level services and wholesale market to potentially reduce wholesale prices through increased competition
Implemented state-wide electric vehicle programs, including the Light Duty Vehicle (LDV) Make-Ready Program, Medium-Heavy Duty Vehicle Pilot, Direct Current Fast Charger (DCFC) Per Plug Incentive Program, Residential Managed Charging throughout 2023, 2024, and 2025.	»»	Removing upfront cost barriers to adoption through direct make-ready incentives and futureproofing, ongoing cost barriers to adoption through direct operating incentives, knowledge and technical barriers to adoption through fleet assessments and technical assistance, and soft cost barriers to adoption through ongoing coordination and stakeholder engagement
Expanded implementation of advanced customer programs for demand-side management (EE, Demand Response (DR)) and beneficial electrification.	»»	Allows for greater DER market participation and increases DSP flexibility to meet system needs
Continued implementation of compensation programs including Phase 2 Value Stack, remote crediting, remote net metering	»»	Provides an expanded set of market signals to DER about the locational and temporal value of operation and a wider array of compensation avenues

Actions		Results
Automated crediting and billing of Community Distributed Generation (CDG)	»»	Supports the widespread adoption of CDG projects and provides timely and accurate billing and compensation for Distributed Generators and retail customers. From 2020-2023, the number of VDER CDG project hosts in NY has more than doubled

4. RECENT PROGRESS ON INFORMATION SHARING IN COMMON WITH THE JU

Expanded access to more transparent, granular, and accessible data sources empowers retail consumers, developers, and other stakeholders to make smarter decisions in the planning, development, and operation of DERs. By providing insights into how to bring the right technologies and services to the right customers at the right time, DSP providers can advance information sharing as a fundamental DSP to create value for stakeholders across the DER ecosystem. At the inception of the REV process in 2014, information sharing was characterized by the provision of traditional downloadable datasets, aligned with developer needs at the time. Because DERs did not yet constitute a significant proportion of system load or capacity, the hosting capacity analysis methodology was still under development. Customer data privacy standards varied and were not yet calibrated to the needs of a growing market for distributed energy services.

From July 2023 through June 2025, the Joint Utilities implemented several key Information Sharing initiatives, which are summarized in Table 4 below.

Table 4: Recent JU Actions and Results in Information Sharing Through June 2025

Actions		Results
PV 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.	→	- Improved stakeholder visibility into specific hosting capacity limitations by clearly indicating whether constraints are driven by voltage, thermal, or protection factors. - Enhanced developer planning capabilities through the integration of Cost Share 2.0 indicators, effectively identifying areas where utility-driven upgrades significantly improved hosting capacity. - Facilitated detailed project feasibility analyses by linking 8760-hour feeder load profiles directly to the PV maps, enabling developers to access comprehensive hourly load data.

Actions		Results
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 back feed limits). - Integrated Cost Share 2.0 project indicators for storage hosting capacity. - Enabled Representational State Transfer Application Programming Interface access for automated data retrieval.	→	- Enhanced locational accuracy of hosting capacity analysis by transitioning from feeder-level summaries to detailed, sub-feeder (node-level) hosting capacity visualizations. - Improved decision-making transparency through the introduction of color-coded nodal visualizations, clearly depicting variations in hosting capacity across individual feeder segments. - Provided actionable insights via interactive pop-ups, explicitly detailing criteria violations at specific nodes, including voltage, thermal, and back feed limits.
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. - Integrated (EJ) area overlays to support equitable electrification planning. - Maintained feeder-level color-coding and breakpoints, ensuring continuity with previous EV maps.	→	- Broadened stakeholder decision-support by evolving the EV Load Hosting Capacity Maps into comprehensive Electrification Hosting Capacity Maps, aligning with regulatory orders and stakeholder inputs. - Improved seasonal planning precision through the addition of summer and winter peak hosting capacity views, directly responding to stakeholders' needs to understand seasonal impacts on capacity availability. - Advanced equitable planning processes by integrating Environmental Justice area overlays, explicitly highlighting hosting capacity status within disadvantaged communities and supporting targeted electrification investments. - Ensured continuity and familiarity for stakeholders by maintaining established feeder-level color-coding and breakpoints consistent with previous EV map versions.
Initiated the data transfer pipelines needed to provide multi-layered real-time energy data to the IEDR Platform. Worked in bi-weekly Utility Coordination Group (UCG) meetings, one-on-one meetings with the IEDR Development Team, and ad hoc strategy sessions throughout 2023, 2024, and 2025 to further automate the process and standardize update schedules.	→	Consolidated state-wide hosting capacity map (via NYSERDA's Energy Infrastructure Assessment Tool (EIAT)) in 2024, with additional map layers also introduced in 2024 to support various Phase 2 use cases, DER asset repository, and more accessible indices of utility tariffs.

Actions		Results
Implemented protections and developed relevant User Agreements to safeguard the data quality and integrity, cybersecurity, and privacy of data delivered to the IEDR platform in 2023 and 2024. Actively sought guidance from DPS on status of Data Access Implementation Plan submitted by utilities as part of the Data Access Framework (DAF) order throughout 2023 and 2024.	→	• NYSERDA filed Proposed IEDR User Agreements in May 2024, which address data quality and integrity standards, cybersecurity, privacy, and other requirements based on outdated filings/examples from the JU. JU filed responses in September 2024 to NYSERDA proposal outlining desired improvements and the need for this to be done within a larger DAF and consistent with DAF Order and related filings.
Enable streamlined access to standardized customer utility data • Worked throughout 2023, 2024, and 2025 to enable streamlined access to standardized customer utility data • Successful transfers of customer data sets to the IEDR • Appropriate mapping in place to advance implementation of IEDR Green Button Connect (GBC) functionality.	→	• Provided IEDR Team with all customer energy data at varying intervals (5-, 15-, and 60-min) in 2023 and 2024 • Implemented processes to deliver customer energy data usage going forward. • Streamlined access to standardized customer utility data and through GBC to accelerate the deployment of clean energy in communities throughout New York State. • Continued activities to support go-live for GBC in 2025.
Bulk Data Exchanges • Supported process improvements in 2023 and 2024 related to bulk data exchanges to guide the successful completion of Phase 1 Program Milestones for the IEDR Program. • Phase 1 was successfully completed in March 2024.	→	• Public release of Initial Public Version (IPV) and Minimum Viable Product (MVP) use cases by the IEDR Team and NYSERDA's announcement • Successful completion of Phase 1 in March 2024.
Quarterly IEDR Reports • Submitted quarterly IEDR reports since Q4 2021 to provide an update on the status of ongoing and planned projects and investments in support of the enablement of the IEDR. • These reports support transparency in process, progress, and investments by providing actionable updates on milestones and use case development.	→	• Reports submitted every quarter from 2023 to 2025 provide stakeholders with continued access to and transparency in progress, process, and investments.

5. RECENT DSP PROGRESS HIGHLIGHTS SPECIFIC TO CENTRAL HUDSON

In addition to working collaboratively with the JU on the common DSP advancements detailed above, Central Hudson has made considerable progress in many DSP areas specific to its service territory. Highlights from the period of July 2023 – June 2025 are described at a high level in the table below, and additional information on each of these can be found in the various sections of this report.

Table 5: DSP Progress from July 2023 to June 2025

Actions		Results	Related Core DSP Function(s)
Completed core Grid Modernization programs relating to Distribution Automation, Advanced Distribution Management System, Network Communications.	»»	Increased visibility and control of the distribution system to enhance reliability, including integration of DER. Foundation for 2025-2030 rollout of Conservation Voltage Reduction (CVR) capability across system.	DER Integration
Completed implementation of the new control center, and the Distributed Systems Operations (DSO).	»»	Modern and state-of-the-art control center and Distribution System Operation Center support dynamic grid operations.	DER Integration
Completed implementation of new Customer Information System (CIS) and CDG billing.	»»	Central Hudson's new Customer Information system is fully deployed and supports full market services billing for Energy Service Companies (ESCOs).	Market Services and Information Sharing
Completed AMI BCA Analysis and included as part of DSIP.	»»	With the transition to monthly billing and the analysis of other system and customer benefits, investment in AMI appears to be beneficial to customers, improving data sharing, allowing market transformation, and improving system operations.	DER Integration, Market Services, Information Sharing
Completed Development of Internal Forecasting Tool, ESRI GIS platform, and transition to CYME Load flow system.	»»	Increased capability to analyze system changes and scenario planning, as well as future support of interconnection studies.	DER Integration,
Implementation of Electrification and DER.	»»	The proactive implementation of EV, Clean Heat, Energy Efficiency, and solar programs has kept the Company on track to meet the goals of the Climate Leadership and Community Protection Act , achieving the most interconnected solar generation per customer and the highest penetration of heat pump installations in the state.	DER Integration, Market Services

E. INTEGRATED IMPLEMENTATION TIMELINE

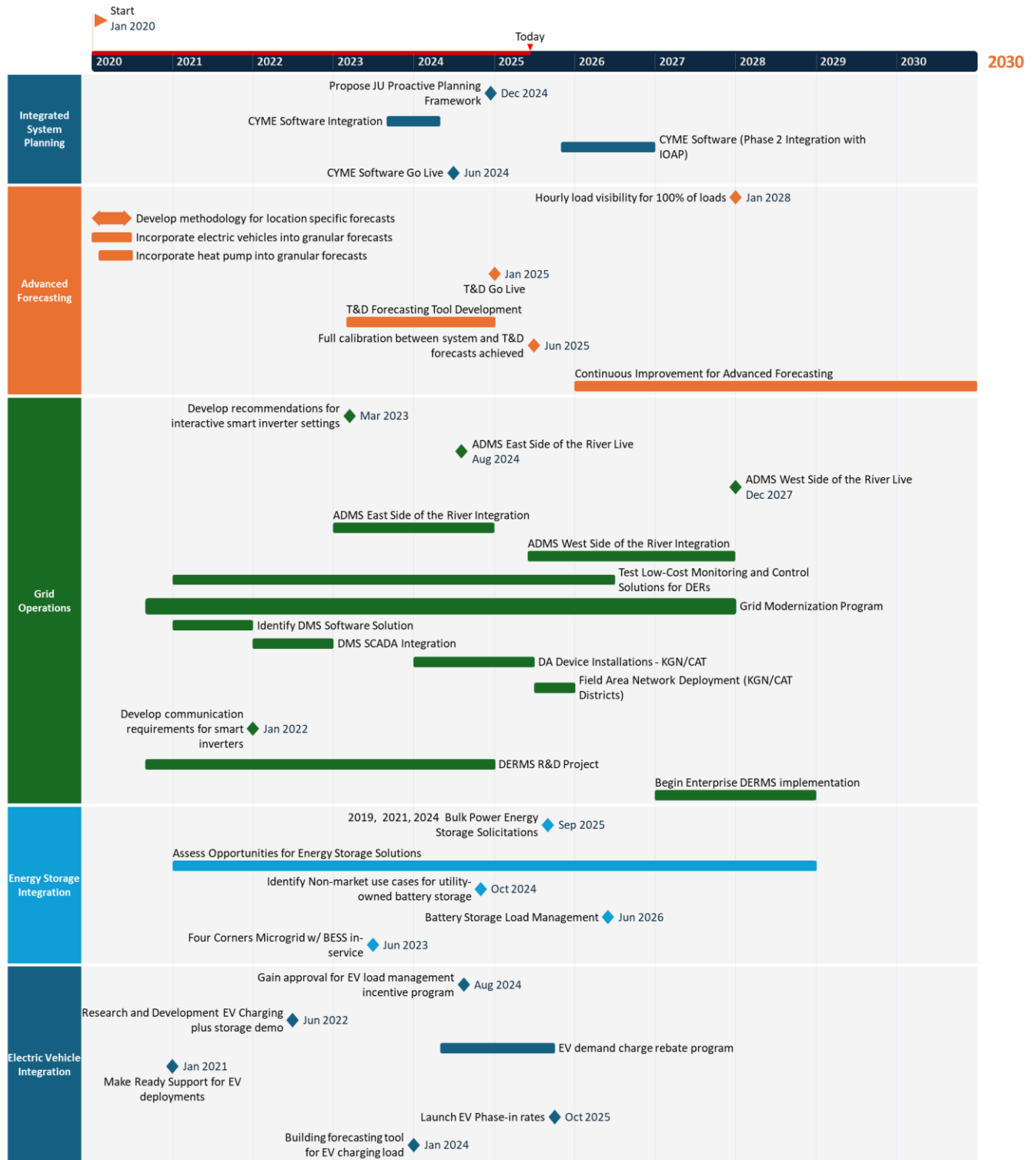
As discussed above, current progress toward the DSP has been significant, including progress made since the last DSIP was filed in 2023. Regarding grid operations, the Company is in the midst of a multi-year implementation of its foundational investments which include Distribution Automation, Distribution Management System, and Network Strategy communication backbone. Aligned with the completion of these investments has been the buildout and staffing of the new transmission and distribution operation center. Due to the complexity of managing and operating a distribution system with significant penetration of DERs and two-way power flows, the company has recognized the need to put in place new control center capabilities as well as develop the resources and the procedures necessary to

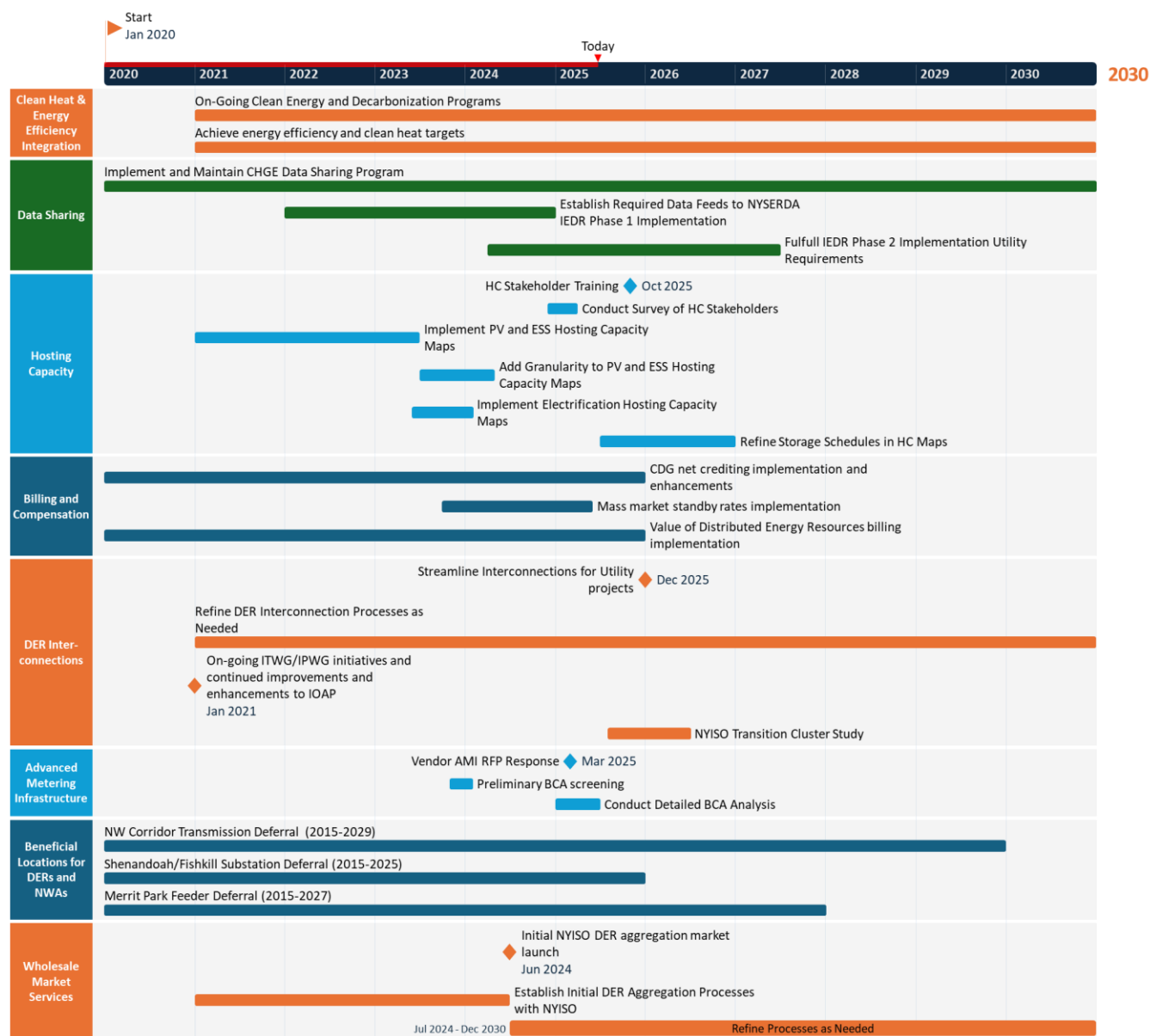
operate this much more dynamic and complex grid. Regarding integrated distribution planning, the company has put in place the DER forecasting capabilities and customer alternatives, including non-wire solicitations, described throughout this document. Regarding the integration of markets, the company has worked closely with the Joint Utilities in engaging with NYISO in its efforts to establish the DER Aggregation Market in New York. These collaborations have resulted in clear DER Aggregation processes, roles and responsibilities, and hand-offs between utilities and NYISO, and this information is now captured in published NYISO manuals. The Company has also implemented a range of customer programs related to beneficial electrification, energy efficiency, and demand response. Additionally, Central Hudson has implemented a new Customer Information System, which provides a modern and scalable platform that can support advancements in future billing and compensation options for DER.

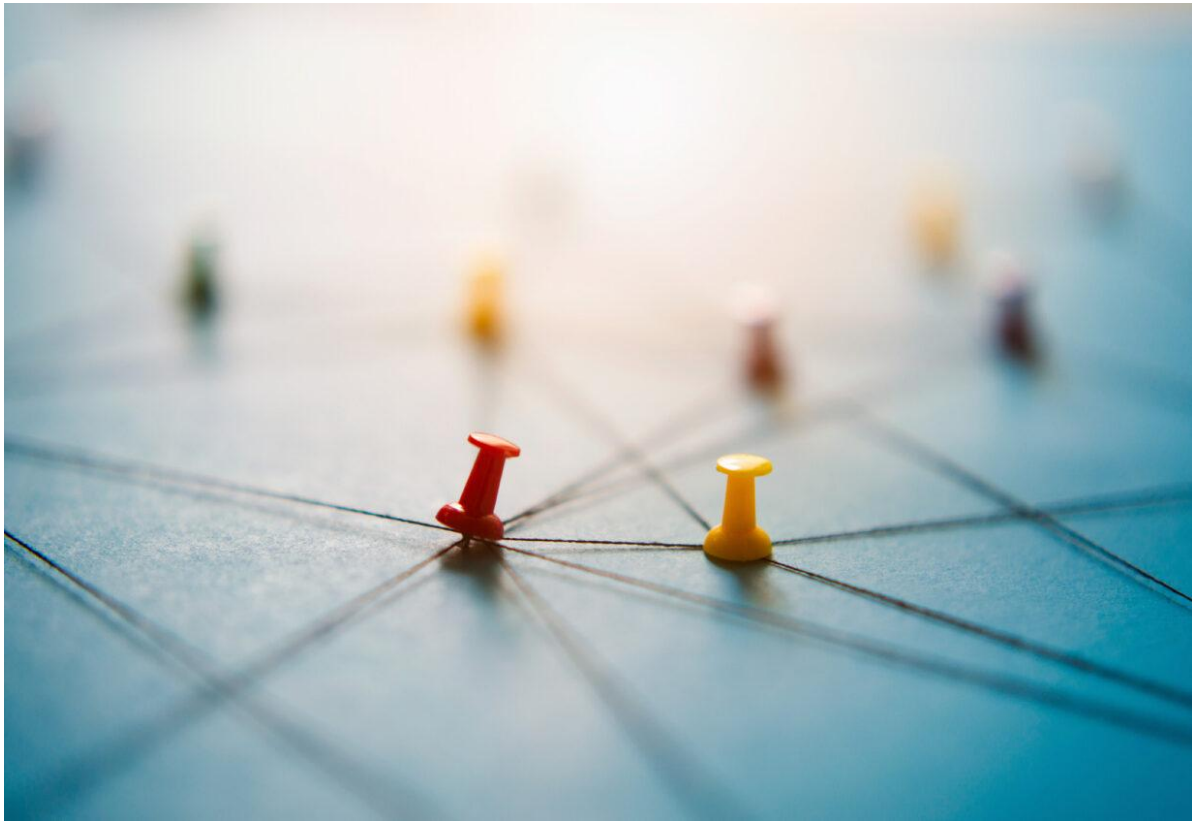
Refinements in all these areas will continue over the next five years, and as the DSP market evolves, there will be an added emphasis on implementing enabling actions, processes, and investments that build on the DSIP progress made to date and push forward toward offering customers additional behind-the-meter and front-of-the-meter flexible options, as envisioned by the Grid of the Future proceeding.

The 2023 DSIP Guidance calls for the DSIP to provide an integrated implementation timeline to be provided in a common format developed with the Joint Utilities. This timeline is presented below and further elaborated within the individual sections of this DSIP.

Figure 4: Grid Investments in Relation to Grid Functions







III. DSIP UPDATE TOPICAL SECTIONS

A. INTEGRATED PLANNING

1. KEY TAKEAWAYS

Central Hudson has continued to progress its integrated planning processes to integrate an increasing number and variety of DERs and electrification technologies while maintaining or improving the safety, reliability, quality, and affordability of electric service.

Since the 2023 DSIP, Central Hudson:

- Implemented a new distribution load flow software, CYME, which allows the engineering team to analyze more complex load flow scenarios, including smart inverters, time series analysis, and electrification impacts. The new software also allows for more efficient hosting capacity analysis.
- Implemented an automated probabilistic forecasting tool in 2024 that forecasts loads by grid level – local transmission, substation, and distribution feeder – and by load component, including native (gross) load, and the loads from solar, battery storage, heat pumps, electric vehicles and energy efficiency and codes and standards.
- Improved granularity for hosting capacity maps for solar and energy storage.

- Implemented a hosting capacity map for electrification to identify areas where heat pumps or EVs can be added.

Going forward, Central Hudson, plans to:

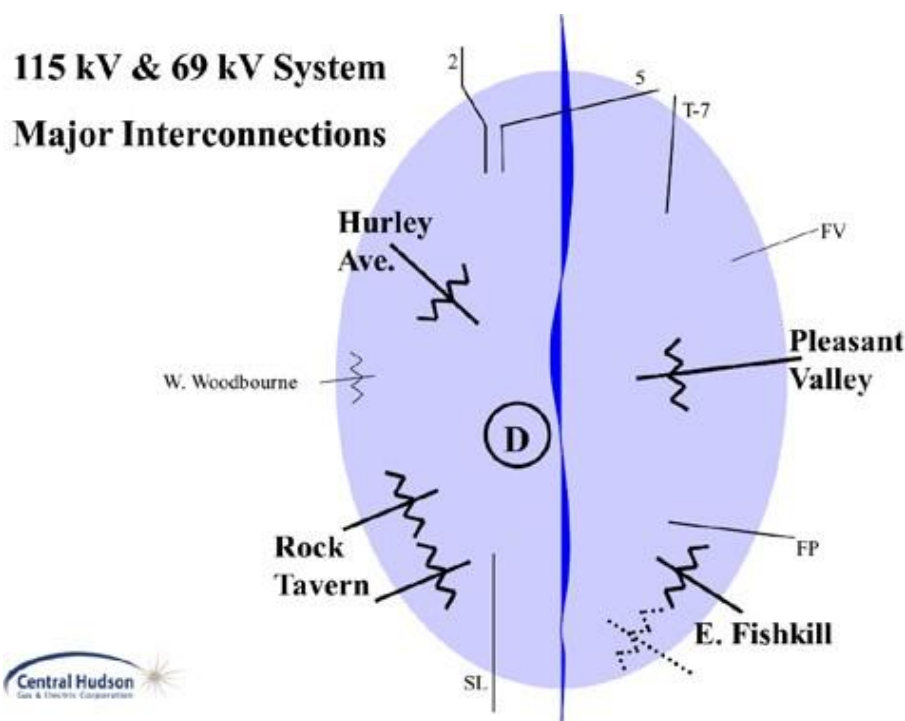
- Refine winter ratings for feeders;
- Develop and update the risk-based planning criteria;
- Investigate the feasibility of performing a granular building and transportation electrification load study to incorporate more granular, site-specific data; and
- Participate in the Commission's Proactive Planning Proceeding to work towards a coordinated approach to identifying the distribution and transmission system improvements that are necessary to address the emergent electrification needs of utility customers while supporting NY State's clean energy policy goals.

2. CONTEXT AND BACKGROUND

Central Hudson's service territory includes a total of 66 distribution load serving substations, 60 of which are fed from the transmission system, and approximately 272 circuit feeders. For planning purposes, substations are grouped into ten load areas, and most load transfers occur between substations and circuit feeders within the same load area. Central Hudson also operates and plans its interconnected transmission system within the service territory. There are a total of ten transmission areas, or load pockets, where transmission lines and generators affect power flow. During 2024, Central Hudson served approximately 270,000 electric residential customers and 46,000 electric non-residential customers. Combined, they were billed for 5,027 GWh of electricity and produced a peak demand of 1,103 MW.

Central Hudson's electric transmission system is tied to the bulk electric transmission system, which is owned and maintained by Central Hudson and other regulated and unregulated transmission owners, but are operated by the New York Independent System Operator primarily at the 345 kV voltage level. These interconnections are at four major substations, which are shown, along with the major 115 kV & 69 kV interconnections supplying Central Hudson's local electric transmission system, in Figure 5.

Figure 5: Major Interconnections



These interconnections also include connections to the transmission systems of National Grid, New York State Electric & Gas, Consolidated Edison, New York Power Authority, Orange and Rockland Utilities, Eversource, and NY Transco. The main criterion describing the capability of the transmission system is System Load Serving Capability (LSC). The determination of LSC includes consideration of facility outages while maintaining flows and voltages within appropriate limits. Currently, Central Hudson's System LSC is 1,470 MW¹⁴. In comparison, Central Hudson's all-time peak load was 1,295 MW, which occurred on August 2, 2006, and the current forecasted peak in 2030 is 1,116 MW.

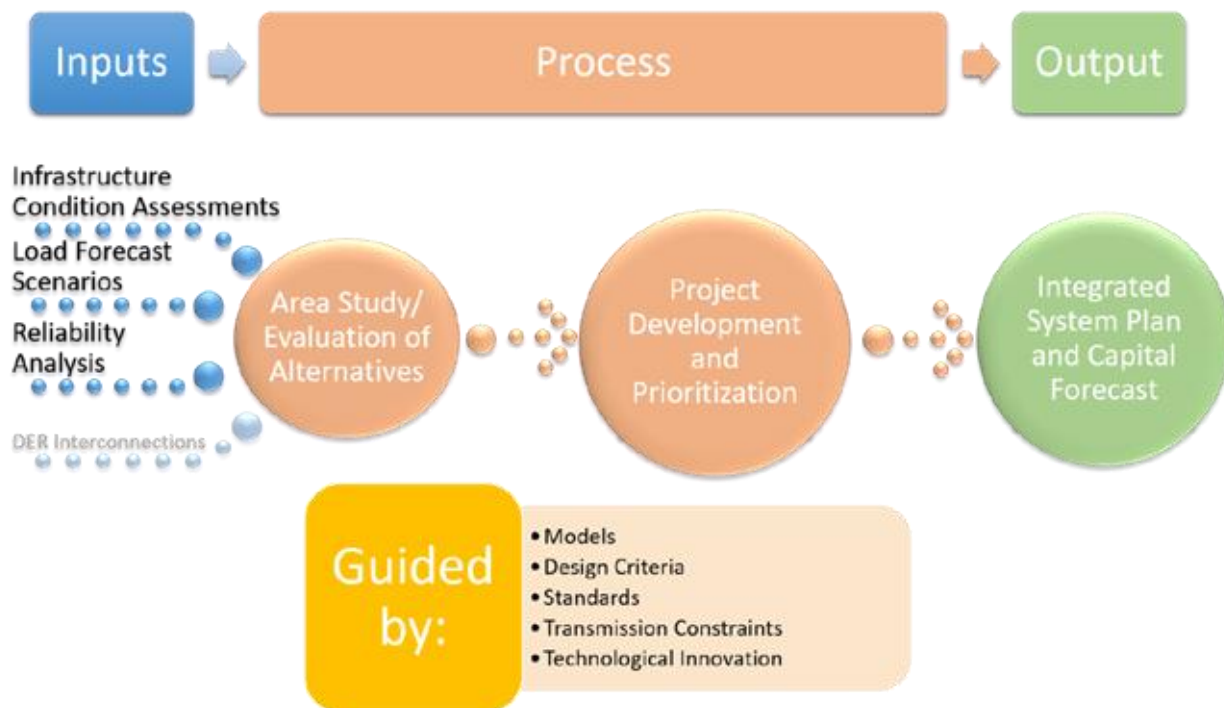
The transmission and substation systems provide the backbone of the distribution system, which includes all assets outside the substation fence operating at 34.5 kV and below. Central Hudson sometimes utilizes load transfers within the distribution system to manage substation and transmission infrastructure or operational and thermal constraints. Therefore, the integrated planning process includes both transmission and distribution components, as well as distributed energy resources.

The System Planning function at Central Hudson serves customers well by planning a safe and reliable electric system while moderating cost pressures. System planning is accomplished by leveraging system knowledge, forecasting, models, new technologies, and innovation to continuously enhance reliability, improve customer satisfaction, and support design, construction, and operations within the utility. Along with sound maintenance processes and programs, the primary outputs of the planning process are the Integrated Long Range Electric System Plan (Appendix F) and Capital Investment Forecast.

¹⁴ Based on the 115 kV East Fishkill – Shenandoah EF line at Summer Long Term Emergency (LTE) Rating following the loss of the 115 kV Pleasant Valley - Manchester M Line with no internal generation.

Figure 6 illustrates how the current components of the Integrated Distribution System Planning process at Central Hudson work together, and this process is summarized below. More details regarding specific components of the process can be found in Central Hudson Gas & Electric's Electric System Planning Guides.

Figure 6: Integrated Distribution System Planning Process



1) Inputs

Inputs to the planning process are described below:

1. **Infrastructure Condition Assessment.** Central Hudson complies with the *Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Granting in Part Petition to Modify Electric Safety Standards (Electric Safety Standards Order)*,¹⁵ identifying and addressing infrastructure concerns that arise through the transmission and distribution system inspection process. Additional thermographic inspections are also completed on an annual basis for substations and the distribution system. An inspection and testing schedule is also followed for each substation asset. As a result of these inspections and additional comprehensive condition assessments of transmission and distribution infrastructure, the Electric Long Range System Plan was developed (see Appendix F) to manage replacement programs associated with individual asset classes. Failing equipment trends are also considered. As any

¹⁵ Case 04-M-0159, *Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Granting in Part Petition to Modify Electric Safety Standards* (issued January 13, 2015).

major components are scheduled for replacement from a transmission, substation, or distribution perspective, an integrated plan is developed considering items such as:

- Remaining life/condition of other assets in the substation;
- Environmental, land use, accessibility, and right-of-way status;
- Distribution and substation modernization program needs;
- Forecasted load in the area;
- Safety, reliability, and power quality considerations;
- Anticipated new customers, DERs, and electrification technologies, including improvement in hosting capacity;
- Current standards;
- Transmission constraints; and
- Other scheduled projects in the same vicinity.

- 2. Load Forecast Scenarios.** The load forecast for the area being studied is a key driver of the process, not only for projects driven by load growth but also for the efficient sizing and design of infrastructure and reliability-based projects for the long term. In 2023, Central Hudson commissioned the development of a T&D forecasting tool, which was fully developed and has been operating on Central Hudson servers and has been accessible to planners since the Fall of 2024. The tool delivers an integrated forecast with all the key building blocks for distribution planning loads: the econometric forecast of existing loads, electric vehicles, building electrification, solar, storage, incremental energy efficiency, and Codes & Standards. It is built around modules for historical loads, forecasted loads, DER and electrification penetration, and scenario planning and T&D deferral. The granular forecasts are available by forecast scenario, year, season, and hour at various grid levels – territory-wide, transmission areas, substations, and distribution feeders.
- 3. Reliability Analysis.** Central Hudson maintains reliability criteria for the planning and operation of its electric transmission and distribution systems. For the transmission system (voltages greater than 34.5kV), these criteria are documented in internal Central Hudson guidelines and within applicable external regulatory body documents/guidelines. These documents include the following: Central Hudson's Transmission Planning Guidelines, the Northeast Power Coordination Council Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System, New York State Reliability Council – Reliability Rules & Compliance Manual For Planning and Operating the New York State Power System, and North American Electric Reliability Corporation (NERC) Standard TPL-001-5.1 – Transmission System Planning Performance Requirements. The Company's distribution system reliability planning criteria are outlined within the Central Hudson Gas & Electric's Electric System Planning Guides and reflected in these DSIP filings. Analysis is completed based on these criteria, and if the criteria are not met, project alternatives are evaluated as part of the Integrated Planning Process.
- 4. DER Interconnections.** Proposed DER interconnections are reviewed by the Electric Planning and Interconnections department, with ongoing project construction due to DERs considered part of the current Integrated Planning Process. Infrastructure projects that also provide an opportunity to increase hosting capacity are considered in the Capital Investment Plan. Additionally, DER and

electrification technology forecasts at the distribution feeder, substation, and transmission levels have been developed separately from existing loads to further integrate DERs and electrification into the planning process.

a) Process

Central Hudson's integrated planning process relies on local system knowledge and experience. It includes an evaluation of project alternatives, the age and condition of the infrastructure, and assessing electric service reliability. Depending on the extent of additional considerations, the process can range from an informal meeting with appropriate stakeholders to a formal, comprehensive Area Study. Ultimately, the process results in recommendations to maintain and improve service reliability and support the capital budget plan. Projects are prioritized based on the Capital Prioritization Guidelines¹⁶.

While Central Hudson's electric capital plan is predominately comprised of condition-based infrastructure-type projects, several of these existing projects also provide incremental headroom capacity benefits. As new project needs are studied, renewable penetration levels, forecasted electrification, and potential headroom capacity improvements are included in the analysis to determine the recommended solution. In support of New York's renewable energy goals, DER and electrification are currently included as an important criterion within the capital prioritization plans. Central Hudson has continued to evolve its planning and prioritization process to further integrate DER and electrification scenarios. Since the 2020 DSIP, this has included identifying capital projects as Phase 1 or Phase 2 Local Transmission projects. Phase 1 Local Transmission projects are capital projects that satisfy reliability, safety, and compliance while addressing bottlenecks or constraints limiting renewable energy delivery. These projects are funded as part of the utility's traditional capital plan. Phase 2 Local Transmission projects (also known as Climate Leadership and Community Protection Act Eligible Projects) are capital projects that are not currently in the utility's capital plans and increase hosting capacity on the local transmission (and distribution) system. These projects are funded under a Federal Energy Regulatory Commission (FERC) formula rate in the NYISO Tariff and are regionally cost allocated through a voluntary Cost Sharing and Recovery Agreement filed at FERC.¹⁷ Going forward, Phase 1 projects will continue to be identified as part of the current system planning and capital forecast processes, while Phase 2 Local Transmission projects (CLCPA Eligible Projects) will be identified as part of the Coordinated Grid Planning Process to facilitate the attainment of NY State's renewable energy goals.

b) Supporting Tasks

In addition to completing the planning process, the key tasks that are a part of the current Electric Distribution Planning function include:

- Establishing and maintaining design and operating criteria to minimize risk and plan for a safe and reliable system;

¹⁶ Ibid, Appendix G.

¹⁷ FERC Docket Nos. ER22-2152, et al., Order Accepting Proposed Cost Sharing and Recovery Agreement, Rate Schedule, Tariff Revisions, and Certificates of Concurrence (issued August 19, 2022).

- Performing analysis of reliability and power quality data and leveraging the use of new technology to continuously improve the T&D systems;
- Developing an asset inspection, repair, and replacement program;
- Complying with all federal, state, and local codes, standards, and regulations;
- Maintaining relationships with local DER developers and municipal officials to stay abreast of and support new residential and commercial economic development;
- Preparing, maintaining, and analyzing electric system models to ensure compliance with voltage, thermal, protection, and reliability standards;
- Forecasting demand and energy growth at the system level and apportioning demand growth into more granular load growth areas, including feeders, substations, and transmission areas;
- Evaluating DER applications and determining what system upgrades will be required to facilitate interconnection; and
- Developing a capital forecast and identifying where a Locational System Relief Value (LSRV) or a non-wires alternative may be considered based on suitability criteria.

2) *Outputs*

After prioritizing projects, they are incorporated into the annual Capital Forecast, and non-wires alternative(s) are pursued as required under our current guidelines. Additionally, system-wide asset management and capital plans are documented in the Long-Range Electric System Plan (Appendix F).

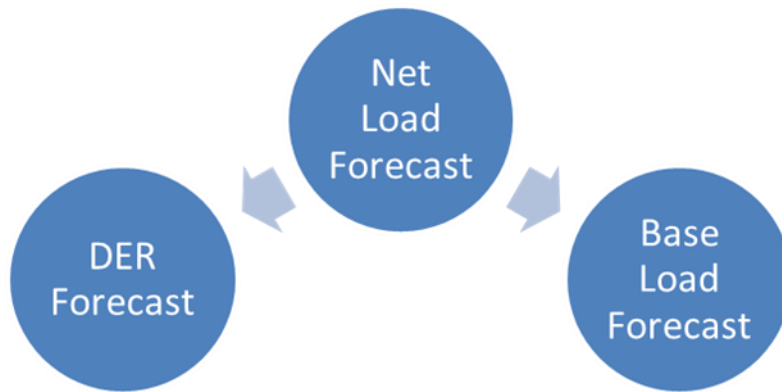
3. IMPLEMENTATION PLAN

1) *Current Progress*

Central Hudson has continued to progress its integrated planning processes to integrate an increasing number and variety of DERs and electrification technologies while maintaining or improving the safety, reliability, quality, and affordability of electric service.

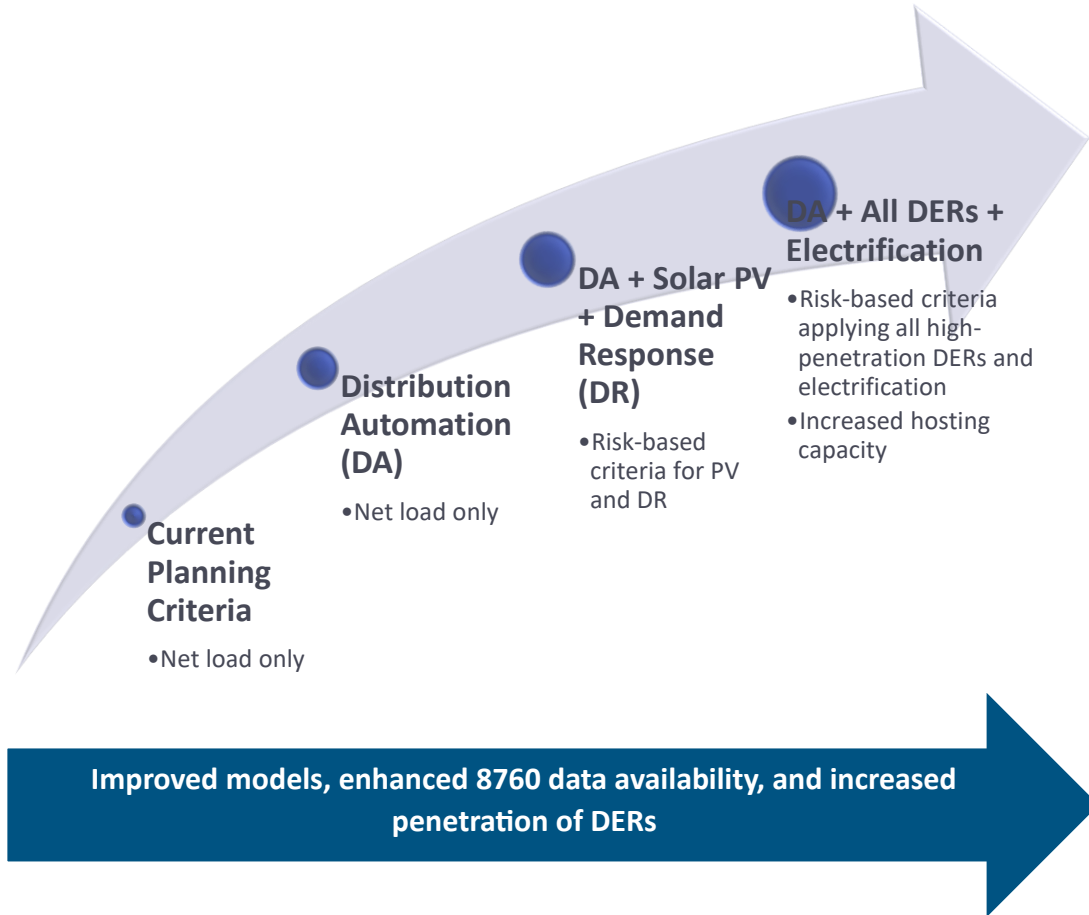
Central Hudson utilizes a T&D System Planning process to incorporate probabilistic and more granular elements. While in the past a net load forecast was sufficient for planning, the forecast going forward is separated into various categories of DER and a base load inclusive of transportation electrification, building heat electrification, behind the meter solar, behind the meter energy storage, energy efficiency measures, and changes to building and appliance codes and standards impacting customer electric loads the industry as shown in Figure 7.

Figure 7: Forecasts Separate DERs, Electrification, and Base (Gross) Loads



As part of utilizing a probabilistic approach, when an area of need is identified through traditional planning methodology, base load, DER, and electrification forecasts are now developed with separate scenarios for each. DER and electrification forecasts consider not only technical drivers of load shapes, but also current and anticipated policy decisions and interconnection queues that will impact the penetration of DERs. Although interconnection studies consider the impact of individual DERs, smaller distributed generation and energy storage systems are not scrutinized as closely and are included in the forecasted load. Their aggregate impact over time is still important to consider in both planning as well as informing the interconnection process. The separation of gross and net load is currently being used for certain applications where it is appropriate for accurate results. This includes hosting capacity analysis, DER integration studies where DER interconnected penetration levels are high, as well as substation load forecasts. This information is applied to understand the system needs, and scenario needs, and to develop alternatives and recommended solutions. To apply the DER forecasts that were developed on a widespread basis, the T&D Design criteria used to assess needs will require updates. Figure 8 shows this evolution.

Figure 8: Evolution of T&D Planning Criteria



Since the initial DSIP filing in 2016, the Company has progressed in transitioning to a more integrated planning process. Historically, Central Hudson applied a deterministic approach to developing a peak load forecast. In 2023, Central Hudson engaged a vendor to deliver a robust probabilistic load forecasting tool (see Advanced Forecasting) that can be utilized by both external consultants as well as internal Central Hudson employees. The T&D Forecasting Tool has been fully developed and operating on Central Hudson servers since the fall of 2024. It is accessible to all Central Hudson transmission and distribution planners and additional staff as needed. This in-house tool was utilized for the development of this 2025 DSIP filing. The tool delivers an integrated forecast with all the key building blocks for distribution planning loads: the econometric forecast of existing loads, electric vehicles, building electrification, solar, storage, and incremental energy efficiency and Codes & Standards. It is built around modules for historical loads, forecasted loads, DER and electrification penetration. The granular forecasts are available by forecast scenario, year, season, and hour at various grid levels – territory-wide, transmission areas, substations, and distribution feeders. The tool also includes a scenario planning and T&D deferral module, providing planners the ability to analyze lump loads, load transfers, and load relief options and develop deferral value analysis for potential NWAs down to the individual circuit level. It was designed to provide a better user interface, dashboards, and interactive tables to enable further integration into planning. As forecasting large lump loads is difficult, the tool allows engineers to incorporate large lump loads as necessary to appropriately identify the most cost-effective capital solutions that serve current

and future needs. This process helps quantify the deferral value of capital projects where current infrastructure cannot accommodate the added new load and helps planners assess if combinations of load relief and load transfers can be used to potentially defer upgrades. To further integrate DERs into the planning process, in 2023, the Electric Planning and Interconnections team began revising processes by developing a methodology to identify native load at the substation level. The team analyzed the generation output of larger interconnections at the point of interconnection via the electronic recloser, and established curves for each location by operating district. The Company then established an output percentage that was applied across all solar interconnections at the substation level and ultimately added back to the substation load to establish a native load during peak. Central Hudson has continued to refine this process and gather additional data.

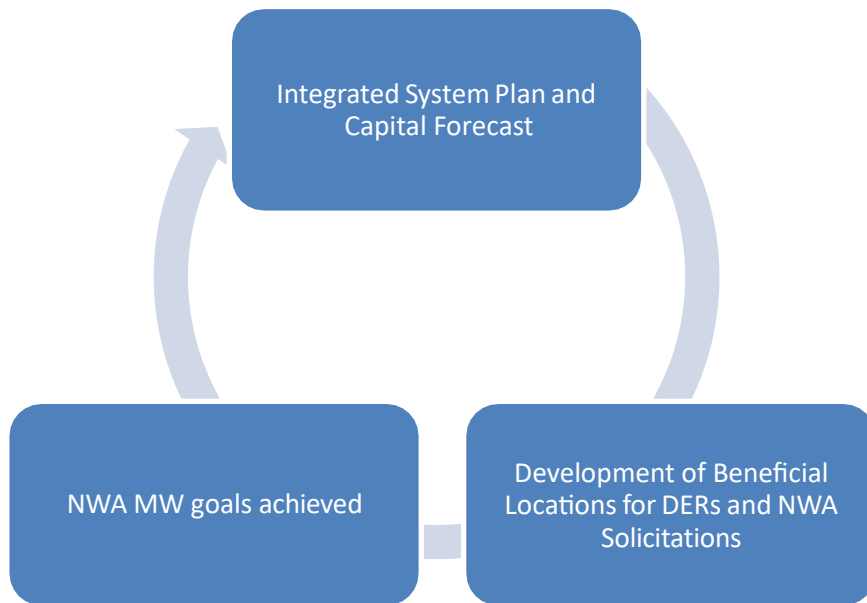
In 2024, Central Hudson implemented a new distribution load flow software, CYME, which allows the engineering team to analyze more complex load flow scenarios, including smart inverters, time series analysis, and electrification impacts. The new software also allows for more efficient hosting capacity analysis. Additionally, Central Hudson plans to implement a Phase 2 Integration with the Company's Interconnection Online Application Portal, with scoping anticipated to commence in the second half of 2025 and implementation in 2026.

While the overall planning process tends to focus on longer-term system needs, both Planners and Electric Operations Engineers are responsible for reviewing near-term requirements of new service requests for individual spot loads. Electric Planning and Interconnections utilizes EPRI's Distribution Resource Integration and Value Estimation tool to assist with the planning and integration of DER, such as solar and energy storage, along with mapping the capacity for electrification technologies such as heat pumps and EVs. Additional information on EPRI's DRIVE tool and the current Hosting Capacity Maps can be found in the Hosting Capacity section.

As further described in the Stakeholder Interface section, Central Hudson engages stakeholders in its planning process through a variety of methods to support their current and future needs. For example, stakeholders can provide direct feedback on capital plans and expenditures identified within the planning process as part of the Company's rate case proceedings. Stakeholders also have access to 8760 load data, where available, and NWA solicitations. Further, Central Hudson seeks to increase hosting capacity within current plans as part of the current planning process and pursuant to Cost Share 2.0 requirements. When there is sufficient time within the design stage, Central Hudson solicits interest from DER developers to identify opportunities to upsize investment upgrades, such as transformers, as part of its capital plan.

However, the planning process does not end with the development of a capital plan. As illustrated in Figure 9, the planning process also results in identifying beneficial locations for DERs and potential solicitations for NWAs to defer or eliminate the need for some of the identified capital investments. A beneficial location is an area identified as a potential candidate for an NWA project but that still needs to undergo a more detailed engineering and load relief potential assessment.

Figure 9: Capital Forecast development with NWAs



The Company continues to enhance its processes as it gains experience with and evaluates the results from existing NWA projects.

2) Future Implementation and Planning

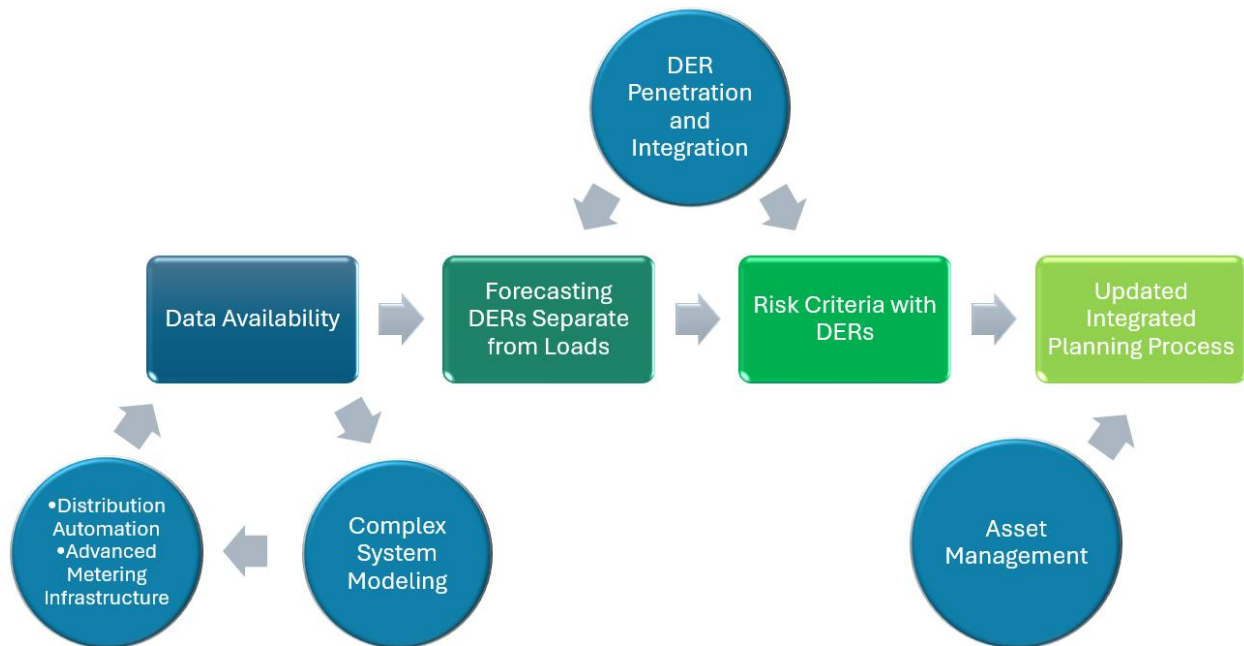
As with current implementation, improvements to data, modeling software, and further integration of DERs into the planning process will provide the ability to identify and address system requirements that consider customer and stakeholder needs. Operating Criteria will need to evolve to integrate foundational investments (i.e., DA and DMS) and DA rollout will continue. This is discussed further in Grid Operations and will continue to improve as the ESRI platform, DMS, and system planning tools become more tightly integrated. While Central Hudson has made significant progress within the Integrated System Planning process since the original 2016 DSIP, some of the remaining gaps in today's Integrated Planning Process include developing risk-based criteria for DERs as well as low-cost monitoring for systems <500kW, which are currently in progress. Additionally, the Company is working on establishing winter ratings for feeders, improving utilization factors for substation transformers and feeders, pursuing a granular load study to incorporate more granular, site-specific data, and continuing to engage in the CGPP. While the Company is reviewing the business case for AMI, investments in AMI technology may improve existing planning functions and processes by providing the ability to timelier analyze data and provide access to even more granular and location-specific data. This may require additional investments in software/vendor solutions for planning engineers to leverage AMI data. Refer to the Advanced Metering Infrastructure section for more details on Central Hudson's current business case for AMI investments. Table 6 summarizes Central Hudson's progress to date and the remaining gaps. Additional discussion of the Proactive Planning and CGPPs is included below. Table 6 illustrates the interdependence of these future items.

Table 6: Integrated System Planning Gaps

Action Item	Task	Currently in place / Implemented	Anticipated Completion
Improve 8760 Data Availability	Load (Substation Head-End Metering)	97%	99% by 2026 100% by 2028
	Solar	> 500 kW monitoring and control Smart inverter availability	< 500 kW low-cost monitoring by 2026
	Battery Storage	> 500 kW monitoring and control Smart inverter availability	< 500 kW low-cost monitoring by 2026
	Electric vehicles	NREL EV Lite Pro Shapes	Granular load study 2026 (pending regulatory approval)
	Building electrification	NREL ComStock and ResStock Load Profiles (County level)	No update expected
	Energy Efficiency and Codes & Standards	NREL ComStock and ResStock Load Profiles (County level)	No update expected
Develop Substation Level Probabilistic Forecasting by Load / Generation Type	Loads, solar, battery storage, efficiency, electric vehicles, and building electrification	Automated T&D Forecasting Tool with vendor and in-house capability	
	NYISO Market considerations	✓	
	Integrate into planning processes	✓	
Improve System Modeling Capabilities	Improve 8760 modeling capabilities	✓	
	Improve model based upon real-time DMS data	Ongoing	
	Integrate T&D constraints	✓	
	Leverage AMI data		Future, pending approval
Improve Asset Management and Reliability Analysis	Maintain Cascade for Distribution Assets	Ongoing	
	Leverage analytical tools along with mapping features	✓	
Develop Risk-Based Planning Design Criteria	Solar PV, Energy Efficiency and Demand Response		2026
	Battery Storage		2026
	Electric Vehicles		2026
	Building electrification		2026
	Scenario Planning		2026
	Other DERs		As needed

Action Item	Task	Currently in place / Implemented	Anticipated Completion
Integrate DER Interconnections	Maintain Technical Guidelines	Ongoing	
	Complete Hosting Capacity Roadmap	Ongoing	
Update Integrated Planning Process	Incorporated Risk-Based Planning Criteria		2026
	Establish Winter Ratings for Feeders		2026
	Improve Substation/Feeder Utilization Factors		2026

Figure 10: Interdependency of Planning Process Roadmap Items



a) Proactive Planning

Central Hudson is participating in the Commission’s Proactive Planning Proceeding. Together with the other Joint Utilities, in December 2024, the Company proposed a long-term Proactive Planning Framework to support transportation, building, and industrial electrification, as well as economic development. As proposed, the coordinated approach will help to identify the distribution and transmission system improvements that are necessary to address the emergent electrification needs of utility customers while supporting NY State’s clean energy policy goals. The proposed Proactive Planning Framework includes the following stages:

- **Stage 1: Load Assessment:** The utilities will align assumptions and approaches, to the extent feasible, for identifying grid impacts specific to the Proactive Planning proceeding. The process will be iterative and allow Central Hudson to incorporate immediate and long-term customer

needs, new data sources, and lessons learned. The Load Assessment stage would rely on Central Hudson's traditional granular electric forecast, NYISO-level forecasts, and customer information, but also bottom-up projections of granular electric demands that incorporate location-specific data to provide increased precision in understanding localized grid needs.

- **Stage 2: Planning and Solution Design:** The utilities will evaluate potential impacts from the load assessments and initiate planning activities to adjust existing plans or design solutions to address grid infrastructure needs accordingly. Each utility will evaluate the impacts of the forecasted load using its existing planning procedures and tools to identify constraints on its respective electric system including, but not limited to, transmission load areas and substations, distribution substations, distribution networks, and radial areas, and more concentrated localized load pockets such as at the individual customer level.
- **Stage 3: Project Eligibility and Prioritization:** The utilities will evaluate the solutions against Proactive Planning Project Eligibility Criteria to demonstrate eligibility to be considered in the Proactive Planning proceeding.
- **Stage 4: Proposal and Project Authorization:** Once prioritized, the utilities proposed a two-category approach for project proposal and authorization. Projects that fall into the Large Project category would have an annual filing opportunity, while projects in the Small Project category would be encompassed in a two-year budget.

Central Hudson currently accounts for electric transportation and building electrification loads in its probabilistic forecast, which includes a scenario aligned with the NYISO Gold Book Forecast. Central Hudson also incorporates customer-driven requests and publicly available data, such as vehicle registration data and Clean Heat Program information. While probabilistic forecasts are useful, certain large loads, such as large DCFC charging stations or large distribution-spot-connected loads, can fundamentally alter forecasts and planning.

Central Hudson has not yet conducted a comprehensive bottom-up, granular load study to incorporate customer site or location-specific load curves and expectations specifically for DCFC and potential electrification scenarios. A key limitation has been the lack of certain customer-specific data, including AMI and telematics data, particularly for medium- and heavy-duty vehicles. A granular load study would provide increased precision in understanding localized needs within a specific area of the Company's electric system, which may be necessary to support charging infrastructure for medium- and heavy-duty vehicles at their parked locations as well as the high-traffic corridors throughout the service territory. In its place, Central Hudson would use additional customer-specific information and other data sources that provide enhanced visibility of future customer demands in a specific geography. Central Hudson anticipates incurring additional costs to conduct granular load studies and has requested cost recovery through the Proactive Planning proceeding.

b) Coordinated Grid Planning Process

The CGPP and DSIP are filings with overlapping but distinct scopes. The CGPP involves the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes the implementation of the much broader set of DSP activities and projects and how those activities holistically align with CGPP and CLCPA goals. The CGPP identifies local transmission and distribution system needs to meet CLCPA State goals and develops

local transmission and distribution investment plans, including capital projects, to meet those needs. Planned capital investments, including technology platform investments and how they will be leveraged, will be included in the DSIP (e.g., AMI, automation, ADMS, etc.), and the results of executing the processes will be used to inform the CGPP.

The CGPP is aimed at implementing a “CLCPA-focused planning process,” including “the State’s bulk transmission, local transmission, and distribution planning processes.” The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO’s bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution and bulk system studies with NYSERDA’s renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on Local Transmission and Distribution and the bulk transmission grid. As part of the CGPP phases, one of the key inputs to the CGPP is the generation of build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects, once approved, will be incorporated and used to inform the normal DSIP and planning processes. As of this DSIP writing, the CGPP is currently in Stage 3 (Local Assessment) of the 6 Stage process.

Additionally, with the introduction of FERC Order 1920 (Order 1920) related to long-term transmission planning, Central Hudson is currently working and will continue to work with the Transmission Owners and NYISO to address and implement the requirements within the Order 1920, including right sizing principles. Part of this includes active discussions with stakeholders, including DPS Staff to identify the interactions and relationship between CGPP and Order 1920. Order 1920 regional filing is due April 30, 2026, and the interregional filing is due June 14, 2027.

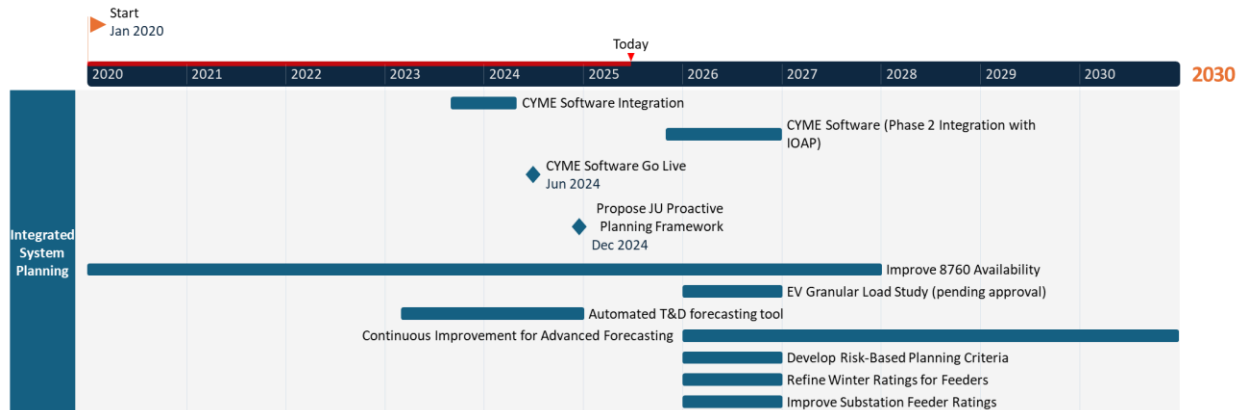
c) Modifying the Distribution Planning Criteria

Central Hudson is currently developing changes to its design criteria to provide increased utilization of existing assets at both the distribution feeder and the substation. The increased visibility into the distribution system via intelligent electronic devices and the Advanced Distribution Management System will allow for improved feeder management on the distribution circuits as well as increased distribution substation loading. The ability to move load during normal and contingency scenarios while maintaining system reliability will improve the utilization factors associated with the distribution assets. The modifications will also incorporate winter ratings for the distribution assets to help manage the expected shift from a summer peaking to a winter peaking system. These modifications, along with new supporting planning documentation, is expected to be completed no later than Q2 2026.

3) Integrated Implementation Timeline

The Integrated Planning timeline, shown in Figure 11, includes a variety of tools, software, sensors, and equipment to assist with visibility, data tracking, planning, and load flow modeling. It also overlaps significantly with the Advanced Forecasting and Grid Operations timelines.

Figure 11: Integrated Planning Timeline



4. RISKS AND MITIGATION

While the Integrated Planning process allows more stakeholders to actively contribute to Central Hudson's system needs, the complexity and inclusion of many new parties and technologies add to the risk of the system. The planning process depends on the System Forecasting process, which will be driven not only by uncertainty in base loads but also by uncertainty regarding the connection of DERs and the adoption of electrification technologies. The Company has limited control over most elements that drive when a DER starts the interconnection process or whether a project will ultimately be completed. It also has limited control regarding customer adoption of electric vehicles and heat pump technologies. In addition, policy changes and pricing changes can also have immediate impacts to the forecast. Many DERs (such as solar photovoltaics) operate intermittently and have few restrictions on when they may disconnect and the notifications required, further challenging the forecasts. Finally, DERs participating in NYISO markets may be driven by economic signals and must be balanced with local distribution system reliability.

To mitigate the risk, the Company utilizes a probabilistic-based forecasting methodology, which separates DERs and electrification loads from base load forecasts. This allows the Company to produce location-specific forecasts with uncertainty in advance, better assess scenarios, and develop plans when needed. In the next five years, for nearly all transmission load pockets and substations, the risk of exceeding thermal limitations is very low, either because loads are declining or flat or because there is ample capacity. The risk is concentrated on a limited number of locations that are growing and have limited capacity to accommodate additional growth or those areas that may see significant impacts due to EVs specific to DCFC requirements. However, as the penetration of electric vehicles and heat pumps grows, Central Hudson anticipates that additional transmission and distribution projects will be required.

Although peak load forecasts were critical in the past, minimum load forecasts are now crucial to understanding when equipment may be back fed, or other system risks may occur. This is particularly important because of the aggregation of several clustered, small DER projects that may not have been rigorously studied. Additionally, with the anticipation of electrification impacts and NY State projecting to become a winter-peaking state, it is essential to differentiate forecasts for both summer and winter periods. Therefore, 8760 summer peak and winter peak forecasts have been completed for all

transmission areas, substations, and distribution feeders, and Central Hudson will continue to produce these forecasts in the future. Additionally, operational processes and procedures will also mitigate the risk as the Advanced Distribution Management System becomes fully integrated. By establishing a Distribution Energy Resources Management System in the future, Central Hudson can further control DERs when needed. As the DMS is further developed, processes, procedures, and possibly market mechanisms will need to be prepared to incorporate this functionality and integrate planning and operational aspects.

Implementation of probabilistic forecasting and the Grid Modernization strategy involves complex projects that do carry scheduling risk. However, due diligence, progress to date, and the continuation of current processes until an appropriate cutover time have mitigated some of that risk. The load requirements to support the electrification of buildings and EVs are critical and could be a risk. Right-sized infrastructure upgrades need to be made at the right locations and at the right time. The Company expects to further discuss these risks and potential mitigations with stakeholders and the other utilities through the Proactive Planning proceeding.

5. STAKEHOLDER INTERFACE

The NYISO, with input from Market Participants, is responsible for the analysis of the New York Control Area's Bulk Power Transmission Facilities, and the Transmission Owners (TOs) are responsible for developing solutions to any identified Transmission Security issues. As part of the NYISO's Comprehensive System Planning Process, the New York TOs provide their Local Transmission Plans at least biennially. For Central Hudson, the Local Transmission Plan is based on the transmission system projects in the Electric Capital Forecast.

For facilities outside of the NYISO's jurisdiction, the stakeholder interface with the Integrated Planning process primarily includes the process's inputs and outputs rather than the process itself. Central Hudson engages stakeholders via various methods which include stakeholder engagement regarding load forecasting is described further in DER Interconnections and Hosting Capacity analysis and their potential ties to the Integrated Planning process. Much of the System Data used to drive the Integrated System Plan is publicly available, as described in Data Sharing.

The key output of the Integrated Planning Process is the Electric Capital Forecast. The 5-year Capital Budget plan is filed annually with the Public Service Commission and is publicly available. Projects that meet the NWA Suitability Criteria are considered through the NWA Procurement Process described in Beneficial Locations for DERs and Non-Wires Alternatives.

While the stakeholder interface with the Integrated Planning process primarily includes the inputs and outputs of the process rather than the process itself, stakeholders can provide direct feedback to capital plans and expenditures identified within the planning process as part of the Company's rate case proceedings.

As part of the Proactive Planning proceeding, Central Hudson expects various opportunities to engage with stakeholders pending approval of the proposed Proactive Planning Framework. This process requires more direct communication with stakeholders to understand their future plans and needs, in particular those commercial and industrial customers within each utility's service territory.

Central Hudson hosts an annual Solar+ Summit which provides DER developers and industry professionals with information on the technical and procedural aspects of interconnecting with the utility, industry updates, available programs, and incentives. The event also provides networking opportunities with industry professionals. At the conclusion of each Solar+ Summit, a survey is provided for feedback from attendees and is utilized for future planning purposes, including specific topics of interest that professionals would like to see and hear about. While the Solar+ Summit is not directly applicable to Integrated Planning, the Summit is a forum in which Central Hudson may present on planning initiatives or functions that may be of interest or benefit to stakeholders and provides them the opportunity to ask questions.

Central Hudson typically holds a DSIP webinar summarizing the content included within each of the topical sections of the DSIP, along with major initiatives or implementations. This session provides stakeholders with the opportunity to attend, listen, and ask questions. This webinar is held shortly after the DSIP filing, and additionally, the Company provides ad-hoc DSIP engagement with interested stakeholders via email or meeting touchpoints over the course of the year about DSIP-related topics. The JU also holds a DSIP enablement webinar twice a year and produces quarterly newsletters to stakeholders. The JU also has a website that is DSIP-focused, includes various references and resources for stakeholders, and is updated on a rolling basis.

6. ADDITIONAL DETAIL

1) Means and methods used for integrated system planning

The means and methods used for integrated system planning are described throughout this section, and any other sections that are referenced, as well as noted in documents such as the Electric System Planning Guides. In general, the integrated system planning process includes inputs such as infrastructure condition assessments, load forecast scenarios, reliability analysis and consideration of DER interconnections. These inputs feed into the process of performing an area study or evaluation of alternatives that result in project development and prioritization which becomes part of the integrated system and capital plans. The planning process is guided by models, design criteria, standards, transmission constraints and technological innovation. Most recently the planning process has also been impacted and will continue to evolve based on various regulatory orders and proceedings such as Order 1920 and Proactive Planning.

2) How Central Hudson'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.

Central Hudson uses a probabilistic, granular forecasting. By design, the approach includes:

1. Tracking when, where, and who adopts individual DERs and electrification technologies (e.g., EVs and heat pumps).
2. Using the data on adoption to fit adoption diffusion curves and forecast aggregate adoption with uncertainty on a territory-wide basis.
3. Estimating the propensity of customers to adopt different types of DERs at a granular level, typically for individual premises.
4. Incorporating end-use load shapes for each DER and electrification technology.

5. Assessing the impact of the adoption of DERs on individual feeder, substation, and transmission areas.

For most DERs – energy efficiency, solar, storage, electric vehicles, and building electrification – Central Hudson has already quantified which customers and locations have a higher propensity to adopt specific DERs based on characteristics such as energy use patterns, weather sensitivity, customer size, participation in other programs, ownership of other DERs, geographic location, and building characteristics (e.g., building type, square footage, year built). The estimates reflect the interrelated effects of DERs and electrification. For example, customers with distributed solar are more likely to adopt electric vehicles and vice versa.

Appendix C provides additional details regarding Central Hudson's T&D, DER, and electrification technologies forecasting methodology. These probabilistic forecasting methodologies have recently been integrated into Central Hudson's planning process.

3) How Central Hudson ensures that the information needed for integrated system planning is timely acquired and properly evaluated.

The key inputs to integrated system planning are: (1) load forecasts, (2) infrastructure assessments, and (3) reliability data.

The load forecasts are highly dependent upon the availability of substation metering data and the DER inventory. The Electric System Planning Guides describe the process for updating metering data. Where electronic hourly data is available, it must also be spot-checked to resolve any inaccuracies. As described in Section III.J, the inventory of distributed generation and energy storage systems is maintained through the Company's Interconnection Online Application Portal and filed with the PSC monthly. Distributed Generation and Energy Storage Systems are also mapped in our ESRI GIS model. Program-based energy efficiency information is also tracked and readily available.

Transitioning to infrastructure assessments, the Electric System Planning Guides document the required analysis. Finally, reliability data is heavily scrutinized to reconcile outage information and report it to the PSC every month. Annually, a detailed System Reliability Report that includes data by distribution feeder is filed with the PSC.

The process for developing the Capital Investment Forecast is documented in the Capital Prioritization Guidelines.¹⁸

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

Sensitivity analysis is typically applied when scenario-based models are employed, key inputs are based on assumptions, or there is substantial uncertainty around critical results drivers. Since Central Hudson uses a probabilistic approach where feasible, it does not typically rely on sensitivity analysis.

¹⁸ Initial DSIP, Appendix G.

Central Hudson's objective is to rely on data-driven, probabilistic analysis, which minimizes assumptions and, by definition, models the range of likely outcomes. When and where possible, Central Hudson has shifted away from scenario-based models, which are more suitable for sensitivity analysis. The uncertainty for key inputs, such as load growth, was explicitly quantified based on the available data, and the implications of the uncertainty on outcomes were quantified based on Monte Carlo simulations, showing the full range of potential outcomes.

Sensitivity analysis still plays a significant role for technologies in a nascent stage or experiencing truly disruptive innovation(s). There are three key components for new technologies: estimating the overall adoption curve and saturation over time, identifying the early and later adopters using propensity scores, and incorporating accurate load shapes for the technology. Different technologies are at distinct stages of the adoption cycle. For example, the solar and battery storage data is carefully tracked, enabling Central Hudson to estimate the adoption curve with uncertainty and develop site-level propensity scores. In addition, Central Hudson has been measuring solar output for most of its larger distribution-connected facilities. The adoption of electric vehicles has reached the point where forecasts are becoming less uncertain and more precise for light-duty vehicles, but substantial uncertainty remains for medium and heavy-duty vehicles. Central Hudson can fit adoption adoptions to actual electric vehicle adoption data for its territory (with minor assumptions) and estimate site-level adoption propensities. However, there is less history for medium and heavy-duty vehicles, and the adoption trends over time are more speculative and driven by policy goals. Heat pump technologies are at a more nascent stage. While Central Hudson tracks heat pump adoption and models adoption propensities at a site-level, it lost full visibility into the adoption of heat pump technologies when the Clean Heat program limited rebates to full-home, cold-climate rebates.

In addition, to the data-driven forecasts, Central Hudson also produces a policy forecast to understand the implication of different levels of electrification and DER adoption on T&D planning, particularly for more nascent technologies.

5) How Central Hudson 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.

The process for Central Hudson to adjust its plans in the short term is not likely to vary from the process in place today. Emerging needs will be addressed by reprioritizing projects within the existing Capital Plan or by releasing contingency funding as necessary. Similarly, if loads do not materialize in an area where a load-based project is required, that project will not move forward unless there are other drivers (e.g., infrastructure considerations). The Capital Prioritization Guidelines were finalized in May 2015 and are also included in Appendix G of the Initial DSIP filing.

By design, the T&D forecasts have been standardized and incorporated into an in-house web-based tool with automated data pipelines to key inputs such as T&D interval data, solar and battery and interconnection applications and completions, EV adoption data, and heat pump program data. The careful tracking and continuous updates of data, allows Central Hudson to assess if forecasted changes in loads are occurring at the anticipated pace and, if not, to update its forecasts.

The Proactive Planning proceeding will lay out a process for short term needs that may not align with a rate filing and are associated with imminent needs to support loads for EVs and electrification. This

process will be more informed once stakeholder sessions have been completed and a final process is approved by the Commission.

In the longer term, the probabilistic-based forecasting methodology provides insight into some of the potential variability from the predicted forecast so that the Company can monitor and more proactively plan for worst-case scenarios. The substation loading forecasts provide an annual check on what areas of the system may require reevaluation. However, when an NWA is already contracted for a project, it is more challenging to undo. Still, a project may have an opportunity for further deferral if the load does not materialize, or a traditional solution may have to be accelerated if the load grows more quickly than anticipated or DERs do not come to fruition as expected.

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

The integration of aging infrastructure into the Integrated Planning Process is described at the beginning of this Section, including a reference to the Long Range Electric System Plan in Appendix F, which is an output of the process. Although Central Hudson's long-term experience is not specific to electric vehicles and beneficial electrification, the Company's existing processes are well-equipped to manage load growth. Multiple EV charging stations have been successfully installed throughout Central Hudson's service territory. Based on preliminary analysis, both EVs and Electrification have shown that they are most likely to have an impact on service laterals and service transformers, which can be upgraded via our normal process. Central Hudson is currently reviewing minimum service lateral and transformer requirements. Small conductor distribution lines may also require upgrades, and Central Hudson has programs within its Distribution Capital Budget to address these typically aged distribution lines consisting of #4 Cu or 4800 V construction.

As part of the April 20, 2023, *Order Instituting a Proceeding On Addressing Barriers for Medium and Heavy-Duty EV Charging Infrastructure*¹⁹ Central Hudson will participate as a stakeholder to identify areas where proactive utility planning may be prudent. This included working with the JU to file a proactive planning framework in December of 2024 to address areas where infrastructure upgrades (such as transmission or substation) will be required to meet electrification needs to support customer needs in a timely manner without adverse impacts. As a part of the current rate plan, Central Hudson continues to advocate for beneficial electrification, especially for programs and rate design that encourage improved load factors and system efficiency, such as expanding the use of geothermal technology and actively funding heat pump electrification projects. The Company continues to monitor other technologies considering electrification through participation in Electric Power Research Institute programs. In addition, Central Hudson has proposed a project under the proactive planning process to develop a granular spot load study in conjunction with stakeholders within our service territory.

Additionally, as part of the All Electric Building Act (Case 25-M-0149), load and DER forecasts will consider the impacts of building electrification due to prohibiting the installation of fossil-fuel equipment

¹⁹ 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 (issued April 20, 2023).

for new buildings seven stories or less (exception of commercial or industrial in excess of 100,000 sq ft.) effective December 31, 2025 and for all new buildings effective December 31, 2028.

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

Similar to other DERs, the impact of energy efficiency and building code changes must be considered in the forecasting process. A system-wide forecast is developed at the corporate level, both with and without the impacts of energy efficiency, and is reconciled with bottom up forecasts to identify allocations to substation and transmission levels. The range of forecasts will allow system planners to monitor longer-term system needs and develop planning alternatives depending on how much of the energy efficiency comes to fruition. Additional details regarding Energy Efficiency Integration and Innovation can be found in Energy Efficiency Integration and Innovation.

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

Central Hudson actively participates with the Electric Power Research Institute's Distribution Planning and Operations program as well as Association of Edison Illuminating memberships. Through attendance at conferences, planning interest group meetings, and webinars, the Company stays abreast of the latest developments in System Planning and integrates learnings into its processes as appropriate.

Central Hudson also participates in the NYISO's Interconnection Process. Through this process, Central Hudson is made aware of projects proposing to connect to its transmission system and neighboring transmission systems. As part of the NYISO Interconnection Process, Central Hudson reviews and contributes to the analyses of these proposed projects. Through NYISO's Electric System Planning Working Group, Central Hudson continues to participate and advocate for improvements to the planning and interconnection process on the bulk electric system and the alignment of those processes within the DSP.

The Joint Utilities of New York and the NYISO also hold periodic meetings and conference calls to discuss the inputs and outputs of the various planning processes, such as forecasting, hosting capacity, interconnection, and non-wires alternatives, at both bulk system and non-bulk levels. As previously mentioned, the JU also frequently meets as part of the Proactive Planning proceeding, which includes discussions to align in as many areas as possible, including identifying what forecast scenarios to utilize and assumptions incorporated into forecasts.

B. ADVANCED FORECASTING

1. KEY TAKEAWAYS

The Central Hudson forecasts and planning are done system-wide and for individual components, including 272 distribution feeder circuits, 66 substations, and 10 local transmission areas. Accurate forecasts are critical since they account for planning conditions and are used to determine the sizing of the grid infrastructure needed to accommodate the loads.

Central Hudson’s actual system peak in 2024 was 1,103 MW.²⁰ The electric peak forecast for 2030 is projected to be a summer peak of 1,087 MW. Overall, per-customer summer peak demand in Central Hudson has declined at a rate of -0.84% per year, likely due to a mixture of energy efficiency, codes and standards, and other changes in end-use loads. Winter peak demand has declined at a rate of -1.17% per year. For comparison, Central Hudson’s all-time electric system peak demand of 1,295 MW was set in 2006.

Forecasts are particularly challenging because the electricity industry and electric utilization is experiencing rapid technological change, particularly with the introduction of distributed energy resources and the electrification of heating and transportation.

Central Hudson has made substantial progress in its advanced forecasting initiative. Most notably, Central Hudson:

- Produces econometric forecasts for each of its 272 feeders, 66 distribution substations, and 10 transmission areas. The forecasts are for gross loads (net loads + solar added back), incorporate the substation-level growth rates, and are weather-adjusted for planning conditions.

Figure 12: Central Hudson Demand Key Facts

KEY FACTS		
2024 customers ~316,950	2024 Summer Net Peak 1,103 MW	2024 Summer Gross Peak (Weather Adj.) 1,185 MW
2010-2024 Customer Growth Rate 0.61%	2010-2024 Summer Peak Demand Per Customer Growth Rate -0.84%	2010-2024 Non-Summer Peak Demand Per Customer Growth Rate -1.17%
Transmission areas 10	Distribution substations 66	Primary Feeders 272

²⁰ The value includes loads and net metered distribution connected solar and storage, which is used for revenue requirements. For distribution planning, the loads used also include non-net metered distribution connected solar (e.g., community solar and storage). Gross Peak (Weather Adjusted) includes net loads, net metered solar production, and community-distributed generation solar production.

- Has developed tools and methods to track the penetration and produce forecasts at feeder-circuit-level allocations for new technologies, including electric vehicles, building electrification, energy efficiency and codes and standards, solar, and storage. These new technologies are incorporated as load modifiers to econometric forecasts. The modeling is done on an hourly basis, enabling an understanding of how loads change across hours of the day and seasons over time.
- Has funded the development of an online T&D forecasting tool for planning that is regularly updated with recurring data pipelines. The T&D planning forecast tool went live in 2024. The tool provides visibility into where, how, and why loads are changing at various grid levels – system, transmission area, substation, and feeder circuits – and offers ready access and visualization of historical and forecast load patterns and load modifiers, including electric vehicles, building electrification, energy efficiency and codes and standards, solar, and storage. By design, the tool can ingest system-level DER and electrification forecasts and update the granular forecasts to calibrate them to the system-level technology forecasts.
- Has expanded the capability to produce granular forecasts to 20 years to enable planning over longer horizons.
- Has developed forecasting processes for key load modifiers such as electric vehicles, building electrification, solar, and storage.
- Produces two forecast scenarios: a Central Hudson forecast and a policy-based forecast. The Central Hudson forecast reflects the best available forecasts given the observed empirical trends. The policy-based forecast reflects the goals that New York has adopted and is based on the NYISO forecast for zone G, adjusted for the Central Hudson share.

Going forward, Central Hudson plans to:

- Develop a plan to improve visibility into heat pump adoption. In 2022, Central Hudson lost full visibility into heat pump adoption when the program incentives were limited to full-home, cold-climate heat pumps.
- Improve electric vehicle load shapes. The current load shapes are NREL-simulated loads and may not factor in the effects of rates and other load management tactics. The long-term goal is to gather access to New York-specific data via telematics.
- Update models for medium-heavy-duty vehicles (MHDV) and buses as more adoption and load pattern data become available.
- Based on the assessment of the impacts of electric vehicles and heat pumps on secondary transformer (pole-top/pad-mount) sizing and service laterals, Central Hudson has implemented modifications to its estimating manuals and standards have been made for minimum sizing values for transformers and service lateral conductors for both the overhead and underground systems. In addition, primary conductors for URDs have also been upsized to accommodate these new technologies.

2. CONTEXT AND BACKGROUND

A vital role of Central Hudson is to ensure that the electricity supply remains reliable by projecting future demand and reinforcing the transmission and distribution network, so the capacity is available to meet local needs as they grow over time. Proper design of the electric grid is critical to ensure that power can be delivered from where it is produced to where it is used.

The forecast and planning are done on a system-wide basis and for individual components of the system, including distribution circuits, substations, and transmission areas. Historically, electric grids were engineered to accommodate a unidirectional flow of electricity from centralized generation to end users. Generation, transmission, and distribution infrastructure components were sized to meet the aggregate peak demand of the customers connected to specific grid components. In addition, the planning process ensures that power can be rerouted in case of prolonged or temporary outages.

The electricity industry and electric utilization are experiencing rapid technological change, particularly with the introduction of distributed energy resources and the electrification of heating and transportation. The shift affects both (1) how, when, and where customers use electricity, and (2) how, when, and where electricity is produced. Several factors have the potential to influence electric grid planning:

- The adoption of electric vehicles;
- Building electrification initiatives;
- The adoption of distributed solar including community solar;
- The introduction of battery storage;
- Customer growth and migration patterns;
- Behavioral changes regarding how and when customers use electricity;
- New appliance and building codes and standards;
- Program-based introduction of energy efficiency; and
- Increased penetration of connected devices, such as smart thermostats, where the power use can be remotely controlled and response automated.

If properly harnessed and directed, technological change can improve the utilization of existing resources, either by shifting the use of power away from peak periods or by injecting power into the grid when and where it is needed most. However, several of these technologies are in their nascent stages, making their adoption and impact on the electric grid challenging to predict. By definition, disruptive technologies are difficult to identify and predict in advance.

1) Forecasting Principles

No one knows precisely when loads will reach levels that trigger infrastructure upgrades. However, linear forecasts assume precise knowledge. In practice, actual growth trajectories are rarely linear, and growth patterns trend over time.

Forecasts inherently include uncertainty and become more uncertain further into the future. The uncertainty for a forecast ten years out is larger than the uncertainty for a forecast one year out. Because a linear forecast assumes exact knowledge, no risk is assigned to the years before the linear forecast exceeds levels that trigger infrastructure upgrades. Probabilistic methods, on the other hand, reflect the potential reality that infrastructure upgrades could be triggered earlier or later.

Because no one knows exactly what the future holds, Central Hudson has embraced probabilistic planning and adopted five guiding principles, shown below.

FORECASTING PRINCIPLES

1. Forecast T&D loads, adoption of DERs, and beneficial electrification;
2. Produce location-specific forecasts as granular as realistically possible;
3. Track adoption of DERs regularly in as granular a manner as possible;
4. Embrace probabilistic methods and produce forecasts that appropriately reflect uncertainty; and
5. Connect the probabilistic forecasts to the assessments of T&D deferral potential and value.

While the approach requires a substantial amount of effort, the results are grounded in empirical data and better reflect the limitations of what we know about changes in T&D loads and the adoption of DERs and beneficial electrification.

2) *System Level Forecasts*

Central Hudson's Initial DSIP filing provided a comprehensive discussion of the company's system-wide forecast, which begins with the development of energy sales projections along multiple electric sectors. These projections are aggregated with a projection of system losses to produce a forecast of net energy, which, in turn, is paired with a peak demand forecast to yield an annual system electric load forecast.

Due to the rapid adoption of new technology, Central Hudson has incorporated improvements to the system-level forecasting process, specifically:

- **Capability to produce system forecasts for 20 years.** Historically, the system-level forecasts focused on a five-year period and were produced for budgeting and rate case purposes. However, due to the increased need for planning over longer T&D horizons, Central Hudson has built the capability to produce 20-year forecasts for distribution planning.
- **Forecasting outputs that align with the NYISO Gold Book format.** Specifically, the forecasts include information to understand why and how peak loads are changing and include details regarding the gross loads and load modifiers, specifically:
 - Econometric gross load forecasts
 - Electric Vehicles (+)
 - Building Electrification (+)

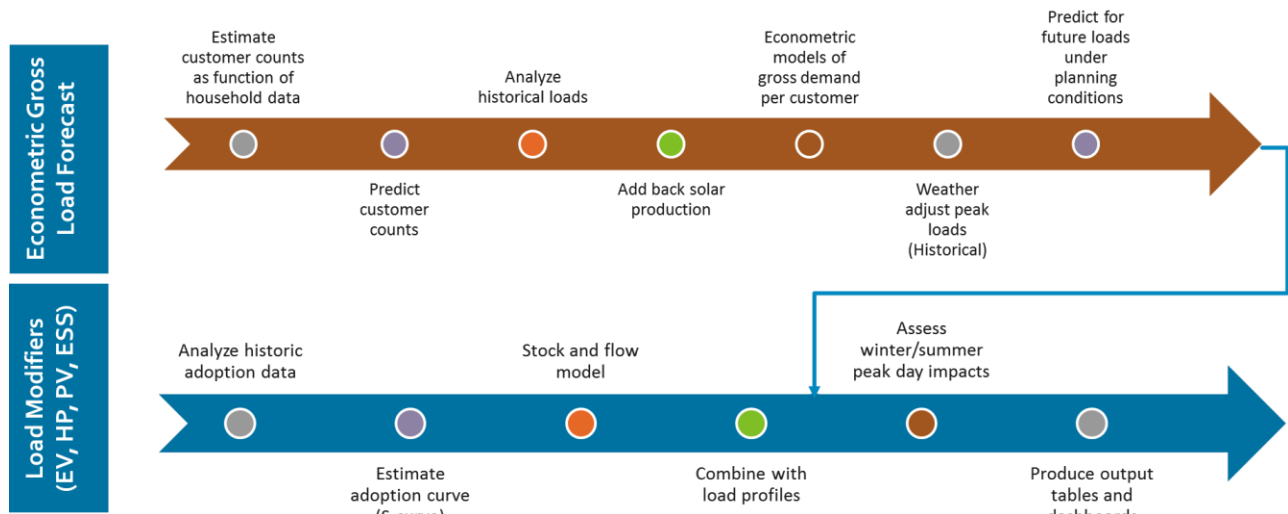
- Energy Efficiency and Codes & Standards (-)
- Solar PV (-)
- Storage Reductions (+/-)
- **Detailed tracking of the Load Modifiers to estimate historical adoption and current penetration levels.** The data is critical for the development of the load forecasts. This is most advanced for more established technologies such as solar, storage, light-duty electric vehicles, and EE & CS. The empirical data for building electrification is at a more nascent stage, and the visibility into the heat pump market share needs to be better established.
- **Production of a Central Hudson Forecast and the NYISO policy-based forecast.** The Central Forecast reflects the empirical trends, patterns, and funding levels. It reflects the best estimate of loads at Central Hudson. The policy-based forecast reflects the New York State goals and is based on the zone G NYISO forecast, scaled for Central Hudson's service territory. It includes projections of various load modifiers – energy efficiency, solar, battery storage, EVs, and building electrification – tied closely to state goals.

Figure 13 shows the general process for developing the forecasts. There are two main tracks: the development of the econometric gross load forecasts and the load modifier forecasts. The process for the econometric forecast develops estimates of customer counts as a function of Moody's household data for the Central Hudson area. It uses the Moody's household forecast to predict future customer counts. From 2010-2024, the number of Central Hudson customers grew at a rate of 0.61% per year. However, future household forecasts project a slowdown in household growth in the next ten years and a slight decline starting in the mid-2030s. The 2010-2024 summer and winter daily peak loads were used to develop econometric models designed to isolate per-customer demand patterns as a function of weather, time, and other day-type characteristics. Overall, per-customer summer peak demand in Central Hudson has been declining at a rate of -0.84% per year, likely due to a mixture of energy efficiency, codes and standards, and other changes in end-use loads. Winter peak demand has been declining at a rate of -1.17% per year. The difference is likely due to the increasing penetration of air conditioning in Central Hudson's territory and differences in the peak hours between summer and winter. The econometric model is then used to weather-adjust historical peaks and predict future loads under planning conditions, with and without incremental energy efficiency and codes and standards.

The process for developing the load modifier forecasts generally follows the diagram below, with a few exceptions.²¹ An innovation diffusion curve is fit to the historic adoption patterns to estimate the new market share of the technology over time. Next, a stock-and-flow model is used to understand how the technology mix (e.g., vehicles) will change as old models age out and are replaced by new ones. It is then combined with load profiles and layered onto the existing demand to understand how summer and winter peak loads will change. Appendix C provides additional details about the data sources, methods, and results for each load modifier.

²¹ The exceptions are larger, distribution connect solar and battery storage, heavy duty vehicles, and fast DC charging.

Figure 13: Process for Developing Forecasts



A unique characteristic of Central Hudson is the quantity of community-distributed generation and remote-solar projects, which are not net-metered but are distribution-connected. As of the end of 2024, Central Hudson had interconnected over 160 such projects with over 170 MW of installed solar capacity, exceeding the roughly 160 MW of net-metered solar capacity.

DERs subject to net energy metering to reduce the system-wide forecast of billed sales and metered peak. In contrast, DERs subject to monetary compensation for exports, such as Community Distributed Generation (CDG), do not impact Central Hudson sales and rates. However, power system, transmission, and distribution planning must account for the impact of all distribution-connected solar and storage on planning. Central Hudson's system-level demand and sales projections for the rate case focus on billed sales. In contrast, the demand forecasts included in this report include the effect of all distribution-connected generation, including CDM and remote-metered sites.

Table 7 shows historical peak demand data for the 2010-2024 winters and summers. Overall, the net peak demand has decreased despite increases in the total number of customers. Once solar production has been added back and demand is adjusted for weather, the overall demand is relatively flat despite a growing customer base.

Figure 14 shows the hourly patterns on annual peak days by season for 2010-2024. The summer system loads follow a typical pattern, peaking in the late afternoon hours, with the more recent peaks occurring later and later into the evening hours due to higher solar penetration. The winter loads have a distinctly different pattern, with both a morning and evening peak. Winter peak loads typically occur in the evening hours and are lower than summer peak loads by roughly 200-300 MW. Central Hudson expects the winter loads in the morning to grow with the increased penetration of heat pumps and electric heating.

Table 7: Historical Peak Demand

Season	Year	Date	Hour	Net Peak Demand	Gross Demand [1]	Gross Demand Weather-Adjusted	Gross Demand (kW) per Customer	# of Customers [2]	Peak Hour Temp [3]	Daily Avg. Temp	Daily Avg. Temp (1-in-2)
Summer	2010	7/6/2010	16	1,230	1,234	1,190	4.18	295,343	99.0	85.1	82.8
	2011	7/22/2011	17	1,225	1,229	1,187	4.15	295,985	100.0	87.9	82.8
	2012	7/17/2012	17	1,168	1,173	1,184	3.98	295,061	95.0	82.8	82.8
	2013	7/18/2013	16	1,202	1,212	1,175	4.10	295,755	95.0	84.9	82.8
	2014	7/23/2014	16	1,060	1,077	1,172	3.64	296,236	89.1	79.4	82.8
	2015	7/29/2015	17	1,059	1,078	1,167	3.62	298,030	93.9	80.3	82.8
	2016	8/13/2016	17	1,088	1,112	1,168	3.73	297,874	93.9	85.4	82.8
	2017	7/20/2017	16	1,034	1,087	1,162	3.62	300,077	90.0	77.2	82.8
	2018	7/2/2018	17	1,114	1,153	1,164	3.81	302,826	91.0	82.8	82.8
	2019	7/21/2019	17	1,109	1,141	1,167	3.74	305,051	93.9	84.3	82.8
	2020	7/27/2020	18	1,142	1,178	1,169	3.83	307,602	93.0	84.0	82.8
	2021	6/29/2021	18	1,148	1,191	1,172	3.82	311,365	93.9	86.7	82.8
	2022	7/21/2022	18	1,109	1,168	1,178	3.72	314,231	93.9	84.4	82.8
	2023	9/7/2023	17	1,046	1,153	1,182	3.64	316,462	88.0	78.3	82.8
	2024	7/10/2024	18	1,103	1,175	1,185	3.71	316,950	86.0	83.1	82.8
Winter	2010	12/14/2010	17	891	892	881	3.02	295,343	19.9	19.9	10.9
	2011	1/24/2011	18	905	905	874	3.06	295,985	5.0	2.3	10.9
	2012	1/21/2012	17	861	862	866	2.92	295,061	21.0	19.0	10.9
	2013	12/17/2013	17	900	902	855	3.05	295,755	20.0	14.0	10.9
	2014	1/7/2014	18	938	938	847	3.17	296,236	8.1	9.1	10.9
	2015	1/7/2015	18	874	875	839	2.93	298,030	10.9	16.8	10.9
	2016	2/15/2016	18	863	863	835	2.90	297,874	19.0	12.8	10.9
	2017	12/28/2017	18	885	885	826	2.95	300,077	10.0	7.8	10.9
	2018	1/6/2018	18	904	904	822	2.99	302,826	6.1	6.3	10.9
	2019	1/21/2019	17	900	900	820	2.95	305,051	10.9	8.3	10.9
	2020	12/16/2020	17	848	848	816	2.76	307,602	24.1	22.4	10.9
	2021	1/29/2021	18	841	841	813	2.70	311,365	18.0	15.6	10.9
	2022	1/22/2022	18	896	896	813	2.85	314,231	16.0	10.9	10.9
	2023	2/3/2023	18	878	878	810	2.77	316,462	8.1	17.4	10.9
	2024	12/22/2024	17	912	912	808	2.88	316,950	10.9	10.5	10.9

[1] Includes solar production addback from net-metered (NEM), CDG, and remote metered distribution-connected solar. For ratemaking purposes, only net-metered (NEM) solar is included.

[2] Count of customers based on bills sent out during the billing cycle.

[3] Mid-Dutchess Airport Weather Station

[4] Based on an analysis of 20 years of historical weather

Figure 14: Hourly Net Loads on Annual Peak Days (2010-2024)

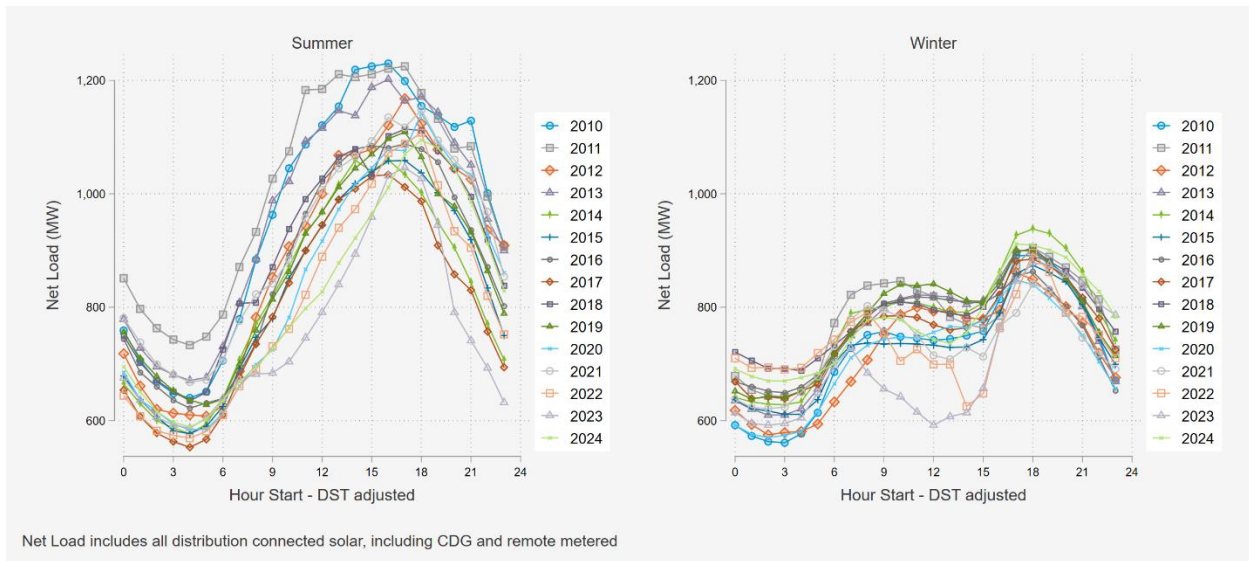


Figure 15 shows the weather sensitivity of net system loads for the most recent three years. Overall, roughly 500 MW of the summer load is weather-sensitive due to cooling and fan loads. The winter loads are lower, slightly below 900 MW, and roughly 300 MW of the winter load is weather-sensitive. While Central Hudson is summer-peaking, it has a substantial amount of winter peak loads, and pockets of the service territory are winter-peaking.

Figure 15: System Net Loads Weather Sensitivity (2022-2024)

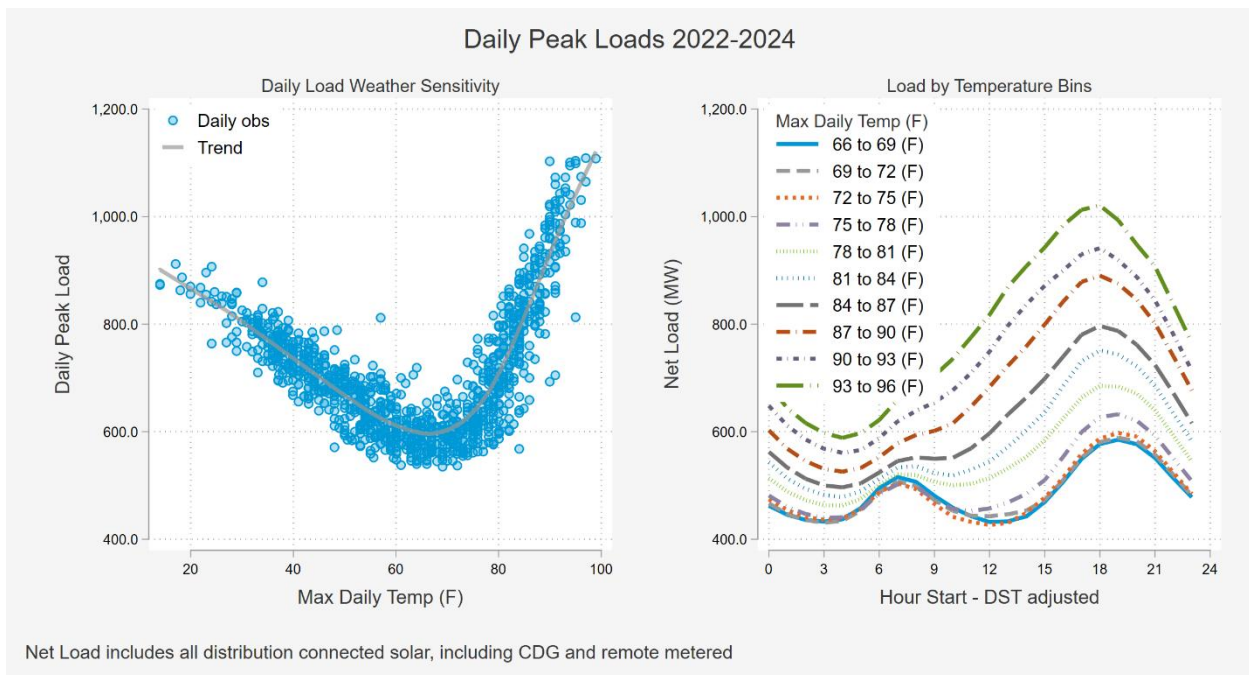


Table 8 summarizes the Central Hudson system-level forecast for the DSIP. As noted earlier, it includes Community Distributed Generation and remote-solar projects, since they impact distribution planning. Overall, Central Hudson is expecting a substantial amount of electric vehicle loads, building electrification, and additional solar storage. The additional loads shift the timing of the peak hours over time, which can also impact the effect of solar on system peak as system peak hours shift later in the afternoon and may potentially impact the season when the Central Hudson System peaks.

Table 9 shows the policy-based forecast. As noted earlier, the policy forecast is based on the NYISO Zone G forecast, adjusted for Central Hudson's share of the zone. The main difference between the policy and Central Hudson scenarios is the heat pump forecast. The policy forecast assumes a 75% saturation of heat pumps by 2050. In contrast, the Central Hudson forecast assumes a 55% saturation of heat pumps by 2050, given the adoption patterns observed. Regardless of the forecast used, Central Hudson is expected to remain a summer-peaking system through the late 2030s, although individual transmission areas, substations, and feeder circuits may become winter-peaking earlier.

Table 8: DSIP Central Hudson Forecast (MW)

Season	Year	Econometric Forecast (Gross Load)	Electric Vehicles	Heat Pumps	EE and C&S	Solar ^[1]	Energy Storage	Integrated Planning Loads
Summer	2025	1,121.8	19.1	-3.3	-18.8	-16.7	-5.0	1,097.2
	2026	1,121.9	25.6	-4.1	-29.5	-18.9	-6.1	1,089.0
	2027	1,122.1	34.1	-5.0	-38.0	-19.9	-10.4	1,082.8
	2028	1,123.0	44.6	-6.1	-46.1	-20.7	-11.1	1,083.7
	2029	1,124.6	57.5	-7.2	-55.4	-21.1	-12.9	1,085.6
	2030	1,126.8	72.7	-8.5	-66.4	-21.4	-15.7	1,087.4
	2031	1,128.9	89.9	-9.8	-77.9	-21.6	-19.7	1,089.8
	2032	1,131.1	109.0	-11.3	-88.6	-21.8	-24.6	1,093.8
	2033	1,132.6	129.6	-12.9	-98.9	-21.9	-30.6	1,098.0
	2034	1,133.7	151.3	-14.6	-108.5	-22.0	-37.1	1,102.8
	2035	1,134.6	173.6	-16.4	-117.4	-22.0	-43.9	1,108.5
Winter	2025	813.1	18.9	30.6	-17.0	-4.7	-4.9	835.9
	2026	813.1	25.4	37.4	-26.6	-5.3	-6.0	838.0
	2027	813.2	33.8	45.1	-34.4	-5.6	-10.3	841.9
	2028	813.9	44.3	53.4	-41.7	-5.8	-11.0	853.1
	2029	815.0	57.0	62.5	-50.1	-5.9	-12.8	865.8
	2030	816.5	72.0	72.4	-60.1	-6.0	-15.6	879.2
	2031	818.1	89.0	82.9	-70.5	-6.0	-19.5	894.0
	2032	819.7	107.9	94.2	-80.3	-6.1	-24.5	910.9
	2033	820.9	128.1	106.0	-89.6	-6.1	-30.4	929.0
	2034	821.8	149.4	118.5	-98.3	-6.1	-37.0	948.4
	2035	771.2	157.7	146.2	-104.0	-0.7	-0.9	969.4

[1] PV includes net metered customers, Community Distributed Generation (CDG), and remote solar projects since they impact distribution planning. By comparison, system forecasts for the rate case focus on direct sales and only include net metered solar.

Table 9: DSIP Policy-Based Forecast

Season	Year	Econometric Forecast (Gross Load)	Electric Vehicles	Heat Pumps	EE and C&S	Solar [1]	Energy Storage	Integrated Planning Loads
Summer	2025	1,183.4	20.2	-0.7	-24.7	-68.3	-0.6	1,109.2
	2026	1,183.8	28.1	-2.2	-38.8	-77.5	-0.7	1,092.8
	2027	1,184.3	38.6	-3.7	-50.0	-86.5	-0.8	1,081.8
	2028	1,185.5	51.3	-5.6	-60.7	-94.4	-0.9	1,075.2
	2029	1,187.5	66.9	-7.6	-72.9	-101.3	-1.0	1,071.7
	2030	1,164.7	91.7	-8.9	-84.2	-48.4	-44.2	1,070.6
	2031	1,167.0	115.0	-10.9	-98.7	-50.7	-47.7	1,074.0
	2032	1,169.4	142.0	-13.1	-112.3	-52.6	-50.8	1,082.6
	2033	1,132.6	175.7	-12.5	-131.7	-14.2	-53.2	1,096.7
	2034	1,133.7	212.4	-14.8	-144.5	-14.6	-55.5	1,116.7
	2035	1,134.6	254.1	-17.3	-156.3	-14.9	-58.3	1,141.7
Winter	2025	813.1	21.9	5.1	-22.6	-2.3	-23.9	791.2
	2026	813.1	30.6	14.5	-35.5	-2.6	-28.2	791.8
	2027	813.2	41.9	24.2	-45.8	-2.9	-32.2	798.4
	2028	813.9	55.6	36.2	-55.6	-3.1	-36.5	810.6
	2029	815.0	72.5	48.6	-66.8	-3.4	-40.5	825.4
	2030	816.5	92.1	61.3	-80.1	-3.5	-43.9	842.4
	2031	767.5	109.5	82.3	-91.9	-0.4	-0.7	866.3
	2032	768.8	135.0	97.8	-104.6	-0.5	-0.7	895.7
	2033	769.8	163.7	114.5	-116.8	-0.5	-0.8	930.0
	2034	770.6	197.4	133.8	-128.1	-0.5	-0.8	972.4
	2035	771.2	235.6	154.6	-138.7	-0.5	-0.8	1,021.3

[1] Solar includes net metered customers, Community Distributed Generation (CDG), and remote solar projects since they impact distribution planning. By comparison, system forecasts for the rate case focus on direct sales and only include net metered solar.

The summaries for Table 8 and Table 9 focus on the peak hour for the integrated planning load. However, the timing, peak hours, and the peak season change over time with the increased adoption of electric vehicles, heat pumps, solar, battery storage, energy efficiency, and codes and standards. Figure 16 shows the various components of the forecast stacked, with components that increase load shown as positive and components that decrease loads shown as negative. The black line is the integrated planning load. The amount of current and forecast distribution connected solar in Central Hudson's territory is significant, pushing the net load peaks into late evening hours over time. In addition, the expected electric vehicle loads, if not properly managed, contribute to the peaks in the summer and winter months.

A key planning issue will be identifying ways to manage or incentivize electric vehicles to charge during off-peak periods. Electric vehicle loads are large, adding between 3,000 to 5,000 kWh per vehicle depending on miles driven. However, they are much more diverse and shiftable than heating and cooling, since not all homes need to charge on the same day or at the same time. The contribution of

heat pumps to peak loads is primarily in the winter. In general, heat pumps contribute a substantial amount of load throughout the day but peak in the morning, when temperatures are colder and home occupancy is high. However, when combined with existing load and other load modifiers (e.g., EVs), Central Hudson still expects winter loads to peak in the evening hours.

Figure 16: 2035 and 2045 Summer and Winter Peak Day Load Changes Central Hudson Forecast



3) Location-Specific Forecasts

The expected growth in electric vehicles, building electrification, solar, and battery storage requires significant changes to how distribution planning takes place and how it is coordinated with system forecasts. The most immediate impact of the adoption of technologies such as electric vehicles, heat pumps, solar, and storage is observed in distribution planning. Newer technology adoption is often concentrated in specific pockets of Central Hudson’s service territory. While a system-level forecast provides a broad view of load growth and adoption of EVs, heat pumps, solar, and storage, a granular

circuit-level forecast is essential for grid planning and reliability. The core questions are: when and where will new electrification and DER technology appear? And how will they impact hourly demand on peak days?

Before the DSIP process was initiated in 2016, the approach was to develop load growth forecasts for each broader area within Central Hudson’s territory and apply them to the specific peak loads for substations and transmission areas. Central Hudson has evolved its planning process to produce granular, location-specific, probabilistic forecasts and to include loads, new electrification, and DER technologies.

A potential key barrier, however, was that not all feeders and substations had meters collecting hourly or sub-hourly data. For Central Hudson, this barrier has been effectively eliminated through ongoing infrastructure replacement programs, installing hourly metering data for nearly all of its substations and feeders, achieving a goal in the 2020 DSIP. However, once meters were installed, several years of data must be collected to accurately estimate local annual and especially hourly load growth trends.

Figure 17 summarizes the process used for transmission area, substation, and feeder circuit forecasts. The bottom-up granular forecasts have been designed to isolate the key drivers of change in loads. Specifically, the approach aims to isolate load growth trends from solar interconnections; historical solar production is added to the observed historical loads. The objective is to quantify the growth in gross loads separately from the changes in electric vehicles, heat pumps, solar, battery storage, and other load modifiers. In addition, the forecasts separately track gross loads, solar, battery storage, building electrification, electric vehicle loads, and incremental energy efficiency (including codes and standards). The granular forecasts are all calibrated to territory-wide forecasts, thus ensuring consistency in outputs.

Figure 17: Process for Granular Distribution Forecasts

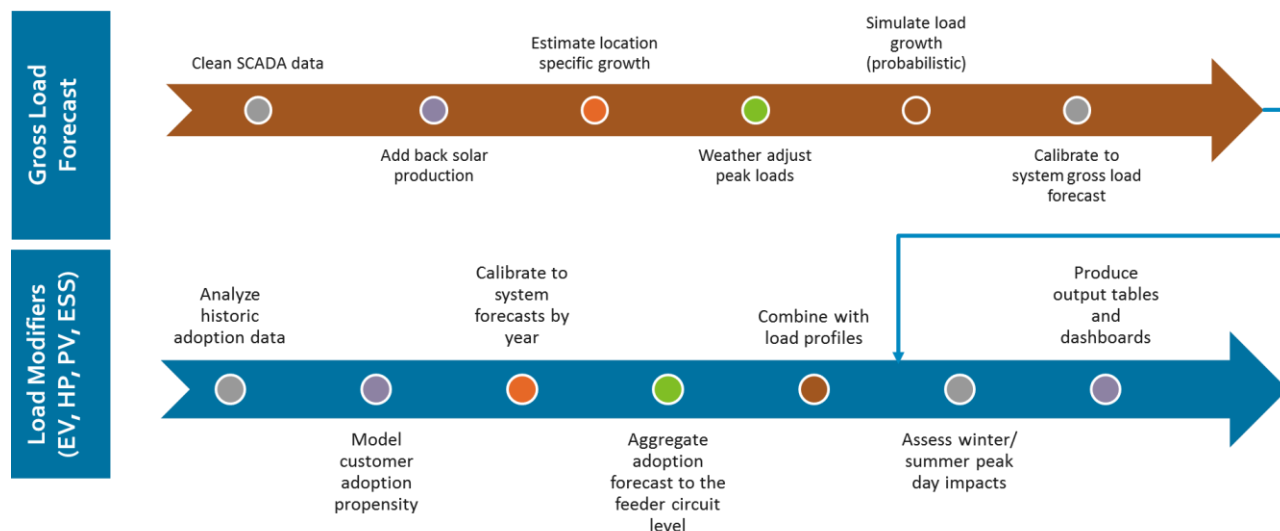


Figure 18 provides a more detailed view of the process for the granular forecasting of load modifiers and includes inputs and key outputs. The process allows Central Hudson to identify potential constraints, prioritize infrastructure investments, and ensure reliable service delivery as EV, heat pumps, solar, and storage adoption increases across different neighborhoods. By understanding when and where these

loads will materialize at various levels – pole top/pad mount transformers, feeders, substation transformers, banks, substations, and transmission load pockets – Central Hudson can better prepare for and manage the impacts of DERs and electrification.

Figure 18: Process for Heat Pumps, Electric Vehicles, Solar, Battery storage, and Energy Efficiency

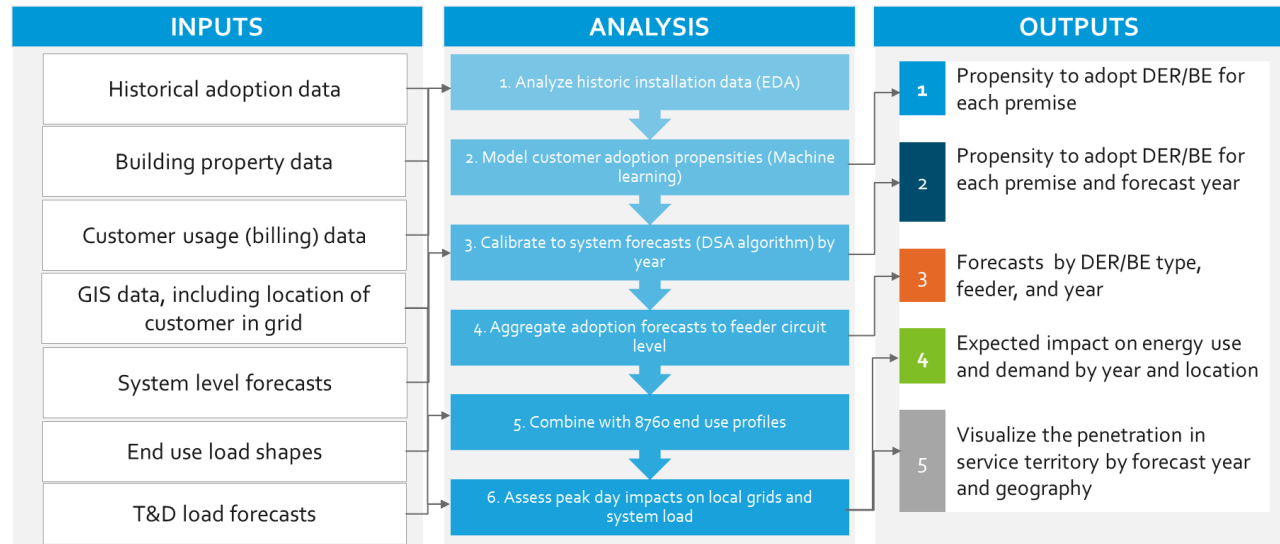


Table 10 illustrates the components of the bottom-up load forecasts for a specific, illustrative substation. The granular forecasts can be summarized for the coincident (territory-wide) or non-coincident (local) summer and winter peak at different levels of geographic granularity – system, transmission area, substation, and feeder circuit. They also can be shown for the single peak hour, for peak days, or for the full 8,760 hours per year and at each level of geographic granularity. As described above, the bottom-up, location-specific forecasts are reconciled with the system-wide forecasts.

Table 10: Example Granular Forecast for a Substation

Season	Forecast year	Econometric Forecast (Gross Load)	Electric Vehicles	Heat Pumps	EE and C&S	Solar ^[1]	Energy Storage	Integrated Planning Loads
Summer	2025	44.0	1.3	-0.1	-1.1	-1.4	-0.1	42.6
	2026	43.4	1.7	-0.1	-1.7	-1.5	-0.1	41.7
	2027	42.7	2.3	-0.1	-2.1	-1.6	-0.1	41.1
	2028	42.2	3.0	-0.2	-2.5	-1.6	-0.1	40.7
	2029	41.8	3.8	-0.2	-3.0	-1.7	-0.1	40.6
	2030	41.6	4.8	-0.3	-3.5	-1.8	-0.2	40.7
	2031	41.2	5.9	-0.3	-4.0	-1.8	-0.2	40.7
	2032	40.8	7.1	-0.4	-4.5	-1.9	-0.3	40.9
	2033	40.6	8.4	-0.4	-5.0	-1.9	-0.4	41.3
	2034	38.4	9.6	-0.6	-5.0	-0.1	-0.5	41.8
	2035	38.4	10.9	-0.6	-5.4	-0.1	-0.6	42.5
Winter	2025	24.6	1.2	0.4	-0.9	-0.1	-0.1	25.1
	2026	24.2	1.6	0.5	-1.4	-0.1	-0.1	24.8
	2027	23.5	2.6	0.7	-1.7	-0.1	-0.1	24.9
	2028	23.2	3.4	0.9	-2.0	-0.2	-0.1	25.2
	2029	23.0	4.4	1.0	-2.3	-0.2	-0.1	25.8
	2030	22.8	5.5	1.3	-2.7	-0.2	-0.2	26.5
	2031	22.6	6.7	1.5	-3.1	-0.2	-0.2	27.3
	2032	22.4	8.1	1.7	-3.5	-0.2	-0.3	28.3
	2033	22.3	9.5	2.0	-3.8	-0.2	-0.4	29.4
	2034	22.2	11.0	2.3	-4.1	-0.2	-0.5	30.7
	2035	22.2	12.4	2.6	-4.4	-0.2	-0.6	32.1

[1] Solar includes net-metered customers, Community Distributed Generation (CDG), and remote solar projects, since they impact distribution planning.

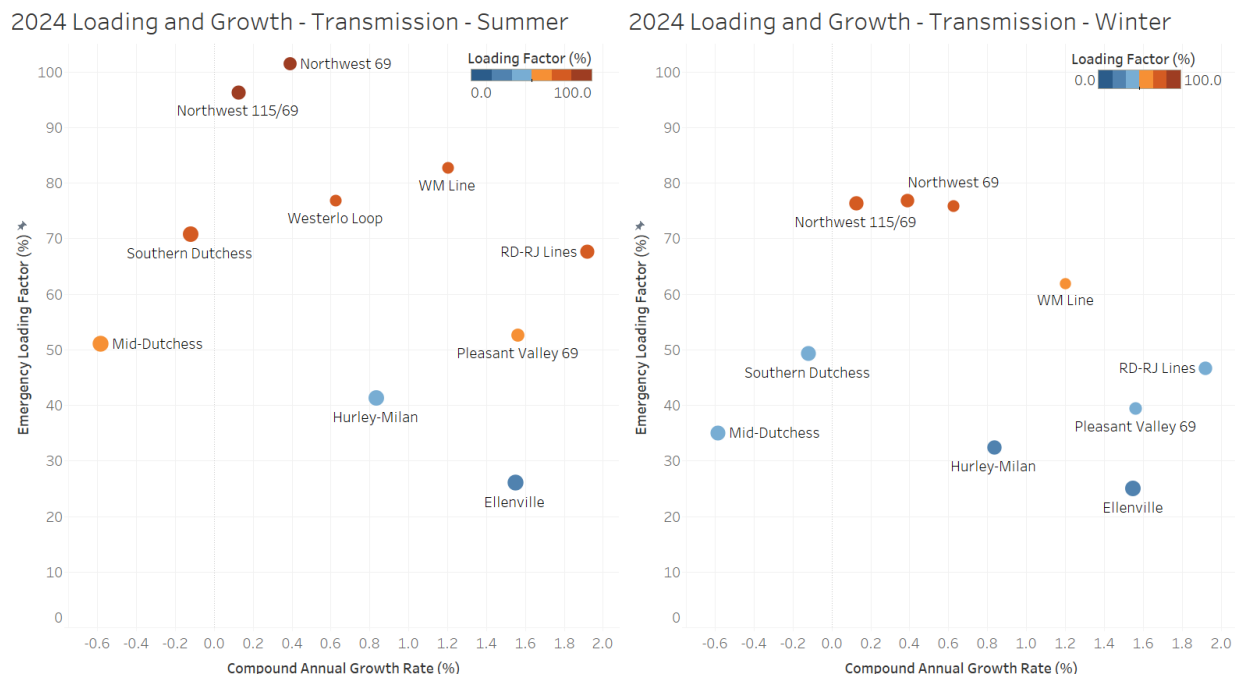
a) Local Transmission Forecasts

Central Hudson has ten local transmission areas. Figure 19 compares the annual load growth rate over the past ten years to the 2024 loading factor (actual peak divided by the location's operating limit) for each of Central Hudson's ten transmission areas. Locations with a growth factor above 0% are experiencing growth and locations where the loading factor is closer to 100% have less room for growth. Roughly 70% of the local transmission areas (load-weighted) have been experiencing growth, but approximately 25% (load-weighted) have loading factors above 85%. The two most highly loaded areas Northwest 115/69 kV and Northwest 69kV are part of non-wires alternative project that has deferred capital costs since 2015 and are scheduled for upgrades in 2029.

All transmission areas in Central Hudson's territory are currently summer-peaking systems. Some are experiencing slow growth or declining loads or have ample room for growth without having to upgrade them. Several of the local transmission areas have multi-value infrastructure projects. As part of the

upgrades, the transmission capacity for those locations will increase in order accommodate increasing amounts of solar, planned battery storage, and load growth.

Figure 19: Local Transmission Historical Growth Rates and Loading Factors



Notes: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

Table 11 summarizes the forecasts for each local transmission area for winter and summer annual peak loads. The forecasts incorporate the historic growth trends, projected changes in household growth, and the forecasts for electric vehicles, building electrification, solar, battery storage, energy efficiency and codes and standards. They are implemented at an hourly level, so the changes in the peak hour and season can be identified.

Table 11: Local Transmission 2025-2035 Integrated Load Forecast

		Actual 2024 Loading (%)	Historical growth rate ^[1]	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer	Ellenville	26.1%	1.5%	59.1	60.7	62.4	64.1	66.3	68.0	69.9	71.2	72.3	73.2
	Hurley-Milan	41.2%	0.8%	70.5	71.3	72.6	73.8	74.8	76.9	78.8	80.5	82.0	83.4
	Mid-Dutchess	51.0%	-0.6%	102.1	99.7	98.3	96.7	95.0	94.3	93.8	94.6	95.4	96.5
	Northwest 115/69	96.2%	0.1%	125.7	124.2	124.4	123.2	123.2	123.3	123.7	124.4	125.3	127.1
	Northwest 69	101.4%	0.4%	103.5	104.2	105.2	106.6	107.2	107.9	109.4	110.5	111.8	113.1
	Pleasant Valley 69	52.5%	1.6%	51.5	52.8	54.6	56.9	59.1	61.0	63.4	64.9	66.4	67.9
	RD-RJ Lines	67.5%	1.9%	90.4	93.5	97.0	100.8	105.2	108.3	112.0	114.1	116.7	119.1

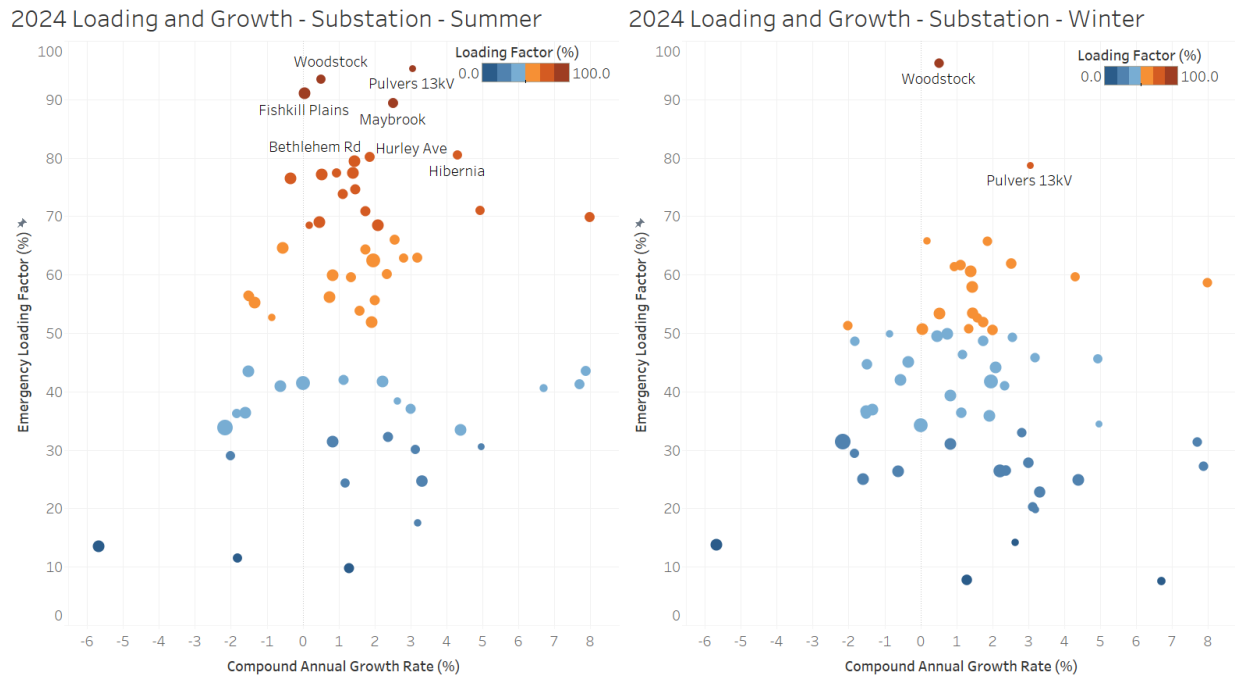
	Southern Dutchess	70.7%	-0.1%	134.6	133.8	133.2	133.0	132.9	132.9	133.9	134.8	137.2	139.6
	WM Line	82.6%	1.2%	52.5	54.0	55.6	56.7	58.5	59.5	60.5	61.8	62.8	63.9
	Westerlo Loop	76.8%	0.6%	55.7	55.9	56.4	57.3	58.3	59.0	59.4	59.7	60.1	60.2
Winter	Ellenville	25.0%	1.5%	62.6	65.5	68.6	71.7	75.4	78.7	82.4	85.9	89.6	93.2
	Hurley-Milan	32.3%	0.8%	64.8	66.2	68.3	70.3	72.2	75.1	77.9	80.6	83.1	85.7
	Mid-Dutchess	35.0%	-0.6%	77.3	76.2	76.0	75.6	75.3	75.7	76.3	77.9	79.7	81.7
	Northwest 115/69	76.3%	0.1%	132.2	131.8	133.6	133.5	134.8	136.2	137.9	140.0	142.3	145.4
	Northwest 69	76.9%	0.4%	113.1	114.5	116.3	118.5	119.8	121.2	123.5	125.4	127.4	129.5
	Pleasant Valley 69	39.3%	1.6%	44.7	46.5	48.8	51.6	54.4	57.0	60.2	62.8	65.3	68.0
	RD-RJ Lines	46.6%	1.9%	69.7	72.6	75.6	79.1	83.0	86.0	89.6	92.0	94.9	97.6
	Southern Dutchess	49.2%	-0.1%	104.1	104.2	104.7	105.4	106.2	107.1	108.9	110.6	113.6	116.6
	WM Line	61.9%	1.2%	42.5	43.8	45.2	46.2	47.9	48.8	49.8	51.1	52.2	53.3
	Westerlo Loop	75.7%	0.6%	64.7	65.6	66.9	68.9	71.3	73.8	76.5	79.5	82.8	86.3

[1] Forecasts are calibrated to the territory wide load forecasts and incorporate forecasted changes in household growth. They include loads and all load modifiers - solar, battery storage, EVs, heat pumps, and incremental EE and codes and standards. The implication is that the future differs from the past.

b) Substation Forecasts

Figure 20 compares the annual load growth rate to the 2024 loading factor for each of Central Hudson's load serving distribution substations. Roughly 75% of the substations have been experiencing growth, most of which has been driven by growth in customers. On average, peak demand per customer has been declining across Central Hudson's service territory. A small share of the substations, less than 8%, are at 85% or more of the operating limit. Most of the substations, 87% of them, remain summer peaking. With a few exceptions, most of the substations have room to accommodate electric vehicles and building electrification loads over the next five years. One of the highly loaded substations, Fishkill Plains, is part of non-wires alternative project that has deferred capital costs since 2015 and is scheduled for upgrades in 2027. Due to the number of substations, the substation level forecasts are included in Appendix C. The forecasts incorporate the historic growth trends, projected changes in household growth, and the forecasts for electric vehicles, building electrification, solar, battery storage, energy efficiency and codes and standards. They are implemented at an hourly level, so the changes in the peak hour and season can be identified and are calibrated to the territory wide forecasts.

Figure 20: Substation Historical Growth Rates and Loading Factors

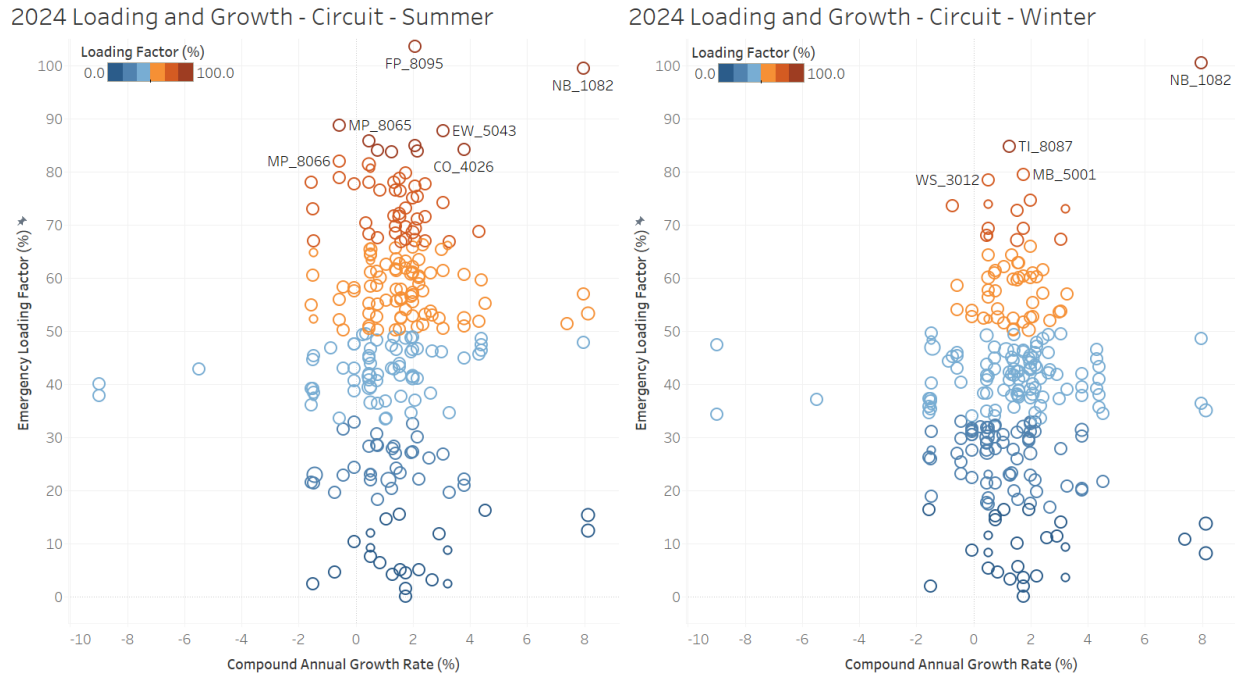


Notes: Bubble size is proportional to the LTE rating of the site. The color reflects the 2024 loading for each site.

c) Distribution Feeder Forecasts

Figure 21 compares the annual load growth rate to the 2024 loading factor for each of Central Hudson's load serving distribution substations. Central Hudson operates most of its distribution feeders so that two nearby feeders can accommodate peak loads for the feeder in question in case of outages or maintenance, ensuring a high level of service reliability. Generally, the feeders can accommodate more load, if needed, without exceeding the thermal limits and the main limitation for additional load is the substation transformer. Table 12 provides a high-level summary of the loading factors by season. With a few exceptions, most of the distribution feeders have room to accommodate electric vehicles and building electrification loads in the near term. The main drivers for feeder upgrades are either reliability, aging equipment, grid modernization efforts, or large lump loads. Due to number, the distribution feeders forecasts are included in Appendix C.

Figure 21: Distribution Feeder Historic Growth Rates and Loading Factors



Notes: Bubble size is proportional to the emergency rating of the site. The color reflects the 2024 loading for each site.

Table 12: Summary of Loading Factors for Distribution Feeders

2024 Loading Factor	# of circuits (summer)	# of circuits (winter)
Less than 50%	129	203
50% to 60%	50	28
60% to 70%	46	21
70% to 80%	23	7
80% to 90%	11	1
90% to 100%	1	0
100% or higher	1	1
Total	261	261

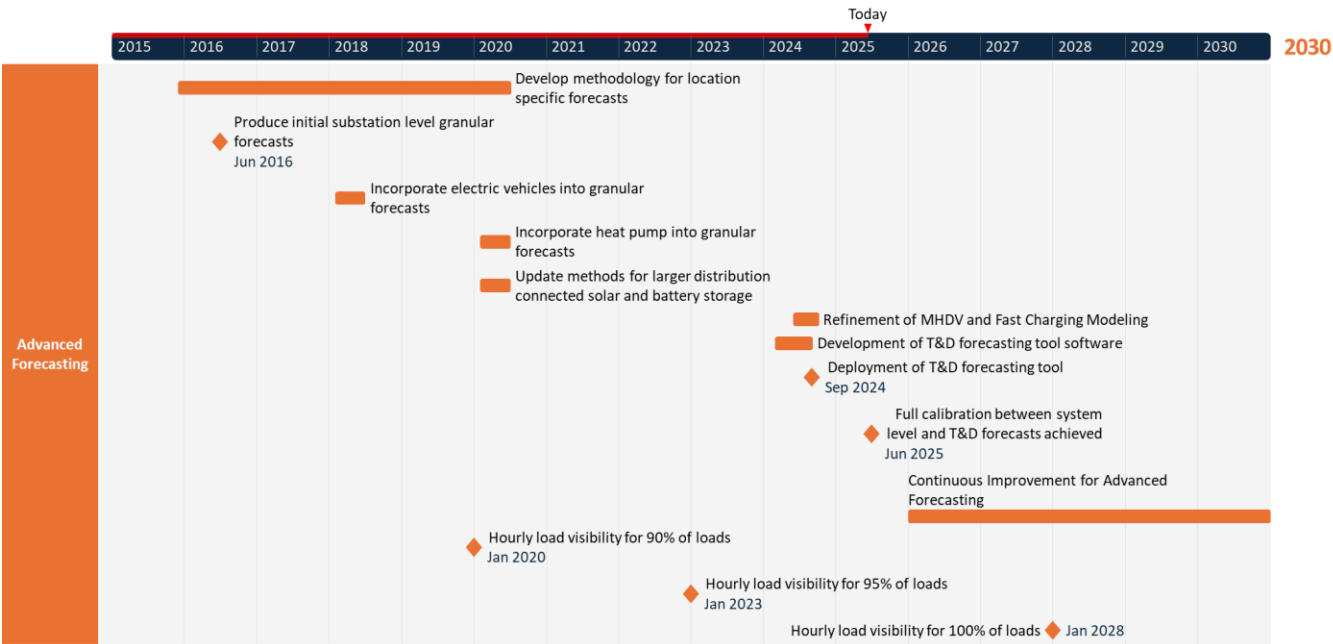
3. IMPLEMENTATION PLAN

Figure 22 shows the steps and milestones in Central Hudson’s advanced forecasting implementation plan. Central Hudson was one of the first utilities to implement granular location-specific forecasts of T&D loads, distributed resources, and beneficial electrification. While the granular growth rates, forecasted loads, and distributed resource and electrification forecasts are incorporated into T&D planning, historically, the updates were performed bi-annually to coincide with the DSIP filing. Over time,

the methodology and data sources have been improved, specifically for electric vehicles, heat pumps, larger distribution-connected solar and storage, and DCFC and MHDV forecasts.

In 2024, Central Hudson commissioned the development of a T&D forecasting tool to standardize, scale, and automate many components of T&D load forecasts and the tracking of DER and electrification penetration. Going forward, minor refinements to the advanced forecasting are planned, such as improving EV load shapes to better reflect the mix between managed, passively managed (Time-of-use rates), and actively managed load shapes, improving visibility into heat pump adoption, and other minor improvements to facilitate the integration of the T&D forecasts into the planning process.

Figure 22: Advanced Forecasting Implementation Timeline



1) Current Progress

The implementation plan for T&D forecasting of loads, DERs, and electrification has been standardized, scaled, and automated, including data pipelines to update the T&D load data and load modifier tracking. As part of the progress Central Hudson hit several key milestones, as shown in Table 13.

Table 13: Summary of Progress by T&D Forecasting Component

	Implementation Step	T&D Gross Loads	Solar	Battery Storage	Energy Efficiency	Electric Vehicles	Heat Pumps
1	Identify data sources	✓	✓	✓	✓	✓	✓
2	Develop granular forecasting methodology	✓	✓	✓	✓	✓	✓
3	Test methodology	✓	✓	✓	✓	✓	✓

	Implementation Step	T&D Gross Loads	Solar	Battery Storage	Energy Efficiency	Electric Vehicles	Heat Pumps
4	Scale methodology for all substations and transmissions areas	✓	✓	✓	✓	✓	✓
5	Produce forecasts	✓	✓	✓	✓	✓	✓
6	Make forecasts publicly available	✓	✓	✓	✓	✓	✓

In 2023, Central Hudson commissioned the development of a T&D forecasting tool, which was fully developed and has been operating on Central Hudson servers and accessible to planners since the Fall of 2024. The objectives of the tool were to:

1. Allow planners to access and incorporate data about load patterns, electrification, and DERs into planning (including the ability to download data).
2. Standardize the data and cleaning process.
3. Create data pipelines to update the underlying historical data, DER participation levels, and distribution system mapping (i.e., shapefiles, customer counts, etc.).
4. Visualize loads geographically and over time, including high-growth areas and heavily loaded areas where the loads are nearing capacity.
5. Visualize the current and forecasted adoption of DERs and electrification geographically and over time, including distributed solar, distributed battery storage, electric vehicles, and heat pumps.
6. Provide planners with the ability to simulate and visualize the effect of lump loads and load transfers on peak loads of individual circuits, substations, and transmission areas.
7. Provide the magnitude and timing of load changes needed to defer projects.
8. Estimate the value of deferring T&D projects.

The tool is built around modules for historical loads, forecasted loads, DER and electrification penetration, and scenario planning and T&D deferral. Most modules that display results from the analyses are interactive and have dropdowns for users to interact with and filter the data by T&D level and area. The historical and forecast hourly data are displayed in interactive data tables, and users can filter data in these tables and download the queried data.

Table 14: T&D Forecasting Tool Overview

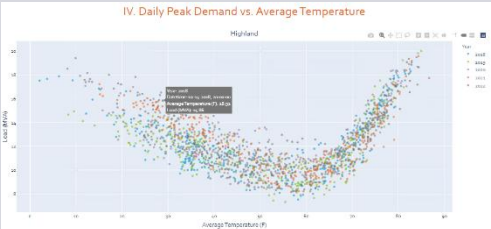
Tool Module

Examples

Historical Loads:

- Historical peaks tables
- Historical growth rates
- Loading factors, actual and weather-normalized
- Historical load data (8,760)
- Hourly patterns on peak days
- Weather sensitivity
- Load duration curves

IV. Daily Peak Demand vs. Average Temperature



I. Historical Peak Loads

Area ID	Date	Season	Hour Ending (EST)	Year	MW
System	01-06-2018	Winter	18	2018	3914.00
System	07-02-2018	Summer	18	2018	1114.00
System	01-21-2019	Winter	19	2019	3001.00
System	07-20-2019	Summer	18	2019	1109.00
System	07-27-2020	Summer	19	2020	1162.00
System	12-16-2020	Winter	18	2020	841.00
System	01-19-2021	Winter	19	2021	841.00
System	08-19-2021	Summer	19	2021	1168.00
System	01-19-2022	Winter	19	2022	891.00
System	07-22-2022	Summer	19	2022	1109.00

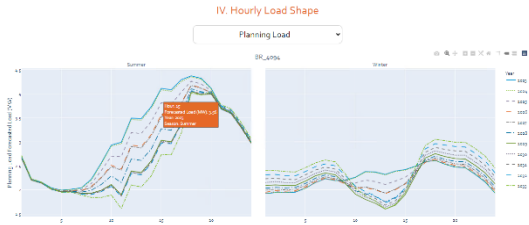
Showing 1 to 10 of 10 entries

Load Growth Forecast:

- Forecasted loads and load modifiers by year, hour, season, and location
- Interactive, downloadable tables
- Peak forecasts with uncertainty
- Hourly plots of peak load by season, hour, and year

IV. Hourly Load Shape

Planning Load



Forecasted Hourly Loads by T&D Level

Substation

Filter By:

All

2021, 2025

100%

Table

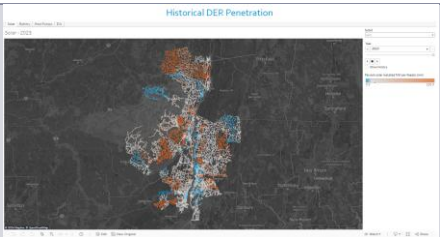
Download CSV

Area ID	Year	Season	Hour	Peak Load (MW)	95% Conf. Int. (MW)	90% Conf. Int. (MW)	50% Conf. Int. (MW)	5% Conf. Int. (MW)	1% Conf. Int. (MW)	0.1% Conf. Int. (MW)
System	2018	Summer	1	18.11	17.11	16.11	15.11	14.11	13.11	12.11
System	2019	Summer	1	17.11	16.11	15.11	14.11	13.11	12.11	11.11
System	2020	Summer	1	16.11	15.11	14.11	13.11	12.11	11.11	10.11
System	2021	Summer	1	15.11	14.11	13.11	12.11	11.11	10.11	9.11
System	2022	Summer	1	14.11	13.11	12.11	11.11	10.11	9.11	8.11
System	2023	Summer	1	13.11	12.11	11.11	10.11	9.11	8.11	7.11
System	2024	Summer	1	12.11	11.11	10.11	9.11	8.11	7.11	6.11
System	2025	Summer	1	11.11	10.11	9.11	8.11	7.11	6.11	5.11
System	2026	Summer	1	10.11	9.11	8.11	7.11	6.11	5.11	4.11
System	2027	Summer	1	9.11	8.11	7.11	6.11	5.11	4.11	3.11
System	2028	Summer	1	8.11	7.11	6.11	5.11	4.11	3.11	2.11
System	2029	Summer	1	7.11	6.11	5.11	4.11	3.11	2.11	1.11
System	2030	Summer	1	6.11	5.11	4.11	3.11	2.11	1.11	0.11
System	2031	Summer	1	5.11	4.11	3.11	2.11	1.11	0.11	0.01
System	2032	Summer	1	4.11	3.11	2.11	1.11	0.11	0.01	0.00
System	2033	Summer	1	3.11	2.11	1.11	0.11	0.01	0.00	0.00
System	2034	Summer	1	2.11	1.11	0.11	0.01	0.00	0.00	0.00
System	2035	Summer	1	1.11	0.11	0.01	0.00	0.00	0.00	0.00
System	2036	Summer	1	0.11	0.01	0.00	0.00	0.00	0.00	0.00
System	2037	Summer	1	0.01	0.00	0.00	0.00	0.00	0.00	0.00
System	2038	Summer	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System	2039	Summer	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System	2040	Summer	1	0.00	0.00	0.00	0.00	0.00	0.00	0.00

DER and Electrification

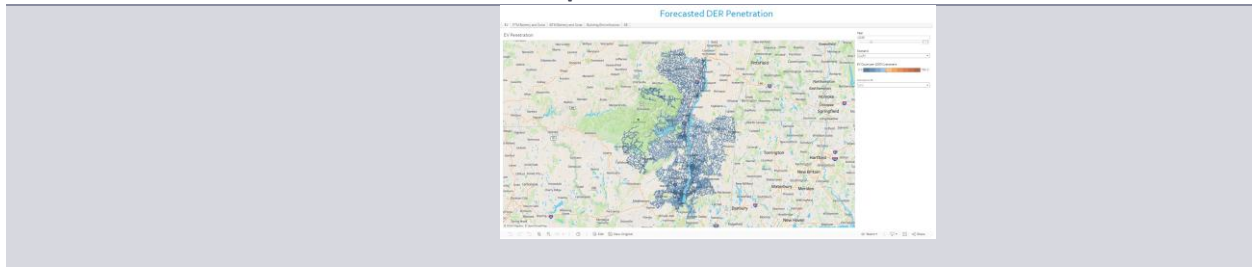
- Historical tracking of penetration by load modifiers and locations
- Forecast of penetration by load modifier and locations
- Hourly plots of load modifiers by season, hour, and year

Historical DER Penetration



Tool Module

Examples



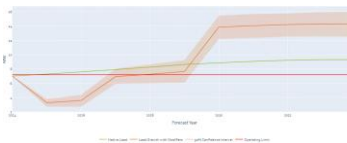
Scenario Planning and T&D Deferral

- Ability to include lump loads, load transfers, and load relief
- Deferral value
- Likelihood of exceeding operating limit
- Load growth with and without load relief
- Load relief needed by year and hour
- Hourly peak loads by year with and without load modifiers

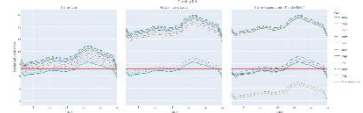
I. Deferral Value Based on Years of Deferral

Years of Deferral	Deferral Rate (\$/kW)	2025 Rate (\$/kW)	2030 Rate (\$/kW)	2035 Rate (\$/kW)
0	\$0.00	\$0.00	\$0.00	\$0.00
1	\$0.00	\$0.00	\$0.00	\$0.00
2	\$0.00	\$0.00	\$0.00	\$0.00
3	\$0.00	\$0.00	\$0.00	\$0.00
4	\$0.00	\$0.00	\$0.00	\$0.00
5	\$0.00	\$0.00	\$0.00	\$0.00
6	\$0.00	\$0.00	\$0.00	\$0.00
7	\$0.00	\$0.00	\$0.00	\$0.00
8	\$0.00	\$0.00	\$0.00	\$0.00
9	\$0.00	\$0.00	\$0.00	\$0.00
10	\$0.00	\$0.00	\$0.00	\$0.00

III. Load Growth With and Without Load Relief



V. Load Growth Forecast with Modifiers



IV. Load Relief Needed (\$/kW)

Year	Load Relief Needed (\$/kW)
2025	\$0.00
2030	\$0.00
2035	\$0.00
2040	\$0.00
2045	\$0.00
2050	\$0.00
2055	\$0.00
2060	\$0.00
2065	\$0.00
2070	\$0.00
2075	\$0.00
2080	\$0.00
2085	\$0.00
2090	\$0.00
2095	\$0.00
2100	\$0.00

2) Future Implementation and Planning

Central Hudson's implementation of advanced T&D forecasting is largely complete. Going forward, minor refinements of the advanced forecasting are planned, such as:

- Improving EV load shapes.** The objective is to better reflect the mix between managed, passively managed (Time Of Use rates), and actively managed load shapes using data specific to New York. Currently, Central Hudson relies on the simulated load shapes from National Renewable Energy Laboratory's EV Lite Pro tool.
- Developing a plan to improve visibility into heat pump adoption.** Visibility into heat pump market share is one of the key areas targeted for improvements going forward. Central Hudson had near full visibility of heat pump adoption through 2021 via its programs, which included both partial and full-home heat pumps. However, starting in 2022, Central Hudson lost full visibility into heat pump adoption when the program incentives were limited to full-home, cold-climate heat pumps. Central Hudson will need to assess the options and costs for improving visibility into heat pump market share and adoption over time.
- Updating models for medium- and heavy-duty vehicles and buses.** The models will be updated as more adoption and load pattern data become available.
- Implementing enhancements to the T&D tool to allow better integration into planning.** This may include incorporation of the Proactive Planning process, adding a load study table to the tool, increasing the detail regarding DERs and electrification reported in the tool, and allowing

planners to flag odd T&D data reads in addition to the existing automated data cleaning processes.

4. RISKS AND MITIGATION

The load forecasts influence decisions about whether to reinforce or upgrade T&D infrastructure. Thus, the risk is double-edged. If the forecasts are too high, it can lead to the expansion of T&D infrastructure that is either too early or too large. If the forecasts are too low, it can lead to overloaded T&D equipment, degradation of the equipment life, and degradation of reliability for Central Hudson's customers. The risks are largest for T&D upgrades with significant lead times to build since forecasts further into the future are inherently more uncertain than near-term forecasts. The largest forecasted changes in Central Hudson loads are arising from the growth in electric heating loads, large distributed solar installations, and lump loads. While electric vehicles add to the load, they do not pose as large a risk to planning because they are inherently more diverse and predictable.

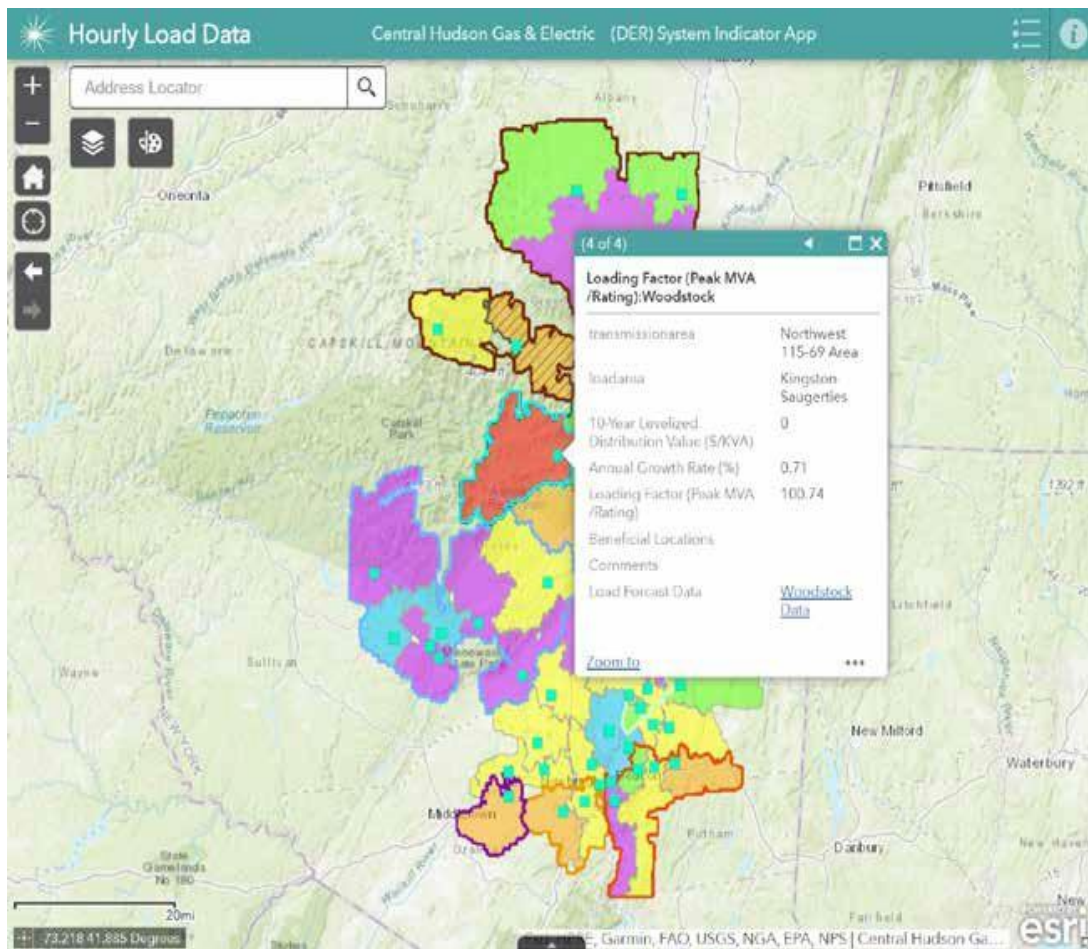
Central Hudson is undertaking the following steps to mitigate the risk associated with forecasting:

- **Continuously updating T&D forecasts.** Doing so provides the most up to date information to enable better decisions.
- **Continuously tracking DER and electrification installation at a granular level.** As discussed earlier, the adoption of electric vehicles and heat pumps is clustered, with some parts of the Central Hudson's territory experiencing faster and deeper adoption than other areas. By tracking the adoption and connecting to the different distribution planning levels – transmission, substations, and circuit feeders – Central Hudson can better identify the locations where electrification will trigger upgrades.
- **Explicitly quantifying uncertainty.** By quantifying the uncertainty, Central Hudson avoids over reliance on point estimates and has a realistic understanding of the risk posed by load growth.
- **Avoiding expanding T&D infrastructure too early.** The build lead times for different T&D resources are known, which allows Central Hudson to balance the risk of overbuilding against the reliability risk.
- **Revising models to improve accuracy.** Central Hudson is relying on a training and testing model framework to improve the accuracy of the forecast models. The data is split into training data used for model development and then used to predict out of sample using the testing data. The accuracy is assessed by comparing the predicted versus actual values using the testing data.

5. STAKEHOLDER ENGAGEMENT

The stakeholder interface will be hosted on Central Hudson's website, and it will be map-based (CenHud Hourly Load Data). The maps, as illustrated in Figure 23, are interactive. The main display is a choropleth map, often called a heat map, which shows which locations have higher or lower T&D deferral value potential. The map includes popup information boxes that, when clicked, provide users with details regarding the name of the substation, expected T&D deferral value, growth rate, loading factor, and Long-Term Emergency ratings. The popup boxes include links that allow users to download historical and forecast 8760-hour data as a CSV file.

Figure 23: Central Hudson Stakeholder Interface



<https://experience.arcgis.com/experience/06a86b7f2ca844dea4caecef6922fbc8>

Central Hudson has reached out to stakeholders overtime for input, including:

- Stakeholder workshop to review the forecasting methods, results, and data access portals in 2016, 2018, 2020, and 2023. The main feedback was to see if the forecast data could be expanded to 10 years, which will be included in the 2025 update.
- Central Hudson hosts an annual Solar+ Summit which provides DER developers and industry professionals, including energy storage developers, with information on the technical and procedural aspects of interconnecting with the utility, industry updates, available programs and incentives. The event also provides networking opportunities with industry professionals. At the conclusion of each Solar+ Summit, a survey is provided for feedback from attendees and is utilized for future planning purposes, including specific topics of interest that professionals would like to see and hear about. This includes speaking on capital infrastructure plans that are identified from forecasts, particularly as it relates to supporting increased headroom for DERs.

- Within the Interconnection Technical Working Group as well as Integrated Planning Working Group, Central Hudson has referenced the historical and forecasted 8760 data that is included within the System Data Portal (based on advanced forecasting analyses) to stakeholders' numerous times. These data points have been mentioned as useful for energy storage systems seeking interconnection to the electric grid.
- Ad-hoc discussions with community organizations engaged in energy planning issues.

6. ADDITIONAL DETAIL

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.

Central Hudson has developed a System Data Portal on its public website at www.cenhud.com, under My Energy and Solar and Distributed Energy.²² The System Data Portal provides substation and transmission area load and supply forecasts for five years and will be updated with the 2025 DSIP forecasts to include a 10-year forecast horizon. The 8760 data can be accessed at:

<https://experience.arcgis.com/experience/06a86b7f2ca844dea4caecef6922fbc8>. The map is interactive and searchable. Clicking on any transmission area or substation brings up a pop up box that includes information for location selected including a downloadable excel file with the historical loads and the forecasted loads for each of the components: gross load, solar, battery storage, electric vehicles, heat pumps, and energy efficiency and codes and standards. Identify and characterize each load and supply forecasting requirement identified from stakeholder inputs.

In discussions held by the Joint Utilities' Load Forecasting Working Group and System Data Working Group, stakeholders identified that historical hourly load data down to the circuit level and forecasted hourly load data at the substation level would be sufficient for their purposes. Also, in these discussions, the stakeholders expressed a desire to have the DER forecasts at the same level of granularity.

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

Central Hudson currently provides load and DER forecasts for five years down to the substation level and makes these forecasts available for third-party use through its System Data Portal, which is described in request 1, above, and in the stakeholder engagement section.

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

Central Hudson's forecasts for both load and DER are provided for five years at the substation and transmission area level and for 8760 hours per year. The forecasts provide details about the components, including gross native loads, electric vehicles, heat pumps, solar, battery storage, and energy efficiency.

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

Central Hudson develops separate forecasts for load and DERs, including energy efficiency, electric vehicles, heat pumps, distributed energy storage, and distributed solar.

²² <https://experience.arcgis.com/experience/06a86b7f2ca844dea4caecef6922fbc8>

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

Central Hudson currently produces probabilistic load forecasts and probabilistic DER forecasts for EE, EV, energy storage, and solar. Central Hudson made significant progress in the development and implementation of probabilistic forecasting capabilities as part of the 2016, 2018, 2020, and 2023 DSIP filings. Central Hudson has continued to advance these methodologies since then, as outlined in this section and within Appendices B (Load and DER Forecasts). The use of probabilistic methods has been integrated into Central Hudson's normal forecasting and planning process. Table 14 provides a more detailed overview of Central Hudson's T&D forecasting tool.

6) Describe how Central Hudson's existing/planned advanced forecasting capabilities anticipate the interrelated effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency.

Central Hudson's existing probabilistic forecasting methods incorporate existing and forecasted DERs and electrification into the forecasts capturing the interrelated effects. Because the timing of these load modifiers varies, the summer and winter peak day loads are stacked at an hourly level to help identify how the peak load hours and seasons will evolve over time. (See Figure 16 as an example). The hourly data by season and forecast year is available at all Central Hudson grid levels, including system, transmission areas, substations, and feeder circuits. Because the forecasts quantify 8760 T&D loads and 8760 hourly end use technology loads by year and location, they allow tracking of how new technologies influence the magnitude and timing of summer and winter location-specific and territory-wide peaks.

The locational aspect is captured by developing propensity scores that quantify the likelihood of adopting various DERs and electrification technologies now and over time. The approach effectively tells us which customers are early adopters versus later adopters. This is done for each of Central Hudson's 315,000 sites. The approach allows Central Hudson's planner to identify pockets where, for example, adoption of electric vehicles is expected to be higher in the near term. The propensities to adopt DER and electrification technologies are interrelated. For example, sites with high solar adoption propensity scores also tend to have higher EV adoption propensity scores. By design, the propensities or likelihood of adoption are calibrated to the territory-wide forecasts. Aggregating the propensities for any given distribution feeders yields the number of sites that are expected to adopt the technology in question for the year selected at that location.

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

The current forecasts for utility use are granular transmission-area, substation, and circuit-level peak-load forecasts. The transition to probabilistic hourly-load forecasts for load and DER has allowed Central Hudson's planning process to transition to utilizing this information for more granular planning of the distribution system, the impacts of DER, and the identification of system issues beyond peak load-serving capability.

8) Describe Central Hudson’s specific objectives, means, and methods for acquiring and managing the data needed for its advanced forecasting methodologies.

Central Hudson utilizes self-generated datasets or publicly available datasets to the extent that they are available and provide the information necessary to produce granular hourly load and DER forecasts.

Central Hudson has more than three years of valid hourly load data from most of its 62-distribution load-serving substations, encompassing over 97% of its cumulative system load. Through the latest Load and DER forecasting process, there were a number of enabling assumptions made regarding the ability of DER in the queue to complete development, the location of future DER development, and the synthesizing of missing data. These assumptions, while enabling the development of the current forecast, will be the focus of future efforts to refine data through experience or expanded data sets.

Central Hudson has collected 8760 hourly end load shapes for solar, battery storage, light-duty electric vehicles (at home, at work, public charging, and fast charging), medium- and heavy-duty electric vehicles, heat pumps (cooling, heating, and water heating), and for significant end uses targeted by energy efficiency. Where possible, the technology end-use profiles are specific to Central Hudson’s territory and weather. Central Hudson will update the library of end-use profiles used for planning as better and more accurate data becomes available.

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

See this Section above and Appendices A for the details on the methods used to produce substation-level load, DER, and electrification forecasts.

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

See this section above and Appendices A for details about the levels of accuracy of the various components of the load, DER, and electrification forecasts.

11) 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.

Central Hudson provides load and DER forecasts at the substation level for five years on an 8760-hour load basis. This provides DER developers with the locational granularity and load shapes needed to understand the area’s loads, expected DER development, potential for future DER development, and, when coupled with other available data elements such as hosting capacity or circuit capacity, an estimate of the available headroom for DER development (both maximum and minimum). The data is publicly available via the System Data Portal, which is described earlier in this section. It is provided at the temporal and spatial granularity that developers agreed was adequate during the discussions with the JU.

12) 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.

Central Hudson utilizes a probabilistic forecasting methodology that relies on a wide range of forecasts and probabilities to reflect the impact of variability, and it does not use sensitivity analyses in this method. Central Hudson does, however, supplement its data-driven forecasts with a policy-based forecast that aligns with the NYISO forecasts for zone G.

Sensitivity analysis is typically applied when scenario-based models are employed, when key inputs are based on assumptions, or when there is substantial uncertainty around critical drivers of results. Central Hudson has transitioned to a probabilistic approach, where feasible, and does not typically apply sensitivity analyses.

Central Hudson's objective is to rely on data-driven, probabilistic analysis, which minimizes assumptions and, by definition, models the range of likely outcomes. When and where possible, Central Hudson has shifted away from scenario-based models, which are more suitable for sensitivity analysis. The uncertainty for key inputs, such as load growth, is explicitly quantified based on the available data, and the implications of the uncertainty on outcomes are quantified based on Monte Carlo simulations, showing the full range of potential outcomes.

Sensitivity analysis still plays a vital role for technologies that are in a nascent stage or experiencing truly disruptive innovation(s). As discussed in Appendix C, while the policy goals for heat pumps are clear, the adoption curve remains uncertain at this point. Likewise, there is limited data regarding the adoption rate and charging mechanisms of medium- and heavy-duty electric vehicles. Planning for those two technologies will require sensitivity analysis until adoption patterns and trends become more predictable.

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

As previously mentioned, Central Hudson utilizes self-generated or publicly available datasets to the extent that they are available and provide the information necessary to produce granular hourly load and DER forecasts. Central Hudson does use information from DER development activities in the service territory (such as projects in the queue and project payments). Central Hudson held webinars after the 2016, 2018, 2020, and 2023 DSIP filings and presented the forecasting approach, including data sources, methods, process, and results, and invited feedback from stakeholders, but so far has not received direct input from DER developers to further inform its forecasting efforts.

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

As part of the REV process, Central Hudson has actively worked with the other JUs in several areas to share lessons learned and identify best practices, both in New York and in other jurisdictions. One of the JU groups is focused on forecasting processes both in New York and other jurisdictions. Central Hudson will continue to be actively engaged in these types of initiatives on an ongoing basis. Central Hudson also remains very actively engaged in the NYISO working groups and committee structures. As the NYISO

makes advances around load and DER forecasting. Central Hudson will remain involved to learn from this work and ensure that it is consistent with the more granular Central Hudson processes.

15) Describe new methodologies to improve overall accuracy of forecasts for demand and energy reductions that derive from EE programs and increased penetration of DER. 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.

Central Hudson already separately forecasts energy efficiency, distributed solar, distributed battery storage, electric vehicles, and heat pumps outside of the load model, but will continue to refine its forecasting methodologies and the accuracy of these forecasts. This will occur first through continued market experience using traditional methods to predict market adoption and saturation, and second, through the development of more granular forecasts by technology and market to further define the expected DER impacts.

For all the forecasts, a training-testing framework is used in model development in order to minimize the potential for over-specification and to ensure the accuracy of results is measured out-of-sample. Central Hudson also utilized machine learning for its DER and electrification technologies that are the foundation for the granular geographic adoption forecasts

C. GRID OPERATIONS

1. KEY TAKEAWAYS, CONTEXT, AND BACKGROUND

The growing penetration of DERs has impacted, and will continue to impact, the Company's grid operations. As DER penetration causes multi-directional power flows across the grid, it will become increasingly important to execute more complex grid functions. To enable these functions, the Company will require enhanced levels of DER monitoring, control, and measurement – all of which will support the ability of DERs to provide value to customers and the system.

Central Hudson, through its Grid Modernization Program, is taking significant steps to accommodate DERs and model the system impacts of DERs to preserve distribution system safety and reliability. Critical to these efforts is a set of foundational investments that will support DSP capabilities. Central Hudson's Grid Modernization Program is comprised of six critical projects:

- Distribution Automation – automated devices, distribution infrastructure (poles and wires).
- Distribution Management System – a centralized software solution with state estimation that enables SCADA telemetry and control.
- Geographic Information System – Common Information Model; provides a single consolidated mapping and visualization system.
- Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS.
- Substation Metering Infrastructure – substation feeder relay metering and transformer LTC upgrades required for accurate DMS power flow.
- Distribution System Operations – the organization responsible for monitoring and controlling the electric distribution system using the DMS.

These six foundational projects are closely interrelated, and the realization of benefits from the Grid Modernization Program depends on the mutual completion of each project.

As Central Hudson continues its path toward an intelligent and resilient grid, we are exploring several strategic future-state capabilities. Key focus areas include enhancing real-time visibility through advanced telemetry and sensor integration, investigating the use of analytics and rules-based systems for early anomaly detection, and preparing our infrastructure for more robust distributed energy resource (DER) management. The Company is assessing technologies that will enable more automated and intelligent demand response, integration of edge intelligence devices for localized decision-making, and closed-loop automation for voltage and reactive power management. Additionally, Central Hudson is evaluating artificial intelligence and machine learning applications for real-time optimization and forecasting to proactively manage load, weather impacts, and DER variability. These exploratory efforts will help position Central Hudson to effectively respond to evolving grid conditions, regulatory expectations, and customer needs.

2. IMPLEMENTATION PLAN

1) Current Progress

a) Distribution Automation

Distribution automation is a family of technologies, including sensors, processors, information and communication networks, and switches, through which a utility can collect, automate, analyze, and optimize data to improve the operational efficiency of its distribution power system.

The DA components of the Grid Modernization Program include distribution system infrastructure upgrades and the installation of IEDs. The distribution system infrastructure upgrades will develop ties between adjacent feeders or upgrade existing ties with larger conductors. Coupled with Intelligent Electronic Devices (IEDs), and the intelligence of the DMS, this will increase switching capabilities between load pockets, improving feeder management by flattening voltage profiles for further voltage reduction and reducing losses. The upgrades will also reduce the frequency and duration of interruptions and increase the ability to defer significant transmission system investments. Through DA, Central Hudson will also address two radial transmission feeders that do not meet the design criteria of 7 MVA of unreserved load. As an alternative to constructing a redundant transmission feed, this DA solution was sought and will be implemented once the DMS is fully functional. While the IEDs provide voltage and current data, additional sensors or select AMI data with even greater accuracy may be required to verify models at fringe points and provide metering information at feeder heads and key locations where substation automation is not yet available. Over 1,600 Intelligent Electronic Devices (e.g. electronic reclosers, switched capacitors, and voltage-regulating devices), are being installed through DA and other projects.

Table 15 presents progress and remaining implementation work related to Central Hudson's DA rollout.

Table 15: Distribution Automation Roll-Out through June 2025

District	2015	2016	2016	2017	2017	2018	2018	2019	2019	2020	2020	2021	2021	2022	2022	2023	2023	2024	2024	2025
	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–	Q3–	Q1–
	Q4	Q2	Q4	Q2	Q4	Q2	Q4	Q2	Q4	Q2	Q4	Q2	Q4	Q2	Q4	Q2	Q4	Q2	Q4	Q2
Fishkill Phase 1	P, D, C	C	I																	
Fishkill Phase 2		P, D, C	D, C	I																
Newburgh Phase 1			P, D, C	D, C	C	C	C	I												
Newburgh Phase 2			P, D	D, C	D, C	D, C	C	C	C	I										
Poughkeepsie Phase 1					P, D	D, C	D, C	D, C	D, C	D, C	C	C	C	C	C	C	I			
Poughkeepsie Phase 2						P	P	D, C	D, C	D, C	D, C	D, C	C	I						
Catskill								P	P, D	D	D, C	D, C	D, C	D, C	D, C	D, C	C	C	C	C
Kingston Phase 1										P	P	D	D	D, C	D, C	D, C	D, C	C	C	C
Kingston Phase 2												P	P	D	D	D, C	D, C	C	C	C

P = Planning; D = Design (field); C = Construction; I = Implemented

To achieve the benefits of DA, two key advanced applications will be implemented along with the infrastructure upgrades: Fault Isolation and Service Restoration (FISR) and Volt/Var Optimization (VVO).

Though still in the implementation phase, there are benefits realized from the Grid Modernization program. The final implementation of the Geographic Information System project December 2023 has enabled the transition to a Common Information Model (CIM) – a digital twin of the distribution network. This CIM allows Central Hudson to have one source of reference and maintenance for the distribution network. The completion of Distribution Automation projects in the Fishkill, Poughkeepsie, and Newburgh Operating regions have increased operating capabilities through stronger circuit ties and increased hosting capacity. The onset of more Electronic Reclosers has allowed the in-service of more local FISR teams to enhance customer reliability and integration into the Distribution Management System.

The above benefits along with the remaining Grid Modernization projects catapulted Central Hudson to a central operating model within a newly formed Distribution System Operations department during the summer months of 2024. As Central Hudson continues to execute the Grid Modernization mission, additional systems will be integrated into the Distribution Management System for centralized operations across all operating districts.

- **Fault Isolation, and Service Restoration (FISR):** Central Hudson has been utilizing Automatic Load Transfer (ALT) teams since 2002. Autonomous teams are currently limited by the need for the devices to be in close proximity and the complexity of the design - required by the current decentralized approach. With the installation of the DMS, decisions can be made on a centralized basis and they can consider data from a much wider geographic area. When a fault occurs, the IEDs will transmit information to the DMS to locate the section in which the fault occurred, isolate it by opening adjacent IEDs, and then close IEDs to restore service to as many customers as possible. With sufficient distribution feeder ties and automated switches, an entire substation can even be restored in the event of a fault on a radial transmission line, avoiding significant transmission system investment to provide a backup feed to these stations. The DMS can also recommend additional manual restoration that can be performed where appropriate and provide potential fault locations to reduce patrol time. Additional electronic reclosers will need to be installed along feeders and at mid-point ties, and supervisory control of feeder head breakers must be added where it is not currently available.
- **Volt/VAR Optimization (VVO):** The concept of VVO revolves around the implementation of voltage reduction and optimization of reactive power flow to improve power quality and efficiency. Applying detailed distribution system models, switched capacitor locations are selected to flatten the voltage profile across a feeder while ensuring that the power factor is maintained in an optimal range and losses are reduced.

Then, voltage-regulating devices (load tap changers or voltage regulators) are sited to lower overall voltage. As the voltage is reduced, the associated energy and carbon emission reductions occur reducing energy usage, while not impacting the customer's energy end use or comfort.

Locations for installation are selected to leverage existing device locations whenever feasible, but new installations are frequently required. Once installed, the devices must be programmed with initial settings, which are coordinated and controlled centrally through a DMS to ensure the

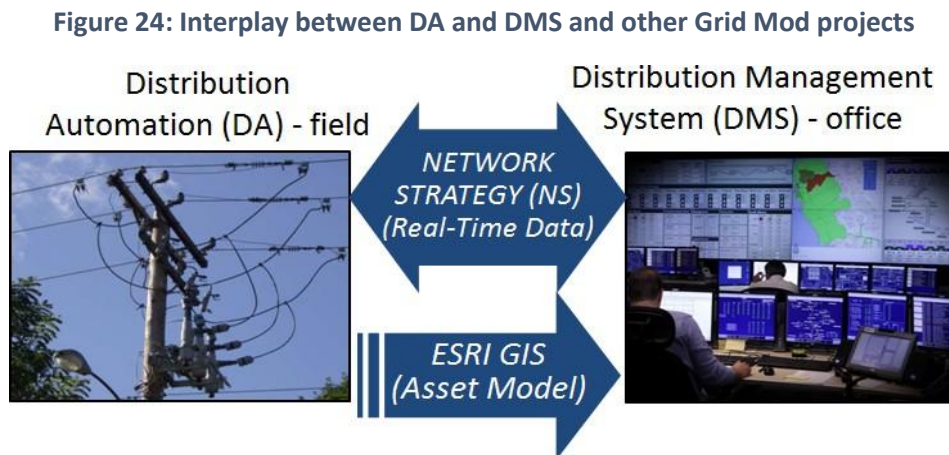
settings account for current system conditions. Voltage regulators and substation load tap changers will need to be retrofitted with two-way communications and control. End-of-line voltage sensors or select AMI locations must be connected, and communications must be added to verify the DMS model and ensure voltages are maintained within the ANSI C84.1 acceptable ranges. Operating the distribution system more efficiently will result in decreased line losses, reduced greenhouse gases, and decreased customer demand.

While Central Hudson currently complies with all existing Conservation Voltage Reduction orders, implementing sophisticated modeling with a DMS and two-way communications and control will enable the Company to achieve the incremental benefits described in the business case provided to DPS Staff as a part of the Case 14-E-0318 Rate Case discovery process. This centralized approach will also provide a platform to integrate DERs.

Initially, the impact will be considered from a technical perspective in terms of switching and CVR. In the longer term, control of third-party devices could be included with enhancements to the DMS if monitoring, control, and markets change in that direction.

b) Distribution Management System

A Distribution Management System is a software platform that helps utilities manage and control their electric power distribution networks efficiently and reliably. The DMS continuously monitors the status of distribution network equipment, providing real-time data for operators to make informed decisions. Devices installed as part of Central Hudson's DA Program communicate with the DMS. Distribution System Operations staff utilize DA devices to regularly feed live electrical system data into the DMS, as shown in Figure 24 below.



Central Hudson's DMS implementation includes:

- Distribution-level SCADA (Supervisory Control and Data Acquisition);
- Advanced System Modeling;
- Near Real-Time Load Flow; and
- Contingency Analysis Capabilities.

The DMS is comprised of a distributed computing environment with open system architecture. The DMS has five separate environments within the Primary Control Center (PCC): Production (PROD), Quality Assurance System (QAS), Distribution Operator Training Simulator (DOTS), Program Development System (PDS), and an alternate Production System within the Alternate Control Center (ACC). The PCC and Backup Control Center environments are highly reliable, fully redundant, and scalable, and contain stringent security features to prevent access by unauthorized personnel.

The DMS is being implemented in a phased approach as it relies on the completion of the other Grid Modernization projects listed earlier in this section, and these components are tightly intertwined. Much of the work on the DMS has been completed, including product acceptance in 2021 and the integration with the EMS system.

The implementation plan for the DMS will be staged to take advantage of opportunities in several sections of the service territory. To achieve optimal benefits, implementation will be focused on an operating district basis in the following order: Fishkill, Poughkeepsie, Newburgh, Catskill, and Kingston. Over 99% of IEDs within the Fishkill and Poughkeepsie Operating District are fully integrated into the DMS, moving said districts to a central operating model during the summer of 2024.

Today, the operation of the distribution system is centralized for the franchise areas located on the East of the Hudson River and decentralized for the franchise areas located on the West of the Hudson River. Following the in-service of Grid Modernization in the Poughkeepsie and Fishkill Operating Districts, Distribution Operators are actively engaged with the DMS. The Catskill, Kingston, and Newburgh Operating Districts still have operational responsibilities for their respective geographic-based operating regions as Grid Modernization is being deployed. Both modes of operation exist in harmony, predominantly in a semi-autonomous mode where intelligent devices such as Automatic Load Transfer (ALT) teams, switched capacitors, voltage regulators, electronic reclosers, fault indicators, and voltage sensors make decisions on their own or only communicate information in one direction.

The addition of stronger tie points will enable Distribution System Engineers to employ the same devices that are applied to FISR during other periods of system stress, such as low voltage conditions or when thermal limitations are exceeded. Alarm points will be triggered on the DMS, and the Distribution Operators will remotely initiate switching to manage these situations.

c) Geographic Information System

A Geographic Information System (GIS) is a computer system designed to capture, store, manipulate, analyze, and present all types of geographic data. GIS works with data that has geographical references, such as coordinates (latitude and longitude), addresses, or boundaries. GIS produces maps and visualizations that help users understand complex spatial relationships and patterns. Electric utilities use GIS systems to manage and optimize their vast networks, from asset management to outage response and customer service. GIS allows them to visualize, analyze, and manage their infrastructure, leading to more efficient operations, better decision-making, and improved customer experiences.

As described above, GIS is a key project of Central Hudson's Grid Modernization Program and was completed in December 2023. Central Hudson's enterprise-wide GIS is an ESRI-based platform that provides a single consolidated mapping and visualization system capable of storing important information on facilities and assets, including DERs, such as geospatial location and other asset properties. GIS enables new capabilities for Central Hudson, including developing accurate distribution

grid models (potentially down to the customer meter) and enabling calculation and visualization of DER installations and hosting capacity.

GIS supports many DMS capabilities, including:

- Greater operational efficiency with improved automation management;
- Preservation of safety and reliability in real-time operations through integration of disparate data sources; and
- Improved interaction with Supervisory Control and Data Acquisition (SCADA) devices, including distribution feeder breakers, substation load tap changers, and DERs.

d) Network Communications Strategy

A critical component of grid operations is the communications network. Since 2014, Central Hudson has been implementing its Network Communications Strategy (NCS), comprising a gradual rollout of technologies for current and future expected communications needs. The scope of the rollout covers Central Hudson's fixed assets. These fixed assets include the Company's corporate offices, gas gate and regulator stations, electric substations, electric system DA equipment, and large customer meter installations. Technical applications such as SCADA, transmission line protection, and security (video and card access) utilize the network, as well as general traffic supporting Voice over Internet Protocol. The Communications Network has enabled Central Hudson to broadly implement DA and DMS.

Central Hudson's communication network rollout includes the following components:

- **WAN:** The WAN is the high-bandwidth backbone connecting the highest-priority sites in the system. The Physical Layer (Layer 1) for the WAN network is a fiber optic cable and point-to-point microwave radio operating at 6 GHz through 18 GHz. The current plan for the WAN Network includes approximately 160 gateways.
- **FAN:** The FAN is a medium-bandwidth network. The FAN is a mesh radio network for communication with DA equipment, electric substations, gas regulator stations, and large customer meter installations. Gateways for connection to the FAN network will be located at the endpoints or nodes of the WAN Network. The current plan for the FAN Network includes approximately 3,000 nodes. The nominal capacity of the Tier 2 radios is 50 Mbps at the gateways, dropping down to 0.75 Mbps at the endpoints of the mesh.
- **FAN Expansion:** The FAN is envisioned to expand to a low bandwidth network. A future possibility for further expansion of the FAN network would be a mesh radio network similar to the FAN network, or an AMI system.
- **Network Monitoring System:** As part of the Pilot Project, a Network Monitoring System (NMS) was established. The hardware for the NMS consists of a high-availability server separated from the corporate network by a firewall. The NMS includes software for the WAN microwave equipment, the WAN Multiprotocol Label Switching system, and the FAN radio mesh system. The NMS provides for remote configuration of the WAN and FAN systems. The NMS also provides for monitoring of the system. Alarms generated remotely by the network equipment are accumulated at the NMS. The NMS has the capability to generate email notifications of alarms.

Table 16 shows the planning, design, and construction phases through 2025.

Table 16: Network Communications Planning, Design, and Construction Phases

District	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kingston Pilot Area	P, D	P, D, C	C									
WAN Fishkill		P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C				
FAN Fishkill		P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C					
WAN Newburgh		P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C			
FAN Newburgh				P	P, D, C	P, D, C			P	P, D, C		
WAN Poughkeepsie			P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C		
FAN Poughkeepsie				P	P, D, C	P, D, C	P, D, C	P, D, C	P, D, C			
WAN Catskill						P, D, C	P, D, C		P, D, C	P, D, C		
FAN Catskill					P	P, D, C			P		P, D, C	
WAN Kingston		P, D, C				P, D, C				P, D	P, D, C	
FAN Kingston	P, D, C								P		P, D, C	
P = Planning; D = Design (field); C = Construction Complete												

Central Hudson recognizes the importance of robust and reliable communication networks to support operational efficiency and comprehensive coverage. Given the unique geographic challenges and existing limitations in available communication coverage of some of Central Hudson’s operating districts, the Company is currently exploring and assessing options for additional fiber backhaul and Tier 2 communication infrastructure. This evaluation process is focused on identifying strategic opportunities to strengthen network resilience and ensure consistent operational coverage. As Central Hudson continues this assessment, specific attention will be placed on understanding deployment feasibility, potential technology alternatives, and cost-effective solutions, allowing the Company to strategically position itself to address current and future operational needs.

e) Substation Metering Infrastructure

Electric substation metering infrastructure refers to the systems used to measure and monitor electrical energy at substations. Central Hudson has been upgrading its substation metering infrastructure, specifically the substation feeder relay metering. The installation of substation-level metering points, which includes per phase data reporting, is necessary to implement both VVO and FISR schemes accurately. The installation of new substation metering is being rolled out in coordination with other aspects of the grid modernization program. This approach ensures synergies across field resources/ under a single scope of work.

f) Distribution System Operations (DSOs)

Distribution System Operations refers to the organization responsible for monitoring and controlling the electric distribution system with the DMS. In 2022, Central Hudson began the construction of a new state-of-the-art Primary Control Center. This is the central location from which utility operations staff monitor and manage the utility system. Construction and commissioning of Central Hudson’s new Primary Control Center was completed in 2025, and as of this DSIP filing, it is now operational. The DMS has five separate environments within the Primary Control Center : Production (PROD), Quality

Assurance System, Distribution Operator Training Simulator (DOTS), Program Development System (PDS), and an alternate Production System within the Alternate Control Center (ACC). The PCC and Backup Control Center environments are highly reliable, fully redundant, and scalable, and contain stringent security features to prevent access by unauthorized personnel.

g) How the Current Implementation of the Grid Modernization Program Supports Stakeholders Current and Future Needs

To safely, reliably, and efficiently operate the distribution system in the future with increasing levels of DERs, the system will no longer be able to run on a decentralized and autonomous basis, and will need to have the ability to react to and manage the changing conditions that may result from these DERs. Central Hudson's Grid Modernization Program, and its current implementation, directly supports stakeholder development and adoption of DER.

An area in which the company's Grid Modernization efforts have been responsive to stakeholder needs relates to advancing options for low-cost monitoring and control (M&C) of DER. Central Hudson has continued to make progress on (1) enhancing M&C capabilities and promoting DER accommodation through the implementation of its Grid Modernization Program and (2) identifying lower-cost M&C solutions.

As part of previous JU efforts related to M&C of DER, there were four main takeaways that still apply today:

- M&C may refer to real-time use cases, such as for traditional utility operations and SCADA devices, and non-real-time use cases, such as for planning purposes. Distinguishing between these two-time dimensions will drive communications backhaul discussions (e.g., periodicity and data payload size).
- Each utility has typically relied on utility-owned assets for M&C for SCADA operations (i.e., real-time). However, less critical operations have been able to use third-party systems for M&C, as long as they have appropriate interfaces within the utility back office. While the increased penetration of these third-party systems will provide enhanced visibility, Central Hudson also acknowledges there will be complexities for integrating these systems from both a technological and process perspective.
- There is still a significant level of uncertainty around lower-cost M&C solutions as to their security and ability to integrate into real-time operations and planning processes. To maintain the cybersecurity of the entire Central Hudson system, the Company must ensure that all digital systems have the same security provisions throughout the service territory. Although this is an important consideration for utilities when adopting new technologies and processes, they often overlook it when solely focusing on a "low-cost M&C hardware" approach.
- Central Hudson has continued to evaluate low-cost M&C solutions for 100 through less than 500 kW interconnections to monitor these sites in real-time for Operations, as these systems have limited visibility to-date. Currently, Central Hudson is working on a low-cost M&C R&D project that leverages Central Hudson's existing Sensus communication network technology. Once the R&D is completed, Central Hudson will look to standardize this low-cost monitoring device for future DER installations in the 100kW-499kW range, to provide better visibility into

how these systems operate (without impacting economics of DER projects). Central Hudson is currently working to implement this solution within the field on a 300 kW solar PV system with an anticipated installation date in 2026, though this timeline is contingent upon the developer/project's schedule.

2) Future Implementation and Planning (Grid Modernization Program)

Central Hudson, as detailed in the previous section, will continue its implementation efforts for key enabling technologies, such as DA, DMS, Outage Management System (OMS), and the Network Communications Strategy projects. Additionally, the Company will continue to make progress towards low-cost M&C solutions, including leveraging smart inverters. The Company has also identified the need to include a DERMS within the Grid Modernization roadmap; however, the DERMS initiative is not anticipated to commence until 2027.

The work and investments, along with the timing and sequence of these investments, are described further below.

Table 17: Grid Modernization Future Activities

Grid Modernization Project	General Description of Future Implementation and Planning (5 years)	Timing and Sequence of Work and Investments (5 years)
Distribution Automation	Implementation is substantially complete. Future work includes construction in the Catskill and Kingston Districts.	Construction will be completed in Q2-2025.
Geographic Information System	Implementation is complete.	Work was completed in December 2023.
Distribution Management System	Implementation is complete.	Remaining effort includes integration of Newburgh, Kingston, and Catskill DA devices, as they are brought online in 2025.
Distribution System Operations	Implementation was completed on August 5, 2024. Future work will include adding additional staffing as more DA devices are integrated and become operational.	The onboarding of Distribution Operators is closely tied to the in-service of DA asset and centralization of Operating Districts. 8-10 Operators will be onboarded by 2025 with an addition 2 Operators in 2026.
Network Communications	Implementation is complete in the Fishkill, Poughkeepsie, and Newburgh Districts.	Future work will comprise the Catskill and Kingston Districts, expected to be completed within the year.
Substation Metering Infrastructure	Implementation remains underway.	Future work will include operationalizing each substation for Conservation

Grid Modernization Project	General Description of Future Implementation and Planning (5 years)	Timing and Sequence of Work and Investments (5 years)
		Voltage Reduction and Wide Area Restoration between now and approximately 2030.
Distributed Energy Resource Management (DERMS) System	This is a new project that will need to be initiated. Work has not started.	DERMS initiative is anticipated to commence in 2027.

a) How the Future Implementation of Central Hudson’s Grid Modernization Program Will Support Stakeholders’ Needs

The Company’s current and future progress towards the Grid Modernization Program will enable the Company to enhance monitoring and control capabilities and accommodate increasing levels of DERs, which support New York State’s energy goals. Additionally, as previously described in the above sections, VVO and FISR components have direct benefits to customers by reducing energy usage and ultimately costs through VVO, as well as improving reliability through FLISR automation. Central Hudson’s future DERMS initiative will optimize DER management and allow the company to determine how it can interconnect and integrate more distributed generation and energy storage devices in the future.

b) Where and How Plans for Grid Modernization Related Work Affect the Coordinated Grid Planning Process (CGPP).

The CGPP and DSIP are filings with overlapping but distinct scopes. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs.

c) Where and How Investment Plans Developed through the CGPP affect Grid Modernization-Related Work and Investments Presented in this DSIP Update

Planned capital investments, including technology platform investments and how they will be leveraged, will be included in the DSIP (e.g., AMI, automation, DMS, etc.) and the results of executing the processes will be used to inform the CGPP.

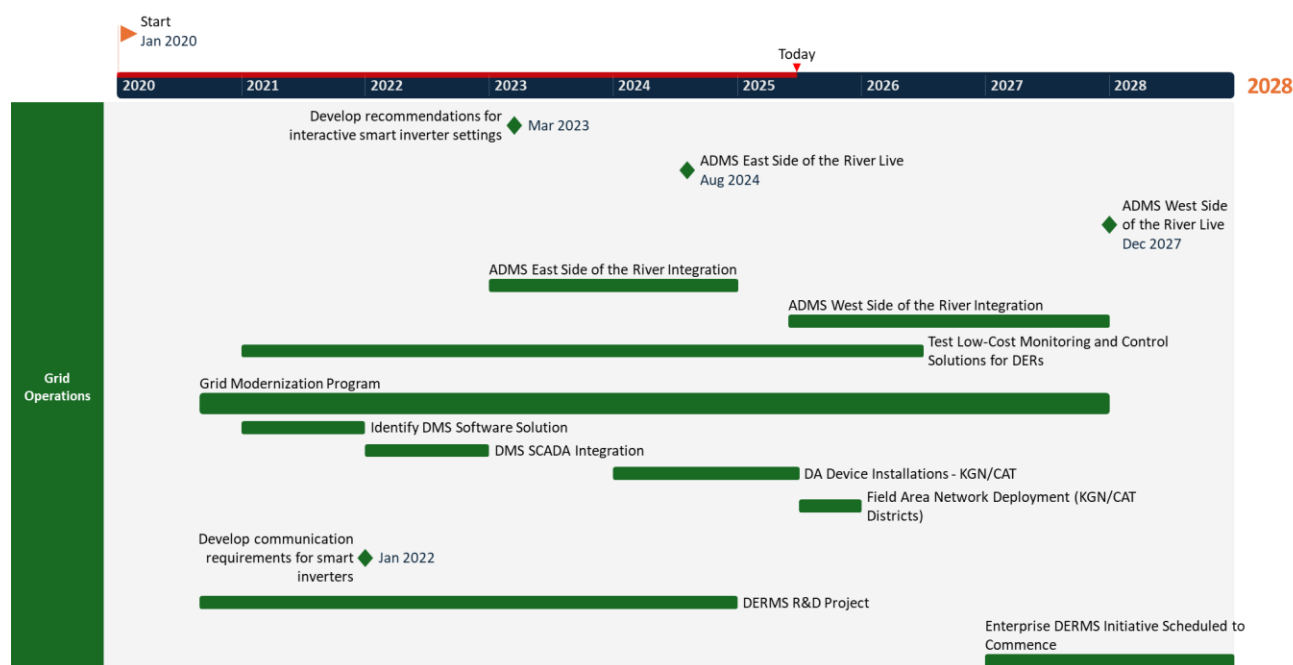
The CGPP is aimed at developing a “CLCPA-focused planning process,” including “the State’s bulk transmission, local transmission, and distribution planning processes.” The goal is to improve planning processes to better coordinate the studies performed by the New York State utilities with the NYISO’s bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution (LT&D) and bulk system studies with NYSERDA’s renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the CGPP stages, one of the key inputs to the CGPP is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council. While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may

result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP processes. As of this DSIP writing, the CGPP is currently in Stage 3 (Local Assessment) of the 6 Stage process.

3) Integrated Implementation Timeline

The Grid operations timeline includes a variety of tools, software, sensors, and equipment to assist with visibility, data tracking, planning, and load flow modeling.

Figure 25: Grid Operations Timeline



3. RISKS AND MITIGATIONS

To continue building the suite of capabilities needed to support advanced grid operations, including advanced monitoring and control, Central Hudson will continue to make sustained investments in grid modernization technologies, including Distribution Automation, the Distribution Management System, and the Network Communications Strategy projects. Consequently, the amount of available funding for these efforts will impact the timing and extent of implementation. Implementation of these assets is a core competency from an Engineering and Construction perspective, which will significantly minimize this risk.

While Central Hudson has hired several staff, staffing will remain challenging. The Distribution System Operator positions are very technical and the Distribution System Operators will be required to work on

a rotating shift schedule. By this stage, however, Central Hudson knows the job requirements, has gained experience hiring for the position, and hired several staff for the position.

An additional risk, as mentioned above, is the continued cybersecurity of the entire distribution system. As the Company continues to integrate both utility-owned and third-party technologies, it will be critical to adequately address any cybersecurity concerns to minimize risk. Central Hudson continues to monitor cybersecurity developments as provided in the Joint Utilities Cyber and Privacy Framework filed in the Supplemental DSIP and is actively engaged in industry discussions. Central Hudson has also developed a set of internal standards for the Cyber Security of Operational Technology and is in the process of implementing these standards throughout the enterprise. More detail on the initiative is discussed in the Energy Efficiency section.

4. STAKEHOLDER ENGAGEMENT

a) Categories of Stakeholders Engaged in DSIP Development and Use

In the DSIP development, a wide range of stakeholders are involved, and their needs are incorporated through various engagement processes. Key stakeholders include developers and market participants, the NYISO, government officials, community members, agencies, customers, and even specific interest groups. The DSIP aims to ensure that all stakeholders are informed, engaged, and have opportunities to provide input throughout the project's development.

b) When and How the Goals and Needs of Each Stakeholder Category are Identified and Incorporated into the DSIP.

Specific to Central Hudson's Grid Modernization program, the company engages with each stakeholder category through several means.

For M&C requirements, the JU have continued to engage with stakeholders to identify barriers to and opportunities for lower-cost M&C solutions. The Joint Utilities will continue coordinating with the DER community to identify mutually beneficial solutions and maintain transparency into utility M&C requirements. These engagements occur through the ITWG.

Moreover, twice per year, the Joint Utilities of NY hosts a webinar to update stakeholders and take questions on matters relating to DSP services, including those enabled by the Grid Modernization Program. Since the last DSIP, stakeholder webinars have been held on 7/21/23, 12/14/23, 6/27/24, and 12/10/24. Stakeholders were invited to provide their feedback and requests in these forums.

Also, on Central Hudson's internet site, the company makes contact information available for stakeholders seeking distributed energy resource information. Stakeholders routinely make use of these contacts to reach out to Central Hudson to discuss their needs.

Additionally, Central Hudson hosts its own touchpoints with DER stakeholders, including the company's annual Solar + Summit, which discusses the company's DER and DSIP programs, including information sharing. Central Hudson solicits feedback from stakeholders at this event. Additional information and past agendas can be found at <https://www.cenhud.com/en/my-energy/distributed-generation/solar-summits/>.

Central Hudson also reviews its foundational technology investments with the Public Service Commission and other stakeholders during rate filings, the most recent occurring under Case 24-E-0461. During this, stakeholders have opportunities to review, question, and comment on the Company's plans.

c) Central Hudson's Need for Stakeholder-Provided Information, Capabilities, and Actions

Central Hudson requires stakeholder information in several ways that are relevant to its processes, including the Grid Modernization program. One key area pertains to customer plans regarding new loads, and plans pertaining to the electrification of buildings and transportation. Another key area pertains to development activities pertaining to distributed generation and energy storage. Each of these areas are an input into the forecasts that Central Hudson develops, which in turn, inform aspects of the rollout of the Grid Modernization program.

d) Means and Methods for Effectively Informing and Engaging Associated Stakeholders as Planning, Design, and Implementation Progress.

As described above, Central Hudson employs several means and methods for informing and engaging stakeholders associated with the Grid Modernization Program. These include but are not limited to Central Hudson collaborating with the Joint Utilities to host webinars, Central Hudson hosting its own touch points such as the Solar + Summit, participation in DPS-staff led working groups, and stakeholder discussions held as part of rate case proceedings.

e) How Central Hudson Will Ensure that Information, Tools, and Engagement Opportunities Deliver the Intended Support

Key to this is maintaining an open line of communication with all stakeholders and incorporating feedback and requests where appropriate and feasible. As described above, Central Hudson actively maintains and participates in several channels of communication and forums for dialogue.

5. ADDITIONAL DETAIL

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

Central Hudson's primary responsibility is to preserve distribution system's safety and reliability. The Company has coordinated with DER aggregators and the NYISO to define operational coordination requirements, including specific roles and responsibilities for each party, to ensure the utility can continue to preserve safety and reliability for a system characterized by increasing amounts of DERs.

As part of FERC Order No. 2222, DERs are anticipated to begin participating in a NYISO wholesale market starting in 2025. The Joint Utilities have worked with the NYISO and defined the roles and responsibilities between the utility, NYISO, DER aggregators, and individual DERs to enable DER wholesale market participation while preserving system safety and reliability.

Deployment of technology platforms like the Distribution Management System (DMS) and Distributed Energy Resources Management System (DERMS) will give the Distribution System Operators (DSOs) added monitoring and controlling capability over the local DER assets. Continued rollout of Central Hudson's foundational technology investments, including Distribution Automation, the Distribution Management System, and its Network Communication Strategy programs, will also create better visibility

of local DER assets. The deployment of these technologies will follow a phased approach. The Company understands that it will be a challenge to obtain monitoring and controlling capability for all DERs in the distribution system, especially the DERs that are already in service.

The DSOs can use these technology platforms to coordinate with NYISO and third-party stakeholders to provide guidance on how to leverage local DERs to benefit the local distribution system, and also 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.

The types of roles and responsibilities defined within Central Hudson's programs and procurements are the requirements necessary for effectively addressing utility needs while providing DER aggregators and individual DERs actionable information to help maintain and operate a safe and reliable distribution system. These requirements are defined by the Company in coordination with third parties. As more DERs are integrated into the distribution system, the utility will look to refine and update its processes to provide additional guidance that is clear and adaptable.

With respect to DER wholesale market participation, the Joint Utilities have coordinated with the NYISO on an ongoing basis to define the roles and responsibilities for relevant parties to facilitate DER wholesale market participation in a safe and reliable manner. The Joint Utilities have continued to hold stakeholder engagement sessions since the 2023 DSIP to update stakeholders on progress they have made in their coordination with NYISO. Similarly, input received through the NYISO stakeholder process has informed the development of these currently defined roles and responsibilities.

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.*

For distribution-related programs and procurements, the utilities will continue to capture all roles and responsibilities within contractual agreements with relevant parties. Central Hudson and the Joint Utilities will continue to coordinate opportunities to align the procurement process, which may help inform a more standardized set of roles and responsibilities across the utilities. While the high-level roles and responsibilities will generally be consistent across the different utilities' programs and procurements, the unique nature of each system may result in differences (e.g., pre-defined time periods in which the DER portfolio is required to be available for performance).

Concerning operational coordination for DER wholesale market participation, the Joint Utilities have worked with the NYISO to define the coordination requirements between the DSP, NYISO, DER aggregator, and the individual DER. Most of the communication and coordination as part of these efforts have been captured, or will be captured, in the NYISO Tariffs or manuals.

With the deployment of DMS and DERMS platforms, DSOs will have a clear line of sight to local DERs, due to added monitoring and controlling capabilities. As information is continuously transferred between the DSO, NYISO, and DER aggregators, the utility DSOs will be able to make more informed decisions. This will lead to more DERs being leveraged for distributed system needs and also will make it easier for DERs to participate in the NYISO marketplaces, as the DSOs will be able to identify any constraints in advance, allowing DERs adequate time to adjust their offering in the NYISO marketplace as needed.

As mentioned earlier, the deployment of these technologies will follow a phased approach. The Company understands that it will be a challenge to obtain monitoring and controlling capability for all DERs in the distribution system, especially the DERs that are already in service.

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 that accommodate and extensively employ DER services. The information provided should address:

- a) organizations;
- b) operating policies and processes;
- c) information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch and control, etc.;
- d) data communications infrastructure;
- e) grid sensors and control devices;
- f) grid infrastructure components such as switches, power flow controllers, and solid-state transformers;

Linked to Central Hudson's foundational technology investments (which include Distribution Automation, the Distribution Management System, and its Network Communication Strategy programs) are the changes that will be necessary to operate this system on a real-time, 24/7 basis and have greater visibility into the operation of the DERs. With regard to the changes that will be made to operate the system, Central Hudson plans to centralize the operation of the distribution system with DSOs similar to how the transmission system is operated today. These DSOs will monitor the operation of the distribution system, and the decisions being made by the DMS, and intervene as needed. This significant change in how the system will be operated will require substantial organizational changes regarding policies and procedures, as well as how the system will be operated during major weather events. The Electric Distribution System Operations Whitepaper (last updated and filed with the 2018 DSIP) provides policy changes and resource changes that will be needed to transition to this structure. In addition to safely and reliably operating the system with the increased level of DERs, the ability to have greater visibility and control over the output or voltage of the larger DER systems, especially, will be critical.

5) Describe the Company's approach and ability to implement advanced capabilities:

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

The Energy Management System provides for monitoring of the transmission system and most of the distribution feeder breakers. The distribution feeder breaker monitoring within the EMS typically includes breaker position (Open or Closed) and feeder analog values, including MW, MVAR, and distribution bus voltage. Throughout the service territory, approximately 769 distribution automation devices, including ALT switches, reclosers, switched capacitor banks, and voltage regulators, are currently deployed and monitored by Sensus.

- b) Identify areas to be enhanced through additional monitoring and/or distribution automation.

The planning of Distribution Automation device locations is completed through a detailed modeling and analytical process. The Company plans to monitor additional distribution circuits in the DMS. The Company plans to eventually implement monitoring of the entire distribution system in the DMS.

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

Additional monitoring of the distribution system within the DMS is dependent on the installation of distribution automation devices and network communication equipment and the development of the DMS GIS models. This is currently underway. Costs associated with this deployment can be found in Central Hudson's Capital Forecast.

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

Additional monitoring of the distribution system will allow for expanded use of FISR and Volt/VAR control as well as accommodate additional DERs.

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

Significant progress has been made in operationalizing the ADMS following its go-live in 2022. As new IEDs are brought online and integrated into the ADMS, advanced applications such as Volt/VAR control and Fault Isolation System Restoration for the distribution circuits become active. Distribution System Operators, who are actively monitoring the system, have control capabilities to remotely operate the distribution system, near real-time, for planned switching or restoration events. Onboard state estimation provides the ability for power flow calculation to converge in the DMS, using GIS model topology, and reports of severely underloaded or overloaded circuit elements, such as transformers, and switches.

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

Over time, additional circuits and IEDs will be integrated into the DMS to provide a complete model, which will allow for wider opportunity to use FISR for reliability benefits and closed loop VVO/CVR for efficiency purposes. A completely integrated system will also have the shared benefit of increased hosting capacity, monitoring, and control of DERs. Additionally, as part of the results of a previous State University of New York at New Paltz (SUNY New Paltz) ESS + PV system Research and Development (R&D) project, Central Hudson has identified the importance of and need to develop advanced forecasting capabilities as a future functionality within the DMS. As a result, the Company is currently supporting a NYSEDA Program Opportunity Notice jointly with Electrical Distribution Design (EDD) and the State University of New York at Albany (SUNY Albany) related to forecasting both load, and DER systems, as well as extreme weather conditions that may result in outages. The Company has also been performing research to understand the number of, and distances at which, irradiance sensors will need to be installed and fed back into the DMS, in order to forecast solar PV systems accurately.

g) Identify Capabilities currently provided by DER Management Systems (DERMS).

As described earlier, Central Hudson's current focus is implementing the Grid Modernization strategy which includes finalizing DMS and Network Strategy integration. Following the OMS upgrade and integration with DMS in 2026, the Company anticipates commencement of the DERMS initiative in 2027.

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

Although Central Hudson's DERMS initiative is not expected to commence until 2027, the Company initiated an R&D project in 2021 related to DERMS functionality to help inform decisions for future

DERMS initiatives. The goal of this project was to provide Central Hudson with guidance and framework on three DERMS use cases: 1. manage equipment capacity and voltage constraints during normal grid states, 2. manage constraints during abnormal grid states, and 3. coordinate operation of DER across the transmission and distribution grid. There were various deliverables as part of this project which was broken down into three phases: Phase 1 – Scenario Creation, Requirements, and Algorithm Development; Phase 2 – DERMS Lab Testing; and Phase 3 – Field Demo, Economic Assessment and Gap Analysis. This R&D project was a partnership with EPRI, Smarter Grid Solutions (SGS), General Electric (GE), and Nexamp to evaluate corrective vs. predictive DERMS, as well as demonstrate the DERMS capabilities via a field demo. EPRI oversaw the project and received funding from NYSERDA via PON 4128. GE demonstrated predictive DERMS within the EPRI test lab environment, and SGS demonstrated the corrective DERMS through a field demo between Central Hudson and the PV site owner, Nexamp. The project was completed in December 2024, with various findings and lessons learned that will help inform Central Hudson with future DERMS initiatives. As with any technology, as DERMS capabilities and functionalities continue to evolve, Central Hudson will stay up-to-date through industry research, as well as collaboration with the NY JU.

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

Based on future DER technologies that allow for greater functionality, the business cases to install these DERs may lead to Central Hudson's desire to operate them in a more refined manner through the DMS, a future DERMS, or as part of its energy resource procurement. As these functionalities are developed, the Company can test the capabilities through pilot projects. As mentioned above, Central Hudson worked with EPRI on the NYSERDA Program Opportunity Notice related to deploying a DERMS. The goal of this DERMS research was to better manage grid performance, particularly in instances where DER penetration has caused the system to exceed thermal and voltage limitations.

As described in DER Interconnections, the Company has seen high penetration of DER in localized areas from DER systems looking to interconnect to the distribution system, medium voltage substation bus, as well as the transmission system. In order to increase the hosting capacity for these locations, Central Hudson sought to understand if a DERMS solution would be sufficient to address these issues. This effort also sought to develop and test NYISO and Distribution System Operations coordination frameworks when DER resources are providing market services.

While there were numerous results and lessons learned for this R&D project, the lab testing of the predictive and corrective DERMS, as well as the field demo of the corrective DERMS, successfully demonstrated the ability to control the output of a 2MW DG site in response to a measured thermal capacity constraint on a 13.2kV feeder. Additionally, for the predictive lab demo, additional constraints for both thermal and voltage violations were eliminated via DERMS by selectively curtailing the DERs that contributed most to the constraints, and the DERMS successfully adjusted DER envelopes to keep both voltage and loading within acceptable ranges during feeder reconfigurations. Given that these are real world scenarios, the results are promising, and the learnings/findings will be used to help inform Central Hudson with future DERMS initiatives.

D. ENERGY STORAGE INTEGRATION

1. KEY TAKEAWAYS

Energy Storage Systems (Energy Storage), such as Battery Energy Storage Systems (BESS), are generally recognized as an important element of the grid of the future. Energy Storage captures and stores energy for later use, a capability which is potentially useful for customers adopting such devices, to the wholesale energy market, and as an integrated part of the electric T&D system, either to defer the need for a traditional upgrade or to improve the operation of the grid.

In recent years, Central Hudson has refined its capabilities to interconnect customer-owned energy storage. This includes having released the preferred BESS charge and discharge schedules in September of 2023 for use by the development community in proposing projects for interconnection. It also includes providing and keeping current energy storage hosting capacity maps that illustrate distribution areas that can potentially accommodate BESS.²³ To date, Central Hudson has interconnected over 1 MW of customer-owned standalone energy storage and 14.53 MW of customer-owned solar PV + energy storage through the SIR process, and several Energy Storage facilities are undergoing assessment for interconnection with the bulk power system and participation in NYISO markets.

As to Energy Storage integrated with the electric T&D system, since the 2023 DSIP, Central Hudson has continued to engage in initiatives to evaluate energy storage deployment. This includes having commissioned the Four Corners Microgrid, which entered service on June 30, 2023, for reliability purposes. Moreover, Central Hudson with the Joint Utilities submitted its study to the Public Service Commission of non-market T&D energy storage use cases in October 2024.²⁴ This study included an engineering and economic review of the types of energy storage applications that utilities can deploy as part of obligations to provide safe and reliable service in the most efficient and effective manner. Central Hudson has also continued to engage in other internal and industry efforts to evaluate energy storage deployment. As described in this section, one such recent effort has been conducting a procurement for bulk power energy storage scheduling and dispatch rights in compliance with Ordering Clause #2 in the Case 18-E-0130 *Order Establishing Energy Storage Goal and Deployment Policy*, issued and effective December 13, 2018.

As with all grid infrastructure investment decisions, a key driving element is the overall cost effectiveness of any solution. The Company's evaluations have explored the costs and benefits of energy storage systems as compared to traditional T&D solutions. These analyses have included the potential additional wholesale market revenues that storage systems can generate. Based on current cost and market data and current incentive levels, the Company's assessments of Energy Storage have not shown instances where this technology class represents lower cost solutions to meet operational or capacity needs on the Central Hudson system. Central Hudson continues to monitor costs, benefits, and technical characteristics of these resources for use as a potential solution for grid needs.

²³ See <https://www.cenhud.com/en/my-energy/distributed-generation/energy-storage-hc-map/>

²⁴ In the Matter of Energy Storage Deployment Program (Case 18-E-0130), Joint Utilities' Study of Non-Market Transmission and Distribution Energy Storage Use Cases and Related Process Proposals, October 29, 2024.

2. CONTEXT AND BACKGROUND

Battery Energy Storage Systems represent flexible energy resources that have the technical capability to operate as both a source and load for energy and capacity. This operating flexibility has the potential to create a number of value streams for the BESS as both a standalone system and when paired with other energy resources (i.e., battery + PV applications). As recognized in *New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage*,²⁵ energy storage will need to play a critical role in supporting New York's decarbonized electric grid by integrating large quantities of variable renewable energy, reducing curtailment, and storing renewable generation for times when it is needed most.

While Central Hudson has had limited direct experience with energy storage systems, since the 2023 DSIP, Central Hudson has continued to engage in initiatives to evaluate energy storage deployment and potential use cases. As with all grid infrastructure investment decisions, a key driving element is the overall cost effectiveness of any solution. The Company's evaluations have explored the costs and benefits of energy storage systems as compared to traditional T&D solutions. These analyses have included the potential additional wholesale market revenues storage systems can generate and as part of on-going and future assessment of energy storage, Central Hudson will look to identify additional benefits that may be prudent to consider. Based on current cost and market data and current incentive levels, both analysis and experience with the Bulk Energy Storage Scheduling and Dispatch Rights Request for Proposal (RFP), assessments have not shown instances where energy storage systems represent lower cost solutions to meet operational or capacity needs on the Central Hudson system. However, Central Hudson is in the process of completing the most recent 2024 Bulk Energy Storage Scheduling and Dispatch Rights RFP and is also participating in various R&D projects associated with energy storage. These efforts will provide additional insight into BESS costs and operational capabilities.

On June 20, 2024, the Commission issued an *Order Establishing Updated Energy Storage Goal and Development Policy*²⁶ (2024 Storage Order) which established a storage target for NY State of 6 GW by 2030 and approved additional NYSEDA funding beyond what was previously authorized in a prior 2018 energy storage order. With this additional funding, the prevalence of energy storage is expected to rise based on incentives at the retail level, along with at the bulk level. As required in the 2024 Storage Order, the Joint Utilities were directed to identify use cases for utility-owned energy storage to provide non-market transmission and distribution services that are cost-effective when compared to traditional alternatives. Central Hudson's efforts as well as collaborative JU efforts on this are discussed further below.

Central Hudson continues to track the system costs and overall cost effectiveness of energy storage solutions and look for opportunities where these systems can provide value. Central Hudson envisions that BESS will have a growing role as a flexible resource on both transmission and distribution systems in the future, when it can be shown to provide value to customers.

²⁵ <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/ny-6-gw-energy-storage- roadmap.pdf>

²⁶ In the Matter of Energy Storage Deployment Program (Case 18-E-0130), Order Establishing Updated Energy Storage Goal and Deployment Policy, June 20, 2024.

3. IMPLEMENTATION PLAN

1) Current Progress

Central Hudson has undertaken several recent or ongoing initiatives regarding the implementation of BESS. These initiatives are focused on assessing the integration of BESS into transmission and distribution systems and gaining additional learnings on the costs, the economic valuation, and the technical applications of BESS. Each of these initiatives is briefly described below.

- **Request For Proposals (RFP) for Bulk Power Energy Storage Scheduling and Dispatch Rights.** In compliance with Ordering Clause #2 in Case 18-E-0130 *Order Establishing Energy Storage Goal and Deployment Policy*, issued and effective December 13, 2018, Central Hudson issued its' third RFP in June 2024 to procure at least 10 MWs of scheduling and dispatch rights of bulk connected energy storage within the service territory. In accordance with the Commission's March 16, 2023 *Order Directing Further Modifications to Energy Storage Solicitations*, the projects submitted for RFP #3 must be operational by December 31, 2028. RFP #3 utilized a two-round approach for all participants: Round 1 evaluations included a review of the bidder financial strength, project economic viability, energy storage technology, project team (including subcontractors) and bidder experience with front-of-meter bulk energy storage projects, interconnection feasibility, site location and control, and project schedule; Round 2 included updates to bidder financial strength, refinements to the project economics, a more detailed look into interconnection feasibility and cost, adherence to Energy Storage Service Agreement terms and conditions, cyber security requirements, site control and project schedule details. The Company completed its Round 2 evaluations by May 9, 2025, in accordance with its' filed Implementation Plan. There were many projects proposed at various locations around the company's service territory. The results of the Company's evaluations are being communicated to stakeholders contemporaneously with this DSIP filing.
- **Advanced Technical Working Group Storage Efforts.** The Advanced Technical Working Group (ATWG) was formed as a result of the Commission's January 2022 *Order on Power Grid Study Recommendations*. The ATWG serves to address the "challenge of identifying and removing barriers to the deployment of advanced technologies."²⁷ The ATWG consists of members from each of the Joint Utilities, including Central Hudson as an active participant, and is supported by multiple organizations including Electric Power Research Institute (EPRI), the Long Island Power Authority (LIPA), NYISO, NYPA and NYSERDA. One of the focus areas of the ATWG was to identify use cases for energy storage. As part of this, the ATWG established the Energy Storage Task Force to prioritize and develop an RFP for conducting an energy storage potential study focused on Transmission and Distribution applications. In May 2023, NYSERDA, on behalf of the ATWG submitted an RFP, seeking a consultant to perform an Energy Storage Potential Study for Electric Transmission and Distribution Applications in New York. In 2024, the consultant was selected and provided high-level analysis and methodology to support identifying the potential for energy storage to support the New York State utilities T&D systems. Additionally, the ATWG drafted a Unified Planning Guidelines for Energy Storage Resources Supporting Electric

²⁷ Case 20-E-0197, Order on Power Grid Study Recommendations, State of NY Public Service Commission, January

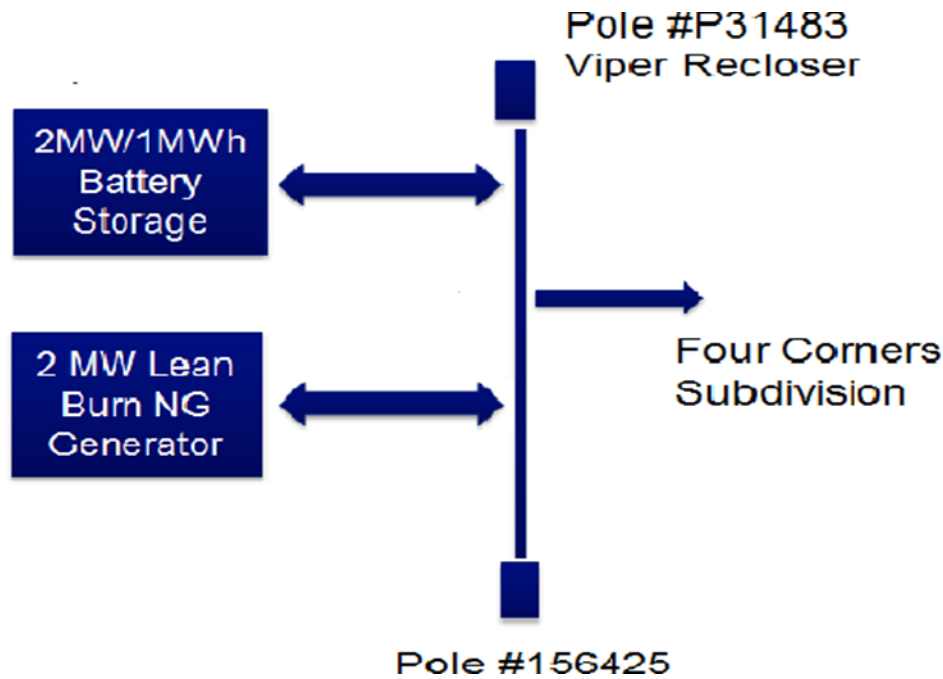
Transmission and Distribution in New York State. These guidelines provided a framework for modeling energy storage in power flow models, characterizing grid needs, and understanding the economic and cost assumptions to assess the suitability of energy storage as a potential T&D solution. As a participant in the ATWG, Central Hudson will continue to track and support the progress within the ATWG related to storage integration into the electric transmission and distribution system.

- **Utility Energy Storage Use Case Work With EPRI, NYPA Advanced Grid Innovation Laboratory for Energy (AGILE) Lab, and NYSERDA.** Central Hudson is in the early stages of working with EPRI and the Advanced Grid Laboratory for Energy (AGILE) through NYSERDA funding, to complete analysis for energy storage use cases. As part of the study, EPRI will complete an analysis to determine the technical and economical applicability of energy storage to resolve current and future constraints in two locations of Central Hudson's system. These areas include Central Hudson's Westerlo Loop and Maybrook/Montgomery area. For the Westerlo Loop, this northern portion of Central Hudson's territory has seen a high penetration of DER, both solar and storage along with some activity from large, lumped loads. As part of the energy storage use case, EPRI will seek to apply energy storage as a mitigation to resolve the thermal and voltage impacts as a result of DERs or loads, in order to enable higher penetration or provide a peak shaving solution. For Maybrook/Montgomery, this area is currently seeing an influx of large, lumped loads proposed which has caused the distribution substation transformer to exceed its long-term emergency rating as well as the transmission transformer to approach its normal and long-term emergency ratings. EPRI will seek to apply energy storage as a mitigation for peak shaving capabilities at the substation, as well as storage in lieu of a 115kV-69kV transformer replacement to alleviate post- contingency transmission concerns. Additionally, strategic location and sizing of the storage should be considered to potentially provide additional operational flexibility for distribution circuits nearing or at their current design ratings. Both studies will review the economic value and cost benefit analysis, including a cost comparison to alternate mitigations. In addition to EPRI's analysis, AGILE will develop dynamic models with transient-stability and/or electromagnetic- transient software tools to run several simulation scenarios within their lab for each of these areas. The scope of work has been finalized for the Westerlo Loop area and the project kicked off in April 2025. A separate scope of work for the Maybrook/Montgomery area will be developed in the second half of 2025.
- **DERMS for Managing Grid Constraints.** Central Hudson worked with EPRI on an R&D project related to the implementation of a DER management system (DERMS) to manage the reliability of the electric grid with a high DER penetration, including energy storage. The goal of this project is to provide Central Hudson with guidance and framework on three DERMS use cases: 1. manage equipment capacity and voltage constraints during normal grid states; 2. manage constraints during abnormal grid states; 3. and coordinate operation of DER across the transmission and distribution grid. There are various deliverables as part of this project which is broken down into three phases: Phase 1 – Scenario Creation, Requirements, and Algorithm Development; Phase 2 – DERMS Lab Testing; and Phase 3 – Field Demo, Economic Assessment and Gap Analysis. As part of the lab simulations and testing completed by EPRI, this project does incorporate storage as an asset within DERMS to control based on a formulated dispatch plan, to help address violations. The R&D project evaluated both a Corrective DERMS (lab and

field demo) as well as a Predictive DERMS (lab demonstration). This project was completed in December 2024. Details on the lessons learned can be found later in Section 6.b.

- **JU Non-Market T&D Energy Storage Use Cases.** As part of the 2024 Storage Order, the JU was directed to conduct a study on the non-market T&D services that energy storage could provide. In response to this, the JUs filed these use cases on October 29, 2024. Within this filing, the JU identified six applications which include: 1. Flexible Transmission Capacity; 2. Flexibility Distribution Capacity; 3. Distribution Resiliency and Reliability; 4. Bridge-to-Wires; 5. Large Scale Renewable Enablement; and 6. DER Integration and Hosting Capacity on Distribution Network. In addition to identifying the use cases, the JUs also described the engineering and economic review of the types of energy storage applications the utilities can deploy as part of their obligations to provide safe and reliable service in the most efficient and effective manner; a description of how utilities will modify system planning and operations to accommodate energy storage as a new tool; and a proposed process for the review and approval of energy storage projects as well as a cost recovery mechanism, if the process does not align with the normal rate case schedules. In January 2025, the PSC solicited initial comments on the JUs storage filing due February 2025 with reply comments submitted in April 2025. Central Hudson will continue following this proceeding and work closely with the JU on integrating energy storage as a potential T&D solution within the planning process should the PSC provide approval for utility non-market ownership.
- **Four Corners Microgrid Project.** The Four Corners Microgrid project is part of a Federal Emergency Management Agency (FEMA) Grant program following Superstorm Sandy. This project was submitted to the Department of Homeland Security (DHS) by the New York State Department of Public Service on behalf of Central Hudson. The project includes the installation of a microgrid to enhance reliability in the Four Corners Area of the Central Hudson service territory. This design includes a 2MW lean-burn natural gas turbine and a 2MW/1MWh BESS to facilitate block loading. The battery is sized to pick up the area load during the initial loss of utility service while the lean burn gas generator ramps up to speed and assumes the load. This project went in service June 30, 2023. In the future the project may provide the optionality to use the BESS for other services (i.e., demand reduction, frequency regulation) during parallel operation. Figure 26 shows a simplified diagram of the microgrid layout.

Figure 26: Microgrid Layout



Central Hudson's current initiatives related to BESS support stakeholders' current and future needs by building the Company's technical understanding of BESS; enhancing the Company's understanding of integrating BESSs into transmission and distribution systems and their impact on our transmission and distribution systems; and identifying potential transmission and distribution use cases that are cost-effective when compared to alternative solutions. These learnings will be applied to future implementations of BESS that support meeting New York State's 6GW energy storage goal. This includes NWA evaluations, interconnection requests, and, potentially, procurement of BESS scheduling and dispatch rights and utility-owned use cases.

2) Future Implementation and Planning

Central Hudson has one active energy storage project as indicated above, as well as various research projects and Joint Utility initiatives underway. Outcomes and learnings from these projects will continue to support Central Hudson's knowledge and understanding of use cases for energy storage, including potential future storage deployments. There are also a number of distribution-level energy storage systems interconnected to the Central Hudson system and several energy storage systems in the New York State Standardized Interconnection Requirements (NYSSIR), Central Hudson and NYISO queues, including some of significant size (20MW to 250MW range). As discussed previously, in June 2024, Central Hudson issued a third RFP to procure at least 10 MW of bulk power energy storage scheduling and dispatch rights. The completion of this RFP process provides the Company with additional insight in operating and utilizing energy storage for system needs. Central Hudson will continue to track the evolution of energy storage as the costs and benefits change with technology and markets. Central Hudson may issue additional RFPs in the future for bulk energy storage scheduling and dispatch rights. In

addition, as these systems become economically competitive with other technologies, Central Hudson will continue to evaluate use cases for storage including potential applications for NWAs. Central Hudson remains technology agnostic in its solicitation process for NWAs, allowing for energy storage solutions, and may modify future solicitations to accommodate storage solutions better.

In addition to the items identified above, Central Hudson has several corporate initiatives that will support the future implementation and planning for Energy Storage integration as indicated on the Integrated Timeline. These initiatives include the system-wide roll out of an Advanced Distribution Management System, advancement of Energy Storage Systems Hosting Capacity mapping functionality; Load Flow software advances; coordination with NYISO on DER aggregations (FERC Order No. 2222); Improving the DER Interconnection process and future DERMS.

As described in Current Progress, Central Hudson's BESS initiatives support the Company's knowledge development which will be applied to future implementations of BESS to help meet NY State's 6GW energy storage goal. The larger corporate initiatives will help support stakeholder's needs by improving the Company's capabilities to plan, integrate and manage increasing levels of energy storage in the distribution system.

As described in Current Progress, continued research and development projects and tracking of BESS costs are required to progress from the current to future implementation. The work and investments needed to progress the additional corporate initiatives identified in the Hosting Capacity and Grid Operations sections of this filing.

Future Implementation and Planning describes the planned timing and sequence of on-going initiatives and investments needed to progress from current implementation to future implementation. The planned timing and sequence of work and investments needed to progress the additional corporate initiatives identified in the sections above are outlined in the pertinent sections (i.e. Hosting Capacity, Grid Operations) sections of this filing.

The Coordinated Grid Planning Process and DSIP are plans with overlapping but distinct scopes. The CGPP will detail the evolution of distribution planning processes needed to meet CLCPA goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments and how they will be leveraged, will be included in the DSIP (e.g., AMI, automation, ADMS, etc.) and the results of executing the processes will be used to inform the CGPP. Additionally, an understanding of the existing energy storage, both third- party owned and utility-owned energy, will be an important input into the analysis as part of the CGPP.

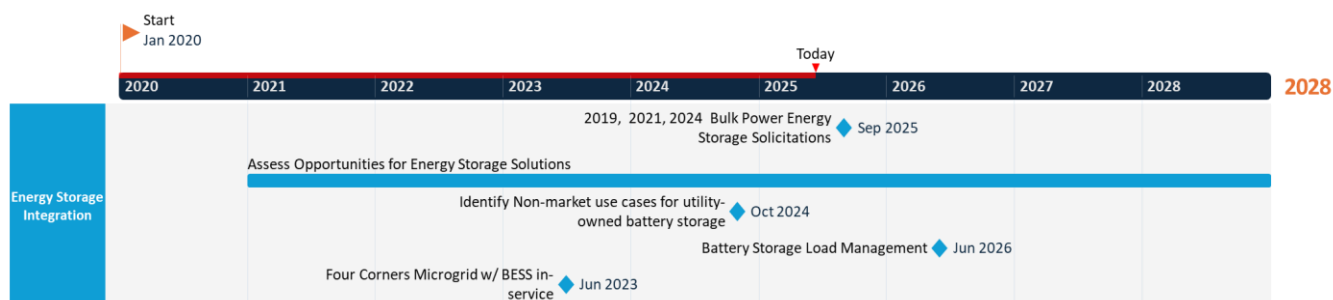
The CGPP is aimed at developing a "CLCPA-focused planning process," including "the State's bulk transmission, local transmission, and distribution planning processes." The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific

locations on the LT&D and bulk transmission grid. As part of the CGPP phases, one of the key inputs to the CGPP is the generation of build-out scenarios identified by the Energy Policy Planning Advisory Council. While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and interconnection processes. This includes ensuring any upgrades identified as part of the CGPP that energy storage systems may benefit from are included within appropriate planning and interconnection analyses.

3) Integrated Implementation Timeline

Figure 27 shows the implementation timeline related to energy storage integration. Central Hudson has been active in identifying opportunities for energy storage solutions, help multiple solicitations for bulk storage, has a microgrid in-service, and expects to implement a battery storage load management program in 2026.

Figure 27: Battery Storage Timeline



4. RISKS AND MITIGATION

For all emergent technologies, Central Hudson evaluates the technical risks associated with the technology and the overall project financial viability/risk profile. Battery technologies have been available for quite some time and are advancing at a rapid rate. The lithium-ion technology utilized in battery energy storage systems is well-developed. Central Hudson believes that the risk profile for the technologies is relatively limited and therefore manageable. These technical risks can be managed as part of the deployment of the systems (redundancy, fail-safe designs, etc.) and with the warranty conditions specified. The applications of BESS to both the transmission and distribution systems represent a greater risk profile as utilities and the industry continue to gain technical learnings on the system interactions and use cases available to BESSs and their ability to meet the identified needs. The different use case assumptions, including the risk that energy storage does not begin to see a reduction in both battery and balance of systems costs or reductions, continue to occur at a much slower rate than previously anticipated, represent higher levels of risk. There are also risks associated with the market revenue forecasts for these installations. The shared learnings amongst the Joint Utilities as storage projects are implemented should provide data and operational experience to help understand and

quantify the risks associated with storage projects. As experience is gained and the applications/markets mature, these risks will be better understood, and appropriate mitigation strategies can be developed.

5. STAKEHOLDER INTERFACE AND ENGAGEMENT

Central Hudson has actively engaged with stakeholders in several different forums concerning energy storage applications. These areas include:

- **Participation in JU Efforts.** As described earlier, Central Hudson was actively involved with the JU efforts as part of the 2024 Storage Order, directing the JU to study the non-market T&D services that energy storage could provide. Within this proposal, the JU identified six use cases for energy storage, including describing the engineering and economic review, how system planning and operations would be modified along with a proposal for cost recovery. As part of the JU's proposal, the PSC solicited comments and feedback from stakeholders that will ultimately be considered within the Commission's ruling.
- **Participation in the Interconnection Technical Working Group (ITWG).** Central Hudson remains very active in both the Interconnection Technical Working Group and the Interconnection Policy Working Group. These New York State working groups include Joint Utilities, developers, and policy makers. These groups continue to meet regularly and work to advance both technical (ITWG) and policy (IPWG) issues related to interconnections. Most recently this includes discussions related to standards and certification requirements when storage and Microgrid Interconnect Devices are utilized for backup power. Additionally, within the ITWG Central Hudson came up with energy storage charging and discharging schedules. This was established to help Central Hudson better manage and track the operation of these systems, as well as enable higher penetration of storage into the electric grid (i.e. by avoiding charging during peak timeframes). These schedules were given directly to stakeholders within the ITWG and based on stakeholder feedback, Central Hudson ultimately adjusted the schedule to not conflict with VDER compensation. The windows currently include permitting charging all year during 10pm-1pm and discharging all year from 7am-1am. In lieu of utilizing a Central Hudson storage schedule, developers/applicants can also be studied unrestricted.
- **Hosting Capacity Maps Surveys.** As described further in the Hosting Capacity section, Central Hudson has developed granular hosting capacity maps for energy storage since the 2023 DSIP and remains engaged in further developing these maps as part of stakeholder input. Most recently this included providing a survey to stakeholders to identify training content that would be most useful for hosting capacity maps (both solar PV, storage, and electrification). This training is currently anticipated to take place via webinar in the fall of 2025.
- **Participation in NYISO Working Groups.** Central Hudson is very active in NYISO committee working groups and has played a significant role in Joint Utility – NYISO work to facilitate dual participation in wholesale and retail markets by DER providers, which as identified in the 2024 Storage Order, will be critical to making the use cases for storage economical.
- **Joint Utility CLCPA stakeholder engagements.** Central Hudson has worked collaboratively with the New York State Joint Utilities on a number of stakeholder engagement initiatives associated with CLCPA initiatives.

- **Annual Solar+ Summit.** Central Hudson hosts an annual Solar+ Summit which provides DER developers and industry professionals, including energy storage developers, with information on the technical and procedural aspects of interconnecting with the utility, industry updates, available programs and incentives. The event also provides networking opportunities with industry professionals. At the conclusion of each Solar+ Summit, a survey is provided for feedback from attendees and is utilized for future planning purposes, including specific topics of interest that professionals would like to see and hear about.
- **DSIP Webinars.** Central Hudson typically holds a DSIP webinar summarizing the content included within each of the topical sections of the DSIP along with major initiatives or implementations. This session provides stakeholders to attend, listen and ask questions. This webinar is held shortly after the DSIP filing and additionally, the Company provides ad-hoc DSIP engagement with interested stakeholders via email or meeting touchpoints over the course of the year about DSIP related topics. The JU also holds a DSIP enablement webinar twice a year and quarterly provides newsletters to stakeholders. The JU also has a website which is DSIP focused and includes various references and resources for stakeholders and is updated on a rolling basis.
- **Direct contact with stakeholders.** Central Hudson has direct email and phone contacts for DER interconnection questions, including a DG Ombudsperson that stakeholders can directly reach out to resolve concerns. This includes all DER technologies, such as energy storage. The following are emails included on the Central Hudson's Distributed Generation website for inquiries related to DERs: dg@cenhud.com, pvmetering@cenhud.com, dgombudsman@cenhud.com, wholesaleaggregations@cenhud.com.

6. ADDITIONAL DETAIL

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.*

As mentioned in previous DSIP filings, working with industry partners, Central Hudson was part of the energy storage installation project located on the SUNY New Paltz main campus which was completed in March 2020. The campus is in New Paltz, New York, within Ulster County. The storage system was interconnected to the Central Hudson 5025 distribution circuit emanating from the Ohioville Substation. This was a PV + Battery storage project which includes the following components:

- Solar PV
 - 100 kW Princeton Power Smart Inverter
 - 100.65 kW CSUN Solar Modules
- Battery Storage
 - 100 kW Princeton Power Smart Inverter
 - 200 kWh Samsung SDI Li-Ion Battery Bank

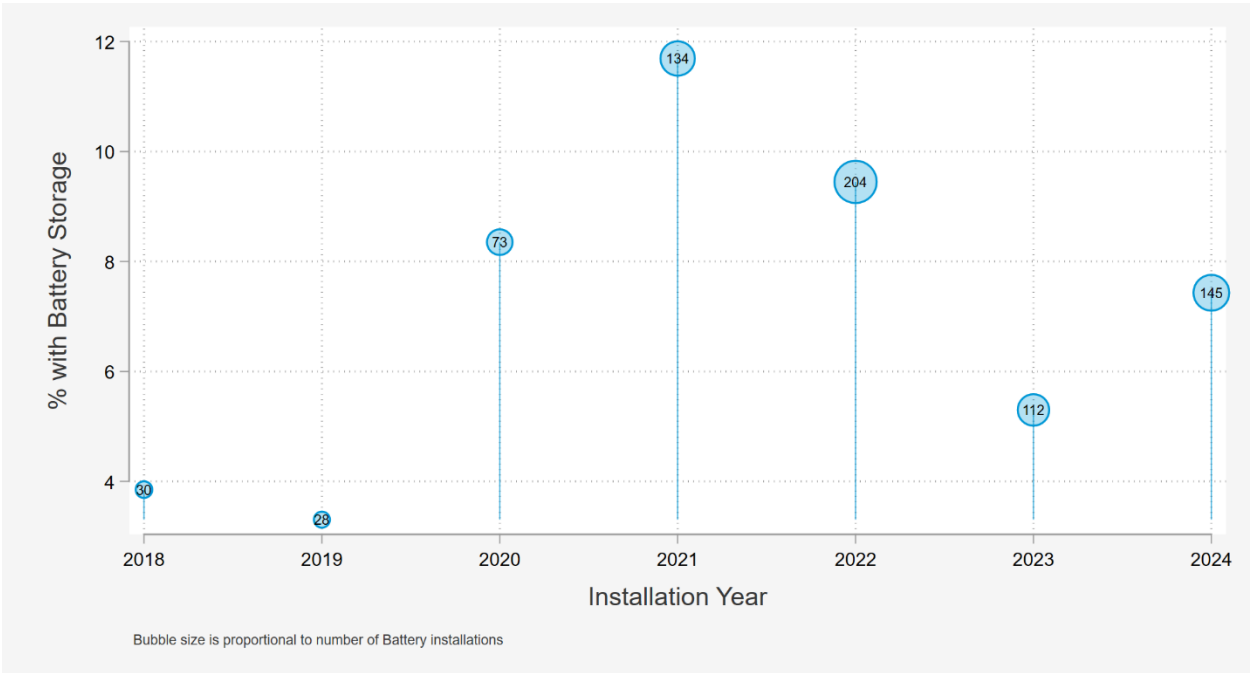
As indicated in the 2020 DSIP, this R&D project had numerous lessons learned and key findings which have been incorporated into Company processes.

Since the 2023 DSIP, the Company’s Four Corners Microgrid, previously described above, went in service on June 30, 2023. The microgrid has not been required to operate for reliability purposes yet; however, the system is started on a monthly basis for a brief isolated run to keep it in good working condition.

Central Hudson has a number of customer-sited battery storage systems interconnected to the distribution system. These are smaller, behind the meter installations co-located with residential or small-commercial PV systems and customer load. As of April 2025, Central Hudson has 794 of these installations spread throughout the service territory, 6 of which are residential stand-alone battery storage systems only. In addition, there are another 103 of these systems in the queue. While customer-sited, it is believed these units are installed to provide customer resiliency and potentially demand reduction. In addition to these storage projects, there currently are 2 solar PV + energy storage CDG projects interconnected with a capacity and energy of 6 MW, and another 12 in queue with capacity and energy of 50 MW. An additional 27 projects going through the NYISO interconnection process (with Central Hudson as the connecting transmission owner) with a total capacity of 2,993 MW; the 19 energy storage projects have a total capacity and energy of 2,468 MW. An additional 4 projects with total capacity and energy of 49 MW currently are in the Central Hudson interconnection process.

Figure 28 shows the share of solar installations paired with battery storage by year. Most of the installations are at residential sites. In 2021, 12.5% of residential solar installations were paired with battery storage. The share of sites installing battery storage with solar decreased in 2022, however, and it is unclear if it’s a normal variation or a trend.

Figure 28: Share of Residential Solar Installations Paired with Battery Storage



2) Describe the Company's current efforts to plan, implement, and operate beneficial energy storage applications.

Central Hudson has actively worked to identify cost-beneficial utility energy storage applications for implementation. These systems would help further develop the Company's working knowledge of the potential benefits both in terms of value-added services and technical advances. As previously identified, there are numerous on-going initiatives to support the implementation of energy storage. Central Hudson currently has R&D projects in the early stages of implementation as well as one construction project which went operational in June 2023 and incorporates energy storage applications (Four Corners Microgrid). In addition, Central Hudson is a participant within the ATWG and supported the completion of the RFP for energy storage uses cases as well as recently completed a solicitation for bulk power energy storage scheduling and dispatch rights for 10 MW or greater of energy storage.

Below, we answer the detailed questions for:

- Bulk Power Energy Storage Scheduling and Dispatch Rights RFP
- Utility Energy Storage Use Case Work With EPRI, AGILE and NYSERDA
- DERMS for Managing Grid Constraints
- Four Corners Microgrid

a) Bulk Power Energy Storage Scheduling and Dispatch Rights RFP

1. **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.** A detailed description of this project is included above under Section III.B.2.a) Current Progress. This project fits into Central Hudson's long range energy storage plans for the integration of increased levels of energy storage within the service territory. This work effort enabled Central Hudson to develop processes and a set of documents which can be utilized to determine energy storage project overall economics/economic viability within the service territory. This project provided Central Hudson with valuable experience in the energy storage RFP process – this is discussed in more detail in item d) below.
2. **The original project schedule.** Central Hudson issued an Energy Storage Request for Proposal on June 10, 2024, with bidder qualifications for evaluation to be received no later than July 8, 2024. Round 1 offers were due no later than September 9, 2024, and Round 2 offers were due no later than February 18, 2025.
3. **The current project status.** The results of the Company's evaluations are being communicated to stakeholders contemporaneously with this DSIP filing. Additional information regarding current project status is unavailable to be shared at this time.
4. **Lessons learned to-date.** The following is a list of lessons learned to-date from energy storage RFPs:
 - A set of energy storage RFP documents for future use were developed.
 - An energy storage RFP solicitation and evaluation process was developed.
 - An energy storage RFP team of Subject Matter Experts (SMEs) for evaluating bidders' project proposals was established. These SMEs cover the following areas:
 - ✓ Bidders' Credit Rating and Financials;

- ✓ Land and Property;
 - ✓ Project Construction Schedule;
 - ✓ Electric Interconnection;
 - ✓ Legal; and
 - ✓ Economic Evaluation.
 - An Energy Storage Project Economic Evaluation model was created, with Central Hudson consultant support. This Economic Evaluation model can be used to evaluate and forecast the potential revenue that may be obtained from owning the dispatch rights for a front-of-the-meter energy storage project that participates in the NYISO market. This potential revenue is based on the following revenue categories:
 - ✓ Net Electric Energy Arbitrage revenue;
 - ✓ Ancillary Service revenue;
 - ✓ Electric Capacity revenue;
 - ✓ Central Hudson Transmission & Distribution Deferral value; and
 - ✓ NYSERDA funding.
 - From the review of the bidders' energy storage project proposals, Central Hudson gained a first-hand experience to increase Central Hudson's knowledge and understanding of the energy storage systems that are currently available in the marketplace and of these energy storage systems' electrical and physical characteristics and capabilities and prices.
 - Central Hudson has compiled a list of energy storage RFP bidders that can be used for future RFP solicitations or for Central Hudson to contact to obtain answers to questions in regard to energy storage systems.
- 5. Project adjustments and improvement opportunities identified to-date.** Central Hudson provided feedback to all the Round 1 project sponsors regarding improvement opportunities. Some of these project sponsors utilized this feedback to submit revised project proposals in Round 2. Additional information regarding these improvement opportunities is not available to be shared in this document.
- 6. Next steps with clear timelines and deliverables.** As described in items (2) and (3) above, Central Hudson has completed its Round 2 review. The results of the Company's evaluations are being communicated to stakeholders contemporaneously with this DSIP filing. Additional information regarding current project status is unavailable to be shared at this time.

b) Utility Energy Storage Use Case Work With EPRI, AGILE, and NYSERDA

- 1. 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.** A detailed description of this project is included in Current Progress. This project fits into Central Hudson's long-range energy storage plans by providing technical learnings in the application of storage systems to resolve current and future constraints related to two use cases which include high penetration of DER integration as well as peak shaving and operational flexibility. In addition to identifying technical applicability, the project will also identify the economic viability of energy storage to resolve the real-world constraints Central Hudson is facing today.

2. **The original project schedule.** This project is estimated to take approximately 24 months to complete. Kick-off for the Westerlo Loop occurred in April 2025 with kick-off for Maybrook/Montgomery project expected the second half of 2025.
3. **The current project status.** The project is currently following the original project schedule identified in (2).
4. **Lessons learned to-date.** This project recently kicked-off and does not have documented lessons learned to- date.
5. **Project adjustments and improvement opportunities identified to-date.** This project only recently kicked-off and does not have project adjustments and improvement opportunities identified to-date.
6. **Next steps with clear timelines and deliverables.** This project is currently following the original project schedule identified in (2).

c) DERMS for Managing Grid Constraints

1. **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.** A detailed description of this project is included in Current Progress. This project fits into Central Hudson's long range energy storage plans by providing technical learnings in relation to utilization of a DERMS to manage reliability of the electric grid due to DER penetration. While this project is not solely geared specifically towards energy storage, one component of this project includes simulating storage as a utility asset within DERMS to address violations.
2. **The original project schedule.** The following provides the initial schedule for the three phases of this project:
 - Phase 1: Scenario Creation, Requirements and Algorithm Development – September 2021 through June 2022
 - Phase 2: DERMS Lab Testing – July 2022 through February 2023
 - Phase 3: Field Demonstration, Economic Assessment and Gap Analysis – March 2023 through December 2023
3. **The current project status.** The following provides the current schedule for the three phases of this project:
 - Phase 1: Scenario Creation, Requirements and Algorithm Development – Completed June 2022.
 - Phase 2: Corrective DERMS Lab Testing – July 2022 through February 2023. Predictive DERMS Lab Testing – September 2024 through March 2025 (Completed).
 - Phase 3: Field Demonstration, Economic Assessment and Gap Analysis – June 2023 through November 2024 (Completed).
4. **Lessons learned to-date.** As part of Phase 1 learnings EPRI published preliminary results in the form of two reports titled "Implementing DERMS to Manage Grid Constraints" and "Analyzing Telecommunications Systems for DER Integration." The first report is based in part on lessons learned while working on this project and is a primer on the drivers of DER growth, the grid implications that result when large numbers of solar generator systems, battery electric storage

systems, electric vehicle chargers, and other DER are interconnected, and how DERMS can help manage a reliable grid. It also provides guidance that utilities need to craft precise DERMS requests for proposals including the three prominent use cases mentioned previously. The second paper conducted an analysis using Central Hudson's existing utility telecommunication network. The results confirmed that legacy utility networks will support DER management. As part of Phase 2, EPRI performed lab testing to evaluate a corrective and predictive DERMS. The following include lessons learned and key findings:

- DERMS was successfully demonstrated at a third-party owned 2 MW distributed generation site and controlled the output of the site in response to measured power (thermal) capacity constraint on the 13.2 kV feeder.
- Coordination between the DERMS vendor and utility IT/OT and cybersecurity teams is necessary in the earliest stages of DERMS deployment to ensure interoperability.
- Data quality and reliability of communications between all layers (including internal utility data streams and data to the DERMS) is critical to successful operation of the DERMS.
- The system operated as designed and followed the specified DERMS control setpoints and followed the specified trim and release settings.

As part of Phase 3, the predictive DERMS lab demo was completed. The following include key findings and lessons:

- Under significant Solar PV penetration scenarios, DERMS eliminated the predicted voltage and thermal overload violations by selectively curtailing the DERs that contributed most to the constraints.
- When feeders were reconfigured (partial or full offloading) due to outages, the DERMS successfully adjusted DER envelopes to keep both voltage and loading within acceptable ranges.
- DERMS readily accommodates aggregator-based market participation by issuing operating envelopes in advance of real-time dispatch. This approach balanced wholesale revenue opportunities with distribution-level constraints.
- Both uniform and priority-based allocation methods were tested, confirming that users can tailor curtailment policies to ensure fairness or to preserve key resources.
- When both Solar PV and BESS were present, the DERMS minimized PV curtailment by directing BESS to absorb or inject power.
- Network models and monitoring capabilities need to be evaluated by utilities before deployment of predictive DERMS controls.
- Early engagements with stakeholders and adoption of standard communication protocols for interoperability like Institute of Electric and Electronics Engineers (IEEE) 2030.5 will help successful execution.

5. **Project adjustments and improvement opportunities identified to-date.** Phases 2 and 3 of this project were adjusted from the original schedule. Phase 2 included deploying two separate lab environments with the Corrective DERMS and Predictive DERMS vendors. Corrective DERMS lab testing was initiated in July 2022 and was completed at the end of May 2023. The lab testing informed the Corrective DERMS field demonstration, which took place from June 2023 through November 2024. Predictive DERMS lab testing took place from September 2024 through March

2025. Phase 3 testing was completed in November 2024, and final reporting was completed by EPRI in December 2024. The main delays for Phase 3 were related to IT/OT requirements for establishing communications between the solar PV site, SGS gateway, SGS DERMS, and EMS/DMS historian.

6. **Next steps with clear timelines and deliverables.** This project is complete, and there are no next steps or deliverables.

d) **Four Corners Microgrid**

1. **A detailed description of each project, existing and planned, with an explanation of how the project fits into the Company's long range energy storage plans.** A detailed description of this project is included in Current Progress. This project fits into Central Hudson's long range energy storage plans by evaluating investment opportunities including reliability-based projects on an overall cost benefit basis. The project incorporates a BESS as part of the overall solution.
2. **The original project schedule.** The original project schedule was to have Phase 1 design complete by August 14, 2018. Phase 2 (construction) was scheduled for completion in February, 2022.
3. **The current project status.** Construction commenced in November 2020 and was completed in March 2023. Functional testing was completed, and the site went into service on June 30, 2023.
4. **Lessons learned to-date.** As this project has not had the opportunity to operate for reliability purposes yet, there are no operational lessons learned to date. Construction of the project provided logistical learning which will better prepare Central Hudson for future design and construction of microgrid systems.
5. **Project adjustments and improvement opportunities identified to-date.** This project deviated from the initial construction schedule due to a few drivers that resulted in delays to the overall project. Two of the top drivers included a significant increase in lead times for the Powell circuit breakers as well as shortages in microprocessor components and trucking delays associated with the Caterpillar engine and generator. As the system is now in service, Central Hudson will evaluate whether adjustments or improvements to the system's operation are necessary.
6. **Next steps with clear timelines and deliverables.** The site went in service on June 30, 2023. While the system has not operated for reliability purposes yet, Central Hudson will continue monitoring the operation of the Four Corners Microgrid system, ensuring the system is operating as intended as well as reviewing the potential for the system to provide any additional benefits to the electric grid.

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.*

Battery storage is a technology with the potential of improving system and distribution utilization by storing energy from low-cost periods for use when prices are high or capacity is short. Battery storage can shave peak loads, fill valleys to flatten energy demand, and deliver a range of grid services that require flexibility and fast response. Because the cost of energy storage has been prohibitive in the past, generation, transmission, and distribution infrastructure was sized to meet extreme peak demand. With

the costs of battery storage assumed to be in decline and the state's focus on integration of energy storage, this has led to an increased focus on energy storage.

Battery storage can be directly connected to the bulk transmission system, or it can be located behind-the-meter at customer facilities or on utility property such as substation pads. The focus of this section is on distributed energy storage which is connected to the distribution grid. At the bulk transmission level (69 kV and above), a total of 2,468 MW capacity currently is going through the NYISO's Interconnection Process within Central Hudson's territory. However, distribution connected storage and, more specifically, behind-the-meter storage adoption is dictated by customer preferences and their ability to monetize benefits.

One of the most unique attributes of battery storage is that they affect multiple aspects of the electricity grid's infrastructure and deliver benefits to customer and utilities. Energy storage can provide concrete benefits to customers – in the form of increased reliability (similar to back-up generator), the ability to manage bills by reducing demand charges and shifting of loads from high priced periods to lower priced periods. It can also provide concrete benefits to the electric grid, including: reductions in the need to build additional generation, transmission and distribution infrastructure; the ability to store cheaper electricity generated off-peak for use during higher cost periods; and fast response services required to ensure reliability and integrate variable resources such as wind and solar.

Central Hudson is currently experiencing flat to no load growth in most of the service territory, with a few exceptions. For most distribution substations and primary feeders, Central Hudson has enough load serving capability to meet peak demands. Moreover, in recent years, both wholesale energy, ancillary services, and generation capacity have been relatively low. Central Hudson expects storage deployment within the service territory to be driven by customer preferences rather than significant changes in the benefits and pay-back period of battery storage. As per the 2024 Energy Storage Order, Central Hudson will look to see if future solicitations for NWAs can better take into consideration the benefits of energy storage systems.

a) Historical Adoption of Distribution Connected Energy Storage

Battery costs have become more stable and predictable over the past decade, resulting in increased deployment. In nearly all cases, battery storage has been paired with solar. To date, there has been virtually no adoption of standalone distribution connected storage.

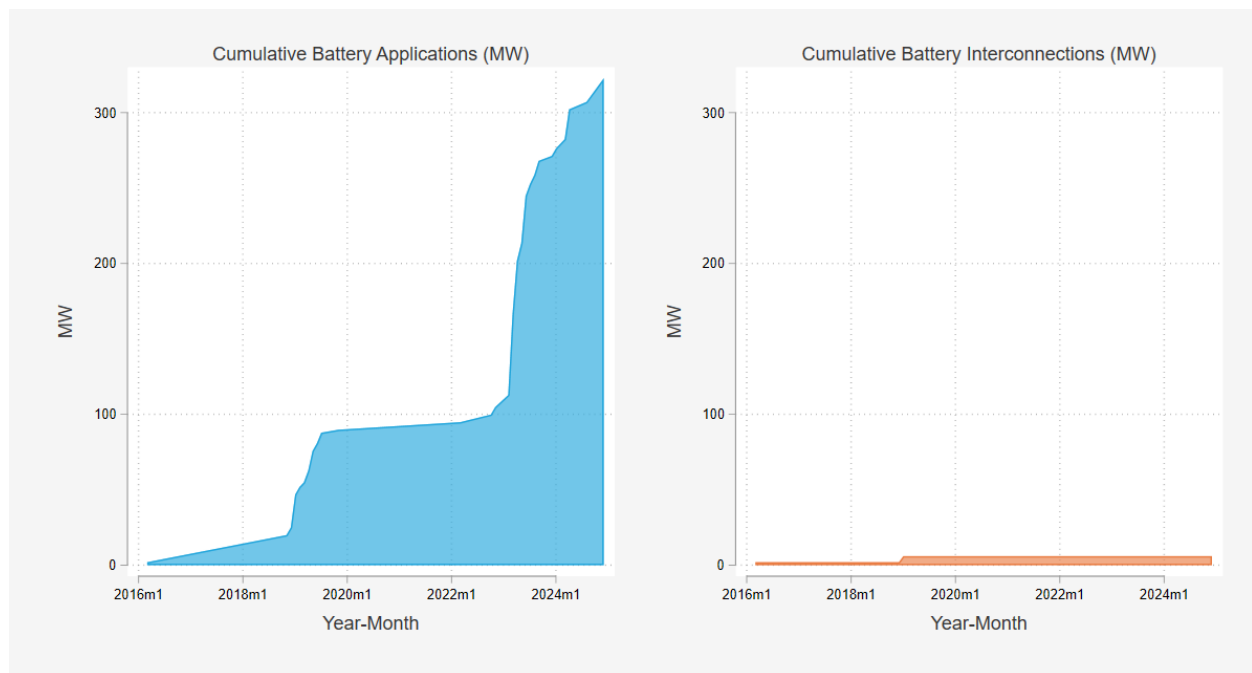
Table 18 shows the annual historic solar and storage interconnection capacity for the residential, non-residential, and community and remote solar from 2020 to 2025, calculated from the historic interconnection data.

Table 18: Historic Residential and Non-Residential Solar and Storage Capacity Interconnections

	Residential			Non-residential			CDG or Remote		
Year	Storage Capacity (MW)	Solar Capacity (MW)	Storage Capacity %	Storage Capacity (MW)	Solar Capacity (MW)	Storage Capacity %	Storage Capacity (MW)	Solar Capacity (MW)	Storage Capacity %
2020	0.32	6.52	5%	0.00	1.65	0%	0.00	26.72	0%
2021	1.04	8.98	12%	0.03	1.89	2%	6.00	45.84	13%
2022	1.15	16.27	7%	0.01	2.10	0%	0.00	36.55	0%
2023	1.25	19.71	6%	0.04	1.88	2%	0.00	8.23	0%
2024	1.10	15.80	7%	0.04	3.16	1%	0.00	8.73	0%
Total	4.87	67.28	7%	0.12	10.67	1%	6.00	126.07	5%

While smaller residential project applications are more numerous, the largest share of the installed nameplate capacity is for community solar and remote net metering applications, which often include battery storage. As discussed in Appendix C, because of its scale and build lead time, a small share of CDG and remote solar and battery applications are eventually completed and interconnected. However, the historical data on the number and size of energy storage units included in the interconnection applications is useful for forecasting future energy storage. Figure 29 shows the cumulative applications and installations of these larger projects over time, using nameplate capacity.

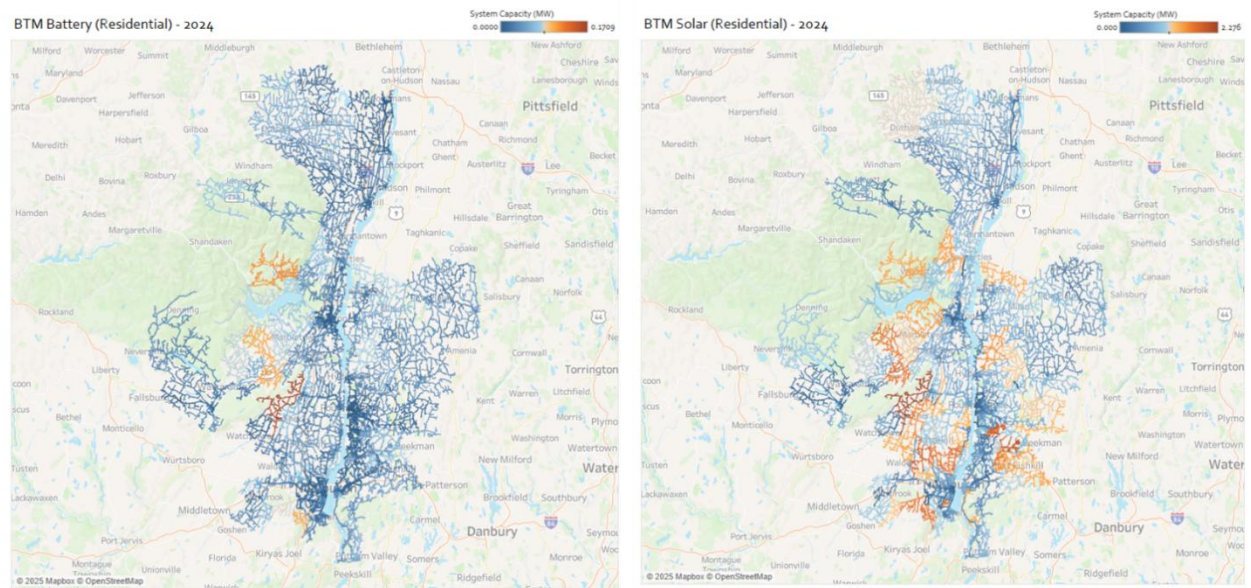
Figure 29: CDG and Remote Battery Applications and Interconnections (Nameplate MW)



Historically, the geographic concentration of solar and battery storage has been higher in specific parts of Central Hudson’s territory, reflecting housing age, homeownership, ability of homeowners to afford

solar, and environmental inclinations. Figure 30 shows the penetration of residential net metered solar and battery storage by circuit.

Figure 30: Location of Residential Net Metered Battery Storage and Solar Installations



Because it’s a relatively new technology, market potential estimates for battery storage are inherently uncertain. Central Hudson used historical data on solar installations, the share of solar sites that installed battery storage, and the interconnection applications and completion rates for each step to develop a storage forecast, shown in Table 19. Most of the growth in the next five years is expected to come from community solar projects with battery storage, but there is substantial uncertainty around these projects and limited data on the rate at which projects proceed all the way to interconnection. Nearly all residential battery installations are paired with solar and most CDG and remote metering battery storage is also paired with solar. Additional details regarding data sources, methods, and results, can be found in Appendix C.

Table 19: Battery Storage Forecast

Year	Residential Installations	Residential Installed Capacity (MW)	Non-res Installations	Non-res Installed Capacity (MW)	CDG and Remote Installations	CDG and Remote Installed Capacity (MW)
2025	884	8.1	14	0.3	2	6.3
2026	1,002	9.2	17	0.3	3	7.8
2027	1,107	10.2	19	0.3	4	14.1
2028	1,199	11.1	21	0.4	4	15.0
2029	1,278	11.9	23	0.4	5	17.5
2030	1,345	12.6	24	0.4	6	21.6

b) Ongoing Monitoring

As part of its normal course of business, Central Hudson continuously processes both distribution and transmission interconnection requests. Central Hudson utilizes this data to monitor the activity level for potential third-party energy storage systems on the system. To date, there are a number of smaller residential type systems paired with PV and a limited number of commercial and CDG systems proposed. In addition to these storage projects, there currently are 19 energy storage projects going through the NYISO interconnection process with a total capacity and energy of 2,468 MW; an additional 4 projects with total capacity and energy of 49 MW are in the Central Hudson interconnection process.

Central Hudson will continue to monitor both cost components and use case applications of these systems and actively participate in the continued development and implementation of the New York Energy Storage Roadmap by the Department of Public Service and New York State Energy Research and Development Authority Staff. Utilizing this information with the storage system queue data from its interconnection processes, and refining the evaluation processes developed in its studies to date, Central Hudson will continue to evaluate energy storage applications as system needs develop. Should the PSC approve the JUs non-market T&D energy storage use case filing, Central Hudson will seek opportunities to incorporate energy storage as a new tool in its planning processes. This includes conducting engineering and economic reviews to determine where energy storage may offer a superior solution compared to traditional T&D infrastructure.

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.

In alignment with the 2024 Energy Storage Order, Central Hudson recognizes the three market segment groupings (bulk, retail and residential) for storage deployment applications. As previously mentioned, Central Hudson will continue to review needs on its local transmission and distribution systems to identify potential storage projects that provide cost-effective services when compared to traditional alternatives.

Consistent with the 2024 Storage Order, Central Hudson recognizes retail bill management, demand response, storage paired with PV, and resilience as potential customer-sited use cases. The Data Sharing section of this filing identifies customer-level data available and the privacy and security issues related to providing this data. The available data can be utilized to help identify potential opportunities for the cost-effective application of customer-sited storage. In addition, Central Hudson's System Data Portal provides 8760 historic circuit load data, where available, and 8760 historic and forecast load data for load serving substations where available on the system (see Section III.I.5.i) for additional information).

For the distribution system use cases, Central Hudson identifies both NWA areas and Beneficial Locations. There are currently three existing Non-Wire Alternative areas in the service territory. These areas provide the opportunity for the beneficial use of energy storage to eliminate or defer the need to complete growth-related T&D capital projects (i.e., capital deferral). To date, storage solutions have not been cost competitive with either demand response or energy efficiency solutions in these areas. The

storage applications that have been assessed to date would require a long operational life to approach the point of being economical. Such long-term certainty is not feasible within the Company's current NWA solicitations that are designed for shorter-term deferral of assets. Additionally, the currently available revenue streams are generally not significant enough to justify the appropriate interconnection requirements and costs for larger scale applications when compared to distributed, behind the meter DERs. However, additional revenue streams through the wholesale markets for storage assets that are deployed to meet utility needs would have a positive influence on project economics or at a minimum offset the costs of projects whose primary purpose is for utility needs.

Central Hudson identifies beneficial locations as part of its probabilistic forecasting process. Beneficial locations are sites where the risk of overloads over the next ten years is above 10% and it does not have an infrastructure project in the capital plan. Beneficial locations are potential candidate areas for NWAs but have not yet undergone a detailed engineering and NWA feasibility assessment. Beneficial locations are open to all load relief resources. Appendix E provides additional details for each location, including: the location, customer mix, historical loads and loading factors, growth rates, and risk of overloads by year. If a beneficial location is designated as an NWA area, Central Hudson produces detailed estimates of the load relief required by hour and forecast year to attain deferral.

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

As one of the requirements in the 2024 Storage Order, the JU were directed to identify the use cases for utility-owned energy storage to provide non-market transmission and distribution services that are cost-effective when compared to traditional alternatives. As a result, Central Hudson has been working on various initiatives as identified earlier, including supporting JU filings along with working on Company specific initiatives. Energy storage T&D use cases have unique parameters that will continue to be evaluated to determine the cost benefit within Central Hudson's service territory. Central Hudson also utilizes probabilistic forecasting to help identify the beneficial or LSRV areas on the Central Hudson system. This data helps inform the projected number of potential storage systems in response to these values. Based on the results of the current study, an increase of storage systems based on these value streams is not anticipated at this time. Another data point Central Hudson utilizes as a planning resource is the energy storage applications within the different interconnection queues (NYSSIR, NYISO, and Central Hudson). This provides a high-level view of potential energy storage systems of various sizes within the service territory. As storage systems with net positive value for customers are identified, Central Hudson would utilize its current processes for system implementation.

As part of discussions within the ITWG in 2024, Central Hudson developed an energy storage charge and discharge schedule that identifies timeframes in which charging and discharging are permitted. These timeframes were identified to support energy storage integration by minimizing potential infrastructure upgrades (i.e. avoiding charging during peak times) as well as help Central Hudson better manage and track these systems. As tracking and managing varying energy storage schedules will become complex as storage integration increases (particularly without a DERMS) this provides Central Hudson with a better method to understand operation within the system. Central Hudson's schedule currently permits charging all year from 10pm-1pm and discharging all year from 7am-1am. In lieu of utilizing this schedule, developers/applicants can opt to choose unrestricted operation as a study option instead.

Central Hudson also maintains a System Data Portal that provides 8760 historic circuit load data, where available, and 8760 historic and forecast load data for load-serving substations where available on the system (see Section G for additional information). This publicly accessible data can be utilized by stakeholders for planning and implementing energy storage at multiple levels in the distribution system.

Central Hudson also maintains a public-facing Hosting Capacity Map that can be utilized for planning purposes. This map provides hosting capacity information for PV, energy storage systems as well as electrification. Additional information regarding the hosting capacity maps can be found in Hosting Capacity.

For system interconnection review, energy storage is considered a type of DER. Central Hudson's current planning processes incorporate the effects of different types of DERs – predominately PV, EE, and demand response at this time. See Section III.2.a) of this DSIP filing for additional information on current status of Central Hudson's integrated planning efforts. Due to the minimal level of storage currently installed on the system, standalone/dedicated systems for the monitoring and management of energy storage assets are not required at this time. Through the New York State SIR and the NYISO Interconnection process, new storage systems will be studied as they go through the interconnection process. New storage installations will be evaluated to determine the required monitoring and management systems. Central Hudson will have monitoring and control as part of its DMS. As the energy storage systems become more prevalent, to the extent dispatch of these assets is necessary, it will become important to invest in a Distributed Energy Resource Management Systems designed specifically for DER and energy storage management. It is expected that this type of system will either be an extension/enhancement of the current DMS or a standalone system that interacts with the DMS.

Below, the sub-questions in the order are addressed:

- 1. Explain how each of those resources and functions supports the utility's needs.** The resources and functions outlined above support Central Hudson's needs by providing a statewide roadmap for energy storage and distribution system locational values for DERs. The current plan to implement a DMS with the ability to increase functionality as needs arise supports the current levels of penetration and permits Central Hudson to add functionality as energy storage levels increase.
- 2. Explain how each of those resources and functions supports the stakeholders' needs.** The resources and functions outlined above support stakeholders' needs by providing a statewide roadmap for energy storage and distribution system locational values for DERs. These resources provide data to help determine the potential value streams for calculating project economics for energy storage assets. The system data portal provides both historical and forecasted 8760 load data at a sufficiently granular level to enable stakeholders to identify potential areas on the system where their specific use case may be cost beneficial. In addition, the interconnection process provides a standard process for determining the interconnection requirements and the timeline to interconnect to the distribution system. As previously mentioned, Central Hudson also established energy storage schedules to provide support for DER integration through the interconnection process. Central Hudson's DMS and network strategies initiatives will provide a cost effective and readily available means to provide the required monitoring and control functionality for these systems to interconnect to the system. The Company's hosting capacity maps provide developers with a graphical interface supplying a number of key data points for the

system, including: the circuit's ID, operating voltage level, number of phases, local hosting capacity values, interconnected and proposed DG in queue, NYISO Load Zone, as well as DG installed since last hosting capacity refresh. Additional information on substation data is also provided including: the substation ID, interconnected and proposed DG in queue, prior year substation peak, and substation back feed protection status. Additional information regarding the hosting capacity maps can be found in Hosting Capacity.

6) Describe the means and methods for determining the real-time status, behavior, and effect of energy storage resources in the distribution system. Information produced by those means and methods could 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, consumer (grid and/or local load), 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.

For items (a) through (d), Central Hudson currently has no energy storage assets interconnected to the system that require means and methods for determining the real-time status, behavior, and effect of energy storage resources in the distribution system. For the Four Corners Microgrid, which went into service June 30, 2023, the system has a Remote Terminal Unit that will feed into the DMS system. This includes MW and MVAR analog points that show the real and reactive power imported and exported for the energy storage system. Currently, only the battery storage MW and MVAR analog points, along with the breaker status will be retrieved through the Remote Terminal Unit. Central Hudson is unwilling to invest in additional infrastructure and systems for this until this type of information is necessary based on penetration levels.

For Item (e), Central Hudson utilizes its existing planning and operational practices to determine the capacity of the distribution system to deliver or receive power at a given location and time.

Energy storage resources interconnected to the distribution system are considered a type of DER. As such, Central Hudson follows the current standards and practices for monitoring the interconnected DERs on its distribution system. These practices have been developed to ensure that Central Hudson maintains the visibility and control necessary to safely and reliably operate the distribution system.

As energy storage systems are interconnected to the system, they will typically fall within three areas or applications which, along with their size and location, will dictate their operation. These applications are bulk/transmission systems that follow the NYISO interconnection process, distribution-level systems that Central Hudson controls or has the ability to dispatch, and storage coupled with other DERs which is under the control of the interconnecting customer. Bulk/transmission systems will be dispatched by the

NYISO. Central Hudson will require sufficient visibility and monitoring of these facilities to operate the system in a safe and reliable manner.

Distribution systems that Central Hudson controls or has the ability to dispatch, including the Four Corners Microgrid system, will be managed through the distribution operations area. It is envisioned that for a number of years, these systems will be managed by simple on/off instructions or curtailment based on system constraints.

The overwhelming majority of the systems controlled by the interconnected customer will be able to operate at full output only limited by customer requirements or distribution system abnormal conditions. Abnormal distribution systems may dictate that the system remains offline until the distribution system returns to normal.

In addition, Central Hudson has several ongoing initiatives that will enable increased functionality in response to higher penetration levels of DERs, including energy storage. As indicated in prior sections, Central Hudson is in the process of implementing a Distribution Management System in conjunction with rolling out a Distribution Automation program and a Network Strategy communications platform. These systems will provide the Company with significantly increased visibility into the distribution system and, ultimately, the ability to operate the distribution system in real-time. As the number of smart distribution devices with monitoring capability installed on the system grows, Central Hudson's overall system visibility and awareness will continue to increase. As indicated previously in this document, the distribution of operational data from smart devices will be transmitted to the DMS via the communications network. In addition to data provided by distribution smart devices, data from DERs as determined by the operational requirements to reliably and safely operate the distribution system will also be integrated into the DMS, and starting in 2027, Central Hudson anticipates commencing the Company's DERMS initiative. This will include the necessary data and analytics to determine the information outlined above (amount of energy currently stored (state of charge); the time, size, duration, energy source (grid and/or local generation), and purpose for each charging event; the time, size, duration, consumer (grid and/or local load), and purpose of each energy storage discharge; 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 the capacity of the distribution system to deliver or receive power at a given location and time) as required by the specific application. Overall, consistent with current practices, the level and complexity of any monitoring required will vary with the size, location, and application of DER's in Central Hudson's system. Energy storage systems represent additional complexity because of their ability to both supply and consume energy. As use cases for storage are expanded, the level of monitoring may need to change to meet specific applications.

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 Company 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;
- 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.

Due to the very limited amount of energy storage resources currently installed within the service territory, Central Hudson does not currently require or have the means and methods for specifically forecasting the status, behavior, and effect of storage resources at future times. Central Hudson is in the process of implementing a DMS and has established a real-time distribution operations center. Advanced capabilities of the DMS will be evaluated, tested, and implemented as required. As the number and size of DERs and storage resources interconnected to the system grow, both the status and control of these resources will be incorporated into the DMS as necessary as well as a future DERMS. Based on the current interconnection process under the NYSSIR, the distribution system would be able to accommodate energy storage charging and discharging as defined in the Interconnection Agreement at all times. The ability to forecast items such as the state of charge, the net effect of charge and discharge operations on the distribution system, and the capacity of the distribution system to deliver or receive power at a given location and time will be incorporated into the DMS when the penetration levels necessitate this functionality. This centralized system will permit Central Hudson to forecast the items identified above as this capability is needed.

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

As described earlier in Section c), the majority of the energy storage systems currently interconnected are at the residential level paired with solar PV. Two additional larger CDG projects are also currently interconnected, and DC coupled with PV. As these projects are eligible and compensated under VDER, there are no additional resources and functions currently needed, outside of the existing VDER compensation process, required for storage. As Central Hudson begins to see further integration of energy storage, including standalone or AC coupled storage, additional metering may be required to ensure appropriate compensation. Depending on the size of the energy storage system, in some cases a separate service for auxiliary heating ventilation and air conditioning (HVAC) loads may be necessary and for utility and NYISO projects, additional telemetry may also be required.

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

Depending on the use case, there are different types of customer and system data that may be necessary for planning, implementing, and managing energy storage. This data includes:

- Customer count by rate class;
- Historical load by customer type;
- Load shape by customer type;
- Capital investment plans;
- Planned resiliency and reliability projects;
- Reliability statistics;
- Hosting capacity;
- Beneficial locations;
- Load forecasts;
- Historical load data;
- NWA opportunities;
- Locational System Relief Value (LSRV) locations; and
- Queued and installed DG.

Much of this data is readily available to developers and other stakeholders and is typically publicly available. In response to stakeholder feedback, the Joint Utilities launched a central data portal on the Joint Utilities' website in June 2017, which has been kept up to date since, with links to utility-specific web portals with available system data and customer data is also being made available through UER. Additional energy data will also be available as part of the state-wide IEDR initiative. The Joint Utilities' website (<https://jointutilitiesofny.org/system-data/>) includes utility-specific links to the system data listed above.

10) By citing specific objectives, means, and methods describe in detail how the Company's accomplishments and plans are aligned with the objectives established in the Climate Leadership and Community Protection Act

Central Hudson's plans are aligned with the objectives established in New York State's initiative to deploy 6,000 MW of energy storage in New York State by 2030 as demonstrated by the following:

- In June 2024, Central Hudson issued a Request for Proposal to procure a total of at least 10 MW of scheduling and dispatch rights for bulk connected energy storage within the service territory. Per the PSC, the project(s) must be operational by December 31, 2028. Central Hudson has completed its evaluation of proposed projects. The results of the Company's evaluations are being communicated to stakeholders contemporaneously with this DSIP filing.
- Central Hudson was an active participant in the JU filing in response to the 2024 Energy Storage Order. This included identifying six use cases where energy storage could provide non-market T&D services, along with describing engineering and economic review, how system planning and operations will be modified to accommodate energy storage as a tool, as well as cost recovery.
- Central Hudson has been a leader within the state in collaboratively working with the Joint Utilities, developers, and policy makers to advance interconnection process improvements. Central Hudson has been very actively engaged in both the ITWG and the IPWG. Improvements in the timeline and efficiency of the interconnection process facilitate the integration of DERs onto the distribution system and help improve their business cases. Most recently, ITWG discussions have resulted in energy storage schedules and requirements associated with storage

and microgrid interconnect device when used for backup purposes. These efforts should help increase the deployment of energy storage within the state.

- Central Hudson has been actively involved in working with the other Joint Utilities and the NYISO to facilitate dual participation of DERs, including energy storage assets. This work will help energy storage assets gain access to additional/multiple value streams including wholesale markets. As the type and number of benefits the energy storage systems are eligible for increase, the greater the likelihood that these assets will pass the cost benefit test thereby increasing their financial viability and spurring additional deployments helping achieve the State goals.
- Central Hudson has reviewed and processed interconnection applications in an efficient and cost-effective manner. Central Hudson is committed to facilitating the interconnection of all types of DERs onto its distribution system. This includes the installation of customer-owned/sited storage systems, either as standalone systems or paired with renewable resources and larger scale storage projects proposing to interconnect to the transmission system.
- In its NWA areas, Central Hudson engages with energy storage providers to identify potential cost-effective solutions that may meet the program needs and, as part of the 2024 Storage Order, will evaluate what additional value streams can be realized by energy storage solutions.
- Central Hudson is in the process of implementing a DMS in coordination with DA and Network Strategy programs. This system and the future integration of a DERMS will significantly expand the visibility and control of the distribution system. Greater real-time awareness and control will ultimately enable the system to better plan for, accommodate, and control (where required) all types of DER assets including energy storage interconnected to the system.
- Central Hudson will continue to track the cost effectiveness of transmission and distribution storage use cases through research initiatives as detailed within Section III.D.a). As the storage assets become cost effective, Central Hudson will incorporate these assets into its investment plans.

11) Explain how the Joint Utilities are coordinating the individual utility energy storage projects to ensure diversity of both the energy storage applications implemented and the technologies/methods employed in those applications.

In response to the 2024 Storage Order, the JU filed six use cases for energy storage non-market T&D services on October 29, 2024. These included: 1. Flexible Transmission Capacity; 2. Flexibility Distribution Capacity; 3. Distribution Resiliency and Reliability; 4. Bridge-to-Wires; 5. Large Scale Renewable Enablement; and 6. DER Integration and Hosting Capacity on Distribution Network. In addition to identifying the use cases, the JUs also described the engineering and economic review of the types of energy storage applications the utilities can deploy as part of their obligations to provide safe and reliable service in the most efficient and effective manner; a description of how utilities will modify system planning and operations to accommodate energy storage as a new tool; and a proposed process for the review and approval of energy storage project as well as a cost recovery mechanism if the process does not align with the normal rate schedules. The PSC solicited initial comments on this filing due February 2025 with reply comments filed in April 2025. Central Hudson is awaiting Commission

ruling on this proceeding and proposal and will continue working closely with JU on integrating energy storage as a potential T&D solution within the planning process.

E. ELECTRIC VEHICLE INTEGRATION

1. KEY TAKEAWAYS

Central Hudson has taken a proactive role in preparing for the future of transportation electrification. Transportation electrification is poised to accelerate rapidly in the coming years in order to meet policy goals of lower greenhouse gas emissions and electrification targets. In order for Central Hudson to continue to serve its customers reliably and at the lowest cost, it is critical to understand what these rapid changes will mean for the distribution system. To plan for the future, however, it is important to understand what has been happening up to this point. Figure 31 outlines key facts about the growth of electric vehicle adoption and charging infrastructure in Central Hudson territory to date.

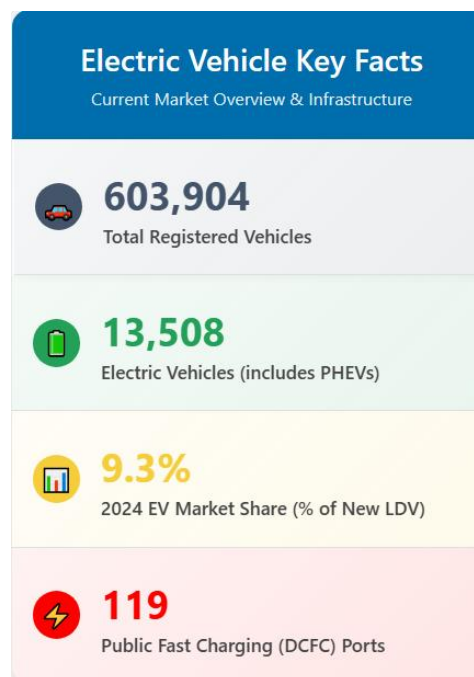
Central Hudson has achieved a number of key wins in supporting transportation electrification as well. The share of new model year light-duty vehicles in Central Hudson that are electric has grown from 1.3% in 2019 to 9.3% in 2024, indicating a growing EV presence in the market. Of the new electric vehicles, roughly 70% are full battery electric vehicles (BEVs) and 30% are plug-in hybrid electric vehicles (PHEVs) in the two most recent years. Central Hudson's EV Portfolio of Programs empowers communities through hands-on education, outreach, and advisory services—positioning the utility as a trusted EV advisor. In addition, Central Hudson is actively monitoring data on transportation electrification progress by tracking EV adoption at the feeder level as well as utilization rates at DCFC and L2 public charging stations. These data points inform ongoing forecasting of EV adoption and EV-related load impacts into distribution planning from the feeder level up.

In addition to the work that has been completed to date, there is a roadmap for further EV-related work at Central Hudson. A few items on this roadmap include the planned development of EV charging load shapes that are specific to the Lower Hudson Valley, the rollout of EV Phase-in rates in October 2025, and the rollout of commercial managed charging in 2026.

2. CONTEXT AND BACKGROUND

The electrification of vehicles is expected to increase overall electric sales and improve the overall utilization of transmission and distribution grid assets in the near term. However, in the long run, as penetration increases it will likely require upgrades to the secondary transformers, feeders, and substations, particularly when combined with building electrification. Each light duty vehicle adds roughly 4,000 kWh of incremental electric use and reduces the use of fossil fuel. If 50% of vehicles

Figure 31: Central Hudson EV Facts



electrify, it would add over 1,200 GWh of annual sales. While electric vehicles loads are substantial, they are typically diversified – vehicles charge on different days and hours – and easy to shift. In the near term, the adoption of electric vehicles will help improve the utilization of existing distribution assets.

Electrifying transportation provides numerous benefits for customers and communities, driving greater efficiency, sustainability, and energy security, while helping to alleviate long-term rate pressure in an era of stagnant sales growth.

According to the U.S. Energy Information Administration, the transportation sector is responsible for 45% of New York State’s greenhouse gas emissions—the largest contributing sector to the state’s carbon footprint.²⁸ As a result, transitioning to zero-emission vehicles (ZEVs) is a critical strategy in achieving New York's clean energy goals.

1) Historical Adoption Patterns

New York makes available vehicle registration data for all 11 million vehicles in New York, including information about the fuel type (e.g., electric, gas, diesel, etc.), the vehicle class, model year, zip code, and VIN number. Additional information embedded in the VIN number (e.g., hybrid and PHEV vehicle information) can be extracted by using the National Highway Transportation and Safety Administration’s VIND decoder. In addition, NYSERDA has provided Central Hudson data about electric vehicle rebates since 2018, which is associated with the Central Hudson data on electricity use and location in the grid. Central Hudson uses the above data sources to understand the vehicle mix in its service territory and how it is evolving.

²⁸ U.S. Department of Energy, Energy Information Administration, “State energy related carbon dioxide emissions by sector” (accessed May 13, 2025)

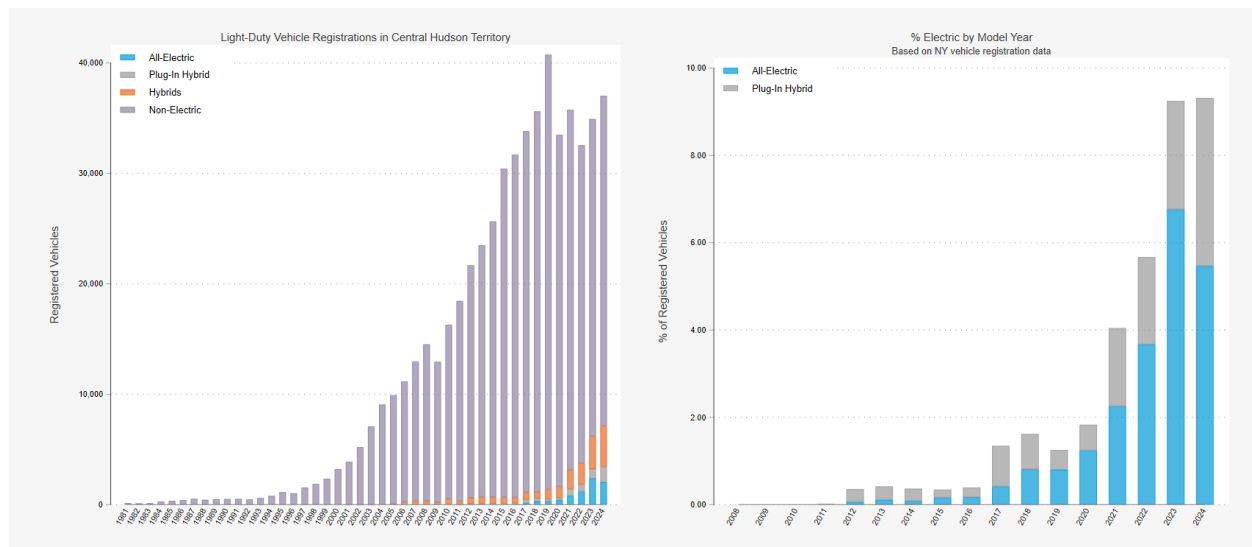
Table 20 shows the registered vehicle counts by class as of March 2025. Figure 32 shows the vehicle stock by model year and the share of electric Light Duty Vehicles (LDVs) that are electric (including plugin-hybrids) by model year.

Table 20: Central Hudson Vehicle Counts (March 2025)

Vehicle Class	Gas	Diesel	Hybrid	Electric	PHEV	Other	Total
LDV	522,706	8,722	20,131	8,073	5,154	2	565,317
MHDV	12,460	18,578	474	227	24	4	32,799
Other	3,455	291	0	29	0	0	3,820
School Bus	174	848	0	1	0	0	1,165
Transit Bus	29	771	0	0	0	2	803
Total	538,824	29,210	20,605	8,330	5,178	8	603,904

Approximately 40,000 new vehicles enter Central Hudson’s territory per year. The rate of entry in recent years has been lower due in part to COVID, supply chain problems, and the reality that not all of 2024 model years have made it from sale lots to driveways. As vehicles age, they either flow out of Central Hudson’s service territory or are retired. Thus, the overall penetration of electric vehicles is influenced most heavily by the share of new vehicles.

Figure 32: Central Hudson Light Duty Vehicle Stock and Electric Vehicle Share by Model Year



Overall, the penetration of electric vehicles in Central Hudson is driven by the share of new vehicles that are electric, the rate of entry of new vehicles, and how newer vehicles flow through the vehicle stock over time. Central Hudson has experienced a notable increase in the share of new vehicles that are electric. In 2019, roughly 1.3% of new model-year vehicles were full electric or PHEVs. By 2024, about 9.3% of new model-year light-duty vehicles were fully electric or PHEVs.

Figure 33 provides a high-level overview of the granular forecasting process. Central Hudson's EV forecasting assumptions, methodology, and results are listed in the Appendix C.

Figure 33: Electric Vehicles Forecast Process Overview

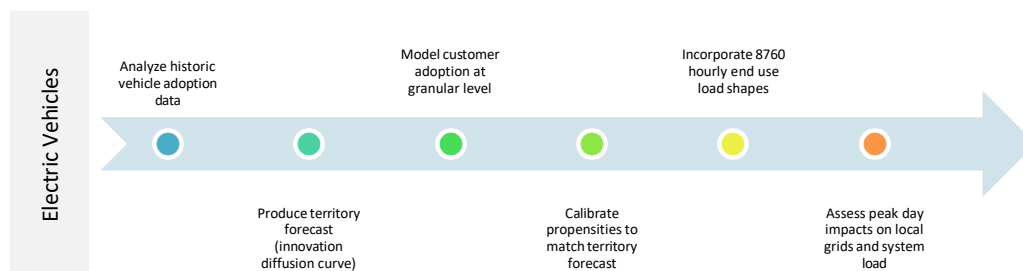
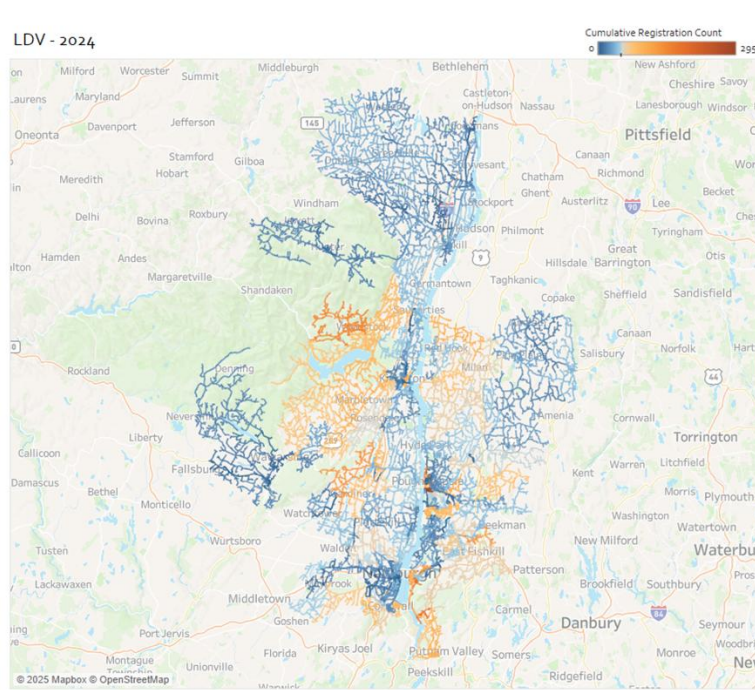


Figure 34 shows the historical geographic penetration of electric vehicles in Central Hudson’s service territory. The map was produced by associating the NYSEDA electric vehicle rebate with Central Hudson accounts (via spatial matching) and circuit feeders. While it does not reflect the full electric vehicle population, it indicates that adoption is higher in specific pockets of Central Hudson’s territory.

Figure 34: 2024 Penetration of Electric Vehicles by Circuit Feeder



2) Forecasted Vehicle Adoption

Table 16 shows the electric vehicle forecasts for 2025 to 2035 and provides details about vehicle counts and annual MWh. Overall, approximately 80% of energy consumption for light-duty vehicles is assumed to occur via home charging, and 20% via public, workplace, or fast charging. Since there is limited data for medium- and heavy-duty vehicles and buses, there is substantially more uncertainty in those estimates.

Table 16: Electric Vehicle Forecast

Scenario	Year	Vehicles			Annual MWh				
		EV Light Duty	EV Medium Heavy Duty	EV Bus	EV Light Duty	EV Medium Heavy Duty	EV Bus	LDV Public Charging (DCFC/L2)	Total MWh
Central Hudson	2025	19,475	164	7	55,069	5,850	196	9,718	70,834
	2026	26,043	210	34	74,108	7,488	693	13,078	95,366
	2027	34,474	269	61	98,672	9,611	1,192	17,413	126,888
	2028	44,988	345	87	129,456	12,346	1,694	22,845	166,342
	2029	57,687	442	114	166,807	15,841	2,210	29,437	214,296
	2030	72,510	565	142	210,596	20,268	2,740	37,164	270,768
	2031	89,229	719	172	260,186	25,816	3,316	45,915	335,233
	2032	107,476	910	205	314,521	32,679	3,925	55,504	406,629
	2033	126,804	1,141	239	372,290	41,046	4,566	65,698	483,601
	2034	146,753	1,419	276	432,128	51,075	5,258	76,258	564,718
	2035	166,897	1,745	315	492,765	62,868	5,988	86,959	648,579

To forecast the impacts of incremental DCFC through 2035, Central Hudson has estimated that additional charging will be built first along main travel route exits and travel plazas, then shopping centers, then travel plaza build-outs, and finally at population centers. For the L2 public chargers, the locations were spread based on the residential population, and for L2 workplace chargers, the locations were spread based on the commercial account population. This distributed additional loading can be used to assess the impact of public and workplace DCFC and L2 charging on circuit loading and the need for peak reduction strategies. Future assessment of utility system impacts, and investment are expected to include a significant amount of MHD EV load.

3) Regulatory Context

New York joined the Multi-State Zero Emissions Vehicle Memorandum of Understanding (ZEV MOU) in 2013, committing to building the necessary infrastructure to support 850,000 ZEVs registered in the state by 2025.²⁹ In September 2021, New York State passed Senate Bill 2758/Assembly Bill 4302, targeting 100% of new light-duty vehicle sales to be ZEV by 2035. As of March 2025, New York, along with other states that signed the ZEV MOU, has successfully met its target, contributing to the collective goal of having 3.3 million electric vehicles on the roads across the signatory states. This achievement is a result of collaborative efforts in building the necessary infrastructure, such as increasing the number of charging stations, and implementing supportive policies and programs.³⁰

²⁹ State Zero-Emission Vehicle Programs, Memorandum of Understanding available at: https://extapps.dec.ny.gov/docs/air_pdf/mhdzevmou102120.pdf

³⁰ https://www.nescaum.org/documents/NESCAUM_Report_ZEV_MOU_FINAL_03102025.pdf

Further solidifying the state's commitment to emissions reduction, New York enacted the Climate Leadership and Community Protection Act in 2019, setting an ambitious goal of achieving net-zero GHG emissions by 2050.³¹ This landmark legislation positions transportation electrification as a cornerstone of the state's broader decarbonization efforts.

New York State has adopted ambitious statewide electrification targets, including enacting policy goals for MHDV decarbonization through the Advanced Clean Trucks (ACT)³² rule, Advanced Clean Cars II,³³ the Zero- Emission School Bus requirement in the State's Fiscal Year 2023 Budget³⁴ (ZEV School Bus Requirement) and requirements outlined in the CLCPA.³⁵

Federal support and funding continue to influence New York's transportation sector, driving advancements in vehicle technology and infrastructure development. The Inflation Reduction Act³⁶ and the Infrastructure Investment and Jobs Act³⁷, are propelling the deployment of EVs in New York State. To achieve these goals, the State must build the EV charging infrastructure required to electrify the transportation sector. EV adoption and mainstream support for EVs continue to grow in response to these state and federal policy goals, and as battery costs decline and more vehicle makes and models become available to customers.

An important factor in adoption, the range of EVs is increasing and, according to the U.S. Department of Energy, the median range of BEVs rose to a new high of 270 miles in model year 2023.³⁸ Studies have shown that a significant barrier to EV adoption continues to be "range anxiety." A study by the NYSEDA

³¹ Chapter 106 of the Laws of 2019. See also, the Climate Act Fact Sheet, available at: <https://climate.ny.gov/-/media/project/climate/files/CLCPA-Fact-Sheet.ashx>

³² ACT will require between 40 and 75 percent zero-emission MHDV sales by 2035, with steadily increasing interim targets starting for sales in 2024 for model year 2025. https://extapps.dec.ny.gov/docs/air_pdf/hdvwebinar021721.pdf.

³³ NYSEDA, All New Cars, Pickup Trucks, and SUVs Sold In New York To Be Zero-Emission by 2035, <https://www.nyserda.ny.gov/About/Newsroom/2022-Announcements/2022-12-29-DEC-Announces-Adoption-of-Advanced-Clean-Cars-II>.

³⁴ New York State Budget for FY '23 mandates all new school bus purchases by 2027 must be zero-emissions and all school buses on the road be zero-emissions by 2035. <https://www.budget.ny.gov/pubs/press/2022/fy23-budget-clean-energy.html>

³⁵ The CLCPA Scoping Plan proposes goals of 50% ZEV sales of medium-duty vehicles by 2030, and 80% ZEV sales of heavy-duty by 2035, <https://climate.ny.gov/resources/scoping-plan/>

³⁶ <https://www.congress.gov/>. "Text - H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022." August 16, 2022. <https://www.congress.gov/bill/117th-congress/house-bill/5376/text/rh>.

³⁷ <https://www.congress.gov/>. "H.R.3684 - 117th Congress (2021-2022): Infrastructure Investment and Jobs Act." November 15, 2021. <https://www.congress.gov/bill/117th-congress/house-bill/3684>.

³⁸ <https://www.energy.gov/eere/vehicles/articles/fotw-1323-january-1-2024-top-range-model-year-2023-evs-was-516-miles-single>

identified upfront cost, technical feasibility, and access to charging as primary barriers to increased EV adoption.³⁹

The electric vehicle supply equipment (EVSE) market exemplifies the need for public investment and the strategic involvement of regulated utilities to accelerate the adoption of electric vehicles. Investing in charging infrastructure, including both financial and non-financial support for necessary upgrades, is crucial for enabling widespread electrification and ensuring seamless integration with existing utility networks. This proactive approach not only supports the transition to cleaner transportation but also leverages utilities' expertise in infrastructure development to meet evolving energy demands efficiently.

On April 24, 2018, the Public Service Commission initiated an EV Proceeding, resulting in the *Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs* ("Make-Ready Order") on July 16, 2020. The Make-Ready Order acknowledged that Commission and utility attention was needed to remove "inappropriate obstacles to adoption and ensure critical electric vehicle supply equipment (EVSE)] and infrastructure is in place to support the state's ZEV targets."⁴⁰

The Make-Ready Program that addresses much of the infrastructure investment through carefully structured utility collaboration and incentives. Central Hudson's Light-Duty EV Make- Ready Program includes an incentive offering designed to reduce the cost of preparing sites to install EV chargers for light-duty vehicles across Central Hudson's service territory. The incentives are intended to increase public access to EV charging stations and are contingent upon site accessibility, universal usability requirements, and the number of chargers at each project site.

Following the PSC's November 16, 2023, Make-Ready Midpoint Order,⁴¹ the Program seeks to offer incentives for make-ready costs of 2,037 Level 2 (L2) chargers and 416 DCFCs across Central Hudson's territory through the end of the program. Central Hudson also offers a medium- and heavy-duty EV Make-Ready Pilot Program, as well as technical assistance for fleets through a Fleet Assessment Service.

In addition to the Light-Duty Make-Ready Program, the PSC issued an *Order Managed Charging Programs with Modifications* ("Managed Charging Program") issued July 14, 2022.⁴² On September 26, 2022, the Company filed its Residential Managed Charging Implementation Plan for passive and active managed charging programs. Central Hudson began accepting applications at the end of 2023. The program offers incentives to customers charging their EVs at home during off-peak hours, which may help the Company avoid grid upgrades while improving the economics of EV adoption for customers.

³⁹ <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Research/Transportation/21-06-New-York-State-Transportation-Electrification-Report.pdf>

⁴⁰ Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding); and Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding), *Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs*, pg. 4 (issued July 16, 2020) (Make-Ready Order).

⁴¹ Order Approving Midpoint Review Whitepaper's Recommendations with Modifications (November 16, 2023) ("2023 Order").

⁴² Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding); *Order Approving Managed Charging Programs with Modifications* (issued July 14, 2022) (Managed Charging Order).

More recently, the Commission directed new utility offerings to address operating cost barriers for commercial EV charging customers, including incentives for load management technologies and new commercial rate offerings and managed charging programs. The Public Service Commission has also opened a proceeding to consider a framework for utilities to proactively plan for and invest in grid infrastructure necessary to support transportation electrification.

Table 21: Proceedings and programs related to EV

Program Type	Detail
Infrastructure Programs	▪ Make-Ready Program: Proceeding 18-E-0138 ▪ Medium- and Heavy-Duty Pilot: Proceeding 18-E-0138 ▪ Future: Medium- and Heavy-Duty Program: Proceeding 23-E-0070 ▪ Load Management Technology Incentive Program: Proceeding 22-E-0236
Operating Cost Relief Programs	▪ DCFC PPI: Proceeding 22-E-0236 ▪ Demand Charge Rebate: Proceeding 22-E-0236 ▪ Time-of-Use rates: Proceeding 22-E-0236 ▪ Commercial Managed Charging Program: 22-E-0236 ▪ Residential Managed Charging: 18-E-0138 ▪ Future: EV Phase-In Rate: Proceeding 22-E-0326
Other Proceedings	▪ Proactive Planning Proceeding: 24-E-0364

4) The Utility's Role

Utilities have played and continue to play a key role in transportation electrification. Electric vehicle loads are large, adding 3,000 to 4,000 kWh of electricity usage per vehicle to demand and, therefore, require careful tracking and integration into planning. The Joint Utilities recognize EVs as essential tools to achieve state clean energy objectives and are committed to supporting and encouraging EV adoption across New York State. Utility efforts have been pivotal in jump-starting EV adoption, advancing demonstrations, pilot projects, and programs, and collaborating with stakeholders such as customers, regional groups, associations, and governments to promote EV initiatives and charging infrastructure awareness.

Utilities are not only facilitating the transition to electric transportation but also ensuring that the necessary support systems are in place to meet the growing demand for EVs. Our proactive approach helps address barriers to adoption, optimize charging infrastructure, and contribute to the state's ambitious clean energy goals.

Central Hudson seeks to maintain flexibility in developing its infrastructure investment strategies. The EV market remains in its early stages of growth, and there is substantial variation in EV adoptions by neighborhood. A key goal is to learn more about where, when, and for how long drivers will charge their EVs, and adapt investment strategies accordingly.

Overall, the EV infrastructure investments need to be proactive and may need to outpace, rather than lag, the market demand. For example, fast chargers are ideally installed two to three years in advance of the adoption of electric vehicles. If vehicle adoption outpaces the installation of fast charging, the inadequate infrastructure may deter further adoptions.

While Central Hudson can forecast electric vehicle growth and help create the infrastructure to support EV adoption, the growth of EV adoption is subject to a number of forces outside of the Company's control, such as vehicle costs and performance, gasoline and other fuel prices, consumer preferences, and public policies. Thus, utility success in the EV market should be determined by objective measures it can control. In the case of investment in EV charging infrastructure, this includes using metrics such as installed charging capacity, number of charging ports deployed, and costs of deploying charging infrastructure.

Since the 2023 DSIP, EV integration has become a very active aspect of the development, primarily driven by regulatory activity, the implementation of Commission-approved programs, the impacts on distribution loads, and emerging issues related to flexible loads. The JU have continued to meet weekly to discuss technical topics, including EV market developments, utility EV customer programs, rate modification proposals, fleet electrification, education and outreach, and program reporting and implementation issues, as well as to discuss positions on emerging issues to share with Department of Public Service Staff and stakeholders.

3. IMPLEMENTATION PLAN

Central Hudson has developed a strategic focus on EV initiatives to increase EV adoption through stakeholder participation and advocacy, and to demonstrate leadership in EV policy. The strategic approach will now focus on utility infrastructure and make-ready incentive implementation, vehicle charging station planning and deployment, and advocacy and education. Ongoing priority actions include:

- Continuing to implement current programs with a focus on customer experience and achieving program targets;
- Maintaining program leadership through cross-functional teams;
- Expanding existing advocacy efforts through annual events and webinars; and
- Continuing outreach to local counties and municipalities.

Central Hudson plays a lead role in deploying EV charging infrastructure in the Hudson Valley and encouraging the transition from gasoline-powered vehicles to EVs. Central Hudson supports the State's goals to increase electrification and reduce emissions.⁴³

Table 22 summarizes key initiatives that Central Hudson has already implemented.

⁴³ <https://www.cenhud.com/en/about-us/Sustainability/>

Table 22: Summary of Current Progress for Electric Vehicles

Topic Area	Activity
EV adoption tracking and forecasting	• Tracking of EV adoptions by substation and feeder: Central Hudson uses EV rebate data provided by NYSERDA to understand the grid location of customers who are adopting EVs. The data is scaled to the public New York Department of Motor Vehicles vehicle registration data. • Develop EV adoption propensity scores: Central Hudson has analyzed all premises/parcel in its service territory and developed propensity adoption scores to understand where EVs are concentrated and pace of adoption. • Forecasting of High Probability DCFC locations and MHDV fleets: Central Hudson enhanced its forecasts by identifying high-likelihood DCFC and fleet locations using data on historical adoption, property and average annual daily traffic data for all travel corridors. • Identifying bus depots: Central Hudson identified most the bus depots in its service territory via use of Google Places API. • EV adoption and load forecasting for individual feeders, substations, and local transmission areas: The Company funded the development of an online T&D forecasting tool for planning that is regularly updated with recurring data pipelines. The T&D planning forecast tool went live in 2024, and provides visibility into where, how, and why loads are changing at various grid levels – system, transmission area, substation, and feeder circuits. It provides ready access and visualization of historical and forecast load patterns and load modifiers, including electric vehicles. • EV Hosting Capacity Map: The maps are a resource for customers and developers to determine whether their site potentially has feeder and circuit-level headroom to install EV charging stations. Central Hudson also publishes a Disadvantaged Communities (DAC) boundary map to assist customers and developers in identifying sites that are within a Disadvantaged Community.
Infrastructure Programs	• EV Make-Ready Program: Supports stakeholders' needs for EV charging in public, workplace, and multi-unit dwellings to accommodate an increased deployment of EVs within New York State by reducing the up-front costs of building EV charging stations. The Make-Ready incentive offsets a large portion of the costs associated with preparing a site for EV charger installation, and in some cases, covers the full cost of infrastructure.

Topic Area	Activity
	• Interoperability and communications: Incentivize 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. • Medium- and Heavy-Duty Make-Ready Pilot: Provides an incentive for up to 50% of customer-side costs, in addition to the incentive for 90% of utility-side costs for certain eligible projects. The program supports the ability to meet the aggressive policy mandates for MHDV and school bus electrification before 2035. This pilot's primary objective is to reduce diesel emissions within DACs. In addition, the pilots support fleets electrification journey by evaluating current fleets and recommending vehicles and transition timelines. • Load Management Technology Incentive Program: Encourages installation of load management equipment, including on-site energy storage equipment, energy storage-integrated EVSE, load management software, and load management hardware. Load management helps customers manage the costs of providing EV charging and eases strain on the grid.
Operating Cost Relief Programs	• DCFC Per Plug Incentive Program: The program incentivized fast charging plugs. As of March 2023, new applications are no longer being accepted. • Demand Charge Rebate: Provides commercial EV charging operators with up to 50% rebate of their applicable billed-demand delivery charges. The EV-Phase-In Rate is scheduled to start in October 2025, and the Demand Charge Rebate will sunset.. • Residential Managed Charging Program: The program offers participating customers incentives for charging at off-peak hours. It incentivizes grid-beneficial behavior to increase utilization and improves load factors.
Education and Outreach	• Host ride-and-drive events. This allows customers to test a range of EV models and learn about the technology firsthand from actual EV owners. So far, these events enabled 691 customers to gain hands-on experience with EVs.

Table 23: Summary of Future Implementation Activities

Activity	Summary	Timeline
Proactive Planning Proceeding	The Proactive Planning Proceeding was initiated in 2024 and utilities filed a planning framework for an annual	2026-2028

Activity	Summary	Timeline
	process to support customers' electrification needs and New York State's clean energy policy goals. The goal is to identify EV related T&D investments that overlap with existing planned projects.	
Development of EV load shapes specific to the Lower Hudson Valley	EVs are highly flexible loads and accurate characterization of the load shapes is critical for long term planning and for the understand the incremental load flexibility that can be achieved. The goal is to collect data on EV at home, at work, and a public/fast charger loads to better inform planning.	2026-2028
Roll out of EV Phase-In Rates	Offers commercial EV charging site operators an opportunity to save on electricity costs while optimizing their charging schedules. This innovative billing method transitions the EV charging account to a time-based rate structure, applying higher rates during peak demand periods and lower rates during off-peak times. By aligning charging activities with periods of lower electricity demand, the EV-PIR not only helps customers reduce their electric bills but also alleviates stress on the power grid during peak hours.	October 2025
Commercial Managed Charging	The programs offer incentives to businesses that install and operate electric vehicle charging stations. This program encourages load shifting and avoids charging during peak hours, which can reduce costs and support better grid utilization.	2026

4. RISKS AND MITIGATION

Central Hudson recognizes a number of risks with its plans for EV integration. While the EV market is poised for significant growth, there are many factors beyond the control of Central Hudson that will ultimately dictate the level of EV penetration and the associated impacts on the electric distribution system. Central Hudson will continue to update its EV adoption forecast so that it will be able to use its normal planning processes to identify system impacts, needs, and potential solutions as changes occur, either due to market changes or technological improvements.

Central Hudson's approach will be to balance the need for EVSE, match the supply equipment to EV adoption, and build in advance of the need, so that it can address the issue of range anxiety and ensure there will be enough charging equipment in place to meet demand. Careful planning and coordination with state and municipal officials will be needed to avoid building unnecessary or poorly placed equipment, ensure that the correct charging equipment is installed as technologies advance, and minimize the chance that deployed equipment will become obsolete.

Another risk is that EV adoption will develop quickly, especially in the MHDV market, and that the impact on Central Hudson's infrastructure would be significant. To avoid this, Central Hudson will participate in the MHDV Proceeding through the Joint Utilities and will remain apprised of EV technology and research

to ensure that as this market develops, the system impacts, and potential mitigation measures are understood well in advance of the need.

5. STAKEHOLDER ENGAGEMENT

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.

Industry supports the DSIP by providing hardware, software, engineering, and planning services to help utility program customers adopt and integrate EVs and EV charging. Stakeholders in this category include automakers, EVSE OEMs, managed charging aggregators, network service providers, consultants, developers, electricians, and installers.

Government entities support the DSIP by providing policy, regulatory, and public investment aligned with the deployment of EVs and EV charging infrastructure. Stakeholders include the PSC, DPS, NYSED, New York State Department of Transportation (NYS DOT), New York State Education Department (NYSED), New York State Department of Environmental Conservation (NYS DEC), Homes and Community Renewal (HCR), NYPA, the Port Authority of New York and New Jersey (PANYNJ), state-level elected officials, and municipalities, and regional governments across the state.

Interest groups support the DSIP by providing technical expertise, community representation, and advocacy for policy objectives such as equity, decarbonization, and advancements in technology. Stakeholders in this category include environmental groups, industry associations, and sector coalitions (i.e., bus fleet operators).

Central Hudson engages with its stakeholders through a variety of different forums to ensure that their program implementation successfully addresses the needs of the utilities, EV drivers, automakers, and the state policy goals.

- **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 and provide ample opportunity for transparency and stakeholder comments to be considered by the utilities and the Commission.
- **Midpoint Review of the Make-Ready Program.** As part of the review, Central Hudson participated in a series of technical conferences to gather feedback from industry stakeholders on topics such as incentive baselines, data reporting, vehicle-grid integration, serving DACs, and MHD charging.
- **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. Examples include:

- The EV Infrastructure Interconnection Working Group, which has been meeting since early 2024 to create an improved process to efficiently manage MRP application queues and improve program transparency.
 - The Technical Standards Working Group, which engaged industry experts to research the accuracy of telematics data collected by EVs participating in the Residential Managed Charging programs.
- **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. Central Hudson's ride-and-drive events are a concrete example of education and outreach efforts.
- **Customer Surveys:** Through online surveys, stakeholders have 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.
- **Up-to-date Webpages.** Central Hudson's EV webpages are kept up to date with program progress tracking, updates to program rules (such as those resulting from the Midpoint Review), and resources for stakeholders.
- **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 updates technical documentation and program guidelines to ensure stakeholders have access to the latest information. This includes posting meeting agendas, supporting materials, and program implementation plan updates online and publicly filing annual and semi-annual program reports.

These methods of continuous customer engagement, often in multi-session series, focused on similar topics, ensure that stakeholders' needs will continue to be met over time. By staying involved with stakeholders in the forums of ongoing working groups and collaborative partnerships, the utilities continue to gain valuable insights into the evolving needs of their stakeholders, and into how program progress and updates are continuing to meet their needs. This continued engagement ensures that stakeholders' needs influence the creation and evolution of the Joint Utilities' EV programs.

Before delivering a new tool, resource, or program offering, Central Hudson and other 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.
- When stakeholders raise certain questions or issues that are applicable to all utility companies, the companies discuss them to first explore how each of them approaches the situation before offering support.

6. ADDITIONAL DETAIL

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:

The common framework envisioned in this directive is a detailed electric vehicle charging infrastructure siting analysis. Initially, the Joint Utilities developed the EV Readiness Framework, which identified key strategies to support EV adoption through utility action, engagement, and collaboration. More recently, Central Hudson has participated in the MHD Proceeding, which seeks to create a unified method (across the Joint Utilities) for anticipating possible infrastructure upgrade needs as electrification penetrates the medium- and heavy-duty vehicle market. While the framework envisioned in this directive is an analytical precursor to investment or engagement at a large scale, for forecasting purposes, Central Hudson has developed a forecast which incorporates the number of light duty EVs in the service territory and estimates their location, the percentage of charging that is done at home, and the number and location of DCFC and Public/Workplace L2 chargers. A separate forecast is then created for the adoption of medium- and heavy-duty vehicles and EV buses. These forecasts then use industry-standard load curves to estimate impacts on the distribution system.

Central Hudson's approach is to monitor adoption closely, update forecasts continuously, and be responsive to customer connection requests and demand. The exact timing of EV growth is uncertain and the impact on distribution upgrade needs will also depend on the growth of load-reducing distributed resources such as solar, battery storage, and energy efficiency. To date, Central Hudson's prior forecasts have tracked well to the actual EV adoption in the service territory.

The growing penetration of electric vehicles will require upgrades at different levels of the transmission and distribution system. Unlike heating and air conditioning loads, which tend to peak simultaneously, electric vehicle charging and subsequent loads are more varied. Different vehicles charge at different times, and they do not all charge on the same day. Thus, the immediate effects will occur in pockets with high penetration of electric vehicles or a high concentration of vehicle charging.

The initial impacts will be home panel upgrades and the need for larger pad mount and pole top transformers in locations where EVs are clustered. The impact on upgrades to primary feeders and substations will initially be limited to locations with fast charging, bus depots, and truck depots, which require larger connections and draw larger amounts of power.

Central Hudson uses actual data about charging location and adoption to develop adoption propensity scores that identify customer sites as early and late adopters. Central Hudson does not create hypothetical scenarios for EV planning but rather uses actual data about adoption by linking sites that received an EV rebate with characteristics about that site and customer. This linked data is used to identify what characteristics are most strongly associated with EV adoption and assign propensity scores to all sites in the territory.

a) The type of location (home, apartment complex, store, workplace, public parking site, rest stop, etc.);

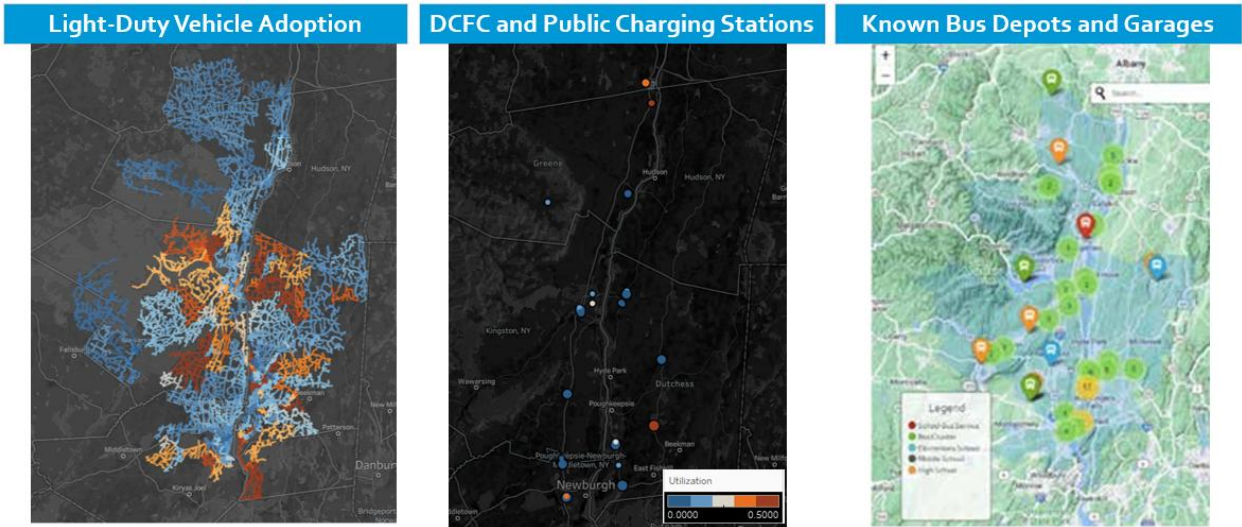
For distribution planning, Central Hudson forecasts EV charging separately for different types of charging: LDV at-home charging, public DCFC charging, MHDV charging, and bus charging. Separate charging propensity models are developed to reflect that different types of charging occur in different locations. For LDV at-home charging, charging is assumed to happen in the same areas where rebates for light-duty vehicles occur the most frequently. For DCFC public charging, a separate propensity model was developed based on where DCFC stations have historically been located; the model incorporates information on the nearby number of retail locations and proximity to existing charging locations. MHDV charging is assumed to be concentrated in existing commercial corridors in the Central Hudson territory, and bus charging is assumed to happen near existing bus depot locations.

Central Hudson anticipates that the initial infrastructure needs will mirror the current locations with high adoption levels or existing public or fast charging. Figure 35 shows where light-duty electric vehicles are registered, the location of DCFC and public charging (including workplace charging) and the location of known bus depots and garages.

b) The number and spatial distribution of existing instances of the scenario;

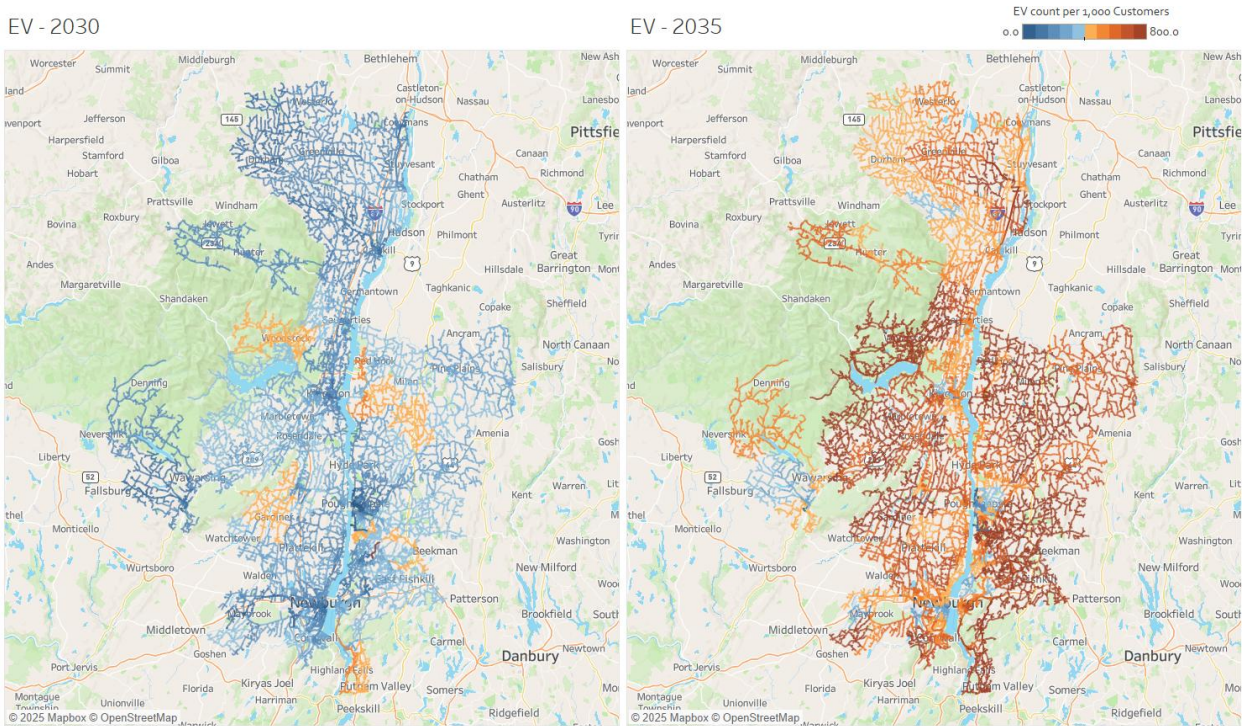
Figure 36 shows the expected spatial distribution of electric vehicle adoption in 2030 (5 years) and 2035 (10 years). The color legend is adjusted to the high adoption rates predicted in 2035. While there is limited historical data on electric MHDV and buses, the location of the current vehicle stock is known at the zip code level. Central Hudson mapped data on vehicle registration zip codes to circuits to understand where electric MHDVs and buses are likely to influence charging loads.

Figure 35: Geographic Location of Electric Vehicle Charging



c) The number and spatial distribution of existing instances of the scenario;

Figure 36: Spatial Distribution of Vehicle Adoption (2030 and 2035)



d) The forecast number and spatial distribution of anticipated instances of the scenario over the next five years;

The number and spatial distribution of existing charging locations are key inputs into the charging forecasts used for distribution planning. For DCFC charging, historical port counts and yearly growth in DCFC ports are used to predict the number of ports in future years. For public DCFC charging locations, it is assumed that new charging locations will not be built too closely to existing charging locations. This requirement ensures a realistic geographic spread of future charging locations.

Table 24 shows the number of existing and forecasted public and fast charging ports. The forecasts were developed using NREL's EV Lite Pro tool and assume that fast charging is built three years ahead of the projected need.

Table 24: Public Charging and DCFC Forecast

Year	Public Level 2	DCFC
Existing	706	119
2025	723	129
2026	965	140
2027	1,274	169
2028	1,432	202
2029	1,832	237
2030	2,127	273
2031	2,615	311
2032	3,145	348
2033	3,703	385
2034	4,272	421
2035	4,846	456

e) The type(s) of vehicles charged at a typical location (commuter car, bus, delivery truck, taxi, ride-share, etc.);

The types of vehicles that will be charged at a typical location depend upon the type of charging that is being modeled. For LDV at-home and public DCFC charging, it is assumed that all vehicles will be commuter cars. For MHDV charging, it is assumed that charging will be done by delivery trucks or other medium- and heavy-duty utility vehicles. Bus charging is modeled separately and includes only electric buses.

While Central Hudson has identified the locations of vehicles and charging, it does not yet have access to telematics data needed to identify when, where, and how long different types of vehicles are charging. Central Hudson has proposed an electric vehicle granular load study that is pending regulatory approval and would help address the above request.

f) The number of vehicles charged at a typical location, by vehicle type;

The charging forecasts used for distribution planning allocate total energy consumption from an overall forecast across locations in the territory according to their propensity. From the annual MWh that is allocated to an individual location, one can calculate the expected number of vehicles from a kWh/year assumption by vehicle type.

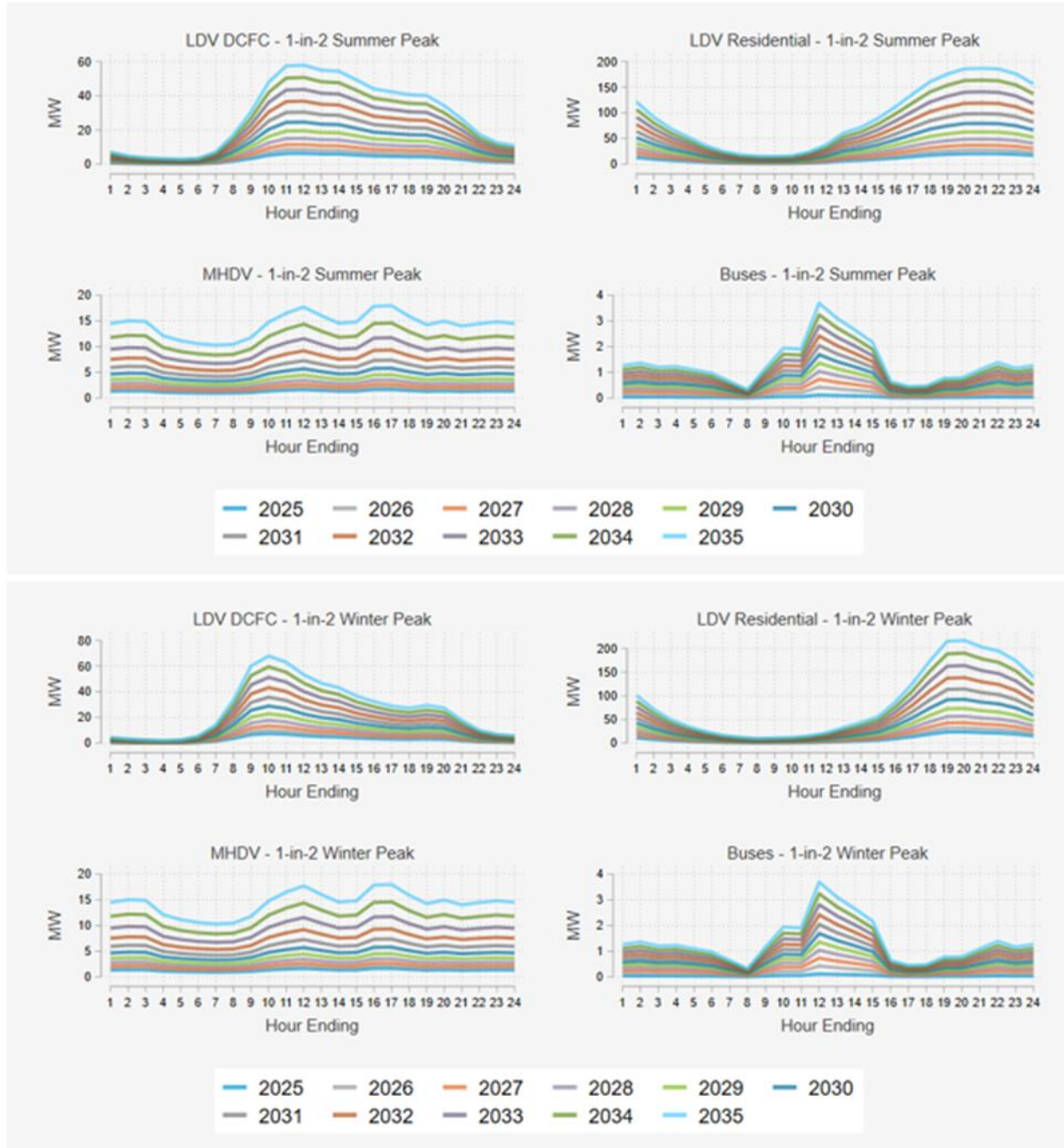
While Central Hudson has identified the locations of vehicles and charging, it does not yet have access to telematics data needed to identify when, where, and how long different types of vehicles are charging. Central Hudson has proposed an electric vehicle granular load study that is pending regulatory approval and would help address the above request.

g) The charging pattern by vehicle type (frequency, times of day, days of week, energy per charge, duration per charge, demand per charge);

While Central Hudson has identified the locations of vehicles and charging, it does not yet have access to telematics data needed to identify when, where, and how long different types of vehicles are charging. Central Hudson has proposed an electric vehicle granular load study that is pending regulatory approval and would help address the above request. Currently, Central Hudson relies on NREL's EV Lite Pro electric vehicle load shapes simulated for the metro areas in Central Hudson's service territory.

Figure 37 shows the electric vehicle charging demand patterns for the summer and winter peak days across all substations in the Central Hudson territory for light-duty vehicles, medium- and heavy- duty vehicles, and buses. The figures reflect the forecasted charging loads. The light-duty vehicle profiles include at-home, workplace, public and fast charging and are based on load profiles from NREL's EV Lite Pro tool. The MHDV and bus profiles draw from profiles made public as part of LBNL's HEVI-LOAD tool, which is still under development.

Figure 37: Vehicle Charging Demand Patterns from Summer and Winter



h) The number(s) of charging ports at a typical location, by type;

Total port counts are forecasted across the territory level (Table 24) and are expected to be allocated evenly across charging locations.

i) The energy storage capacity (if any) supporting EV charging at a typical location;

Energy storage capacity is forecasted separately for distribution planning. Energy storage load profiles are used to calculate the incremental load that is added or subtracted from energy storage, which offsets

or adds to the granular forecasted EV charging loads. There is no specific process that is used to differentiate forecasts between EV charging locations with collocated energy storage or without.

j) An hourly profile of a typical location's aggregated charging load over a one-year period;

For each location, the yearly charging profile is made up of the aggregation of the different charging types that happen in that location. The hourly load profiles, which are based off of publicly available tools from NREL and LBNL, are first converted to an 8760 shape, all charging types (LDV at-home, Public DCFC, and MHDV/bus) are added together, then yearly forecasted charging energy is allocated to that load shape to create hourly loads.

k) The type and size of the existing utility service at a typical location;

l) the type and size of utility service needed to support the EV charging use case;

Location-specific equipment ratings, along with native load forecasts, are used to calculate the likelihood that growth in electric vehicle load over time will trigger infrastructure upgrades. By stacking the incremental load added by EV charging with native load shapes and growth and other load-modifying DERs, the needed capacity increase to accommodate these loads into future years can be derived from the forecasted loads and current equipment ratings. Further detail on this process is provided in the Granular Load, DER, and Electrification Forecast (Appendix C).

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

Central Hudson and the Joint Utilities will undertake measures that support EV adoption in a nascent market, helping to achieve and, where possible, accelerating the long-term potential of transportation electrification. The Joint Utilities of New York have prioritized planning for charging infrastructure, streamlining infrastructure deployment in New York, advancing rate design considerations that will improve the customer experience while minimizing impacts on utility system operation, and conducting education and outreach efforts that raise awareness about EVs.

The role of the utility varies considerably across the core elements of the EV market. In some cases, readiness will be achieved through proactive measures, while in others the utilities remain in a position of information gathering. Consider, for instance, rate design – Central Hudson plans to roll out EV phase-in rates that seek to encourage behavior that supports and improves prospects for increased EV adoption and addresses state goals by improving system load factor and minimizing peak demand growth. On the other hand, utilities are tracking initiatives that promote interoperability and standardization, rather than spearheading them.

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 support the Company's needs.

b) Explain how each of those resources and functions support the stakeholders' needs.

Up to this point, the modest adoption of EVs to date has not warranted dedicated resources and functions; rather, utilities have generally been able to manage EV charging via existing processes. Central

Hudson, in this DSIP filing provides more detail on the resources and functions required for planning, implementing, monitoring, and managing EV charging. The Load and DER Forecasts specifically highlight the impacts of both at-home charging and station charging on the distribution system under both expected EV penetration levels (policy forecast and current market forecast). In addition, Central Hudson has deployed a tool for T&D planners to enable the tracking and continuous updating of loads from distributed energy resources, electric vehicle charging, and building electrification.

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.

As noted previously, the Joint Utilities are in the early stages of planning, implementing, and managing EV charging infrastructure and services. Through use case discussions held with stakeholders, it was determined that there are a variety of customer and system data sources needed to complete this process. The Joint Utilities have identified a subset of the higher-priority data that will be required, as noted below.

- Customer load profile: The utility will need to know the customer load profile, including charging capacity prior to the installation of EV charging infrastructure to help understand the impact on the customer as well as system-level impacts.
- Likely EV charging demand: In workplace or other non-residential types of EV charging, the utility would need to know the anticipated charging demand (e.g., how many EVs are likely to be charging) and at what level (e.g., L2 charging vs DCFC; more likely the former). This will help characterize the charging capacity required at the facility. For a residential installation, the utility would need to know the level of charging that the customer is seeking, namely Level 1 (L1) or L2. Note that it is unlikely that the utility plays a substantive role in deploying L1 charging infrastructure.
- Distribution asset load profile: The utility will need to know the load profile on the nearest substation or similar distribution asset to understand the likely impact that may arise from increased load attributable to EV charging. This will enable the utility to update its asset management strategy for that substation, feeder, etc.
- Potential location of EV charging infrastructure: To the extent that "implementation" of EV charging infrastructure is inclusive of installation, the layout of the proposed installation, namely the location of the physical hardware referred to as Electric Vehicle Supply Equipment (EVSE), will help determine the associated costs. More specifically, the trenching and cutting costs associated with the installation of EVSE at existing facilities can vary significantly depending on the location of the planned installation relative to the point of connection with utility service.
- Distribution asset normal and emergency ratings: The equipment's normal and emergency ratings are critical to understanding if the asset can accommodate the forecasted loads.

At this time, there are no formal mechanisms for utilities to share customer data with third parties. In some cases, customer load data may be shared with the consent of the site host. Central Hudson makes

five-year hourly (8760) load forecasts publicly accessible for transmission areas, substations, and feeders, including subcomponents such as electric vehicle loads.

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

Central Hudson, along with the other Joint Utilities, has significantly adapted our approach to the various DER-related billing and compensation programs that we maintain or have begun in the past five years. The JUs currently maintain the following compensation programs:

- Volumetric net metering;
- Monetary net metering;
- Remote net metering;
- Remote crediting;
- Net crediting;
- Phase 1 NEM;
- Customer Benefit Contribution (CBC) with NEM;
- Phase 1 Value Stack; and
- Phase 2 Value Stack.

In addition to these existing programs, an additional two programs – volumetric net crediting and wholesale value stack – will be implemented in the near future. It is important to note that setting up, testing, and maintaining each program can be complex, especially when considering interactions with other programs, so the Company continues to devote the appropriate time and resources to support each of these programs from design, programming, and implementation to on-going IT and administrative maintenance. Central Hudson 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.

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.

Central Hudson's plans are aligned with the policy objectives set forth in the "Multi-State ZEV Task Force" which established an organization-wide goal of 3.3 million ZEVs by the end 2025 and an estimated 850,000 for New York State by the end 2025 as demonstrated by the following:

- The current EV forecasts have scenarios based on the current market growth projections as well as a high market growth scenario
- The current forecast for number of LDVs in the service territory by 2030 is 72,510 (Table 25), along with 565 medium and heavy-duty vehicles, as well as 142 EV buses, which are in the same magnitude as other projections that will meet the ZEV goals.

Table 25: Electric Vehicle Forecasts

Vehicles	Annual MWh
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Scenario	Year	EV			EV			LDV Public Charging (DCFC/L2)	Total MWh
		EV Light Duty	EV Medium Heavy Duty	EV Bus	EV Light Duty	EV Medium Heavy Duty	EV Bus		
Central Hudson	2025	19,475	164	7	55,069	5,850	196	9,718	70,834
	2026	26,043	210	34	74,108	7,488	693	13,078	95,366
	2027	34,474	269	61	98,672	9,611	1,192	17,413	126,888
	2028	44,988	345	87	129,456	12,346	1,694	22,845	166,342
	2029	57,687	442	114	166,807	15,841	2,210	29,437	214,296
	2030	72,510	565	142	210,596	20,268	2,740	37,164	270,768
	2031	89,229	719	172	260,186	25,816	3,316	45,915	335,233
	2032	107,476	910	205	314,521	32,679	3,925	55,504	406,629
	2033	126,804	1,141	239	372,290	41,046	4,566	65,698	483,601
	2034	146,753	1,419	276	432,128	51,075	5,258	76,258	564,718
	2035	166,897	1,745	315	492,765	62,868	5,988	86,959	648,579

- Using these forecast scenarios, and other information regarding the granularity of the existing EV ownership, Central Hudson is assessing the impacts on system demand and energy growth down to the substation level. Efforts are being made to determine impacts down to the feeder level with the development of an interactive tool for T&D planning.
- Central Hudson will be using this information in its planning process to assess the impact of EVSEs on the broader distribution system.
- In addition, Central Hudson has run “pressure test” scenarios in its forecasts to assess the impact of EVs at even higher levels of penetration.

Additionally, in 2020, the New York Public Service Commission filed an *Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs* that established programs to support the estimated 20,000 to 50,000 additional public L2 ports, 35,000 to 80,000 additional workplace L2 ports, and 1,000 to 4,000 additional direct current fast charger ports that New York will need.

To address these barriers to EV adoption, Central Hudson is currently offering a portfolio of EV programs to its customers including the Make-Ready Program, LMTIP, Residential Managed Charging Program, and Demand Charge Rebate. The Company is also in the process of developing a Commercial Managed Charging Program, and an EV Phase-in Rate pursuant to the Commission Order in Case 22-E-0236.

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;
- f) next steps with clear timelines and deliverables;

EV Integration Milestones and Investments	Programs Dependent	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Make-Ready Program: 18-E-0138: Supports stakeholders' needs for EV charging in public, workplace, and multi-unit dwellings to accommodate an increased deployment of EVs within New York State by reducing the up-front costs of building EV charging stations. The Make-Ready incentive offsets a large portion of the costs associated with preparing a site for EV charger installation, and in some cases, covers the full cost of infrastructure.													
Milestone: Make-Ready Program 1.0 Order													
Investment: Make-Ready Program 1.0 Implementation													
Milestone: Midpoint Review													
Milestone: Make-Ready end-of-program review	Significant Dependencies: LMTIP												
Milestone: Make-Ready Program Order 2.0 (expected)	Significant dependencies: MHD Pilot												
Investment: Make-Ready Program 2.0 Implementation (expected)													
Residential Managed Charging: 18-E-0138: The program offers participating customers incentives for charging at off-peak hours. It incentivizes grid-beneficial behavior to increase utilization and improves load factors.													
Milestone: JU Residential Managed Charging Proposals													
Milestone: Resi. Managed Charging Order													
Investment: Resi. Managed Charging Program Implementation													
Investment: Submetering testing accuracy research													

[illegible]

[illegible]

Lessons learned to date include:

- Development of charger sites takes more time than anticipated, much of which is not related to utility service or processes;
- Site types reflect Central Hudson's territory of small businesses dotting the Hudson Valley region;
- Statewide program has helped contractors and customers with multiple properties work seamlessly across the JU territories;

- There is a need to look for new and creative ways to engage and support active approved contractors and attract new contractors to participate; and
- Interested in LMTIP is higher than expected.

8) Describe how the utility is coordinating with the efforts of the New York State Energy Research and Development Authority (NYSERDA), the New York Power Authority (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 that represent stakeholders in EV policy and program implementation in New York. The Joint Utilities meet regularly with DPS Staff to discuss the implementation of the Make-Ready Program, Managed Charging Programs, LMTIP, a unified MHDV planning framework, and rate design programs. They share insights into market trends, program progress, stakeholder feedback, and emerging technologies. They also discuss the challenges faced by program participants, proposing 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, as well as state EV adoption mandates and policy goals. Where utility incentive programs may overlap with incentives offered from the state (such as the utility MHDV Pilot and the NYSERDA New York School Bus Incentive Program 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 respective agency to ensure well-documented processes for information exchange.

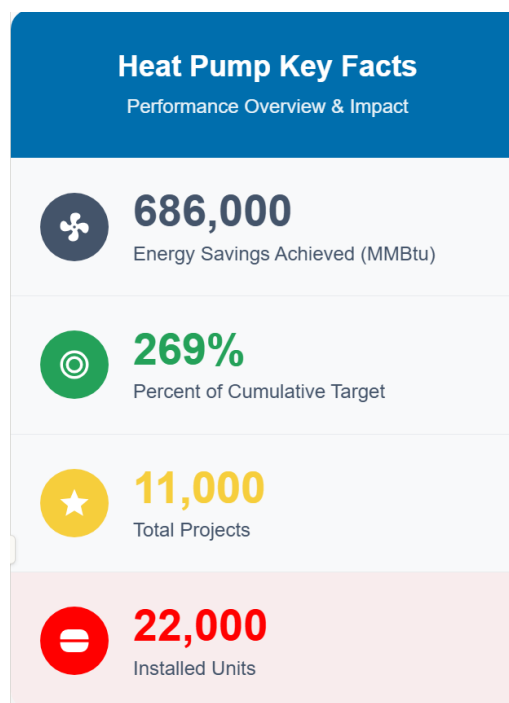
The utilities have facilitated consistent communication with NYPA, NYSDOT, and NYSERDA regarding high-profile, federally funded EV charging installations that also participate in the Make-Ready program, to ensure that they move efficiently through the program and help meet the State's goals.

F. CLEAN HEAT INTEGRATION

1. KEY TAKEAWAYS

New York State Clean Heat is a statewide program designed to support customers in transitioning to energy-efficient electrified space and water heating technologies. Central Hudson has made significant strides in advancing clean heat technologies across its service territory, exceeding statewide targets and laying the groundwork for long-term electrification of building heating. Through the New York State Clean Heat Program, Central Hudson has achieved over 686,000 MMBtu in energy savings—269% of its cumulative target—by incentivizing the adoption of air-source and ground-source heat pumps, as well as heat pump water heaters. With over 11,000 projects and 22,000 installed units, Central Hudson achieved the highest market penetration rate among all utility territories in the Program. This success was driven by leveraging a robust trade ally network, implementing targeted marketing and education campaigns, and collaborating with NYSERDA and the Joint Utilities to expand contractor training and consumer awareness.

Figure 38: Clean Heat Key Facts



Due to market response and high project volume, Central Hudson was granted an additional \$21.2M of funds to support the program through a Commission Order in June 2023. Central Hudson’s Clean Heat portfolio now focuses on full load electrification, including incentives for both residential and commercial sectors. This approach allows Central Hudson to sustain momentum and meet growing demand.

Central Hudson’s Clean Heat strategy is closely aligned with New York State’s climate goals. By exceeding targets, investing in workforce development, and enhancing stakeholder engagement, the utility is not only fostering a sustainable market but also ensuring that customers and all stakeholders are equipped to participate in the state’s clean energy transition. Moving forward, Central Hudson and the statewide utilities will continue to focus on comprehensive “whole-home” energy efficiency solutions in addition to ongoing heat pump adoption.

2. CONTEXT AND BACKGROUND

Heating makes up the largest portion of residential energy use. Historically, most homes in Central Hudson territory have relied on fossil fuel sources—fuel oil, propane, and wood. In the last decade, there have been significant advancements in heat pump technologies, allowing its use in cold climates such as New York. Heat pump technologies are extremely efficient compared to fossil fuels, often using 20-40% of the energy used by the fossil fuel equivalent technology because heat pumps transfer heat from an external source—air, ground, or water. In addition, electrifying heating reduces overall emissions due to conversion from a fossil fuel source (mostly fuel oil) to a cleaner source (electricity).

In the near term, heat pump loads increase grid utilization without increasing peak loads that drive infrastructure sizing because the heating loads peak in winter mornings when there is more room to accommodate loads. However, as penetration grows, they can potentially lead to new peak loads at a local level and, eventually, at the system level, requiring additional infrastructure investments to support the loads. For context, a whole-home heat pump adds between 6,000 to 7,000 kWh per household and increases winter peak demand by about 3 kW. If scaled to saturation of 50% of Central Hudson residential loads, it would lead to an additional 910 GWh of electricity consumption and 420 MW of incremental winter peak demand. Finally, the impact of heat pumps on affordability is a critical consideration. When converted to the same unit basis, electricity is approximately twice the cost of fuel oil and three times the cost of natural gas. For fuel oil, the improvement in efficiency outweighs the cost difference, leading to lower customer bills. Conversions from gas to electric heat can be more challenging, however, since it can lead to higher or lower bills for customers depending on the heat pump's efficiency.

Central Hudson has promoted air-source heat pumps (ASHP) with its Environmental Beneficial Electrification program, which incentivizes ASHP installations in residential fuel-switching applications, since July 2018. On January 16, 2020, a Statewide Heat Pump initiative was established in the *Order Authorizing Utility Energy Efficiency and Building Electricity Portfolios Through 2025* (January 2020 Order) from the New York State Public Service Commission in Case 18-M-0084.⁴⁴ The NYS Clean Heat Program is an initiative between the New York State electric utilities to deliver incentives to both customers and qualified participating contractors for the installation of eligible heat pump technologies. The Clean Heat Program provides a uniform incentive structure with shared eligibility between all utilities to foster the adoption of heat pump technologies throughout the state.

The January 2020 Order also authorized an incremental \$43.2 million to support the achievement of approximately 255,000 MMBtu of energy savings through heating electrification. Heat pump technologies present an excellent opportunity to meet the ambitious statewide greenhouse gas reduction goals due to their ability to provide efficient heating and cooling for both residences and businesses. Heat pumps are approximately three times as efficient as electric resistance heating, offer cost savings for fuel-switching oil and propane consumers, and can fully decarbonize heating energy usage when paired with renewable technologies. As of April 1, 2020, the Clean Heat Program replaced all existing Central Hudson heat pump initiatives. Central Hudson implemented the statewide structure, which allows participation by all electric customers and addresses the MMBtu savings targets within the statewide program.

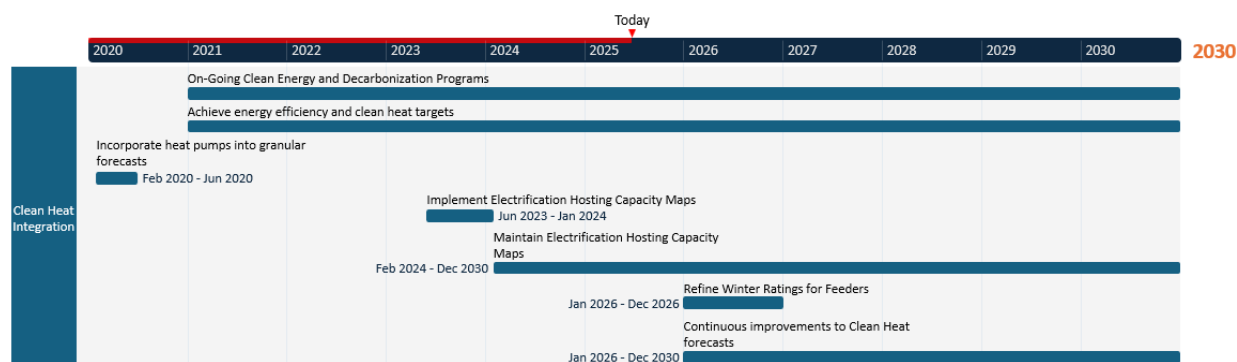
In 2023, Central Hudson and the Joint Utilities phased out partial space heating measures as part of a greater focus on full load and decommissioning projects. The measures within the NYS Clean Heat Program now include incentive rebates for full load installations of 100-120% heating capacity for qualified “cold climate” air-source and geothermal (ground-source or water-source) heat pumps. In addition, incentives for efficient heat pump water heaters across residential and commercial classes are included.

⁴⁴ <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=18-M-0084>

3. IMPLEMENTATION PLAN

Figure 40 shows the Clean Heat Integration Timeline. At a high level the activities can be bifurcated into programmatic efforts to lower costs and remove barriers to adoption via the Clean Heat Program, and activities to prepare the electric grid for higher levels of building electrifications.

Figure 39: Clean Heat Integration Timeline



1) Program Efforts

Central Hudson utilized its existing trade ally network to promote cold climate air-source heat pumps, ground source heat pumps, and heat pump water heaters to residential and commercial customers throughout the service territory. Under the statewide framework, prescriptive ASHP and GSHP projects are incentivized on a \$/10,000 MMBtu of heating capacity, while Heat Pump Water Heaters are incentivized on a \$/unit basis and custom projects based on a \$/MMBtu basis. Qualifying systems are eligible for rebates regardless of the original fuel source, and the prescriptive measures are defined by system size as opposed to a strict residential versus commercial descriptor for custom measures.

Central Hudson implements the Clean Heat program through a structured and collaborative framework that ensures high-quality installations and streamlined contractor participation. A key component of this framework is the engagement of Quality Service Providers, who are contracted to perform third-party inspections and enforce Quality Assurance (QA) standards. These providers utilize standardized inspection checklists developed in coordination with the Joint Utilities (JU) to ensure consistency and compliance across all projects. Central Hudson also works closely with implementation vendors to simplify and digitize the project application process, making it easier for contractors to submit and track projects while maintaining adherence to program requirements.

To continuously improve program delivery and address evolving stakeholder needs, Central Hudson participates in specialized working groups focused on areas such as QA, technical considerations, and contractor engagement. These groups bring together utility representatives, implementation vendors, and industry experts to evaluate best practices, review program data, and recommend enhancements to program design and execution. This collaborative approach not only supports continuous improvement but also fosters transparency and responsiveness, ensuring that the Clean Heat program remains effective, scalable, and aligned with New York State's clean energy goals.

Central Hudson, the JU and NYSERDA collaborated to provide heat pump education and institute market enablement initiatives to grow the qualified labor force for Clean Heat and expand the heat pump marketplace. As the Clean Heat program progressed, Central Hudson leveraged its existing trade ally network to achieve over 685,000 MMBtu of annual energy savings, 269% of its program target of 255,292 MMBtu through 2024.

Table 26: Central Hudson Clean Heat Program Spend and Achievement 2020-2024

Category	Spend (\$)	Savings (MMBtu)
Cumulative 2020-2024 Spend/Achievement	\$62,701,842	686,370
Cumulative NE:NY 2020-2025 Budget/Target	\$43,221,312	255,292
Share of NE:NY Budget/Target Realized Through 2024	145%	269%

In December of 2022, Central Hudson expended its cumulative Clean Heat Program budget for 2020–2025. Pursuant to the budget flexibility authorized in the New Efficiency New York (NENY) Order, the Company utilized a total of approximately \$4.6 million in unspent funds from the Non-LMI Electric portfolio for Clean Heat, having achieved the annual electric portfolio targets for years 2018-2022 without spending the full budget in each year.

In February 2023, in a request to provide additional funding beyond the transfer of unspent funds, the Company petitioned the Commission for the authorization to transition \$13.5 million of its cumulative electric energy efficiency budget to Clean Heat. As a contingency to the authorization, Central Hudson demonstrated its potential to achieve its NENY-ordered cumulative electric energy efficiency (EE) savings target even after the transfer of these funds. In June 2023, the Commission, through its *Order Approving Funding for Clean Heat Program*⁴⁵ authorized the Company an additional \$21.2M to support the program through mid-2024.

Moving forward, Central Hudson continues to engage in market enablement initiatives, provide Quality Assurance education and work with key stakeholders, including key distributors and manufacturers, to increase access to heat pump space and water heating technologies.

2) Preparing the Grid for Higher Levels of Building Electrification

Starting with the 2020 DSIP, Central Hudson developed granular forecasting models for building electrification. The process started by identifying the sites that had installed heat pumps, and heat pump water heaters, and identifying the building, usage, and location characteristics that predicted the customers and locations where heat pump adoption is highest.

⁴⁵ Case, 18-M-0084. In the Matter of a Comprehensive Energy Efficiency Initiative, Order Approving Funding for Clean Heat Program (Issued and effective June 23, 2023), (Order Approving Funding for Clean Heat Program)

To further enable Clean Heat, Central Hudson developed and began publishing electrification hosting capacity maps to enable customers and developers to understand the amount of heat pumps and electric vehicles different segments of the electric grid could support.

Going forward, Central Hudson will aim to refine its winter ratings for feeders to better define and understand the ability of distribution feeders to support heat pumps and winter peaking loads generally. In addition, Central Hudson will be actively participating in the Proactive Planning Proceeding and incorporating both electric vehicle and heat pump load forecasts. Lastly, Central Hudson is looking to refine and improve its heat pump forecasts over time.

4. RISKS AND MITIGATION

Key barriers to heat pump adoption include limited consumer awareness, high upfront costs, contractor availability, and customer perception about heat pumps and their potential benefits. To address these, Central Hudson and the Joint Utilities, in partnership with NYSERDA, have launched targeted marketing campaigns emphasizing the benefits and cost-effectiveness of heat pumps. Through the statewide Clean Heat program, rebates are strategically set to influence customer decisions and reduce adoption barriers. To meet rising demand, the Joint Utilities have also expanded on-demand training for participating and interested contractors to ensure a qualified workforce capable of completing projects that meet the required quality assurance standards within the Clean Heat program.

Future adoption may face headwinds from policy shifts, including uncertainty around federal tax credits and rebates related to the Inflation Reduction Act. These factors could dampen customer interest and stall project timelines. Additionally, the PSC has indicated that minimum building weatherization requirements will take effect in 2028, which has the potential to increase project complexity and limit eligibility of some buildings. Mitigation strategies include clear customer and contractor communication and may consider increasing Clean Heat incentives, but at the cost of higher program unit costs. Additionally, weatherization incentives will be available to help offset costs to help support buildings to meet minimum weatherization requirements and remain eligible for Clean Heat participation.

5. STAKEHOLDER INTERFACE

Central Hudson regularly interacts with stakeholders to continuously develop and enhance its Clean Heat program. This includes interaction with participating contractors, customers, distributors, manufacturers, advocacy groups, DPS Staff and more.

Central Hudson and the Joint Utilities conduct a quarterly Participating Contractor and Industry Partners (PCIP) meeting to discuss program progress, receive stakeholder feedback, announce program changes, and more. Following these meetings, Central Hudson and the JU prepare a brief report summarizing the input received and items addressed, to be published on the New York State Clean Heat Resources webpage. These items include market feedback on the project application process, QA best practices to assure quality installations, or reviewing emerging heat pump technologies that may fold into the program in future updates. This interaction drives future decisions and program requirements to better achieve statewide goals of increased adoption and savings.

The Clean Heat webpage contains a dedicated page for onboarding of new participating contractors and new distributor enrollment. In addition, the Clean Heat webpage contains a Contractor Resources page,

containing all relevant program documents and updates for continued reference throughout program operations.

6. ADDITIONAL DETAIL

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:*

- a) The type of location (single-family residence, multifamily residence, commercial space, office space, school, hospital, etc.);

Table 27: Clean Heat Installations by Category

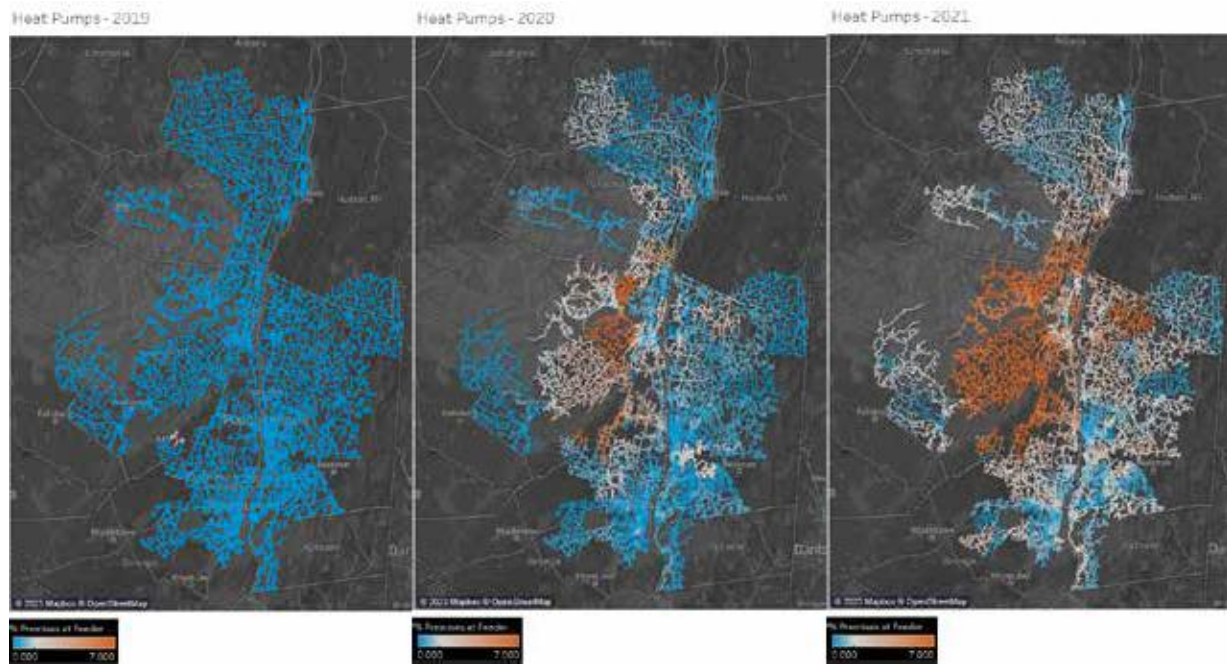
Category	Sector	New?	Total # of Projects	# of Dwelling Units	Total Energy Savings (MMBtu net of increased MWh usage)
Category 1 ASHP: Partial Load Heating	Res	Existing	1,362	1,362	47,069.64
		New Construction	33	33	983.16
	MF	Existing	20	100	659.22
	Comm	Existing	43	-	1,612.70
		New Construction	2	-	43.45
Category 2 ASHP: Full Load Heating	Res	Existing	4,604	4604	343,886.60
		New Construction	302	302	18,074.54
	MF	Existing	81	405	4,979.36
		New Construction	10	50	1,156.32
	Comm	Existing	173	-	7,856.32
		New Construction	33	-	837.37
Category 2a w/ integrated controls	Res	Existing	24	24	1,748.30
Category 2b w/ decommissioning	Res	Existing	1,757	1,757	145,872.10
		New Construction	8	8	540.08
	MF	Existing	10	50	699.44
		Existing	28	-	1,590.52
	Comm	New Construction	2	-	79
Category 3 GSHP: Full Load Heating	Res	Existing	237	237	23,765.54
		New Construction	89	89	7,213.56
	MF	Existing	4	20	445.29

Category	Sector	New?	Total # of Projects	# of Dwelling Units	Total Energy Savings (MMBtu net of increased MWh usage)	
Category 4 Custom Space Heating Applications	Res	Existing	8	8	916	
		Existing	5	25	2,336.13	
	MF	New Construction	8	0	5,298.49	
		Existing	11	-	29,130.16	
	Comm	New Construction	3	-	1,154.06	
		Existing	2,079	2,079	25,535.61	
Category 5 HPWH (up to 120 gal)	Res	New Construction	98	98	572.54	
		MF	Existing	40	63.39	
Category 7 GSHP Desuperheater	Res	Existing	50	50	4,645.12	
		New Construction	21	21	2,327.97	
	MF	Existing	2	10	169.01	
		Existing	1	1	74.73	
Category 8 Dedicated DHW WWHP	Res	New Construction				
		MF	Existing			
Category 9 Simultaneous Install of Space & Water Heating	Res	Existing	83	83	5,034.28	
	MF	Existing	-	-	-	
	Comm	Existing	-	-	-	

b) The number and spatial distribution of existing instances of the scenario;

Figure 40 shows the historical adoption rates of heat pumps by feeder. The Clean Heat program went through a major policy shift in 2020 when statewide heat pump adoption goals were initiated. This is evident in the historical adoption rate increase between 2019 and the end of 2020.

Figure 40: Historical Heat Pump Adoption Rates by Feeder



- c) the forecast number and spatial distribution of anticipated instances of the scenario over the next five years;

Figure 41 shows the forecasted heat pump adoption rate by feeder. The scale for the forecasted adoption rates ranges to an upper limit of 30%, while the historical adoption rate scale in the previous figure was capped at 7%. By 2028, we expect to see relatively high adoption of heat pumps across Central Hudson's service territory with a concentration in Woodstock, East Kingston, and Kerhonkson.

Figure 41: Forecasted Heat Pump Adoption Rates by Feeder



d) The type(s) of clean heat solution installed at a typical location (ASHP, GSHP, HPWH, etc.);

Table 28 shows the types of clean heat solutions installed from 2019 through 2022. New York heat pump goals went into effect in 2020, reflected by the strong increase in heat pump adoption from 2019 to 2020.

Table 28: Mix of Clean Heat Solutions Installed

Year	ASHP	GSHP	HPWH	Mini-Split
2019	0	2	1	8
2020	162	86	306	2,532
2021	449	109	626	5,545
2022	156	79	547	4,093
2023	218	147	665	3,901
2024	228	130	455	2,353

e) An hourly profile of a typical location's aggregated clean heating load over a one-year period;

Figure 42 shows the 8760 Load Shape for Whole Home Heat Pumps. They are based on NRELs ResStock and ComStock data. These loads are scaled to the average homes that installed heat pumps. There is increased load over the winter months with relatively low loads in the summer evening hours. Figure 43

shows the 8760 load shape for Mini-Splits. This load shape considers the average number of installed mini-splits.

Figure 42: 8760 Load for Whole Home Heat Pump Profile

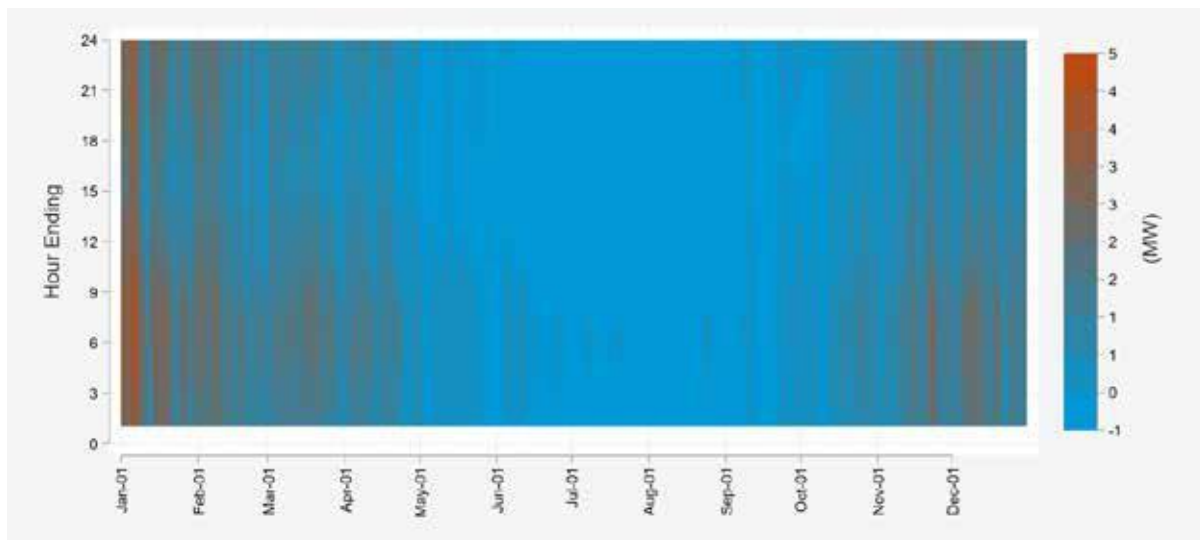
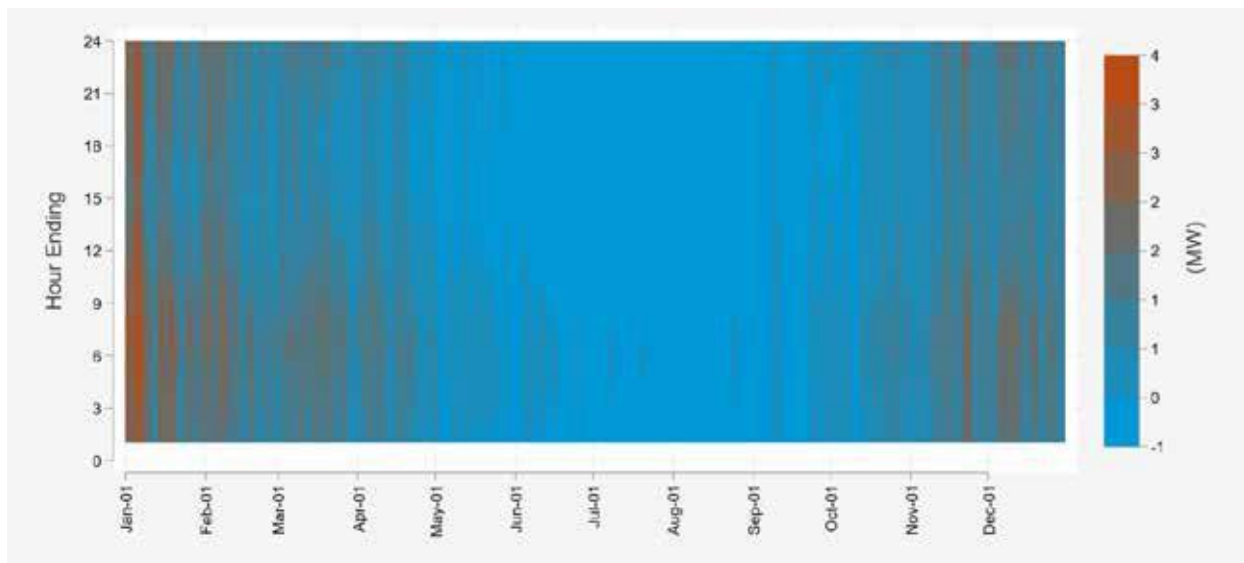


Figure 43: 8760 Load Shape for Mini-Splits



f) the type and size of the existing utility service at a typical location;

Table 29 below shows the breakout of primary heating fuel as a percent of premises. In Central Hudson territory, the primary heating fuel is oil at 60% of premises, followed by electricity at 18%, and gas at 12%.

Table 29: Percent of Premises With Each Heating Fuel Type

Existing Heating Fuel	Premises
Electricity	18%
Gas	12%
Oil	60%
Propane	9.5%
Wood	0.5%

g) the type and size of utility service needed to support the clean heating use case.

Most homes that upgrade to heat pumps require an upgrade to a 200-amp panel. Most homes that convert from oil, gas, propane, and wood are older and have smaller panels that cannot support a heat pump heating without an upgrade.

In addition, as the penetration of heat pumps grows, the feeders, substations, and transmission areas will convert to winter peaking. The exact timing is uncertain and the impact on upgrades will also depend on the growth of load reducing distributed resources such as solar, battery storage, and energy efficiency. In addition, Central Hudson needs to calculate design ratings and criteria for winter peaking loads particularly for feeders.

2) Describe and explain the utility's priorities for supporting implementation of the clean heating use cases anticipated in its service territory.

Central Hudson is undertaking measures to accelerate heat pump adoption in its service territory and support long term heating electrification. Along with the Joint Utilities, Central Hudson prioritized consumer awareness and contractor education to cultivate the long-term potential of the heat pump marketplace.

Central Hudson and the JU are also working with distributors to increase heat pump and water heater stock to promote midstream adoption and increase heat pump availability in the broader market.

Through increasing awareness of the benefits and ability of heat pumps to improve customer perception, targeted contractor education to improve workforce readiness, and distributor partnerships to increase availability, Central Hudson and the JU are laying the framework for long term, stable heat pump adoption to meet ambitious New York State goals.

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.

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

Central Hudson is setting up tools to actively track penetration of building electrification, transportation electrification, and distributed energy resources down to the circuit feeder level. The tool is updating

forecasts continuously and converting the forecasted heat pump penetration into hourly loads for T&D planning.

- 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.*

The updated granular heat pump forecast data will be posted on Central Hudson's website and available starting August 1, 2025.

- 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.*

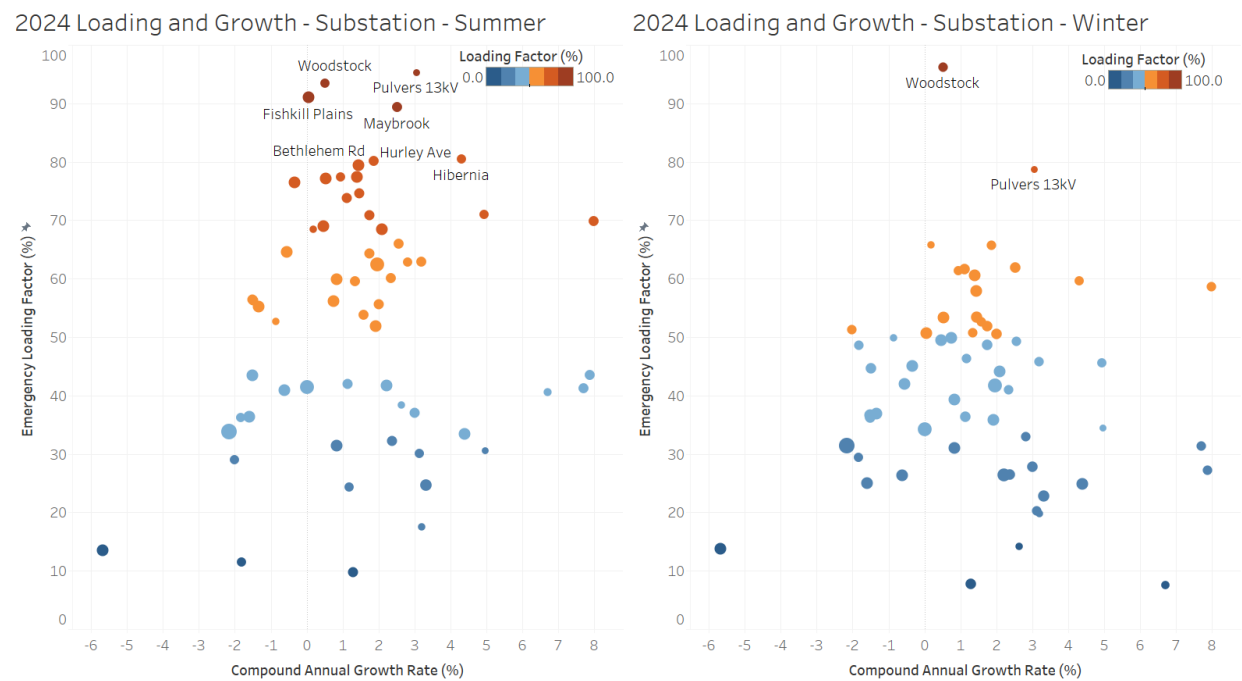
Central Hudson has met and exceeded targets for heat pump installations set by New York State. Central Hudson is promoting training and incentivizing contractors to install heat pumps. In addition, Central Hudson is collaborating with other New York utilities to pool aggregated historical data on heat pump incentives and installation volume to better understand the relationship. Quantifying the relationship between incentive levels and participation in heat pump programs will allow Central Hudson to calibrate and optimize incentive levels to better attain statewide goals.

- 6) Describe the utility's current efforts to plan, implement, and manage clean heat-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 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.

Central Hudson has not experienced winter peaks that have triggered T&D projects to date. The sole exception is the Woodstock substation, which historically has been dual-peaking with slightly larger winter loads due to resistance heating. Figure 44 shows that most substations have headroom to accommodate heat pump loads for the next ten years. Table 30 identifies the substations that are or are projected to be winter peaking in the next ten years. Most of those locations have ample headroom.

Figure 44: Most Central Hudson Substations Have Headroom to Accommodate Heat Pumps Loads



Further details on this can be found in Appendix C. Central Hudson is in the process of developing project plans and updating its design criteria and ratings to better accommodate and plan for winter peaks.

Table 30: Locations with Forecasted Winter Peaks by 2035

Substation	2024 Winter Loading (%)	Historical growth rate ^[1]	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Clinton Ave	19.8%	3.2%	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.3	5.4	5.4
Coxsackie	30.9%	0.8%	39.7	39.5	39.1	39.0	39.1	39.2	39.2	39.5	39.5	39.7	40.1
Hunter	48.6%	-1.8%	9.1	8.9	8.7	8.4	8.2	8.0	7.9	7.8	7.8	7.8	7.8
Lawrenceville	51.3%	-2.0%	13.8	13.4	13.0	12.8	12.5	12.3	12.1	11.9	11.9	12.0	12.1
Smithfield	34.5%	5.0%	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	3.9
Vinegar Hill	46.3%	1.2%	9.7	9.7	9.8	9.8	9.9	10.1	10.2	10.3	10.5	10.6	10.9
Woodstock	96.2%	0.5%	21.0	21.3	21.7	22.4	23.1	23.8	24.7	25.5	26.5	27.5	28.6

7) Describe how the utility is coordinating with the efforts of the New York State Energy Research and Development Authority (NYSERDA), the New York Power Authority (NYPA), New York Department of Environmental Conservation (DEC), DPS Staff, or other governmental entities to facilitate statewide clean heat market development and growth.

Central Hudson has recurring discussions with the Joint Utilities, NYSERDA, DPS Staff and other key stakeholders to address strategic marketing campaigns and materials to increase customer awareness of the benefits of heat pump technologies. In addition, the Joint Management Committee works with implementation vendors and NYSERDA to make available on-demand training materials and conduct training sessions for new and existing Clean Heat participating contractors to reinforce workforce development and keep Clean Heat technologies as a top option for consumers throughout the state. To address availability in addition to education and training initiatives, the Joint Management Committee continues to grow a network of distributor partnerships throughout the state to increase the stock of Clean Heat space and water heating technology in all territories.

G. ENERGY EFFICIENCY INTEGRATION AND INNOVATION

1. KEY TAKEAWAYS

Over the past several years, Central Hudson has achieved measurable success in advancing energy efficiency and electrification programs, helping customers reduce energy use and costs while supporting system reliability and decarbonization goals. Between 2020 and 2024, Central Hudson delivered over \$98 million in energy efficiency and beneficial electrification incentives and services, with 51% of those benefits reaching Disadvantaged Communities, representing the highest level of DAC benefit penetration among New York's investor-owned utilities. Over that same period, Central Hudson also implemented the most cost-effective electric and gas energy efficiency portfolios in the state.

As part of its commitment to continual improvement and data-driven program design, Central Hudson has undertaken a range of innovative studies and initiatives to better inform the evolution of its energy efficiency and electrification portfolios. These efforts help identify communities with the highest need, the opportunities for the greatest potential for impact, and valuable insights on building and customer characteristics. The Company also conducts regular impact evaluations and program analyses to ensure cost-effectiveness and to guide enhancements in program delivery and outcomes.

Building on these insights, Central Hudson is transitioning away from measures with shorter lifespans, such as LED lighting and advancing toward more strategic, durable solutions, such as beneficial electrification and weatherization to align with the Commission's July 2023 Order Directing Energy Efficiency and Building Electrification (EE/BE) Proposals.⁴⁶ In Q1 2024, the Company quickly pivoted to launch a successful Retail Weatherization Products program, offering discounted do-it-yourself energy-saving measures like spray foam and insulation at major local retailers. These new measures broaden our

⁴⁶ 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 23, 2023), ("July 2023 Order Directing EE/BE Proposals")

portfolio of solutions for our customers and complement Central Hudson’s anticipated comprehensive building weatherization strategies for the 2026–2030 time period. These efforts are bolstered by community-based outreach, including a Memorandum of Understanding with the Mid-Hudson Library System to distribute energy kits and program information to customers, with a focus on underserved populations.

Within its 2025 Joint Proposal,⁴⁷ the Company proposed Earnings Adjustment Mechanism (EAMs) opportunities for 2026–2028 to incentivize exceptional performance across key areas promoting DER integration, load management, and EV adoption. These metrics directly support New York’s clean energy goals under the CLCPA by promoting renewable energy deployment, grid flexibility, and beneficial electrification.

Looking ahead to 2026–2030, Central Hudson’s proposed \$148 million energy efficiency (EE) and building electrification (BE) portfolio builds upon our strong foundation and aligns with the new strategic framework established by the Public Service Commission. At least 85% of portfolio funding is planned for strategic measures, with an emphasis on whole-home weatherization, heat pump deployment, and deeper market penetration in DACs. Additional priorities include the continued refinement of cost-effectiveness, digital customer engagement, integrated outreach, and comprehensive project bundling. Across all efforts, Central Hudson is committed to delivering durable energy savings and measurable community benefits, ensuring its programs not only comply with state mandates but also continue to serve as models of innovation, inclusion, and durable, cost-efficient performance.

2. CONTEXT AND BACKGROUND

Central Hudson has been administering a portfolio of energy efficiency programs continually since 2009. During this time, the portfolio has grown to include new technology areas and customer segments. Central Hudson is proud to deliver innovative and cost-effective programs that empower customers to manage their energy and contribute to the achievement of New York State’s ambitious clean energy goals.

Central Hudson has designed its programs with a focus on maximizing value by seeking innovative ways to reduce the cost of the energy efficiency portfolio while increasing the quantity of MWh savings attained.

This section provides context and background, starting with the NENY Order, as well as an overview of Central Hudson’s company-specific non–Low-to-Moderate-Income (LMI) energy efficiency portfolio and collaborative LMI programming, followed by a description of Central Hudson’s Earnings Adjustment Mechanisms and recent successes.

a) New Efficiency: New York

Energy efficiency is one of the cornerstones in New York State’s national leadership on clean energy and combating climate change. The PSC has consistently emphasized that energy efficiency programs not

⁴⁷ Cases 24-E-0461 and 24-G-0462, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service. “Joint Proposal” (submitted May 13, 2025) (“2025 Joint Proposal”).

only lower energy costs for homes and businesses implementing projects but also help reduce system-wide costs for all customers by decreasing overall energy use, potentially avoiding or deferring costly infrastructure investments.

Through a new comprehensive strategy issued in 2018, New York State embarked on a path to accelerate energy efficiency and reduce greenhouse gas emissions, decrease consumer energy costs, and create job opportunities.⁴⁸

As part of this initiative, New York’s utilities were called upon to achieve significantly more in their energy efficiency activities, in both scale and innovation. The PSC’s December 2018 Order⁴⁹ adopted significantly accelerated utility energy efficiency targets, which doubled utility energy efficiency targets from 2019 to 2025.

The PSC’s subsequent *Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025*⁵⁰, issued January 16, 2020, directed Central Hudson to achieve an incremental 68,753 MWh and 51,797 MMBtu of natural gas savings above previously approved levels by 2025. The Order also authorizes \$15.2 million of incremental energy efficiency funding to achieve these targets, including \$3.0 million specifically allocated to serve the Low-to-Moderate-Income market.

Further evolution of utility energy efficiency and beneficial electrification portfolios came in the PSC’s May 15, 2025, *Order Authorizing EE/BE Portfolios for 2026–2030* (“EE/BE Order”),⁵¹ which recognizes a strategic framework for EE and BE portfolios, requiring utilities to allocate a minimum of eighty-five percent (85%) of program budgets to strategic measures, namely weatherization and full building electrification. The EE/BE Order authorizes Central Hudson to implement a combined cumulative EE/BE portfolio budget of \$148.7M and total lifetime energy savings target of 36.16 million MMBtu-e for the 2026–2030 period, while also reaffirming alignment with CLCPA’s mandate to direct a minimum of thirty-five percent (35%), with a goal of forty percent (40%) of overall clean energy benefits to Disadvantaged Communities (DACs).

b) Central Hudson Energy Efficiency Programming

Central Hudson currently implements a comprehensive portfolio of electric and gas energy efficiency programs, which include a variety of solutions for residential, commercial, and industrial customers, as outlined in Table 31 below.

⁴⁸ New Efficiency: New York, NYSEDA. <https://www.nyserda.ny.gov/About/Publications/New-Efficiency>

⁴⁹ Order Adopting Accelerated Energy Efficiency Targets, Issued and Effective December 13, 2018, Case 18-M-0084. (“December 2018 Order”)

⁵⁰ Case 18-M-0084. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025. (Issued and Effective January 16, 2020). (“2020 NE:NY Order”)

⁵¹ Case 25-M-0248, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Authorizing Non–Low-to-Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026–2030 (issued and effective May 15, 2025), (“May 15, 2025 Order Authorizing EE/BE Portfolios for 2026–2030”)

Table 31: Central Hudson’s 2020–2025 Energy Efficiency Portfolio

Program	Portfolio	Description
Residential		
Retail Lighting Program	Electric	Utilizes an upstream strategy to increase the penetration of efficient lighting in customer homes by incentivizing the purchase of LED lighting at retail. (Program concluded at the end of 2023.)
Retail Weatherization Program	Electric and Gas	Offers incentives for energy-efficient products including pipe wrap, door sweeps, spray foam, batt insulation, windows, and window shrink kits. (Program launched in 2024.)
Residential HVAC and Efficient Products Program	Electric and Gas	Offers incentives for energy-efficient residential HVAC, thermostats, and appliances.
Appliance Recycling	Electric	Offers an incentive to residential electric customers to recycle used refrigerators or freezers. (Program concluded in 2023.)
Behavior Modification	Electric and Gas	Customers are automatically enrolled to receive paper and emailed communications about their energy use and opportunities for energy saving, with the goal of reducing energy consumption of the treatment group relative to a control group.
Residential Weatherization Program Pilot	Electric and Gas	Pilot program aimed to collect useful insights on customer sentiment and market characteristics in advance of a full-scale comprehensive residential weatherization program anticipated in 2026–2030.
Non-Residential		
Commercial Custom and Prescriptive	Electric and Gas	Offers non-residential customers incentives for a range of efficient technologies including lighting, HVAC systems, and commercial equipment.
Small Business Direct Install	Electric	Provides traditionally hard-to-reach small business customers with a turnkey retrofit solution including a facility audit, project design and proposal, measure installation, and beyond. Includes lighting and refrigeration measures.
Municipal Streetlights Program	Electric	Incentivizes municipal customers to upgrade streetlights to new efficient LED fixtures.

c) Collaborative Low-to-Moderate-Income Programming

Central Hudson works collaboratively with NYSERDA and the New York Joint Utilities on Low-to-Moderate-Income programming.

As described in the Statewide Low- to Moderate Portfolio Implementation Plan (LMI IP)⁵², in response to the 2020 NE: NY Order, Central Hudson is collaborating with Joint Utilities (JU) across New York State and NYSEDA to deliver coordinated statewide efficiency initiatives targeting LMI customers. Specifically, Central Hudson has taken an active role in the development of each of the initiatives presented in the LMI IP, participating in stakeholder engagement, requesting transparency of data assumptions and inputs to be used in the development of savings projections and budget development. Central Hudson also seeks to ensure all LMI customers have equal access to all programs regardless of the funding source for the full duration of the LMI IP. Furthermore, Central Hudson strives to streamline burdensome administrative processes while maintaining utility independence to best serve customers, e.g., leveraging local and trusted partnerships to reach LMI customers. The current iteration of the LMI IP includes the following initiatives:

- One to Four Single Family Homes
- Affordable Multifamily Building
- Affordable New Construction
- Partner-Based Programs

The portfolio also includes funding for customer engagement and pilots with new approaches for the adoption of energy efficiency for LMI residents and communities, as demonstrated with the launch of the Weatherization Kit program where weatherization measures are offered to low-income customers utilizing services from community outreach partners, such as the United Way and local food pantries.

d) Central Hudson's Earnings Adjustment Mechanisms

On May 13, 2025, the Company filed its 2025 Joint Proposal⁵³ under Cases 24-E-0461 and 24-G-0462, which proposes the establishment of new Earnings Adjustment Mechanisms (EAMs) for the years 2026, 2027, and 2028. Contingent upon the Joint Proposal being approved, the Company will have an opportunity to be incentivized for achieving exceptional performance in five distinct electric system categories, while also having four additional "tracking-only" scorecard metrics. DER Utilization – Photovoltaic, DER Utilization – Battery Energy Storage, Electric Load Management, Residential Managed Charging, and EV Adoption are eligible for earnings, while Load Factor, Residential Electric Energy Intensity, Commercial Electric Energy Intensity, and Gas Peak Reduction are tracking-only metrics with no specific targets or earnings eligibility.

⁵² Statewide Low- to Moderate-Income Portfolio Implementation Plan Version 5, Filed December 20, 2024, Cases 18-M-0084 and 14-M-0094.

⁵³ Cases 24-E-0461 and 24-G-0462, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service. "Joint Proposal" (submitted May 13, 2025) ("2025 Joint Proposal").

In addition to the proposed EAMs outlined in the 2025 Joint Proposal, an Electric Vehicle Supply Equipment (EVSE) EAM is already in place, having been previously authorized by the PSC in the 2020 Make-Ready Order.⁵⁴

Central Hudson could earn pre-tax earnings adjustments once minimum targets are achieved and on a prorated basis for performance between minimum and midpoint performance levels, and between the midpoint and maximum performance levels. The EAMs are intended to provide the Company with incentives to:

- Increase system efficiency through distributed energy resource utilization and electric load management; and
- Reduce carbon emissions through increased penetration of beneficial electrification technologies, such as Electric Vehicle (EV) Adoption and Electric Vehicle Supply Equipment (EVSE).

Central Hudson believes these EAMs place significant emphasis on the value of producing results through new and innovative approaches to achieving the State's objectives. Specifically, the EAMs associated with DER Utilization, Electric Load Management, Residential Managed Charging, and EV Adoption directly support state policy objectives and the CLCPA by encouraging renewable generation, electrification, and electric load management.

The DER Utilization – Photovoltaic EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER PV resources in the Company's service territory. This metric will measure the sum of the megawatts alternating current nameplate of all incremental solar interconnections less than or equal to 5 MW AC in Central Hudson's service territory, including projects participating in the statewide Solar-For-All or Renewable Energy Access and Community Help (REACH) programs.

The DER Utilization – Battery Energy Storage (BESS) EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER BESS resources in the Company's service territory. This metric will measure the sum of the MW AC nameplate of all incremental BESS interconnections less than or equal to 5 MW AC in Central Hudson's service territory, including projects participating in the statewide Solar-For-All or REACH programs.

The Electric Load Management (ELM) EAM metric encourages the Company to achieve greater growth in its load management programs by increasing the total MW of load reduction participating in the programs. This EAM promotes grid flexibility by developing a larger and more reliable portfolio of load management resources that can be called on to reduce peak demand, and during system contingencies. The metric will measure the operationally available MW achieved through all of the Company's load management programs,¹ such as the Commercial System Relief Program and the Term- and Auto-Dynamic Load Management programs, as well as the NYISO Special Case Resource (SCR) program within the Company's service territory. The Electric Load Management EAM is the sum total operationally

⁵⁴ Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding); and Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) ("Make-Ready Order").

available MW from the Company's load management programs and the portion of the NYISO SCR program within the Company's service territory in any given calendar year.

The Residential Managed Charging (RMC) EAM metric encourages Company efforts that will (1) increase electric vehicle (EV) enrollment in the EV ChargeSmart managed charging program, (2) encourage program participants to avoid EV charging during system peak hours (2PM – 7PM) and (3) reduce program participants' EV charging demand coincident with system peak hours. The RMC EAM measures enrollment, and the peak coincident demand of all customers enrolled in ChargeSmart. The RMC EAM measures enrollment through the end of the calendar year. The RMC metric measures avoided peak charging in kilowatts (kW) per EV on the road in the Company's service territory.

The EV Adoption EAM incentivizes the Company to reduce greenhouse gas emissions by facilitating greater penetration of EVs. EVs reduce GHGs relative to traditional internal combustion engine vehicle technologies that rely on emissions-intensive fuel sources like gasoline and diesel. The EV Adoption metric is an outcome-based metric and will be measured as the incremental lifetime metric tonnes ("tonnes") of avoided CO₂ from incremental EVs registered in Central Hudson's service territory. EVs are defined as battery electric vehicles and plug-in hybrid electric vehicles. BEVs and PHEVs have lifetime avoided emissions factors due to their distinct fueling profiles, where BEVs displace a greater number of gasoline miles annually than PHEVs.

The Load Factor scorecard metric tracks the deployment of energy storage and other DERs. The Company will track changes to load factor over time and monitor the potential impacts to load factor that result from the utilization of DER's throughout the system. This metric is a tracking-only scorecard metric. The Company will track and report the absolute load factor (non-weather normalized) at the substation level. The data can be weather normalized later if required by DPS Staff.

The Residential Energy Intensity scorecard metric will be measured as the annual residential MWh sales divided by the 12-month average number of residential customers. Within this calculation the annual residential MWh sales will be: 1) normalized to correct for the weather-related impacts on electricity sales, 2) reduced by the aggregate MWhs produced by Community Distributed Generation resources and allocated to residential customers through the value stack tariff, and 3) adjusted to exclude the impacts of beneficial electrification, such as new load from heat pumps and electric vehicles.

The Commercial Electric Energy Intensity scorecard metric measures the reduction of commercial (Service Class 2 non-demand) customers' total usage on a per-customer basis. This metric will be measured as the annual commercial MWh sales divided by the 12-month average number of commercial customers. Within this calculation, the annual commercial MWh sales will be: 1) normalized to correct for the weather-related impacts on electricity sales; 2) reduced by the aggregate MWhs produced by Community Distributed Generation resources and allocated to commercial customers through the value stack tariff; and 3) adjusted to exclude the impacts of beneficial electrification, such as new load from heat pumps and electric vehicles.

The Gas Peak Reduction scorecard metric measures the gas system peak reductions that provide additional system benefits and lower supply costs to customers, to the extent that there is a decline in the actual weather-adjusted gas system peak below the prior rate year baseline level established for the Gas Peak Reduction metric. (Note: Weather-adjusted refers to the extrapolation of realized historic data up to the design day temperature to consider the level to which the Company plans the necessary

capacity, supply, and demand response system resources to meet firm customer demand during extreme winter peaks.)

The EVSE EAM promotes performance within Central Hudson’s Electric Vehicle (EV) Make-Ready Program. The goal of the EV Make-Ready Program is to support the development of electric infrastructure and equipment necessary to accommodate an increased deployment of EVs within New York State by reducing the upfront costs of building charging stations for light-duty EVs. Through this EV Make-Ready Program, those seeking to install or participate in the installation of Level 2 (L2) and/or Direct Current Fast Charging chargers can earn incentives that will offset a large portion of, or in some cases, all the infrastructure costs associated with preparing a site for EV charger installation.

Table 32: System Efficiency, and Beneficial Electrification EAM Targets

EAM	Targets			
	2025	2026	2027	2028
DER-PV (MW)	N/A	31.71	34.88	38.37
		36.03	39.63	43.60
		43.24	47.56	52.32
DER-BESS (MW)	N/A	4.70	5.97	7.58
		5.34	6.78	8.61
		6.41	8.14	10.33
Electric Load Management (MW)	N/A	10.34	Determined formulaically based on prior years’ actual performance	
		12.22		
		14.10		
RMC Targets (Percent Improvement in Avoided Peak Charging per EV on the road)	N/A	5%	5%	5%
		10%	10%	10%
		17%	17%	17%
EV Adoption (Lifetime CO2 Tons)	N/A	302,860	393,880	489,907
		435,417	671,173	1,001,217
		567,974	948,466	1,512,527
EVSE L2 (Plugs)	1,528	N/A		
	1,732			
	2037			
EVSE DCFC (Plugs)	208	N/A		
	312			
	416			

3. IMPLEMENTATION PLAN

1) Current Progress

Since 2009, Central Hudson has implemented a portfolio of energy efficiency programs with specific initiatives targeted at various end uses and customer segments. Central Hudson's progress in these efforts is illustrated in the chart below. As Central Hudson's energy efficiency programs have evolved, continual improvements have been made in program awareness and penetration, and unit-cost efficiencies have improved. For the years 2020–2024, Central Hudson achieved the lowest cost per MWh savings amongst New York electric utilities. Additionally, during these years, the Company attributed more than 50% of its energy efficiency and electrification benefits to Disadvantaged Communities. In 2024, Central Hudson received the Energy Star Partner of the Year Award for Sustained Excellence from the U.S. EPA and U.S. DOE. It was the seventh consecutive year of the Company being recognized by the Energy Star program and the third consecutive year receiving the highest honor of sustained excellence. Central Hudson has received this honor more times than any other utility in New York.

Table 33: Central Hudson Historical MWh Savings and Costs

Framework	Years	MWh Savings	Expenses	Avg Annual MWh Savings	\$/MWh
Energy Efficiency Portfolio Standard (EEPS)-1	2009– 2011	75,133	\$21,459,934	25,000	\$286
EEPS-2	2012–2015	152,804	\$32,393,211	38,200	\$212
Energy Efficiency Transition (EET)	2016–2017	105,005	\$13,508,138	52,500	\$129
Energy Efficiency Transition Implementation Plan (EETIP)	2018	81,964	\$8,773,420	81,964	\$107
System Energy Efficiency Plan (SEEP)	2019	75,827	\$9,155,639	75,827	\$121
SEEP	2020	79,455	\$10,190,637	79,455	\$128
SEEP	2021	72,973	\$7,507,492	72,973	\$103
SEEP	2022	76,470	\$9,265,289	76,470	\$121
SEEP	2023	55,819	\$8,262,380	55,819	\$148
SEEP	2024	34,568	\$6,302,032	34,568	\$182
Total		810,018	\$126,818,172		

2) Future Implementation and Planning

To align with the priorities of New York's CLCPA, Central Hudson is exploring its internal programming as well as collaborating across the state to continue to implement and evaluate programs to accelerate energy efficiency and reduce greenhouse gas emissions, decrease consumer energy costs, and create job opportunities.

a) Balancing Energy Efficiency and Clean Heat Programming

The 2020 NE: NY Order provides utilities with the flexibility to adjust portfolio budgets to maximize their effectiveness with a few key limitations: "Current practice allows utilities to shift budgets from year to year within a portfolio to accommodate the timing concerns that arise with commitments and outlays and to avoid artificial program stops and starts. Utilities may also adjust budgets and targets among programs within the same portfolio, e.g., funds may be shifted from one electric efficiency program to another. These practices will be continued, with two additional requirements: (1) heat pump targets must be maintained as separate targets within the electric utility portfolios; and (2) funds cannot be transferred from LMI to non-LMI programs. Utilities will not have general flexibility to shift funds among gas, electric, and heat pump budgets. Gas, electric, and heat pump targets are established in this Order to align with policy goals; a utility may shift funds among these portfolios only if it can demonstrate that it will meet the annual target for the portfolio from which funds are being transferred."⁵⁵

In December 2022, Central Hudson expended its cumulative Clean Heat Program budget for the years 2020–2025. Pursuant to the budget flexibility authorized in the 2020 NE: NY Order, The Company utilized a total of approximately \$4.6 million in unspent funds from the Non-LMI Electric portfolio for Clean Heat, having achieved the annual electric portfolio targets for years 2018–2022 without spending the full budget in each year. In February 2023, in a request to provide additional funding beyond the use of previously unspent funds, the Company petitioned to transition \$13.5 million of its cumulative electric energy efficiency budget to Clean Heat. As a contingency to the authorization, Central Hudson demonstrated its potential to still achieve its 2020 NE: NY-ordered cumulative electric EE savings target even after the transfer of these funds. In June 2023, the Commission's *subsequent Order Approving Funding for Clean Heat Program*⁵⁶ granted the Company's request allowing for continued program services and incentives for electric EE and Heat Pumps in Central Hudson's territory.

The Commission's May 15, 2025, *Order Authorizing EE/BE Portfolios* for 2026–2030 direct deeper, more durable energy efficiency savings directs strict adherence to established Strategic Framework to guide utility-administered Non-LMI energy efficiency and building electrification (EE/BE) portfolios for 2026 through 2030. At the core of this framework is the requirement that at least 85% of each utility's programmatic budget be allocated to Strategic measures which directly support New York's decarbonization goals, such as building weatherization improvements, full heat pump electrification, and comprehensive projects. Utilities may allocate up to 15% of budgets to neutral measures, which offer energy savings but are not central to long-term emissions reductions, such as smart thermostats or high-

⁵⁵ 2020 NE: NY Order, pp. 69–70.

⁵⁶ Case, 18-M-0084. In the Matter of a Comprehensive Energy Efficiency Initiative, Order Approving Funding for Clean Heat Program (Issued and effective June 23, 2023), (Order Approving Funding for Clean Heat Program)

efficiency electric HVAC motors. Funding for Non-Strategic measures, such as lighting, residential gas-fired equipment, and plug-in appliances, is prohibited after 2025.

To ensure meaningful investment in decarbonization-ready buildings, the *Order Authorizing EE/BE Portfolios* for 2026–2030 establishes minimum budget requirements: at least 25% of electric program budgets and 50% of gas program budgets must support small residential weatherization, while no more than 50% of electric budgets may be allocated to electrification programs, including Clean Heat. Utilities are permitted to shift 15% to 30% of budgets between years, depending on their proposal, but must remain within their approved cumulative five-year allocations. These directives signal a definitive shift away from legacy energy efficiency measures and toward deeper, longer-lasting system and societal benefits.

Implementation plans for the 2026–2030 portfolios are being developed in the latter half of 2025. These implementation plans will further detail more specific program annual savings targets and budgets to align with a cumulative five-year budget and savings target of \$148.7M and 36.16 million MMBtu-e, respectively.

b) Evaluation Activities

In accordance with the *Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan*⁵⁷ (Utility EE Order 2021) and The Clean Energy Guidance document CE-08: Gross Savings Verification Guidance,⁵⁸ Central Hudson conducts periodic program evaluations. The evaluation strategy for each program varies based on the measures being evaluated, the size and scope of the program, and the available data. Individual plans outlining the evaluation activities for each program were filed prior to the evaluations under Matter 16-02180. An overview of the 2019–2024 efforts is presented in Table 34.

Table 34: Planned Program Evaluation Activities

PORTFOLIO (NE: NY Electric EE)	Plan Submission Date	Start Date	Completion Date	Status
Impact Evaluation – 2024 <i>Weatherization Kits</i>	2024 Q4	2024 Q4	2025 Q2	Completed
Impact Evaluation – 2024 Retail <i>Weatherization</i>	2024 Q4	2024 Q4	2025 Q2	Completed
Impact Evaluation – 2023 Small <i>Business Direct Install</i>	2023 Q3	2023 Q4	2024 Q3	Completed
Impact Evaluation – 2022–2023 <i>Streetlight Dimming Pilot</i>	2023 Q3	2023 Q4	2023 Q4	Completed
Impact Evaluation – 2022 <i>Residential HVAC and Efficient Products</i>	2023 Q3	2023 Q3	2023 Q4	Completed

⁵⁷ Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, Cases 20-E-0428 and 20-G-0429, Issued November 18, 2021..

⁵⁸ New York State Department of Public Services, Gross Savings Verification Guidance, CE-08, Version 1, Issued August 23, 2019. <https://dps.ny.gov/system/files/documents/2022/11/ce-08-gross-savings-verification-guidance.pdf>

Impact Evaluation – 2022 <i>Residential Behavioral Modification</i>	2020 Q2	2023 Q2	2023 Q4	Completed
Impact Evaluation – 2019 <i>Residential Behavioral Modification</i>	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – 2020 <i>Residential Behavioral Modification</i>	2020 Q2	2021 Q2	2021 Q3	Completed
Impact Evaluation – 2021 <i>Residential Behavioral Modification</i>	2020 Q2	2022 Q2	2022 Q4	Completed
Impact Evaluation – 2019–2020 <i>Residential HVAC</i>	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – 2021 <i>Residential Retail Lighting</i>	2021 Q3	2022 Q3	2022 Q4	Completed
Impact Evaluation – 2020 <i>Residential Retail Lighting</i>	2021 Q3	2021 Q3	2021 Q4	Completed
Impact Evaluation – 2018–2019 <i>Residential Retail Lighting & Efficient Products</i>	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – 2020–2021 <i>Commercial Custom</i>	2021 Q3	2021 Q3	2022 Q4	Completed
Impact Evaluation – 2021–2022 <i>Commercial Prescriptive</i>	2021 Q3	2021 Q3	2022 Q4	Completed
Impact Evaluation – 2019–2020 <i>Commercial Custom and Prescriptive</i>	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – 2021–2022 <i>Small Business Direct Install</i>	2021 Q3	2021 Q3	2022 Q4	Completed
Impact Evaluation – 2019 Small Business Direct Install	2019 Q2	2019 Q2	2021 Q3	Completed
Impact Evaluation – 2019 CenHub Online Store	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – 2018–2019 <i>Appliance Recycling</i>	2020 Q2	2020 Q2	2021 Q3	Completed
Impact Evaluation – 2018–2019 <i>Community Lighting</i>	2020 Q2	2020 Q4	2021 Q3	Completed
Impact Evaluation – 2018–2019 <i>Municipal Streetlights</i>	2020 Q2	2020 Q3	2021 Q3	Completed
Process Evaluation – 2021–2022 <i>Commercial Custom and Prescriptive</i>	2021 Q3	2021 Q3	2022 Q4	Completed
Process Evaluation – 2019–2020 <i>Commercial Custom and Prescriptive</i>	2020 Q3	2020 Q3	2021 Q3	Completed
Process Evaluation – 2021–2022 <i>Small Business Direct Install</i>	2021 Q3	2021 Q3	2022 Q4	Completed
Process Evaluation – 2019–2020 <i>Residential Retail Efficient Products</i>	2020 Q3	2020 Q3	2021 Q3	Completed

Process Evaluation – 2019–2020 <i>CenHub Online Store</i>	2020 Q3	2020 Q3	2021 Q3	Completed
Baseline Study	2019 Q3	2019 Q3	2019 Q4	Completed
Potential Study	2019 Q3	2019 Q3	2020 Q3	Completed
Free-ridership and Attribution Studies	2020 Q3	2020 Q3	2021 Q3	Completed
Program Support and Planning	N/A	2019 Q1	Ongoing	Ongoing

4. RISKS AND MITIGATION

New York investor-owned utilities are undergoing a dynamic change including a transition away from higher-volume, lower-unit-cost measures, with anticipated increases in unit costs and program comprehensiveness, and changes to local, state, and federal-level energy priorities.

As federal efficiency standards have taken effect, phasing out traditional lighting products, Central Hudson ceased incentivizing LED lighting through its Retail Lighting Program at the end of 2023. This eliminated a historically low-cost, high-volume savings source, which had attributed as much as 40% of annual electric EE portfolio savings in years past. C&I programs have continued with strong LED savings but will be discontinued at the end of 2025. Additionally, other cost-effective programs including other retail products (such as ENERGY STAR®-certified air purifiers, dehumidifiers, and smart power strips), appliance recycling, and Behavior Modification have either already ceased or will by the end of 2025.

In addition to the impact on portfolio cost effectiveness, the reduction in measure scope will reduce the variety of solutions available to our customers for EE savings and may affect general awareness of Central Hudson’s EE initiatives.

As portfolios shift towards deeper, more complex retrofits like HVAC, weatherization, and comprehensive projects, it is expected that these projects will be more unique to each customer, harder to scale and more expensive to deliver, but with longer-term, “durable” savings and with an opportunity to have a deeper impact on customers’ energy savings.

As portfolios evolve to include more intricate retrofits such as heat pumps and weatherization, these programs demand more detailed discussions, comprehensive strategies, and greater cost considerations for customers. These measures are more durable and comprehensive but come with a higher cost and require a contractor. The pivot toward labor-intensive measures increases demand for certified technicians and BPI-trained professionals. Limited contractor availability can delay project delivery, reduce program uptake, and restrict the ability to meet equity-focused targets unless workforce development efforts ramp up. These projects do, however, provide an opportunity for Central Hudson to promote meaningful building improvements and have a deeper level of engagement with its customers.

Global supply chain volatility and domestic inflation have raised the costs of materials like insulation, windows, and heat pumps. In addition, pending federal tariff negotiations, particularly on foreign-made components may further increase measure costs and reduce adoption.

The Company’s mitigation strategy involves diversifying portfolio measures, working collaboratively with statewide stakeholders to expand electrification initiatives and align utility and statewide priorities.

5. STAKEHOLDER INTERFACE

Central Hudson continues to engage its stakeholders ranging from energy efficiency program champion trade allies to interested vendors, customers, and Department of Public Service Staff. These engagements inform Central Hudson program design, implementation, and priorities.

a) Vendor and Trade Ally Interfaces

Central Hudson regularly interacts with prospective and current vendors and trade allies. The Company regularly participates in industry conferences, such as those facilitated by the Association of Energy Service Professionals (AESP). Through these events, the Company keeps abreast of best practices in the industry, as well as new offerings from a multitude of energy efficiency vendors. Additionally, Central Hudson participates in various energy efficiency-related working groups, which provide an opportunity to interface with stakeholders. For example, as part of its participation in various LMI working groups (see Joint Utility and DPS Staff Interfaces subsection below), Central Hudson engages with interested trade allies and vendors through PCIP webinars to engage interested stakeholders in programmatic developments and progress.

Furthermore, when Central Hudson determines that a service provider is needed, a request for proposal (RFP) is sent out. The RFP contains detailed information about the Company and the services required. As part of the RFP process, Central Hudson allows responders to submit questions and discuss relevant topics during at least one pre-bid meeting. Finally, Central Hudson works with trade allies to implement various energy efficiency programs and has sponsored various training events and feedback sessions.

b) Customer Interfaces

Central Hudson is dedicated to making clean energy more accessible by helping customers improve energy efficiency, lower utility bills, and support a more sustainable future. The Company connects with customers through a variety of outreach and education initiatives, including its website, contractor webinars, trade ally events, Energy Ambassador program, open house events, and presentations at both traditional and vocational schools.

To ensure programs are effective and continuously improving, Central Hudson conducts process evaluations that assess customer awareness, satisfaction, and engagement. These evaluations gather feedback from participating customers and provide insights to refine program design and delivery.

Recognizing the value of community partnerships, Central Hudson has strengthened outreach efforts through collaborations with trusted organizations, such as United Way, Habitat for Humanity, and Dutchess Outreach. These relationships help expand program access to income-eligible households and DACs. In 2025, the Company also signed a Memorandum of Understanding (MOU) with the Mid-Hudson Library System, enabling in-branch resources and DIY energy assessment kits to further increase community engagement.

To help customers better understand the real-world clean energy projects, programs, and benefits, Central Hudson has expanded the use of case studies highlighting successful installations across its portfolio. In 2024, the Company hosted its first Energy Efficiency and Electrification Summit, convening over 20 community organizations to exchange ideas, recognize local clean energy leaders, and foster collaboration. Complementing these efforts, the Company has coordinated three Ride & Drive events, giving nearly 700 participants a hands-on introduction to electric vehicles while showcasing Central

Hudson's full range of offerings including energy efficiency, weatherization, beneficial electrification and demand response. Together, these initiatives demonstrate Central Hudson's holistic and customer-focused, community-driven approaches to accelerating New York's clean energy transition.

c) Joint Utility and DPS Staff Interfaces

As part of the New York Joint Utilities, Central Hudson participates in multiple Energy Efficiency, LMI, and Clean Heat working groups in partnership with the other New York State Joint Utilities and NYSERDA. The working groups engage regularly with DPS staff. Through these efforts, the Company strives to create coordinated programming across the state to enhance customer engagement across sectors, end-uses, and fuel types.

6. ADDITIONAL DETAIL

1) The resources and capabilities used for integrating energy efficiency within system and utility business planning.

Central Hudson's NWA solicitations are technology-agnostic, so energy efficiency may be utilized as part of a solution if it's determined to be a good fit for a particular project. In September 2018, the Company launched a targeted commercial and industrial (C&I) energy efficiency initiative within two of its three existing NWA locations. The initiative has continued through 2019 and is designed to impact locational loads by concentrating efficient retrofit projects within NWA areas. High adoption rates are achieved using enhanced incentives and marketing. This initiative has supplemented load reductions achieved through other demand management initiatives.

System-wide load constraints are minimal for Central Hudson. The marginal avoided costs associated with peak load reductions, as determined through a recent comprehensive study, are considered as a benefit within EE initiatives, but are not a significant driver of initiating projects.

2) The locations and amounts of current energy and peak load reductions attributable to energy efficiency and how the utility determines these.

Central Hudson's energy efficiency portfolio is designed to meet the targets set forth within the NE: NY proceedings. Recently, future targets have been provided in the May 15, 2025, *Order Authorizing EE/BE Portfolios* for 2026–2030 and also proposed in the Company's 2025 Joint Proposal. For most energy efficiency projects, the Company tracks the location of each participant and can readily identify the overall impact on the local system at the circuit or substation level. Load reductions are assessed using the New York State Technical Resource Manual, where applicable. In some cases, custom computations are used to calculate the impacts of certain measures on peak load. Within the Company's upstream and midstream delivery programs, aggregate participation data is obtained, such as by vendor or local store, as opposed to individual end-user. Geographic distribution estimates may be developed based on the available data.

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 Climate Leadership and Community Protection Act (CLCPA).

Clean Heat: Through the Clean Heat program, Central Hudson has promoted energy efficiency and decarbonization of the heating sector by incentivizing the adoption of cold climate heat pump technologies. As of the end of 2024, the Program had already achieved more than 270 percent of its cumulative 2020–2025 savings target achieving over 690,000 annual MMBtu savings since program inception in 2020. By collaborating with key stakeholders to increase consumer awareness, provide accessible workforce education opportunities, and increase the stock of heat pump technologies in all territories, Central Hudson and the Joint Utilities have created a sustainable framework for long-term heat pump adoption in New York State. More information on Central Hudson's Clean Heat program can be found under the DSIP Topical Section of Clean Heat Integration.

Electric Vehicles: As of May 12, 2025, Central Hudson incentivized the installation of 89 DCFC and 672 L2 chargers in its territory at a unit cost below its prescribed targets within the mission's *Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs*. The Company's Electric Vehicle Supply Equipment program has a target of installing 2,037 Level 2 (L2) chargers and 416 DC fast chargers throughout the service territory by 2025.

As of December 3, 2024, an additional 7,618 BEVs and 4,866 plug-in hybrid electric vehicles have been registered into Central Hudson's territory. Strong marketing efforts and the EVSE make-ready program are used to promote the benefits of electric vehicles. Marketing and events promoting EV adoption will continue into the near future. More information on Central Hudson's efforts to promote EV adoption and the proliferation of charging equipment can be found under the DSIP Topical Section of Electric Vehicle Integration.

4) Summary information on energy efficiency programs offered by the utility, with direction to annual filings for more detailed information on energy efficiency programs

As discussed in the Context and Background section above, Central Hudson has been offering customers energy efficiency programming since 2009.

Table 35 and Table 36 below provide an overview of the 2019–2022 electric and gas energy efficiency portfolio actuals and 2023–2025 planned spending and savings. Additional details can be found in the 2024 SEEP.⁵⁹

⁵⁹ Central Hudson Gas & Electric System Energy Efficiency Plan, Filed April 28, 2023, Case 18-M-0084.

Table 35: Central Hudson Electric Energy Efficiency Portfolio Actual and Planned Spend and Savings (2019–2025)

Program	Actual Spend 2019–2024	Planned Spend 2025	Actual Savings MWh 2019–2024	Planned Savings MWh 2025
Retail Lighting ⁶⁰	\$12,454,404	\$0	169,994	0
Residential HVAC and Efficient Products	\$2,656,276	\$749,500	7,361	2,148
Appliance Recycling ⁶¹	\$1,860,906	\$0	9,601	0
Behavior Modification	\$2,069,224	\$56,535	72,148	,000
CenHub Online Store ^{62*}	\$416,110	\$0	3,867	0
Commercial Customer and Prescriptive Program	\$9,623,680	\$1,969,286	64,142	24,371
Small Business Direct Install	\$17,239,369	\$ 1,514,329	60,167	6,000
Municipal Streetlights	\$17,408	\$0	477	0
Residential Weatherization Retail Products	\$513,978	\$892,889	7,187	3.650

Table 36: Central Hudson Gas Energy Efficiency Portfolio Actual and Planned Spend and Savings (2019–2025)

Program	Actual Spend 2019–2024	Planned Spend 2025	Actual Savings MMBtu 2019– 2024	Planned Savings MMBtu 2025
Residential HVAC and Efficient Products	\$3,548,230	\$596,212	95,913	20,234
Behavior Modification	\$293,683	\$28,267	175,753	0
CenHub Online Store*	\$169,126	\$0	13,018	0
Commercial	\$2,054,199	\$203,460	136,382	11,222

⁶⁰ Discontinued in 2023

⁶¹ Discontinued in 2023

⁶² Discontinued in 2021

Program	Actual Spend 2019–2024	Planned Spend 2025	Actual Savings MMBtu 2019– 2024	Planned Savings MMBtu 2025
Customer and Prescriptive Program				
Residential Weatherization Retail Products	\$172,726	\$300,090	165,300	116,862

5) Describe how the utility is coordinating and partnering with NYSERDA’s related ongoing statewide efforts to facilitate energy efficiency market development and growth.

Central Hudson coordinates closely with NYSERDA to support statewide efforts in energy efficiency market development and customer access. Through joint initiatives, such as the EmPower+ program, Central Hudson and NYSERDA provide no-cost energy efficiency upgrades to income-eligible customers, streamlining services through shared outreach, contractor networks, and program delivery infrastructure. The Company also collaborates with NYSERDA on regional Clean Energy Hubs and joint community outreach, including co-branded events and materials designed to increase program awareness.

In addition, Central Hudson participates in Joint Utility working groups with NYSERDA and DPS Staff to align strategies, avoid duplication, and accelerate program improvements. Together, Central Hudson and NYSERDA are driving market transformation by expanding access to energy efficiency services and incentives, increasing customer engagement, and supporting contractor development across New York.

H. DATA SHARING

1. KEY TAKEAWAYS

Central Hudson maintains a robust data sharing program, which has continued to grow and evolve since the last DSIP was filed in 2023. Built over approximately a decade-and-a-half, this program makes available key energy system and customer usage data that are collected within Central Hudson’s information systems.

Significant emphasis remains on the role of system data in facilitating market development and greater DER adoption as well as customer data in support of the development of new energy products and services, while also protecting customers' privacy. Thus, the information that Central Hudson published through the data sharing program is made available to all key stakeholder groups, which include customers, DER developers, communities engaged in clean energy planning, government officials, and others, in compliance with requirements and customer privacy considerations.

Central Hudson makes system and customer energy usage data available through several channels. Customers can access their usage information through their online customer accounts. Central Hudson

publishes over a dozen other data sets and key reports relevant to the DER market, making these available on the Central Hudson website, the Joint Utilities of NY website, and in regulatory filings on the DPS website.

In addition to those resources shared directly by Central Hudson, stakeholders can access an increasing level of Central Hudson service territory information through platforms administered by NYSDERDA, specifically the Integrated Energy Data Resource (IEDR) and the Utility Energy Registry (UER). These platforms allow stakeholders to see information on a statewide basis, across utility service territories. Since the last DSIP, Central Hudson has established an IEDR data sourcing program to supply its relevant information to the IEDR, working closely in support of NYSDERDA as it has launched use cases and as it plans more for future release.

Central Hudson remains committed to maintaining its data sharing program and incorporating new requirements and feedback from stakeholders as needs and conditions change over time. Central Hudson intends to build upon progress already institutionalized as part of the DSIP and other processes and continue evolving its data sharing program as advancements in the digitization of information are implemented.

2. CONTEXT AND BACKGROUND

Significant emphasis has been placed on the role of system data in facilitating market development and greater DER adoption, as well as customer data in support of the development of new energy products and services, while also protecting customers' privacy. The DSIPs were largely intended to serve as a vehicle for collecting and sharing information that facilitates retail market development, including data related to distribution system planning and grid operations. The Company's focus over the past two years has included continued development and sharing of the datasets identified by the Commission as essential for improving the transparency of utility planning and operations and aiding market growth. In addition, the Company's efforts have continued to be guided by the regulatory shift in this area toward the statewide data-sharing effort.

Since the filing of the Initial DSIP, Central Hudson and the Joint Utilities, in conjunction with the feedback received from various stakeholder sessions, have made significant progress toward the development of System Data Portals for DER developers and other stakeholders to gather valuable system data.

Since the 2016 DSIP, Central Hudson and the Joint Utilities have made extensive progress in the development of online machine-readable data and data portals with map visualizations. The data available through Central Hudson's website or through links on the Joint Utilities website include:

- DSIP Filing Documents
- Solar PV Hosting Capacity Maps
- Energy Storage Hosting Capacity Maps
- Electrification Hosting Capacity Maps
- Annually updated five-year Capital Investment Plans as filed with the Public Service Commission (PSC)
- Planned Resiliency / Reliability Projects as filed with the PSC

- Reliability Statistics at the circuit level as filed with the PSC
- Hosting Capacity Maps for all circuits above 12 kV
- Beneficial Locations Maps for DER
- Load Forecasts- 8760 hourly by substation and transmission area for five years
- Historical Load Data- 8760 hourly by circuit, substation, and transmission area
- NWA Opportunities
- Queued and installed DG
- SIR Pre-Application Information.
- Climate Vulnerability Assessment and Climate Change Resilience Plan
- Green Button Connect Customer Data Download

On May 29, 2020, the Department of Public Service Staff released a whitepaper ("Recommendation to Implement an Integrated Energy Data Resource") to propose the next steps to enabling access to useful energy data. This action initiated an effort to establish a centralized state-wide platform providing access to energy data and information from electric, gas, and steam utilities across the state. Over the last several years, this effort has included significant regulatory and implementation actions.

Regulatory actions have included the following:

- On February 11, 2021, the Commission issued an Order approving the design and implementation of a statewide Integrated Energy Data Resource platform to centralize data access, including utility data (customer and system data) and other energy-related data (i.e., EV registration, building characteristics, DER operations) in support of New York's clean energy goals.
- On April 15, 2021, the Commission issued an Order adopting a Data Access Framework (DAF), which aims to standardize cybersecurity and privacy protections, data quality standards, and customer consent processes for third-party access to energy data. The Commission took the following noteworthy actions:
 - Ordered the implementation of a statewide Data Ready Certification to be administered by a third-party vendor and operational in 2022. This certification will be needed for third parties soliciting non-public information from the IEDR.
 - Adopted data quality and integrity standards for data sets delivered by the utility to third parties.
 - Adopted data performance metrics categories to measure the effectiveness of data delivery.
 - Removed registration for hosting capacity maps.
 - Removed data fees for customer energy usage under 24 months old.
 - Adopted a statewide data privacy aggregation standard of 4/50.
 - Required eight joint and individual utility filings over July-September 2021.

- On May 17, 2021, the DAF Matrix was approved, mapping the existing Commission-authorized cybersecurity and privacy requirements to the various combinations of purpose, access mechanism, and data type. The matrix includes the components of all the existing Data Security Agreements and the Self-Attestation, as well as the other existing data access requirements. Each requirement is listed with a name, description, where it originated from, indicators for access mechanism and/or data sets, and the use case applicability.⁶³
- On August 12, 2021, the Commission addressed the UER Status Report and directed NYSERDA to form a standing UER working group to manage and publish versions of the NY UER Protocols, identify refinements and additions to the structure of the reported data fields, and rebalance the application of UER use case-specific privacy screens.⁶⁴
- On October 12, 2023, the Commission clarified that, pursuant to the IEDR Order and DAF Order, Central Hudson and the Joint Utilities shall transfer the defined Customer Data Sets to the IEDR Administrator without customer consent, as such transfer is an exchange of customer data between data custodians. The Commission also clarified that the IEDR Administrator shall not share Customer Data Sets without customer consent, subject to the data protection requirements set forth in the PSC's DAF Order and related orders. Finally, the PSC authorized each utility to file utility-specific tariff changes that expressly eliminate utility liability for any improper access or sharing of Customer Data Sets by the IEDR Administrator.⁶⁵
- On November 13, 2023, the Joint Utilities filed tariff revisions as required by PSC order to limit the liability resulting from misuse of data provided to the IEDR platform. This filing was required before the Joint Utilities could provide the IEDR with unmasked and non-aggregated customer data.
- On May 12, 2023, NYSERDA submitted a proposal for the structure and funding of Phase 2 of the IEDR Program.
- On May 12, 2023, Central Hudson submitted its proposal for supporting the development of the IEDR Phase 2.
- On January 18, 2024, the PSC issued their Order Approving Integrated Energy Data Resource Phase 2 Budgets.
- On November 19, 2024, the Commission issued an order approving tariff amendments and directed each utility to submit further tariff revisions regarding limitations of liability associated with inadvertent disclosures of data from the IEDR platform.⁶⁶ Central Hudson and the Joint Utilities filed tariff modifications in November 2024.

⁶³ Case 20-M-0082, Data Access Framework Matrix (issued May 17, 2021) p.1.

⁶⁴ Case 17-M-0315, Order Adopting Utility Energy Registry Modifications (issued August 12, 2021) p.3.

⁶⁵ Case 20-M-0315, Order Addressing Integrated Energy Data Resource Matters (issued and effective October 13, 2023), p. 2.

⁶⁶ Case 20-M-0082, In the Matter of the Strategic Use of Energy Related Data (IEDR Proceeding), Order Approving Tariff Amendments, With Modification, On a Permanent Basis (issued and effective November 19, 2024), p. 12.

- On December 20, 2024, the Public Service Commission issued an order related to the transition of utility reported community-scale energy usage data to the IEDR.

Implementation actions have included NYSERDA initiating and continuing its work on the IEDR, and Central Hudson and the Joint utilities supporting NYSERDA in its leadership of this undertaking. As part of its implementation efforts, Central Hudson implemented routine transmission of system and customer data to the IEDR platform in January of 2024. Since the last DSIP, Central Hudson has established, managed, and refined its internal IEDR data sourcing program, which has included the following activities:

- Developing the architecture for the utility's IEDR Data Sourcing resources and processes.
- Developing and integrating detailed designs and specifications for the utility's IEDR Data Sourcing resources and processes.
- Deploying and integrating the utility's IEDR Data Sourcing resources and processes.
- Testing IEDR Use Cases.
- Operating and managing the utility's IEDR Data Sourcing resources and processes

Central Hudson looks forward to continuing to work collaboratively with DPS Staff and NYSERDA to help achieve a useful and valuable IEDR resource.

IMPLEMENTATION PLAN

1) *Current Progress*

CENTRAL HUDSON ADMINISTERED INFORMATION SHARING RESOURCES

Prior to the 2016 DSIP, there was only traditional availability and accessibility of system data to third-party developers, there were no online portals dedicated to system data, the data available was often not available in machine-readable formats, there was no generalized hosting capacity information, and there was limited developer insight into areas with greater locational value.

Since the 2016 DSIP, Central Hudson and the Joint Utilities have made extensive progress in the development of online machine-readable data and data portals with map visualizations. The data available through Central Hudson's website or through links on the Joint Utilities website include the following, put in place prior to the 2023 DSIP:

- DSIP Filing Documents
- Solar PV Hosting Capacity Maps
- Energy Storage Hosting Capacity Maps
- Annually updated five-year Capital Investment Plans as filed with the PSC
- Planned Resiliency / Reliability Projects as filed with the PSC
- Reliability Statistics at the circuit level as filed with the PSC
- Hosting Capacity Maps for all circuits above 12 kV

- Beneficial Locations Maps for DER
- Load Forecasts- 8760 hourly by substation and transmission area for five years
- Historical Load Data- 8760 hourly by circuit, substation, and transmission area
- NWA Opportunities
- Queued and installed DG; and
- SIR Pre-Application Information
- Green Button Connect Customer Data Download

Since 2023, the following resources have been added:

- Electrification Hosting Capacity Maps
- Added detail to the Energy Storage Hosting Capacity Maps
- Climate Vulnerability Assessment and Climate Change Resilience Plan

Additionally, the historical and forecasted load and DER data contained in this DSIP are an enhancement of the extensive system data available through Central Hudson's online data portals, which are linked to the Joint Utilities central data portal. This data provides greater transparency into locations on the distribution system where DER integration may have higher value relative to other locations, greater insight into areas with potentially lower interconnection costs, and greater visibility into system characteristics and needs. Together, these factors foster market development.

Central Hudson provides System and access to Customer data primarily through its public website at www.cenhud.com. On the My Energy page in the menu of the home page, customers can find access to their usage data, tariffs and rates, and energy options. Also, developers can find a myriad of information in the solar energy and distributed energy sections, including interconnection application documents, technical requirements for interconnection, and links to the PowerClerk interconnection portal, the Hosting Capacity Map, the interconnection queue, and the System Data Portal (below Figure 47). Other data, such as the DSIP regulatory filings, reliability data, Capital Expansion Plans, and DER interconnection data, are included on the Joint Utilities System Data portal at (<http://jointutilitiesofny.org/system-data/>). The information mentioned above is also shared in a consolidated manner on the Joint Utilities of New York System Data Portal⁶⁷, as depicted in Figure 45 below.

Finally, Central Hudson has Green Button Download functionality enabled for customers within their online accounts.

⁶⁷<https://jointutilitiesofny.org/system-data>

Figure 45: Overview of Currently Accessible System Data

Utility System Data Portal

Public System Information

View below for information on available utility data for developers and customers.

System Data Type	What's Included?	Update Frequency
Distributed System Implementation Plans	Information on the utilities' recent progress, current activities, and future plans to continue the transition towards a clean, resilient, distributed, modern, and customer-centric electricity system	Biennial
Capital Investment Plans	Projected capital expenditures for utilities over the next 5 years	Annual
Electric Reliability Reports	Overview of planned resiliency and reliability projects, as well as utility reliability statistics	Annual
Hosting Capacity Analysis (HCA) Maps	Estimates of the amount of DER that may be accommodated on the grid under current configurations and without requiring infrastructure upgrades	Biannual
Beneficial Locations	High-priority locations where there is a potential for localized DER deployment to address system needs	Annual
Load Forecasts	Hourly or 8760 load forecasts by substation and/or feeder area	Annual
Historical Load Data	Hourly or 8760 historical load data by substation and/or feeder area	Annual
NWA Opportunities	One type of beneficial location - provides developers with information on where future DER opportunities may exist in advance of a formal RFP solicitation for non-wires solutions	Annual
Queued DG	Utility interconnection queue data such as type of technology, installed capacity, location, and status	Monthly
Installed DG	Utility interconnection queue data including installation status	Monthly
SIR Pre Application Information	Forms, documents, and information needed to complete an interconnection application and avoid project delays	As needed

NYSDA ADMINISTERED RESOURCE INFORMATION SHARING RESOURCES: INTEGRATED ENERGY DATA RESOURCE (IEDR) AND UTILITY ENERGY RESOURCE (UER)

While Central Hudson and the Joint Utilities continue to engage stakeholders and work internally to improve the information-sharing resources that the company administers, emphasis has now shifted to supporting NYSDA in its implementation of the statewide Integrated Energy Data Resource (IEDR).

Since the last DSIP, Central Hudson has established, managed, and refined its internal IEDR data sourcing program. As mentioned above, Central Hudson implemented routine transmission of system and

customer data to the IEDR platform in January 2020. Through the provision of system and customer data, Central Hudson's IEDR data sourcing program has supported NYSERDA in its implementation of the Initial Public Version (IPV) release in Q1 2023 and the Minimum Viable Product (MVP) release in Q1 of 2024. Collectively these IEDR platform releases, and Central Hudson and the Joint Utilities' contributions toward them, have resulted in the following use cases being implemented and now available on the IEDR:

- Consolidated Hosting Capacity Maps
- Installed Distributed Energy Resources (DERs)
- Planned Distributed Energy Resources (DERs) (Interconnection Queue)
- DER Siting –Environmental, Community, Terrain, Land, and Property Assessment
- EIAT (Electronic Infrastructure Assessment Tool) Hosting Capacity & DER Map Enhancements
- Efficient and Effective Access to Existing Customer Billing Data
- Find and Filter Rate Options Across NYS IOU Utilities
- Access to Basic Rate Data and Tariff Book for Individual Rate

Additional information regarding the above use cases can be found on NYSERDA's IEDR Program Website.⁶⁸ A summary of Central Hudson's activities and current implementation related to the IEDR can be found in quarterly reports, filed in matter number 20-M-0082 on the NYS Department of Service Website.

In addition to Central Hudson's work in support of the IEDR, the company has continued to provide aggregated energy data to NYSERDA's Utility Energy Registry (UER) Portal, which is meant to support communities in climate and decarbonization planning.

2) Future Implementation and Planning

Central Hudson agrees with the need to provide access to useful energy data to enable the achievement of the State's energy policy goals and plans to continue its comprehensive data sharing program.

Regarding Central Hudson-administered resources, the company plans to continue its efforts to refresh these sets of information, as appropriate. This includes but is not limited to making twice-annual updates to Solar PV Hosting Capacity Maps, Energy Storage Hosting Capacity Maps, and Electrification Hosting Capacity Maps. Additionally, Central Hudson will continue to work with the Joint Utilities on common updates and improvements to the consistency of individual utility data portals, as well as refining and/or expanding system data use cases to better meet stakeholder needs.

Regarding the NYSERDA-administered UER portal, on December 20, 2024, the Public Service Commission issued an order related to the transition of utility-reported community-scale energy usage data to the IEDR. Central Hudson will continue working with NYSERDA and the IEDR Development Team to facilitate this transition, as required.

⁶⁸ <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program>

Regarding the NYSERDA-administered IEDR platform, Central Hudson will continue its IEDR data sourcing program in support of NYSERDA, which transitioned to Phase 2 in April 2020 with the stated intention of developing at least 40 use cases by Q1 2027. NYSERDA's IEDR Phase 2 Proposal, filed in matter number 20-M-0082 on the NYS Department of Service Website, detailed the following use cases to be incorporated into the IEDR during Phase 2.

Table 37: NYSERDA Phase 2 Use Cases

Theme	Phase 2 Use Case
DER Market Expansion and Installation Efficiency	Accelerate DER/commodity installation implementations
Community Energy Planning	Community energy planning (simplification and rebrand of the community choice aggregation use case in Phase 2 Proposal)
Community Energy Planning	Enhanced Community Distributed Generation (CDG) Customer Data Coordination
Comprehensive Whole Building Energy Analysis	Enable whole building energy consumption analysis
Customer Data Access and Privacy Management	Aggregated customer data analysis for improved energy efficiency (EE) programs
Customer Data Access and Privacy Management	Customer meter data access upon enrollment in DR and DER programs
Customer Data Access and Privacy Management	Efficient and effective access to existing customer billing data
Customer Data Access and Privacy Management	Enhance identification of heating, ventilation, and air conditioning (HVAC) energy efficiency opportunities
Customer Data Access and Privacy Management	Improving access to customer data for DERs
Customer Data Access and Privacy Management	Unlocking and Operating Flexible Demand Response (DR) Programs at Scale
Customer Data Access and Privacy Management	Customer-Initiated Customer Usage and Billing Data Sharing
Data-Driven Clean Energy Strategy	Developing and implementing more effective clean energy strategies and programs
Data-Driven Clean Energy Strategy	Electricity emissions data for improvement of GHG regulation
DER and Renewable Integration	Accelerated DER siting
DER and Renewable Integration	Accessible DER interconnection (hosting capacity) information
DER and Renewable Integration	DER registry
DER and Renewable Integration	Determine customer site hosting capacity
DER and Renewable Integration	State of DER dashboard

Theme	Phase 2 Use Case
DER Customer Engagement	Identifying and engaging new customers for DERs
DER Customer Engagement	Explore Aggregated Usage Data Combined with Other Data to Find New Customer Target Groups for Distributed Energy Resources (DERs) Use Case
DER Customer Engagement	Reduced Sales Costs for Distributed Energy Resources (DERs) Developers Through Comprehensive Customer Data Access Use Case
Inclusive Energy Access and Equity	Informing and enhancing utility programs to support disadvantaged communities (DACs)
Inclusive Energy Access and Equity	Reducing energy cost burden for LMI households
Integrated EV and Building Electrification	Accelerating EV charger siting and program opportunities
Integrated EV and Building Electrification	Building electrification site identification
Utility and Market Operations	Enhancing the implementation of customer time-of-use plans for electric vehicle (EV) charging
Utility and Market Operations	Facilitate IEDR wholesale services
Utility and Market Operations	Improving reliability benchmarking for utility operational performance
Utility and Market Operations	Metrics to establish renewable gas program
Utility and Market Operations	Performance evaluation of DERs
Utility Rate Plan Access	Rate plan data

FUTURE IMPLEMENTATION PLAN SUPPORT OF STAKEHOLDER NEEDS

The future implementation plans described above will continue to support stakeholder needs in the future in several ways. For example, Central Hudson is continuing its updates to the various hosting capacity maps and transmitting this information to the IEDR can help developers, communities, Brad, and other stakeholders better understand where there is capacity to site new distributed generation, energy storage, and loads. Also, Central Hudson's efforts to make and publish DSIP updates, distribution forecasting information, areas for DER opportunity, and other aspects of the company's data sharing program can help inform developers and other market participants in bringing new energy solutions to fruition. Links to available system data can be found on the Joint Utilities of New York website (<http://jointutilitiesofny.org/system-data/>). These data resources remain active and in place today, providing a stable resource of needed data for DER developers and other stakeholders.

Furthermore, Central Hudson's work in support of NYSERDA's efforts to develop the IEDR, allows for a consolidated and comprehensive resource that shares data state-wide, facilitating identification and evaluation of opportunities across the NY utility service territories.

CHARACTERIZATION OF WORK AND INVESTMENTS TO PROGRESS FROM CURRENT IMPLEMENTATION TO PLANNED FUTURE IMPLEMENTATION AND TIMING AND SEQUENCING THEREOF

Regarding Central Hudson administered data sharing resources, the methods, processes, and organizational roles and responsibilities for keeping these up to date are mature and well established. Central Hudson will maintain these data sharing resources, continue to engage with stakeholders to make enhancements as these are identified, and incorporate any future changes required by the Commission. The update frequency for these resources varies from monthly to annual, as needed, and can be found at <https://jointutilitiesofny.org/system-data>.

Regarding the NYSERDA-administered UER resource, Central Hudson will work with NYSERDA in its transition of this information to the IEDR, as NYSERDA determines its timeline and sequence of work for this process.

Regarding the NYSERDA-administered IEDR resource, Central Hudson's PSC-approved budgetary cap for its IEDR data sourcing program is approximately \$8.78 million. Total costs as of April 30, 2025, are approximately \$628k, representing roughly 7% of the total budget cap. This year and next, Central Hudson plans to continue working with NYSERDA's IEDR Development Team in support of the IEDR's continued development. Anticipated activities include ongoing data transfers to the IEDR, implementation of single sign-on (SSO) functionality, continued testing to prepare for GBC Certification, enhancements regarding the efficiency and consistency of data transfer pipelines, resolution of discrepancies in nodal data uploads and continued quality assurance for deposited data, continued progress on the process necessary for the Rate Plan Data use case, and ongoing collaboration with the IEDR Development Team and IEDR Program Manager on issues related to customer data sharing opt out requests. To facilitate all these activities and enhance timelines, efforts will continue to focus on automating the data transfer process with tools to provide feedback on the data provided and mechanisms to promote high-quality data ingestion for data sent to the IEDR platform. Additionally, Central Hudson will continue to support NYSERDA's IEDR development team in its implementation of the new use cases requiring utility system and customer data, as NYSERDA's team makes its specific future project plans known.

EFFECTS ON THE COORDINATED GRID PLANNING PROCESS AND VICE VERSA

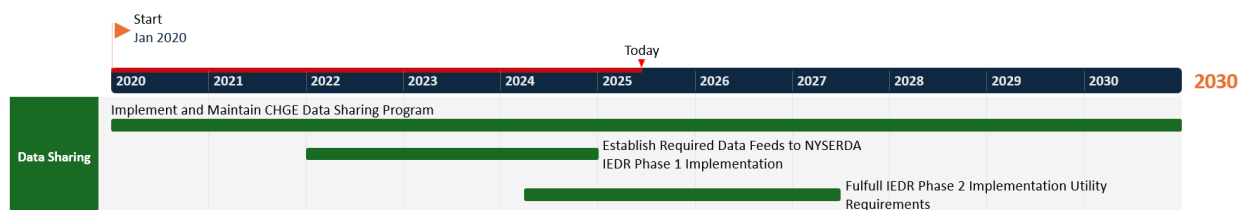
The first cycle of the Coordinated Grid Planning Process is presently underway. This planning process will allow Central Hudson and the state's other utilities to identify transmission investments needed to meet the objectives of the CLCPA. The CGPP includes a process of data collection, modeling, system studies, and transmission solutions development, culminating in an initial report with recommended system investments in 2026, for the PSC's consideration. Upon the PSC's decision regarding the proposed investments, the same multi-step study cycle will repeat thereafter every two years.

During this inaugural cycle of the CGPP, Central Hudson and the other utilities have been primarily sharing information through the New York DPS-hosted Coordinated Grid Planning Working Group site at <https://dps.ny.gov/coordinated-grid-planning-working-group>. To date, Central Hudson has not observed that DSIP-oriented information sharing work and investments affect the CGPP, nor vice versa. However,

as the output of the inaugural cycle of the CGPP is made available in 2026, Central Hudson will look for opportunities to enhance its information sharing program by including this information.

3) Integrated Implementation Timeline

Figure 46: Data Sharing Timeline



4. RISKS AND MITIGATION

Central Hudson continues to be responsive to developers through the stakeholder process in developing an understanding of the System Data elements needed to enhance stakeholder ability to access and utilize available data. There are several risks related to the System Data function of the DSP that must be recognized, including Critical Energy Infrastructure Information (CEII) data, customer privacy, data refresh frequency, data accuracy, and the benefits and costs of providing data elements. Central Hudson will continue to address the risks associated with CEII and customer privacy by applying its policies and procedures to protect sensitive data.

Regarding the refreshing data and continued accuracy thereof, Central Hudson will continue to improve the processes used to create the system data. This will be accomplished through the continued investment in station and distributed metering, internalizing the process of historical data cleansing and forecasting, and refinement of Central Hudson's planning processes to ensure accuracy.

Another risk is that information could become less relevant or accessible to stakeholders over time, as the market and circumstances evolve. To help ensure that information remains as useful and accessible to stakeholders as possible, Central Hudson will continue to engage with stakeholders to gain their input on data sharing resources.

As mentioned above, since 2023, Central Hudson has placed increased focus on its IEDR data sourcing program to support NYISERDA's implementation of the IEDR. Because NYISERDA has plans to develop over 40 use cases for the IEDR in a relatively short period of time, and because its detailed workplans are still being made available, there is a risk that Central Hudson's IEDR data sourcing program may not be able to provide the needed data elements or functionality to the IEDR when needed if sufficient lead time is not clearly established. To mitigate this risk, Central Hudson and the Joint Utilities continue to engage closely with NYISERDA's development team on the two-times monthly Utility Consultation Group call hosted by NYISERDA, as well as in ad-hoc communications and meetings. Central Hudson and the Joint Utilities continue to communicate, collaborate, and share feedback with the IEDR Development Team and Program Manager, on a regular basis, regarding Central Hudson's IEDR data sourcing program and its standing need for information regarding NYISERDA's IEDR development priorities, activities, milestones, timelines, and coordination needs with Central Hudson and the Joint Utilities. To ensure successful

implementation, the JU shared a risk matrix with the IEDR Development team that outlined risks, impacts, and mitigating strategies to allow for adequate planning and resource allocation.

Finally, Central Hudson has joined with the other utilities in offering some guiding principles to NYSERDA for its consideration in implementing the IEDR. These principles are:

- Enhancing customer value should be the guiding principle for designing a statewide data platform.
- The JU recognizes that a statewide data platform may have benefits, but to make it work well and be valuable for all parties, it is critical to first understand the specific goals that such a data platform strives to achieve.
- Security and governance of data are paramount.
- Understand the steps needed, use cases, benefits, and costs.
- System planning and operations must remain with the utility as the DSP.
- A collaborative approach aimed at crafting a practical plan to meet data availability goals, based on lessons learned from pilots and other data initiatives, should be adopted.

5. STAKEHOLDER ENGAGEMENT

CATEGORIES OF STAKEHOLDERS ENGAGED IN DSIP DEVELOPMENT AND USE

In the DSIP development, a wide range of stakeholders are involved, and their needs are incorporated through various engagement processes. Key stakeholder types include developers and market participants, government officials, community members, agencies, customers, and even specific interest groups. The DSIP aims to ensure that all stakeholders are informed, engaged, and have opportunities to provide input throughout the project's development.

WHEN AND HOW THE GOALS AND NEEDS OF EACH STAKEHOLDER CATEGORY ARE IDENTIFIED AND INCORPORATED INTO THE DSIP.

Specific to Central Hudson's information sharing program, the company engages with each stakeholder category.

Through the Joint Utility Information Sharing Working Group, extensive stakeholder engagement has been used to progress the understanding of and access to DSP system and customer Data. Biannually, the Joint Utilities of NY hosts a webinar to update stakeholders and take questions on matters relating to Distributed System Platform services, including data sharing. Since the last DSIP, stakeholder webinars have been held on July 21, 2023, December 14, 2023, June 27, 2024, and December 10, 2024. Each of these webinars included discussions regarding data sharing and each stakeholder type was invited to participate and provide their feedback and requests. Stakeholder needs expressed in these forums and others are taken into consideration in Central Hudson's data sharing program and this DSIP. For example, Central Hudson and the Joint Utilities have made ongoing improvements to the Hosting Capacity maps, being responsive to stakeholder feedback.

Also, on Central Hudson’s website, the company makes contact information available for stakeholders seeking distributed energy resource information. Stakeholders routinely make use of these contacts to make outreach to Central Hudson discuss their needs. Customers, developers, or community groups engaged in clean energy planning often make use of these contact methods regarding matters pertaining to information needs regarding specific projects under consideration and other times relating to broader information needs. In any event, Central Hudson also takes feedback garnered through these channels into consideration in its DSIP development and the refinement of its information sharing program.

Additionally, Central Hudson hosts its own touchpoints with DER stakeholders, including the company’s annual Solar + Summit, which discusses the company’s DER and DSIP programs, including information sharing. Central Hudson solicits feedback from stakeholders at this event. Additional information and past agendas can be found at <https://www.cenhud.com/en/my-energy/distributed-generation/solar-summits/>.

CENTRAL HUDSON’S NEED FOR STAKEHOLDER-PROVIDED INFORMATION, CAPABILITIES, AND ACTIONS

Central Hudson requires stakeholder information in several ways that are relevant to its processes, including the information sharing program. One key area pertains to customer plans regarding new loads, and plans pertaining to the electrification of buildings and transportation. Another key area pertains to development activities pertaining to distributed generation and energy storage. Each of these areas is an input into the forecasts that Central Hudson develops and publishes as part of its DSIP and related information sharing processes. Central Hudson has processes in place to take in this information from stakeholders. For example, our New Business group is in close communication with developers and customers in handling new load requests. Also, Central Hudson has processes and teams in place for the facilitation of interconnections, including individual DER projects and community distributed generation.

Another area in which Central Hudson has a need for stakeholder-provided information, capability, and action relates to the IEDR initiative. Central Hudson’s IEDR data sourcing program is a supporting function to NYSEERDA’s overall leadership of the IEDR implementation effort, including its efforts to incorporate the functionality of the UER into the IEDR. As described above, Central Hudson requires ongoing information regarding NYSEERDA’s IEDR development priorities, activities, milestones, timelines, and coordination needs with Central Hudson and the Joint Utilities.

MEANS AND METHODS FOR EFFECTIVELY INFORMING AND ENGAGING ASSOCIATED STAKEHOLDERS AS PLANNING, DESIGN, AND IMPLEMENTATION PROGRESS.

As described above, Central Hudson employs several means and methods for informing and engaging stakeholders associated with the information sharing program. These include but are not limited to Central Hudson collaborating with the Joint Utilities to host webinars, Central Hudson hosting its own touch points such as the Solar + Summit, ad-hoc meetings with stakeholders such as developers, customers, and community groups, and participation in DPS-staff led working groups.

HOW CENTRAL HUDSON WILL ENSURE THAT INFORMATION, TOOLS, AND ENGAGEMENT OPPORTUNITIES DELIVER THE INTENDED SUPPORT

Central Hudson maintains an open line of communication with all stakeholders and incorporates feedback and requests where appropriate and feasible. As described above, Central Hudson actively

maintains and participates in several channels of communications and forums for dialogue regarding the information sharing program and its evolution thereof.

6. ADDITIONAL DETAIL

1) Provide a functional overview of the planned IEDR;

On February 11, 2021, the Commission issued an *Order Implementing an Integrated Energy Data Resource* (“IEDR Order”)⁶⁹ platform to centralize data access, including utility data (customer and system data) and other energy-related data (i.e., EV registration, building characteristics, DER operations) in support of New York’s clean energy goals. Through the provision of system and customer data, Central Hudson’s IEDR data sourcing program has supported NYSEDA in its implementation the Initial Public Version release in Q1 2023 and the Minimum Viable Product release in Q1 of 2024. Collectively these IEDR platform releases, and Central Hudson and the Joint Utilities’ contributions toward them, have resulted in the following use cases being implemented and now available on the IEDR, as part of its Phase 1 development:

- Consolidated Hosting Capacity Maps
- Installed Distributed Energy Resources (DERs)
- Planned Distributed Energy Resources (DERs) (Interconnection Queue)
- DER Siting –Environmental, Community, Terrain, Land, and Property Assessment
- EIAT (Electronic Infrastructure Assessment Tool) Hosting Capacity & DER Map Enhancements
- Efficient and Effective Access to Existing Customer Billing Data
- Find and Filter Rate Options Across NYS IOU Utilities
- Access to Basic Rate Data and Tariff Book for Individual Rate

NYSEDA intends for its Phase 2 to enable 40+ additional data use cases over 30-36 months (2024-27). The New York State Energy Research and Development Authority serves as the program sponsor for this effort and maintains a Steering Committee with the Department of Public Service (DPS) Staff.

2) Activities across Phases 1 and 2 will enable the sharing of and access to system and customer data with customers and authorized parties to support innovative clean energy business models for customers in New York State. More information regarding the IEDR can be found at <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program>. Provide an overview of NYSEDA’s IEDR implementation program, including information pertaining to stakeholder engagement

The IEDR Order designated NYSEDA to assume the Program Sponsor's role with overall accountability for the IEDR initiative. NYSEDA is leading the development of the IEDR with significant focus on

⁶⁹ Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data, Order Implementing an Integrated Energy Data Resource (Issued February, 11, 2021).

stakeholder engagement to ensure the platform's primary audiences will be able to access and analyze elements of the State's energy system and customer information that are most useful to them. Deloitte Consulting LLP (Deloitte) was awarded a contract to serve as Program Manager for the IEDR. The Program Manager is responsible for organizing and administering the activities related to the Program. Pecan Street Inc. (Pecan Street) was awarded a contract to serve as Utility Data Advisor for the IEDR. Utility Data Advisor is a dedicated resource to oversee and provide guidance on the utility data sourcing efforts, including the technology needed to provide data to the IEDR and related investment. E Source Companies, LLC (E Source) serves as the Solution Architect and Development Team (Development Team) for the IEDR. The Development Team (including UtilityAPI, Flux Tailor, TRC Companies, and HumanLogic) is responsible for designing, building, and operating the IEDR platform. These responsibilities include:

- Use Case Development
- Requirements Definition & Achievement
- Testing & Deployment

Central Hudson maintains an internal IEDR data sourcing program. As part of this, Central Hudson implemented routine scheduled transmission of system and customer data to the IEDR platform in January of 2024. Through the provision of system and customer data, Central Hudson's IEDR data sourcing program has supported NYSEDA in its implementation the IPV release in Q1 2023 and the MVP release in Q1 of 2024. Collectively these IEDR platform releases, and Central Hudson and the Joint Utilities' contributions toward them, have resulted in several use cases being implemented.

As part of its stakeholder engagement program, NYSEDA and its vendors maintain several stakeholder forums, including various Advisory Group tiers and a Utility Consultation Group that meets two times monthly to discuss matters pertaining to the provision of utility system and customer data. Central Hudson is a participant in the Tier 1 Advisory Group and the Utility Consultation Group.

3) Provide the web link to NYSEDA's IEDR home page along with a summary of the information provided therein

A link to NYSEDA's IEDR homepage can be found at <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program>. The website includes information on the milestones schedule, use case development, meetings, program participants, and other IEDR resources such as NYSEDA's quarterly reports.

4) Describe the Company's role in supporting IEDR design, implementation, and operation

Central Hudson maintains an internal IEDR data sourcing program. As part of this, Central Hudson implemented routine transmission of system and customer data to the IEDR platform in January of 2024. Through the provision of system and customer data, Central Hudson's IEDR data sourcing program has supported NYSEDA in its implementation the IPV release in Q1 2023 and the MVP release in Q1 of 2024. Collectively these IEDR platform releases, and Central Hudson and the Joint Utilities' contributions toward them, have resulted in several use cases being implemented. Central Hudson is a participant in the Tier 1 Advisory Group and the Utility Consultation Group that discusses and works through utility customer and system data concerns.

To facilitate ongoing coordination, the Joint Utilities collaborate with NYSERDA and DPS Staff by attending the Utility Coordination Group (UCG) monthly meetings and additional workshops. Topics discussed during UGC meetings include:

- Utility to IEDR data transfer methodology
- Customer consent considerations and the impact of policy and statutory requirements on the IEDR Platform, including but not limited to indemnity and liability issues, state legislation indicating opt-in approaches may be required, federal legislation on data sharing requirements, and other regulatory requirements governing privacy policies and data sharing responsibilities
- Data availability of a small subset of requested data elements
- Consistency of data element nomenclature across all utilities
- Sensitivity of certain requested data elements

Central Hudson continues to manage and refine its internal data sourcing program to provide needed information to the IEDR as its development team works on additional use cases for the platform.

5) Describe the utility's progress, plans, and investments for generating and delivering its system and customer data to the IEDR

Central Hudson and the Joint Utilities extensively supported the IEDR Development Teams to prepare the Phase 1 use cases involved in the IPV and MVP releases, including work on consolidated hosting capacity maps, registries of installed and planned DERs, information on customer bill elements and tariff components, and aggregated readouts of system data.

In Phase 2, the utilities have focused on specific development milestones to increase the availability of system and customer data to support the IEDR and support future higher volume data transfers. More specifically, this year and next, Central Hudson plans to continue working with NYSERDA's IEDR Development Team in support of the IEDR's continued development. Anticipated activities include ongoing data transfers to the IEDR, implementation of single sign-on (SSO) functionality, continued testing to prepare for GBC Certification, enhancements regarding the efficiency and consistency of data transfer pipelines, resolution of discrepancies in nodal data uploads and continued quality assurance for deposited data, continued progress on the process necessary for the Rate Plan Data use case, and ongoing collaboration with the IEDR Development Team and IEDR Program Manager on issues related to customer data sharing opt out requests. To facilitate all these activities and enhance timelines, efforts will continue to focus on automating the data transfer process with tools to provide feedback on the data provided and mechanisms to promote high-quality data ingestion for data sent to the IEDR platform. Additionally, Central Hudson will continue to support NYSERDA's IEDR development team in its implementation of the new use cases requiring utility system and customer data, as NYSERDA's team makes its specific future project plans known. To generate and deliver system and customer data needed to enact the use cases that NYSERA plans for the IEDR, Central Hudson is taking necessary steps, including:

- Having established an internal team to manage the IEDR data sourcing program and scaling the team as needed to support the IEDR in its development process. Resources that have been made available include a Project Manager from the IT Project Management Office, Business

Data & Analytics Lead, Data & Analytics Program Manager, Data Engineers, Data Architect, and Business Analyst, a Middleware Integration Analyst for configuration and deployment of scheduled data pipelines, Q\A Testers and Cyber Security Analyst.

- Making hardware and overall IT infrastructure investments necessary to support IEDR Phase 2 data gathering, transformation and transfer of information to the statewide IEDR platform. These costs will include license and infrastructure costs for Development, Test Quality Assurance and Production environments in order to provide the ability for Central Hudson to provide necessary lifecycle deployments.

Central Hudson's PSC-approved budgetary cap for its IEDR data sourcing program is approximately \$8.78 million. Total costs as of April 30, 2025, are approximately \$628k, representing approximately 7% of the total budget cap. Additional information can be found in Central Hudson's IEDR Phase 2 Utility Budget Estimate filed on May 12, 2023, in Commission Case No. 20-M-0082.

6) Identify and characterize each type of data to be delivered to the IEDR;

Central Hudson and the Joint Utilities provide two general types of data to the IEDR: system data and customer data, as mandated by the Commission. System data includes scheduled deposits of datasets detailing the distribution system topology, time-varying historical loading information, and granular hosting capacity estimates for photovoltaic, battery energy storage system, electric vehicle, as well as chargers and substations. Customer data, provided in a non-anonymized and non-aggregated form, encompasses customer account details, billing data, usage data, load profiles, rate and tariff information, meter data, DER/EV-related data, program enrollment data, and customer demographic data. These data points are crucial for precise analysis and personalized services, ensuring a comprehensive understanding and management of energy consumption and customer interactions.

7) Describe the resource(s) and method(s) used to deliver each type of data to the IEDR

Data is delivered to the IEDR daily, weekly, and monthly, as required by the IEDR Development Team.

For transfers of system data, the Central Hudson and the Joint Utilities have worked extensively with the IEDR Development Team to provide input on their data transfer specifications needed to align the transfers of utility-specific data across numerous system metrics and ensure that these data streams could be appropriately ingested and reflected on the IEDR platform for future stakeholder use.

Coordination activities have included separation of datasets by energy system classification, discussions on the naming convention for file transferred to the IEDR and the mechanisms by which the IEDR Development Team and Program Manager can coordinate with the Joint Utilities are data quality and transfer performance metrics.

Regarding customer data, Central Hudson and the Joint Utilities are supporting NYSERDA's efforts to enable the IEDR to ingest inputs from repositories like the statewide hosting capacity maps and DER repositories, read-outs of aggregated community-scale and whole energy building consumption, and data on customer rates and utility tariffs which form the basis of customer bills. These data inputs provide additional map layers for stakeholders to review the interaction with other IEDR use cases, provide information on interconnected and in-queue generation projects, and more accessible indices of utility tariffs with searchable catalogues of rate plans. The JU went to great lengths to support modeling of this data across different utility tariffs and develop more consistent cost-estimating tools across New

York State. Like transfers of system data, activities focus on the data quality of data transferred from the utilities to the IEDR and general transfer performance metrics to improve the speed, accuracy, and usability of IEDR outputs.

Summary of Data Delivery to IEDR

Central Hudson utilizes a combination of skilled personnel, advanced technology platforms, and structured processes to ensure accurate and timely data delivery to the Integrated Energy Data Resource. The approach is organized by data category.

- **Customer Data.** An Extract, Transform, Load process securely transfers information from SAP to the Netezza data warehouse, capturing historical IEDR customer data transmissions. In alignment with Phase II specifications, Microsoft Fabric has been designated as the long-term solution, with Power Platform supporting automation. Automated pipelines are in place to ensure data quality through duplicate removal and format validation. Twelve customer data CSV files are delivered daily to the E Source SFTP site, each adhering to the current E Source schema and including the most recent five days of billing and interval data.
- **Network Data.** Geospatial and attribute data are Sourced from the GIS system by the GIS team. Eventually, CYME software will be used to export both geometry and associated data in an integrated format. Until that transition is complete, the GIS team continues to perform validation and transmission. Data pipelines are optimized for schema compliance and quality assurance, and the deposits include hosting capacity data for EVs, PV systems, BESS, chargers, and substations. Five network data ZIP files are delivered monthly to the E Source Secure File Transfer Portal site, conforming to the latest schema requirements.
- **Rate Plan Data.** Microsoft Fabric and Power Platform are used to automate ETL processes, with data delivered to the E Source SFTP site. Automated workflows support CSV delivery and are designed to accommodate future XML formats. Deposits are updated in response to new schema specifications or PSC-approved rate plans, with ongoing efforts focused on harmonization and governance. Eleven CSV files are delivered to the E Source SFTP site upon approval of new rate plans or updated specifications provided by the E Source development team.

8) Describe how and when each type of data provided to the IEDR will begin, increase, and improve as IEDR implementation progresses

The implementation of the Integrated Energy Data Resource (IEDR) platform involves a structured and phased approach to data provision, focusing on enhancing the transfer, quality, and automation of the following data types.

Customer data is delivered to the IEDR platform through daily deposit pipelines and processes, with utility processes optimized to enhance transfers. Established practices for reporting these data streams are implemented, and automated processes ensure data quality by identifying duplicate records and maintaining the integrity of Customer User IDs. Continuous collaboration is in place to update requirements and specifications, ensuring seamless data transfers and automated processes. Improvements are focused on enhancing data security measures, ensuring high data quality and

integrity, increasing automation for data transfers and quality assurance, maintaining the integrity of Customer User IDs, and promoting high-quality data ingestion processes.

Network data is provided via monthly deposit pipelines and processes, with utility processes optimized to enhance transfers. Reporting practices for streams, including hosting capacity and other sources, are implemented. Automated procedures ensure accuracy. Requirements for hosting capacity deposits have been refined into separate energy systems to align with the latest specifications as of February 25th, 2025. Monthly data deposits are currently being met. The focus in 2025 is on security, data quality, automation, and quality assurance through enhancements via CYME software.

Rate plan data is deposited after schooled Rate Planning, provided through the approval process by the PSC. The latest requirements focused on improving data harmonization among the JUs. Collaboration with E Source on February 12, 2025, resolved outstanding issues. Updated deposits meeting all final requirements were delivered on February 27, 2025. An automated business process for distribution was developed in Q4 2024 and is expected to be applied during the next rate plan deposit in June 2025. The proof of concept utilizing Microsoft Fabric is well established as of Q1 2025, awaiting V0.99 specifications. Enhanced deposits include automation, improved data integrity, historical change capture, harmonization, alignment with the latest specifications, and streamlined delivery.

Community-scale energy usage data, reported by utilities, was transitioned to the IEDR platform following a PSC order on December 20, 2024. This order requires Central Hudson to discontinue Utility Energy Registry reporting to the UER and begin direct transmission to NYSERDA. Currently, Central Hudson's UER data is transmitted directly to NYSERDA. The future process involves phasing out the UER and implementing new or existing deposit specifications to aggregate data according to the UER model.

Green Button Connect (GBC) within the IEDR platform is progressing through distinct stages focused on testing, configuration, and refinement. The IEDR Development Team unveiled an updated proposed GBC Deployment Plan Summary Timeline during the February 18th UCG meeting. A crucial part of this initial delivery phase has involved Central Hudson collaborating with the IEDR Development Team to continue Alpha and systems integration testing procedures, as well as working with UtilityAPI throughout Q1 and Q2 to complete testing for configuring single sign-on (SSO) functionalities. While UtilityAPI confirming successful SSO integration deemed sufficient for data testing in Q4 2024, Central Hudson continues to develop and test this integration with the IEDR platform in the staging environment. GBC availability and functionality are intended to increase as implementation progresses through key testing milestones towards public availability. The NYSERDA proposed timeline indicates a goal for utilities to complete the "go-live portion of testing by the August/September 2025 timeframe". Improvements to GBC as part of the IEDR implementation are primarily occurring through the iterative testing and feedback processes currently underway. Central Hudson has been engaged in strategy meetings and has maintained successful collaboration with subject matter experts (SMEs), ESource and UtilityAPI, and ongoing valuable feedback continues to enhance testing processes.

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;

Central Hudson provides System and access to Customer data primarily through its public website at www.cenhud.com. On the My Energy page in the menu of the home page, customers can find access to their usage data, tariffs and rates, and energy options. Also, developers can find a myriad of information

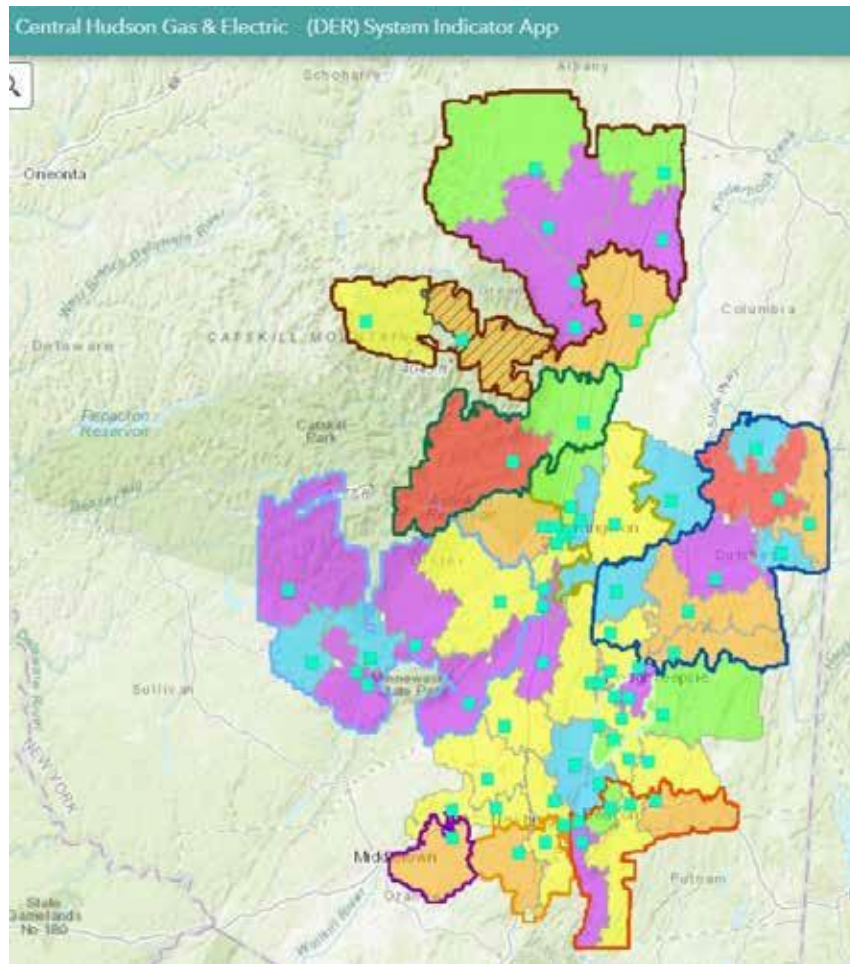
in the solar energy and distributed energy sections, including interconnection application documents, technical requirements for interconnection, and links to the PowerClerk interconnection portal, the Hosting Capacity Map, the interconnection queue, and the System Data Portal (Figure 47). Additional data, such as the DSIP regulatory filings, reliability data, Capital Expansion Plans, and DER interconnection data, are included on the Joint Utilities System Data portal at (<http://jointutilitiesofny.org/system-data/>).

Figure 47: Central Hudson Website – Solar & Distributed Energy Page



The System Data portal is a GIS map-based data portal providing historical and forecasted load data by location. See Figure 48 for an example.

Figure 48: System Data GIS Map



Web Link: <https://experience.arcgis.com/experience/06a86b7f2ca844dea4caecef6922fbc8>

By clicking on a circuit, substation, or transmission area, a pop-up screen will appear that provides details on the circuit or station and reveals a link to the historical and forecasted load data in Excel file format. See Figure 49 for an example.

Figure 49: Historic and Forecasted Load Example

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	date	hour	mva	estimate	substation	year	month	temp1_1in	mva_tin2	mva_p01	mva_p05	mva_p10	mva_p25	mva_p50	mva_p75	mva_p90	mva_p95
2	1/1/2013	1	4.816827	0	STAATSEU	2013	1	35.96	4.38822	4.298005	4.324433	4.338522	4.362063	4.38822	4.414376	4.437918	4.452006
3	1/1/2013	2	4.481281	0	STAATSEU	2013	1	33.98	4.164555	4.078938	4.104019	4.11739	4.139731	4.164555	4.189378	4.211719	4.22509
4	1/1/2013	3	4.329494	0	STAATSEU	2013	1	35.96	4.073923	3.990169	4.014705	4.027784	4.04964	4.073923	4.098206	4.120061	4.133141
5	1/1/2013	4	4.203004	0	STAATSEU	2013	1	35.96	4.06331	3.979774	4.004246	4.017292	4.03909	4.06331	4.087529	4.109328	4.122373
6	1/1/2013	5	4.304238	0	STAATSEU	2013	1	35.96	4.173105	4.087312	4.112445	4.125843	4.148231	4.173105	4.197979	4.220366	4.233764
7	1/1/2013	6	4.320101	0	STAATSEU	2013	1	35.96	4.396927	4.306533	4.333014	4.34713	4.370718	4.396927	4.423135	4.446723	4.46084
8	1/1/2013	7	4.430614	0	STAATSEU	2013	1	37.04	4.667696	4.571736	4.599848	4.614833	4.639874	4.667696	4.695519	4.72056	4.735546
9	1/1/2013	8	4.779088	0	STAATSEU	2013	1	37.04	4.923841	4.822615	4.852269	4.868077	4.894492	4.923841	4.95319	4.979605	4.995413
10	1/1/2013	9	5.193162	0	STAATSEU	2013	1	37.04	5.004168	4.90129	4.931428	4.947494	4.974339	5.004168	5.033996	5.060841	5.076907
11	1/1/2013	10	5.674557	0	STAATSEU	2013	1	37.04	5.072093	4.967819	4.998366	5.01465	5.04186	5.072093	5.102325	5.129536	5.14582
12	1/1/2013	11	5.884081	0	STAATSEU	2013	1	37.04	5.067095	4.962924	4.993441	5.009709	5.036892	5.067095	5.097298	5.124482	5.14075
13	1/1/2013	12	5.929034	0	STAATSEU	2013	1	37.04	5.058444	4.993628	5.024333	5.040702	5.068054	5.098444	5.128833	5.156185	5.172554
14	1/1/2013	13	5.796375	0	STAATSEU	2013	1	37.04	5.162618	5.056483	5.087575	5.10415	5.131845	5.162618	5.19339	5.221087	5.237661
15	1/1/2013	14	5.851172	0	STAATSEU	2013	1	37.04	5.162425	5.056294	5.087385	5.103959	5.131654	5.162425	5.193196	5.220891	5.237465
16	1/1/2013	15	5.878343	0	STAATSEU	2013	1	35.96	5.186447	5.079822	5.111057	5.127708	5.155532	5.186447	5.217361	5.245185	5.261836
17	1/1/2013	16	5.992133	0	STAATSEU	2013	1	35.06	5.438532	5.326724	5.359478	5.376939	5.406115	5.438532	5.470949	5.500125	5.517585
18	1/1/2013	17	6.80878	0	STAATSEU	2013	1	33.08	6.199911	6.07245	6.10979	6.129695	6.162955	6.199911	6.236866	6.270127	6.290031
19	1/1/2013	18	7.117798	0	STAATSEU	2013	1	32	6.542593	6.408088	6.447491	6.468496	6.503595	6.542593	6.581591	6.61669	6.637695
20	1/1/2013	19	7.092557	0	STAATSEU	2013	1	30.92	6.416113	6.284208	6.32285	6.343449	6.37787	6.416113	6.454358	6.488778	6.509377
21	1/1/2013	20	7.052381	0	STAATSEU	2013	1	30.02	6.289248	6.159953	6.197828	6.21802	6.25176	6.289248	6.326735	6.360476	6.380667

The information mentioned above is also shared in a consolidated manner on the Joint Utilities of New York System Data Portal.⁷⁰ Finally, Central Hudson has Green Button Download functionality enabled for customers within their online accounts.

Central Hudson remains committed to maintaining its data sharing program and incorporating new requirements and feedback from stakeholders as needs and conditions change over time. Central Hudson intends to build upon progress already institutionalized as part of the DSIP and other processes and continue evolving its data sharing program as advancements in the digitization of information are implemented.

I. HOSTING CAPACITY

1. KEY TAKEAWAYS

Central Hudson continues to enhance the transparency and utility of its Hosting Capacity Maps to support clean energy developers, policymakers, and other stakeholders. Central Hudson's solar and energy storage maps are mature and widely used, offering actionable insights that help developers make informed interconnection decisions. A significant development since the 2023 DSIP is the launch of the first version of our electrification maps in January 2024, as directed by the Public Service Commission. These maps now include voltage information for various segments of each feeder, providing a more granular understanding of grid conditions and supporting beneficial electrification planning.

One of Central Hudson's key accomplishments over the past year has been the implementation of a new enterprise-grade ESRI GIS platform and the deployment of CYME load flow analysis software. This marks

⁷⁰ <https://jointutilitiesofny.org/system-data>

a substantial step forward in our analytical capabilities, enabling a more streamlined and robust Hosting Capacity mapping process. These tools support more accurate assessments of grid capacity and improve Central Hudson's maps' overall quality and usability. While Central Hudson's experience with standalone or hybrid energy storage systems above 50 kW remains limited, the Company continues to gather feedback and explore improvements, particularly in how storage is modeled based on charge/discharge schedules and operational use cases.

Looking ahead, Central Hudson will remain actively engaged in the Integrated Planning Working Group, which serves as the primary forum for guiding enhancements to the Hosting Capacity Maps. Through ongoing collaboration with this group and sustained stakeholder engagement—via surveys, webinars, newsletters, and training sessions—Central Hudson will continue refining our mapping approach, especially in anticipation of broader energy storage deployment. As the energy landscape evolves, these efforts will help ensure our maps remain relevant, forward-looking tools for grid modernization.

Hosting Capacity Maps are foundational in Central Hudson's efforts to enable decarbonization, electrification, and distributed energy adoption across our service territory. While not explicitly tied to Central Hudson's recent rate cases or other regulatory filings, the Hosting Capacity efforts align closely with broader Distributed System Platform (DSP) objectives, including data sharing and planning transparency. Central Hudson's commitment is to continuously improve these maps to meet stakeholder needs and support a clean energy future.

2. CONTEXT AND BACKGROUND

In order to support DER integration, Central Hudson provides estimates of its system's hosting capacity, or the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line or secondary network system.⁷¹ This information is of particular interest to stakeholders, as it allows prospective interconnection customers to make more informed business decisions before committing resources to an interconnection application.

Central Hudson calculates hosting capacity at the nodal level for each circuit by evaluating potential power system criteria violations that could result from interconnecting large solar PV and/or Energy Storage systems⁷² to ≥ 13.2 kV three-phase distribution lines. This approach was deliberately chosen to deliver value in a timely manner to DER developers who are most active in New York State. The analysis increases visibility into hosting capacity for larger-scale solar PV and/or Energy Storage systems that often target rural areas where land is available but where hosting capacity can vary substantially from site to site. The primary use case for hosting capacity data in New York is to help guide DER investments and marketing activities to areas of the grid where the interconnection costs are likely to be the lowest.

⁷¹ Electric Power Research Institute (EPRI), Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, Report Number 3002008848 ("EPRI Roadmap"), June 2016, p. 2.
<http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848>.

⁷² Solar and/or Energy Storage with an AC nameplate rating starting at and gradually decreasing from 6000 kW.

Since the 2023 DSIP, Central Hudson has continued to update the public hosting capacity maps. Both solar PV and energy storage maps include nodal-level hosting capacity values for three-phase line segments ≥ 13.2 kV. The color of a node is reflective of the maximum DER (in MW) the node can accommodate based on the most constrained violation criteria category; thermal, overvoltage, undervoltage, and voltage regulation tap movement. Along with the JU, Central Hudson also incorporated "Cost Share 2.0" indicators, showing areas with cost-sharing opportunities for upgrades and providing data accessibility through APIs for third-party integration. Additionally, the JU have been working with the IEDR initiative to ensure that hosting capacity data is available through a centralized statewide platform, allowing stakeholders to access and analyze hosting capacity information across multiple utility territories in a consistent format. The maps are updated on a regular cycle (full system update annually, mid-cycle updates for significant changes, and monthly updates to interconnected and in-queue data), ensuring stakeholders have current information.

EPRI's DRIVE tool continues to be utilized to conduct hosting capacity analysis, in order to support alignment and a common approach across the JU, while enabling utilities to leverage existing circuit models in a utility's native distribution planning software.

Since the 2023 DSIP, EV Hosting Capacity Maps have evolved into broader Electrification Maps. Initially, the JU developed EV load serving capacity maps at the feeder level to show where electric vehicle charging loads could be added without major system upgrades. Following stakeholder input and regulatory orders in 2023, the JU expanded the EV maps into Electrification Capacity Maps covering all new electrification loads. The Public Service Commission directed the utilities to provide both summer and winter peak capacity views, given the seasonal differences in electrification impacts. In response, the JU collaborated with DPS Staff and launched the new Electrification Map on January 16, 2024, which offers feeder-level load serving capacity headroom for both summer and winter peak conditions. These maps utilize the Energy Storage Hosting Capacity Map charging layer colors for consistency between maps depicting load serving constraints. The Electrification Capacity Maps also overlays layers for indicators to help identify EV Charging Target Zones and Disadvantaged Community areas.

Collectively, since initiation, the scope of hosting capacity maps has broadened from solely DER generation to include load electrification, providing a more comprehensive view of the distribution system's capabilities. The granularity has improved from whole-feeder averages to detailed segment-by-segment values, increasing the maps' accuracy and usefulness. The JU have also enhanced stakeholder accessibility to these maps: what began as static or annual PDF summaries is now delivered via interactive web portals with data download options and API access for developers. This evolution reflects ongoing feedback from stakeholders and policy changes.

3. IMPLEMENTATION PLAN

1) Current Progress

Since Stage 1 Hosting Capacity Maps were developed in 2016, Central Hudson has worked with the JU, industry stakeholders, and Staff to continuously develop and refine hosting capacity maps to improve transparency, support grid planning, and enable better decision-making for Distributed Energy Resources, Battery Energy Storage Systems, and electrification-related load growth. These maps have evolved from high-level circuit indicators to detailed, data-rich tools with sub-feeder granularity, nodal

constraint visibility, and expanded data accessibility via APIs. This evolution has been guided by stakeholder input, regulatory directives, and technological advancements in power system modeling and distribution planning.

Since the 2023 DSIP, Central Hudson has shifted from utilizing Electric Distribution Design's Distribution Engineering Workstation load flow software to Eaton's CYME. The Company has replicated electric feeder model extraction automation between CYME and the EPRI DRIVE tool for Hosting Capacity (HC) analysis.

Table 38, Table 39, and Table 40 provide a detailed, chronological breakdown of the major updates and enhancements made to the PV, BESS, and Electrification Hosting Capacity Maps.

Table 38: PV Hosting Capacity Map Updates

Update	Details
Initial Feeder-Level Hosting Capacity (2016–2017)	- Launched the first Stage 1 Hosting Capacity Maps, providing basic feeder-level indicators showing general circuit availability for DER interconnections. - Maps displayed high-level traffic light indicators (red/yellow/green ratings) to show where DERs could likely interconnect without major system upgrades.
Feeder-Level Hosting Capacity & Standardized Methodology (2017–2018)	- Released the first feeder-level hosting capacity values using EPRI's DRIVE tool. - Provided standardized methodologies across all utilities, ensuring consistency. - Introduced additional system data fields based on stakeholder input. - Began updating maps annually through utility DSP portals.
Sub-Feeder Granularity & Existing DER Integration (2019)	- Introduced sub-feeder (nodal) granularity, allowing hosting capacity to be displayed at different points along a circuit rather than a single feeder-wide value. - Existing DER capacity is included in calculations to reflect remaining capacity more accurately. - New "Local Hosting Capacity for PV" pop-up tab added, showing minimum and maximum hosting capacity per section. - Included a field tracking DG Installed Since Last Refresh, giving stakeholders insight into circuit changes over time.
Data Transparency & Enhanced Pop-ups (2020)	- Provided downloadable feeder summary tables (CSV/XLS format) with all map details. - Added substation equipment information, including substation transformer bank thermal capacity (MVA rating) and 3V0 protection limits. - Enabled annotated notes on circuit-specific situations.
Increased Update Frequency & API Access (2021)	Implemented a targeted 6-month refresh cycle for circuits experiencing rapid DER growth (>500 kW of new DG added in 6 months).

Update	Details
	Launched REST API access for third-party developers to programmatically retrieve hosting capacity data.
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.

Table 39: Battery Energy Storage Hosting Capacity Map Updates

Update	Details
Initial Storage Hosting Capacity Map (2022)	- First storage-specific hosting capacity maps released, modeled after PV hosting capacity methodology. - Displayed feeder-level hosting capacity for both charging (load) and discharging (generation). - Toggle feature implemented to switch between storage as generation vs. storage as load. - Included sub-transmission lines to highlight additional interconnection opportunities beyond feeders.
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.

Table 40: Electrification Map Updates

Update	Details
EV Load Hosting Capacity Map Development (2020)	- First EV Load Hosting Capacity Maps released in response to the EV Make-Ready Order (July 2020). - Provided feeder-level hosting capacity values for EV charging loads, mirroring the PV hosting capacity approach. - Incorporated color-coded circuit indicators to display remaining capacity for new electric load.
Electrification Hosting Capacity Expansion (2023–2024)	Expanded EV Load Hosting Capacity Maps into full Electrification Hosting Capacity Maps per regulatory orders.

Update	Details
	▪ Added dual seasonal hosting capacity values, allowing users to toggle between summer and winter peak conditions. ▪ Integrated Environmental Justice (EJ) area overlays to support equitable electrification planning. ▪ Maintained feeder-level color-coding and breakpoints, ensuring continuity with previous EV maps.

The JU aligned the annual update of all three hosting capacity maps (solar PV, storage, and electrification) to occur in April of each year, as solar PV, storage, and electrification were previously annually updated out of sync (October, April, and January of each year respectively). The Electrification Hosting Capacity Maps were updated with key enhancements aimed at improving data granularity and transparency. This includes the addition of voltage information for each node, providing stakeholders with more precise electrical details to better assess grid capacity. Additionally, notes identifying upstream constraints will be incorporated to highlight potential limitations at substations that could impact hosting capacity, ensuring a clearer understanding of grid constraints for electrification planning.

a) Updates Related to HC-Data Sharing with IEDR

The integration of hosting capacity data into the IEDR has evolved significantly since the platform's launch. Early 2023 marked the IEDR's Initial Public Version, 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 circuit section. The focus was on consistency: "users can view all hosting capacity maps for the entire state in one map view with consistent data". However, the granularity and features of the HC data have expanded through 2023 and 2024, driven by the Joint Utilities' HC roadmap.

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, and integration of data from the Public Service Commission's Cost Share 2.0 order (i.e. planned upgrade projects to increase hosting capacity, with details on the affected substation, the expected capacity increase, anticipated in-service date, and upgrade cost). All JUs implemented these updates around the same time, meaning the IEDR received a richer dataset for HC by mid-2023. The IEDR's Electric Infrastructure/Hosting Capacity module was updated to display these new fields so that developers could see, for example, if a section of the grid is slated for an upgrade that will boost its hosting capacity and when that will occur.

From a procedural standpoint, one notable change since 2023 is the move toward more frequent incremental updates. As noted, the JUs agreed to do interim six-month updates for rapidly changing circuits (which is a new practice starting in 2023). Procedurally, this means the utilities must re-run hosting capacity calculations for certain feeders out-of-cycle and push those updates to IEDR without waiting for the next full system refresh.

Since integrating the HC data, the Joint Utilities have continuously refined data quality controls. In late 2022, the JU worked on "consistency of data element nomenclature across all utilities" so that fields like circuit ID, voltage, available MW, etc., mean the same thing for Central Hudson as for National Grid, ConEd, etc... By 2023, this standardization paid off – the IEDR's consolidated map presents uniform column headings and units for all territories. During Phase 1, the JUs also sent test data and engaged in iterative feedback with the IEDR development team to iron out any mismatches. This collaborative debugging continued into Phase 2: in 2024 the utilities participated in working sessions on data defects and used an online portal to report any HC dataset issues in IEDR for prompt resolution.

2) Future Implementation and Planning

In late 2024, the JU sent out a survey to stakeholders to identify training interests and opportunities for better understanding the three different hosting capacity maps. The JU received feedback in late Q1 of 2025, indicating an interest in an introductory and advanced hosting capacity map training via webinar. The JU are currently working to outline and implement this training, scheduled for the fall of 2025.

The JU may consider expanding the use cases for Electrification Hosting Capacity Maps to better support the strategic siting of electrification projects, depending on stakeholder feedback. This could support identifying suitable locations for school bus charging infrastructure and public EV charging stations, ensuring that these projects are deployed in areas with sufficient hosting capacity. By incorporating these specific use cases, the maps could provide targeted insights for fleet operators, municipalities, and charging providers, helping them align electrification efforts with grid readiness. While there are no plans to make these enhancements at this time, this expansion could potentially improve the maps' ability to guide infrastructure investments and facilitate the transition to electric transportation.

The Integrated Planning Working Group and the Interconnection Technical Working Group are working together to explore potential updates to the Energy Storage Hosting Capacity Maps, specifically regarding the possible incorporation of BESS operating schedules. The goal of this collaboration is to ensure that any changes to the HC maps align with Standardized Interconnection Requirements (SIR), the Coordinated Electric System Interconnection Review (CESIR), and other interconnection processes, making the maps more useful for developers navigating the interconnection process.

As part of this effort, each utility has published tentative ESS operating schedules through the ITWG. These schedules provide insight into how storage systems may operate at different times (charge and discharge) and could help improve interconnection planning, CESIR evaluations, and system impact assessments. However, the utilities and industry stakeholders are still determining how these schedules should be used and whether they should be reflected in the energy storage Hosting Capacity Maps.

The JU collaborates with stakeholders to prioritize developer needs. As such, there is no prescriptive long term implementation timeline. Instead, the JU continuously works with stakeholders to enhance the hosting capacity maps in the near term. This provides many 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 hosting capacity 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.

The goal of the HC maps is to help stakeholders understand how much hosting capacity is available at a given location. While they are not meant to replace the interconnection process, they are meant to assist developers in initiating it. Continued granularity will support stakeholders in this process.

Hosting capacity maps are useful for developers and stakeholders because they provide critical information about the ability of the electric grid to accommodate new distributed energy resources such as solar panels, wind turbines, and energy storage systems. These maps help identify areas where DERs can be added to the grid without causing reliability or safety issues.

Developers can use hosting capacity maps to identify areas with available capacity for new DER projects. This information can help developers make informed decisions about where to site new projects, which can reduce costs and save time. By avoiding areas with limited hosting capacity, developers can reduce the need for expensive upgrades to the grid infrastructure.

To support on-going improvements to the HC maps, the JU will need to:

- Continue JU collaboration to identify best practices that will further progress the maps.
- Continue stakeholder engagement to better understand and respond to stakeholder needs.
- Continue working towards HC map automation to streamline updates and enable the provision of further functionality.

The JU will continue to meet periodically, ramping up as needed, to discuss hosting capacity initiatives and engage with stakeholders throughout the year.

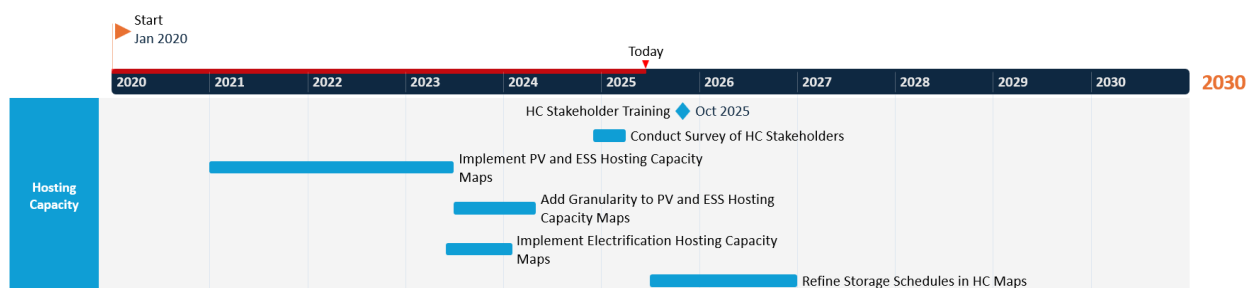
The Coordinated Grid Planning Process and DSIP are filings with overlapping but distinct scope. The CGPP will detail the evolution of distribution planning processes needed to meet Climate Leadership and Community Protection Act goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes the implementation of the much broader set of DSP activities and projects and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet New York State CLCPA goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments and how they will be leveraged, will be included in the DSIP (e.g., AMI, distribution automation, Advanced Distribution Management System [ADMS], etc.), and the results of executing the processes will be used to inform the CGPP. This includes planned investments that support an increase in hosting capacity (i.e., CGPP Phase 1 projects).

The CGPP is aimed at developing a “CLCPA-focused planning process,” including “the State’s bulk transmission, local transmission, and distribution planning processes.” The goal is to improve planning

processes to better coordinate the studies performed by the Utilities with the NYISO’s bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution and bulk system studies with NYSERDA’s renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. One of the key inputs to the CGPP is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council. While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and hosting capacity process. This includes ensuring the upgrades identified as part of the CGPP that increase hosting capacity are included within appropriate analysis. As of this DSIP writing, the CGPP is currently in Stage 3 (Local Assessment) of the 6 Stage process.

3) Integrated Implementation Timeline

Figure 50: Hosting Capacity Integrated Timeline



The integrated system implementation timeline, shown in Figure 50, includes the implementation timeline related to hosting capacity which includes efforts and investments as part of Integrated System Planning. As mentioned in the section above, there is no prescriptive long-term implementation timeline for hosting capacity map enhancements. In 2025, the JU will engage stakeholders by responding to the requests made in the stakeholder engagement survey that called for introductory and advanced training sessions related to the three hosting capacity maps. In 2026 and beyond, the JU will continue to engage stakeholders to discuss near-term and long-term improvements that can be made to the HC maps, for example, the potential to expand Energy Storage Hosting Capacity map functionality to include utility energy storage operating schedules.

Additionally, Central Hudson will continue to improve our electric circuit model load flow software, CYME, which will improve engineering analysis of DER interconnections, EV load requests, hosting capacity, and electrification.

4. RISKS AND MITIGATION

The risks to Hosting Capacity Analysis are primarily driven by software and analytical capabilities, availability of data, and the efficiency of circuit model updates. To mitigate this risk, Central Hudson

participates in the EPRI DRIVE user group to help influence the development and prioritization of software capabilities to align with the needs of stakeholders in New York. Central Hudson continues to refine hosting capacity analysis by improving the load flow models of the entire distribution system and incorporating hourly load data available on 97% of electric distribution feeders. Hosting capacity analysis is also impacted by the execution of the capital plan, which leads to distribution system improvements and the significant number of Distributed Generators that are interconnected every year. As a part of the Company's ESRI GIS roadmap, there will be improved integration of distribution design work into the ESRI platform so that field changes can be more quickly incorporated into the GIS model and other interfacing software, such as the load flow models that drive hosting capacity analysis. However, there will still be limitations to incorporating the impacts at the substation and transmission level into these models.

There is also risk involved in integrating newer DER technologies into hosting capacity analysis. While initial hosting capacity analysis focused on solar photovoltaics, the process has become more complex as energy storage technology with distinct operating characteristics has been introduced. While the JU is working with the ITWG to identify valuable energy storage use cases that can be incorporated into the hosting capacity maps, the additional scenarios will ultimately require additional labor and resources. The balance between complexity, efficiency, and accuracy must be considered to provide stakeholders with the most timely and practical information. Supplementary Electric Planning & Interconnection resources may also be required to manually reconfigure circuits to consider alternate configurations and incorporate additional DERs with their own complex set of operating characteristics. Flexible interconnection, including a mix of technology capabilities, smart inverter functionality, and varying schedules, also introduces risks and complexities in providing valuable and comprehensible results to stakeholders.

5. STAKEHOLDER INTERFACE

The Joint Utilities of New York place stakeholder engagement at the core of developing and improving Hosting Capacity and Electrification maps. These maps are intended to serve a broad user community – from renewable developers and EV charging companies to municipal planners and customers – their value depends on meeting stakeholder needs. By actively involving stakeholders, the JU ensures the maps remain useful, transparent, and aligned with real-world requirements, ultimately streamlining DER interconnections and guiding efficient grid investments. In practice, this engagement builds trust in the data and tools provided, empowers users to make informed decisions, and helps New York achieve its clean energy and electrification goals through collaborative planning.

Stakeholder needs are continuously documented through formal sessions, surveys, and other feedback channels. The user priorities drive the evolution of map features. For example, the JU convene dedicated Hosting Capacity Stakeholder Sessions (open webinars and technical conferences) where developers, industry groups, and community representatives can voice their needs, ask questions, and suggest enhancements. These sessions are a cornerstone of the planning process – the JU present current map capabilities and solicit input on what to improve next. In these forums, stakeholders' priorities emerge (e.g., desire for more granular data, easier data access, or new map types), and the JU actively record and consider this input. Crucially, stakeholder feedback is not only heard but systematically incorporated into map enhancements.

As the JU have noted, third-party input directly influences the prioritization of both near-term and long-term HC map upgrades. A clear example is how stakeholder requests for greater detail led to the addition of sub-feeder level data and nodal constraint indicators on the maps. Similarly, stakeholders advocated for more frequent data refreshes to keep the maps current; in response, the JU moved from purely annual updates to also providing mid-cycle updates for rapidly changing circuits (e.g. introducing six-month refreshes on PV maps where distributed generation grew >500 kW between annual updates). Even the introduction of the new Electrification Load Serving Capacity Maps in 2024 was driven by the growing electrification efforts of customers and policymakers – stakeholders signaled the need to understand where the grid can accommodate new electric vehicle chargers and building electrification loads, prompting the JU to include these maps as the latest stage of the HC roadmap. By identifying needs through constant engagement and acting on them in each iteration of the maps, the JU demonstrate a highly responsive approach.

The content and functionality of HC and Electrification maps today reflect extensive stakeholder-provided input, data, and feedback. Many enhancements are traceable to stakeholder contributions. For instance:

- **Map Features and Data Fields:** Developers and other users often request specific information to aid their project planning. In response to such feedback, the JU have progressively enriched the maps. Substation-level and feeder-level granularity, existing DER visibility, and nodal voltage constraint data were all added following stakeholder discussions about what information would help them screen interconnection locations. The JU explicitly credit stakeholder sessions for shaping these upgrades, confirming that stakeholders helped guide which features to implement next on the roadmap.
- **User Capabilities and Data Access:** Some stakeholders (e.g. consultants and large developers) have advanced analytical tools and requested direct access to underlying data to integrate with their own planning models. The JU incorporated this by enabling data downloads and Application Programming Interfaces (APIs) for the HC maps. For example, storage hosting capacity data is now available via an API, and 8760-hour load profile data links are provided within system data portal, features that make the maps more useful for those who wish to perform custom analysis. These capabilities were added to support sophisticated users based on feedback about how stakeholders wanted to use the information.
- **Feedback Loop for Ongoing Improvements:** The JU treat stakeholder feedback as an invaluable resource for continuous improvement. The JU catalogs suggestions from meetings, support surveys, then feed them into the design cycle for future map versions.

The Joint Utilities employ a multi-faceted engagement strategy to involve stakeholders. Key means and methods include:

- **Dedicated Stakeholder Sessions and Webinars:** The JU have hosted regular stakeholder meetings specifically focused on Distributed System Platform initiatives, with Hosting Capacity Maps as a frequent agenda item. For instance, the utilities have made it a practice to hold stakeholder engagements devoted to hosting capacity updates. In these sessions, the JU have presented recent map updates or new features, then open the floor for questions and discussion. This format allows real-time stakeholder input on what is or isn't working. In the

past, the JU have also arranged thematic webinars (e.g. a Storage Hosting Capacity map deep-dive in May 2022) to walk through new map tools and gather stakeholder reactions in detail. Meeting materials underscore these goals. All webinars are open to the public and broadly announced, ensuring any interested party (developers, trade organizations, community representatives, etc.) can participate.

- **Surveys, Feedback Forms, and Direct Outreach:** To supplement meetings and inform new initiatives, the JU employ targeted feedback mechanisms to understand stakeholder needs. A practical example is their approach to the upcoming Fall 2025 Hosting Capacity Maps training. Rather than designing the training based on assumptions, the JU first distributed a user survey to identify specific knowledge gaps and challenges. This proactive step ensures the training will address actual stakeholder needs rather than presumed ones. The survey collects input on preferred training topics, format preferences, and specific questions users have about the maps. By gathering this feedback before finalizing the training agenda, the JU demonstrates their commitment to creating truly useful resources that respond to real user challenges.
- **Transparent Information Resources:** As part of engagement, the JU make extensive information readily available to stakeholders, empowering them to self-educate and provide informed input. The Joint Utilities' website hosts a dedicated section for Hosting Capacity, complete with user guides, FAQs, definitions of criteria, and downloadable data. By equipping stakeholders with knowledge (e.g. criteria and assumptions used in the Hosting Capacity Analysis are published for transparency), the JU facilitate more productive stakeholder interactions – users can understand the context and limitations of the maps and thus give more pointed feedback or requests. Additionally, the JU publish quarterly DSP newsletters and timely announcements (e.g. via email lists) so stakeholders are kept up-to-date on new map features or upcoming engagement opportunities. This ongoing communication keeps stakeholders engaged throughout the cycle, not just at formal events.

Throughout their engagement efforts, the Joint Utilities remain vigilant that the information and tools provided are clear, effective, and do not inadvertently mislead or burden stakeholders. Through these efforts, the Joint Utilities work to ensure that stakeholder engagement is not only frequent but effective – meaning the provided information is understood as intended and genuinely useful. Several practices underscore this commitment:

- **Standardization Across Utilities:** A major focus has been making the HC maps consistent in format and quality statewide, despite each utility maintaining its own map and unique system operating characteristics and configurations. Stakeholders voiced that it's confusing if each utility's map has different scales or conventions. The JU responded by closely coordinating on map design so that a developer or customer can "cross a utility's boundary and see the same exact hosting capacity maps on the same exact scales," enabling users to get up to speed quickly anywhere in New York. This standardization minimizes the learning curve and prevents errors that could arise from inconsistent data presentations. It reflects a unified approach to meeting stakeholder needs uniformly, which industry observers have noted is a key part of the JU strategy.
- **User Guidance and Training:** The JU recognize that providing complex grid data without context can cause misinterpretation – an unintended challenge the JU work to avoid. To that end, every

map release is accompanied by clear documentation and user guidance (definitions of fields, caveats on data usage, etc.). Utilities often include pop-up explanations or legends on the maps themselves to guide users. Moreover, as described in above, the JU are initiating formal training sessions to ensure stakeholders fully understand how to navigate the maps and apply the data. By educating users, the JU mitigates the risk of misuse.

- **Phased Implementation and Testing:** The staged roadmap approach for HC map enhancements was intentionally designed to gradually introduce complexity – this gave both the JU and stakeholders time to adapt. At each stage, the JU gathered feedback on the last set of features before proceeding to the next, ensuring that new data layers or functions were adding value and not confusion. This iterative rollout, guided by stakeholder input, prevented the maps from becoming overwhelming or unwieldy. It also allowed the JU to refine features in response to any early challenges. For example, when the first sub-feeder data was launched, the JU closely watched how developers used it and solicited feedback; any clarity issues could then be addressed (through improved tooltips or FAQ explanations) before expanding further. This careful, stepwise implementation helped avoid unintended negative consequences and built stakeholder confidence in each new feature.
- **Quality Control and Reliability of Data:** Stakeholders rely on the maps for important decisions, so the JU takes data accuracy and currency seriously to avoid leading users astray. Procedures are in place for regular data validation. Additionally, the JU have worked to update the maps more frequently where needed. By updating hosting capacity and electrification maps at least annually (with mid-year updates for circuits with high interconnection of DER), they reduce the risk that stakeholders act on outdated information. The JU also coordinate these updates in parallel across all member utilities, so stakeholders receive refreshed data around the same time statewide – preventing a situation where one area's map is current and another is lagging. All these measures ensure stakeholders can trust the information, thereby using the tools effectively.

Across planning, development, and implementation of Hosting Capacity and Electrification maps, the Joint Utilities of New York have established a thorough, collaborative process that keeps stakeholders at the forefront. Stakeholder engagement is not treated as a checkbox exercise but as an integral part of the maps' life cycle – from the initial roadmap crafted with stakeholder input to each incremental update influenced by user feedback. The JU actively seeks out stakeholder needs through diverse means (workshops, working groups, surveys, and direct communications) and then demonstrates real responsiveness by translating those needs into map enhancements, support tools, and policy adjustments. This continuous dialogue has led to maps that are ever more useful, detailed, and user-friendly, while also ensuring stakeholders fully understand and trust the information provided. The ongoing training and survey initiative is the latest testament to this philosophy of engagement, showing the JU's commitment to not just deliver data, but to cultivate an informed user community around that data.

Specific to Central Hudson stakeholder initiatives:

- Central Hudson hosts an annual Solar+ Summit, which provides DER developers and industry professionals, including energy storage developers, with information on the technical and procedural aspects of interconnecting with the utility, industry updates, available programs, and

incentives. The event also provides networking opportunities with industry professionals. At the conclusion of each Solar+ Summit, a survey is provided for feedback from attendees and is utilized for future planning purposes, including specific topics of interest that professionals would like to see and hear about. Hosting capacity and hosting capacity maps are typically a topic that is included within presentations provided by Central Hudson, to provide stakeholders with insight into these maps as well as give them the opportunity to ask questions.

- Central Hudson typically holds a DSIP webinar summarizing the content included within each of the topical sections of the DSIP along with major initiatives or implementations. This session provides stakeholders with an opportunity to attend, listen and ask questions. This webinar is held shortly after the DSIP filing and additionally, the Company provides ad-hoc DSIP engagement with interested stakeholders via email or meeting touchpoints over the course of the year about DSIP related topics. The JU also holds a DSIP enablement webinar twice a year and quarterly provides newsletters to stakeholders. The JU also has a website which is DSIP focused and includes various references and resources for stakeholders and is updated on a rolling basis.
- Central Hudson has direct email and phone contacts for DER interconnection questions, including hosting capacity, along with a DG Ombudsperson that stakeholders can directly reach out to resolve concerns. This includes all DER technologies, such as energy storage. The Electric Distribution Planning and Interconnections team holds several one-on-one hosting capacity training sessions with stakeholders that request a meeting. The following are emails included on the Company's DG website for inquiries related to DERs: dg@cenhud.com, pvmetering@cenhud.com, dgombudsman@cenhud.com, wholesaleaggregations@cenhud.com.

6. ADDITIONAL DETAIL

- 1) *The utility's current efforts to plan, implement, and manage capital infrastructure projects related to hosting capacity. Information provided should include: 1) 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; 2) the original project schedule; 3) the current project status; 4) lessons learned to-date; 5) project adjustments and improvement opportunities identified to-date; and, 6) next steps with clear timelines and deliverables*

Central Hudson has initiated and completed several projects that increase the hosting capacity of DERs on its system. The Energy Storage Integration section describes the Energy Storage projects, or research, that have been completed, or are currently being evaluated, at Central Hudson. One of the primary use cases for these Energy Storage projects and research is to understand the technology's capability to unlock additional hosting capacity on the electric distribution and transmission systems as DG penetration continues to increase and saturate regions of the service territory. Central Hudson requires the use of smart inverter settings and utilizes these settings as part of impact studies as a means for increasing hosting capacity across the service territory without requiring extensive upgrades to the electric system infrastructure.

Although not the primary project driver, Central Hudson has initiated and completed several T&D infrastructure projects that increase the hosting capacity of DERs on its system. As shown in detail in Central Hudson's 2026-2030 Electric Capital Plan filed July 2025, there are many programs Central Hudson will execute over the next five years that will convert areas from 4kV to 13.2kV operation or reconductor wire to reduce voltage drop and improve system capacity. All of these projects have the added benefit of increasing hosting capacity. A significant amount of circuitry will be reconducted as a part of the copper wire replacement program and operating/infrastructure programs. Central Hudson will also increase interconnection headroom after completing infrastructure upgrades within substations and on the transmission system. Over the next several years, a number of substation transformers will be replaced with larger units and two substations will expand from one to two transformer stations. Transmission lines will be rebuilt due to age and condition and as a result their capacity and capability will increase. Finally, the Distribution Automation/Distribution Management System projects described in further detail in DER Interconnections will allow for enhanced monitoring and control of DERs, while increasing hosting capacity. These projects will be fully designed, managed, and completed following Central Hudson's Project Management Guidelines.

2) Where and how DER developers/operators and other third parties can readily access the utility's hosting capacity information.

Hosting capacity maps are available on Central Hudson's Distributed Generation website at: <http://www.cenhud.com/dg>.

New York JU hosting capacity map information is available on the JU Hosting Capacity website at: <https://jointutilitiesofny.org/utility-specific-pages/hosting-capacity/>

New York Integrated Energy Data Resource (IEDR) website: <https://iedr.nyserda.ny.gov/>

Accompanied by the IEDR Electric Infrastructure Assessment Tool (EIAT) which provides access to JU Hosting Capacity information: <https://iedr.nyserda.ny.gov/spatial-tool/layers>

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 of the IEDR.

Central Hudson is currently sending DER interconnection data and Hosting Capacity map data for all three maps (solar PV, energy storage, and electrification) on a monthly basis to the IEDR. In March 2025, the IEDR implementation team made slight adjustments to the format of the hosting capacity data transfer by breaking out the different map layers into separate file geodatabases. Central Hudson will continue to coordinate with our IEDR implementation consultants to make changes as needed.

Phase 2 of the IEDR (2024–2026) implementation is anticipated to explore new potential use cases, which may involve hosting capacity data in more advanced or detailed ways.

Central Hudson's implementation plan for IEDR can be found within the DSIP in the Data Sharing section. For more information on the IEDR, please visit: <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program/About-IEDR>.

4) The means and methods used for determining the hosting capacity currently available at each location in the distribution system.

Central Hudson developed interactive maps that illustrate hosting capacity for distribution circuits. The analyses presented in these displays provide the nodal level solar PV and energy storage hosting capacity for distribution circuits emanating from a substation at 12kV and above. The analyses were conducted under current electric system configurations and prior to infrastructure upgrades such as installing a recloser or remote terminal unit at the Point of Common Coupling, replacing a voltage regulating device or controller to allow for reverse flow, substation-related upgrades including 3V0 protection, or other protection-related upgrades. The lowest value of the four different violation criteria determines the Section Hosting Capacity Megawatt value at each node. The pop-up display shows the Section Hosting Capacity value and each of the criteria (Thermal, Primary Overvoltage, Primary Undervoltage, Primary Voltage Deviation, and Voltage Regulation Deviation) so that the map user has an understanding of which violation is most constraining at that node. Additionally, pop-up displays include information regarding feeder details (feeder ID, source substation, section/node ID, and section/node voltage), DG details (interconnected DG, in-queue DG, DG interconnected since last HC analysis), NYISO load zone, 3V0 upgrades, flicker, anti-islanding, HC analysis refresh date, and any feeder/region specific notes. Similar information is given at the substation transformer level, as well.

Each circuit's hosting capacity is determined by evaluating the impacts of large, centralized solar PV installations (300kW and greater) along the three-phase distribution mainline. These analyses include nodal level hosting capacity along the distribution circuit and relevant hosting capacity data at the substation level. The analyses include the explicit modeling of existing solar PV or energy storage as well as steady-state distribution system configurations and electric distribution device settings.

System constraints related to circuit protection require further analysis to make a definitive determination of hosting capacity. This hosting capacity data is being provided for informational purposes only and is not intended to be a substitute for the established interconnection application process. Tabulated data is included in the form of data pop-up displays to indicate the hosting capacity, dictated by violation criteria, at any given location.

The interconnected and queued DER values, as well as how much DER has been interconnected on each specific feeder since the last refresh, are included within the data pop-ups and are updated monthly.

Figure 51: PV Hosting Capacity Map for Central Hudson's Service Territory

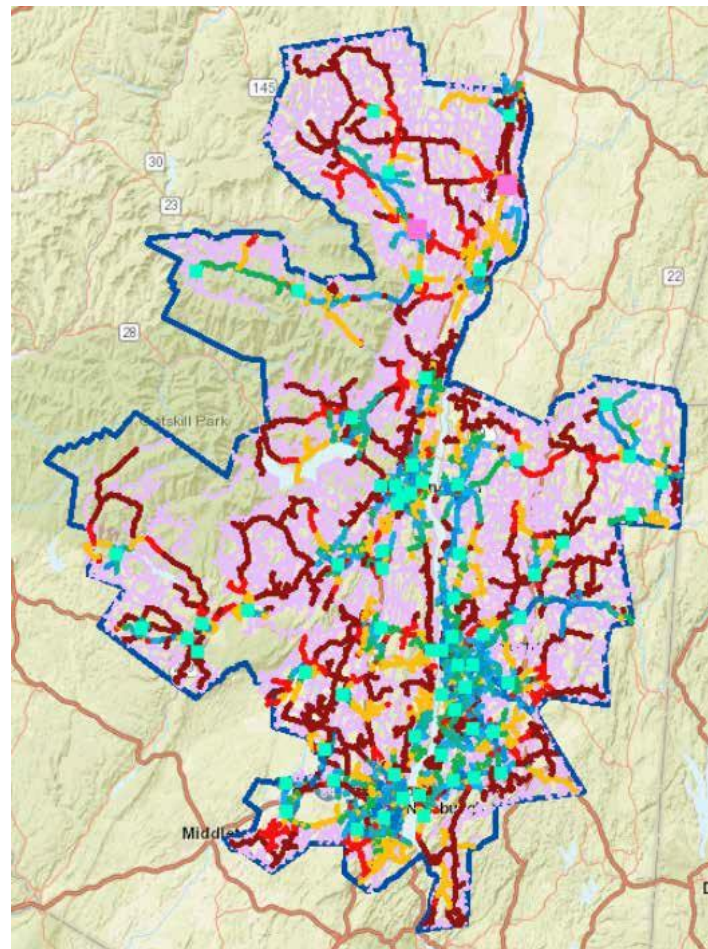
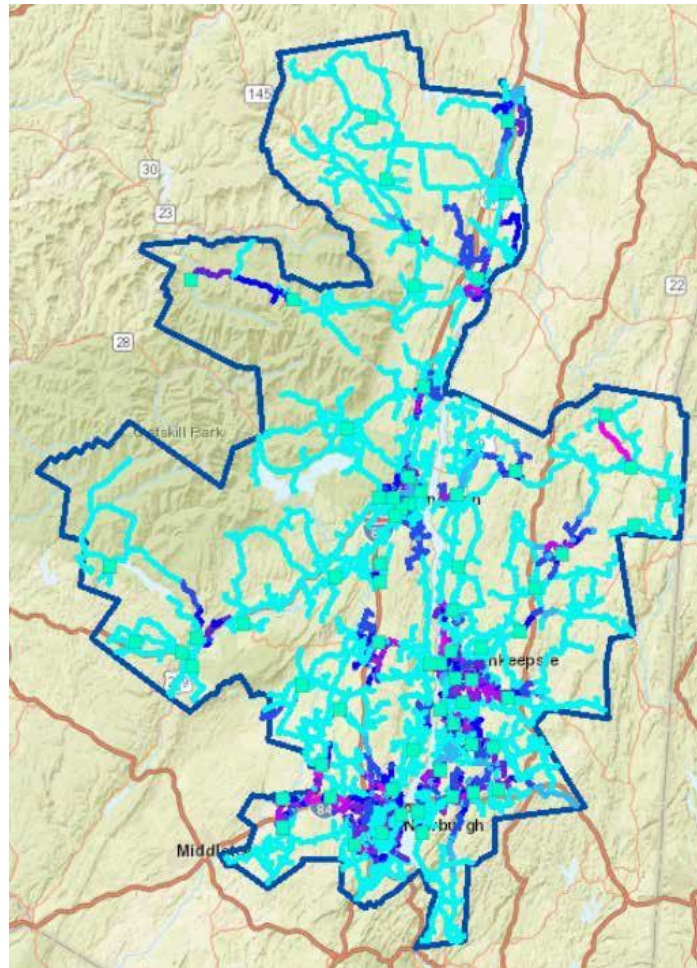


Figure 52: Storage (Charging) Hosting Capacity Map for Central Hudson's Service Territory



Once in the map, as shown in Figure 51 and Figure 52 above, a user can utilize the address search toolbar in the top left corner to zoom into a specific address and click on the primary segments displayed to bring up additional information about the circuit. This information includes the circuit's ID, operating voltage level, number of phases, nodal hosting capacity, hosting capacity value per each violation criteria, interconnected and proposed DG in queue, as well as the amount of DER interconnected since the last annual refresh. Information on substation is also provided, including the substation ID, interconnected and proposed DG in queue, prior year substation peak, substation bank thermal capacity, 3V0 protection status, and estimated 3V0 protection threshold if applicable. A legend is included in the top right corner of the map. The PV Hosting Capacity Map legend has added information about Capital Infrastructure Projects that will increase hosting capacity and the ESS Hosting Capacity Map legend allows the user to toggle between charging (load) and discharging (generation) layers.

The operating voltage may denote voltages below 12kV such as 2.4kV Line-Gnd, 4.16kV Line-Gnd, 4.8kV delta, or 7.62kV Line-Gnd. Hosting capacity values, however, are only included for the three-phase mainline of distribution feeders, which emanate from a substation operating at 12kV and above. Voltages below 12 kV classification indicate locations served by one or two phases, or located downstream of a step-down transformer (e.g., transformation from 13.2kV to 4.16kV).

5) The means and methods used for forecasting the future hosting capacity available at each location in the distribution system.

The detailed means and methods will be determined if forecasting of hosting capacity is further defined and prioritized within the Hosting Capacity Stakeholder Sessions.

6) 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.

Central Hudson will update the <http://www.cenhud.com/dg> website with additional hosting capacity information and maps as they are available. Additionally, along with the Joint Utilities, Central Hudson, host stakeholder webinars as needed to roll out new features of the analysis.

Central Hudson does publish the publicly available System Data Portal which provides 8760-hour historical and forecasted load data for electric distribution feeders:

<https://experience.arcgis.com/experience/06a86b7f2ca844dea4caecef6922fbc8>.

7) The utility's specific objectives and methods to: 1) identify and characterize the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development; directing users to the Coordinated Grid Planning Process filing for further information and, 2) timely increase hosting capacity to enable productive DER development at those locations, directing users to the IEDR platform when applicable for more information.

While the hosting capacity maps identify the approximate capacity available to interconnect solar PV and energy storage, these maps are intended to be used as a reference and do not replace the interconnection process. While some utility infrastructure upgrades may be identified as part of the interconnection process, they do not always result in a barrier to DER development.

Central Hudson has improved the System Planning Process through the use of a probabilistic approach to integrate DERs into the risk and growth profiles. This process will encompass both how asset replacements are determined and the methods used to optimize the portfolio of projects and programs. Also, in recognition of the State's aggressive renewable goals as identified in the Climate Leadership and Consumer Protection Act and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB), the Company is modifying its planning process to better align with these goals. As noted, the electric capital plan is predominantly comprised of condition-based infrastructure type projects. A number of these existing projects provide incremental hosting capacity benefits and are identified as Phase 1 projects. As new project needs are studied, renewable penetration levels and potential hosting capacity improvements are included in the analysis to determine the recommended solution. Finally, as part of the New York JU's proposed Coordinated Grid Planning Process, the CGPP is intended to identify Phase 2 projects, which are capital plans that increase hosting capacity on the local transmission and distribution system and funded under the FERC load ratio share methodology. For more information on the CGPP refer to Case 20-E-0197.

Central Hudson currently updates hosting capacity maps on an annual basis for all circuits 12kV and above, and a bi-annual basis for circuits with >500kW DG interconnected since the last refresh. The Company also updates queue information on a monthly basis. Additionally, by July 1st of each year, as

part of the Cost Share 2.0 Order, the Company identifies on the hosting capacity maps, capital investment projects that are planned for construction within two years and create additional hosting capacity beyond the system baseline. The capital improvements made on Central Hudson's system that benefit hosting capacity will be captured on hosting capacity maps per the described refresh cycle. As part of NY State's Integrated Energy Data Resource initiative, hosting capacity data is one of the items included within this platform. Central Hudson is currently sending over hosting capacity data to the IEDR monthly. For more information on IEDR efforts visit NYSEDA's website at <https://iedr.nyserda.ny.gov/>.

J. BILLING AND COMPENSATION

1. KEY TAKEAWAYS

Central Hudson customers are being billed timely and accurately, with significantly lower numbers of estimated readings following the transition to monthly meter reading.

Key billing metrics are very strong, with over 99% of invoices being issued on a timely basis. Adjusted bills have been averaging less than 1.5%, which is our target level, and recently close to 1%, which is lower than the prior CIS system. Moving forward, Central Hudson strives to meet customer expectations and build customer trust.

Current billing system development is focused on the regulatory Value of Distributed Energy Resources and Distributed Energy Resources programs, which are discussed below. These programming efforts are, for the most part, large system enhancements and will require a considerable amount of time, resources, and testing to complete. Substantial effort has gone into developing test scripts and validations to ensure a smooth upgrade.

2. CONTEXT AND BACKGROUND

One of the most critical shifts in the electric grid is how, where, and when power is produced and delivered. Historically, power flows and associated compensation has been one-directional. Power was generated at large bulk power stations, transmitted over large distances, and delivered via a distribution network to customers. Customers were billed for both the supply and the delivery of electricity. The growth in distributed generation – mainly from rooftop solar and battery storage – and the shift from a centralized bulk system to a distributed grid has changed how the grid operates and the billing requirements significantly. Many customers now generate power and export the power via the distribution grid. Those with storage can also either reduce their reliance on bulk-power plant supply or store solar for later use. Thus, billing processes have needed to evolve to enable two-way compensation in order to provide credits for power generation, and reflect the change in the use of the electricity transportation system known as the electric grid. Much of the progress in the past decade has been enabling billing systems to better support a distributed grid where homes both produce and consume power via the grid.

Another significant shift has been the introduction of community distributed generation (CDG) and remote-metered (RM) solar. CDG, often called community solar, allows individuals and businesses to subscribe to and receive credits for electricity generated by larger off-site solar projects. It enables access to renewable energy for homes and businesses who might not otherwise be able to install solar panels on their property, such as renters or those with limited roof space. Remote-metered solar is a

similar concept. It allows businesses and farms to install solar panels on one property and then credit the excess energy generated to other properties under the same ownership, allowing businesses to offset their energy bills. The penetration of remote and net-metered solar in Central Hudson is substantial. As of the end of 2024, Central Hudson had almost 17,000 installations of net metered solar with approximately 160 MW of installed capacity, 59 CDG sites with approximately 140 MW of installed capacity, and 93 remote metered generation sites with 34 MW of installed capacity. To place it in context, Central Hudson has over 330 MW of distributed solar capacity, while the system peaks at roughly 1100 MW.

By the end of 2024, the 59 CDG sites had over 16,400 Central Hudson subscribers. Figure 53 and Figure 54 show the overall number of CDG subscribers and sites over time.

Figure 53: Subscriber Count for All CDG Projects (2019 to Present)

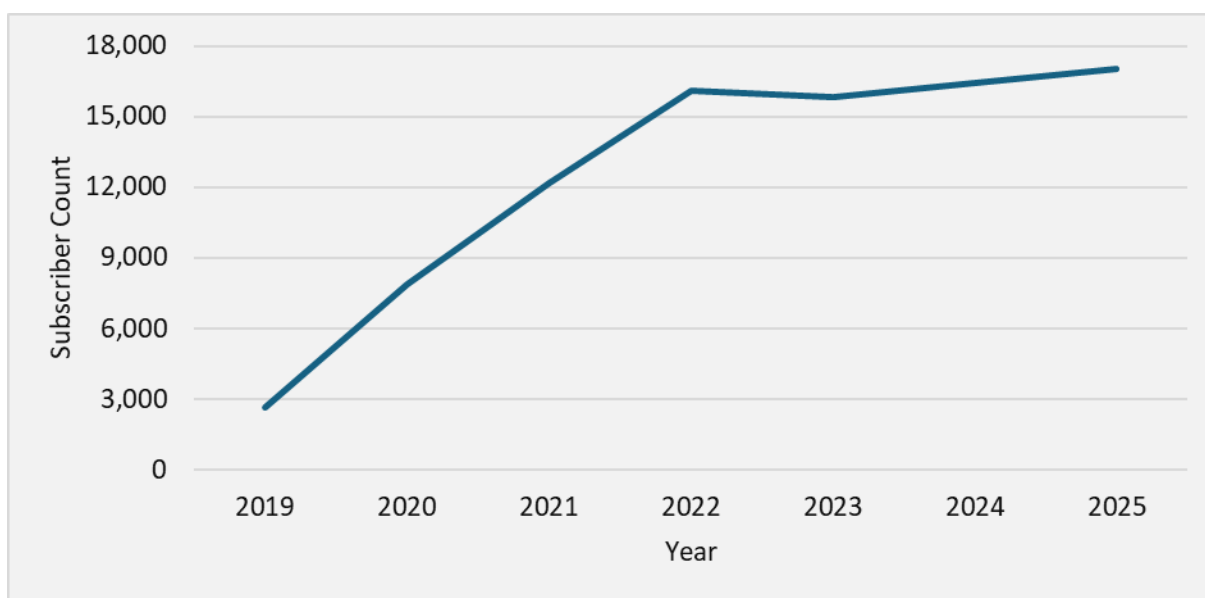
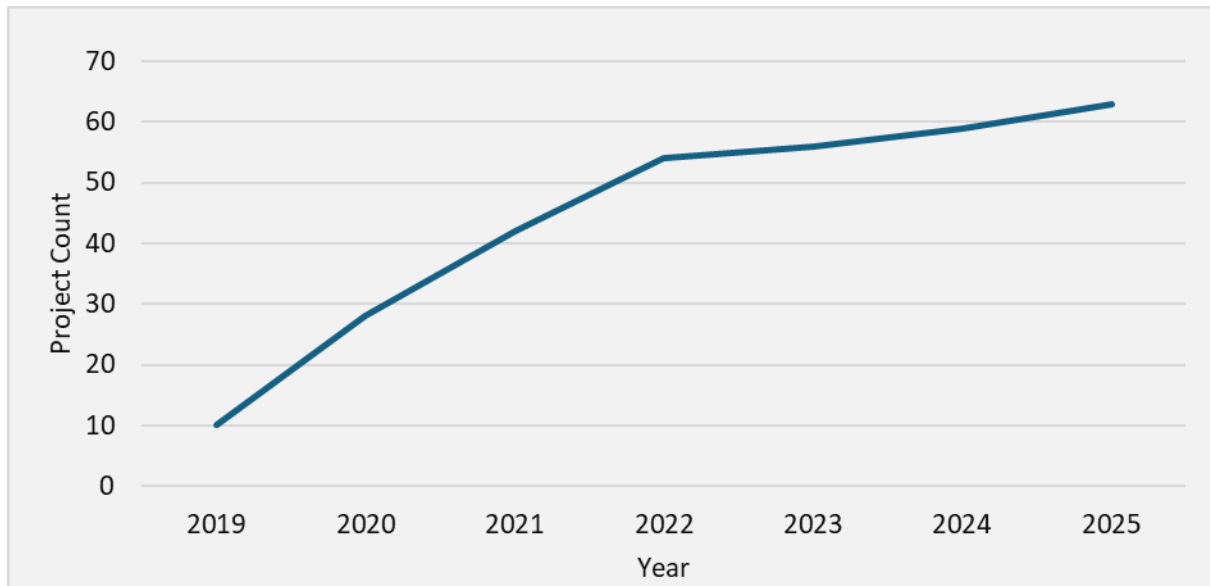


Figure 54: Total Number of CDG Projects (2019 to Present)



Two additional changes in billing are noteworthy. Until 2024, meter reads and billing for Central Hudson customers were on a bi-monthly basis (every other month), supplemented with a bill estimate produced every other month. Starting in March 2024, Central Hudson shifted to monthly meter reads and billing for its customers. In addition, Central Hudson upgraded its customer information and billing system to SAP in 2022.

3. IMPLEMENTATION PLAN

1) *Current Progress*

The Company completed its full automation of CDG billing and crediting in January of 2024, pursuant to the Commission's order on September 15, 2022, in Case 19-M-0463. This allowed the process to come full circle from an initial fully manual process, to a semi-automated one, to full automation. After a brief period of true-ups to correct any errors from manual processing time periods, CDG full automation has been functioning well for over a year. Since that time, CDG customers have been billed timely and accurately, with minimal rebilling to adjust credits. It has been well received by both the subscribers and the host providers.

The Company has significantly stabilized and streamlined its general billing and approach to the various DER-related billing and compensation programs that it maintains. The Company currently bills and/or compensates customers under the following tariff-based/on-bill programs, which are generally encompassed under the VDER umbrella:

- Volumetric net metering;
- Monetary net metering;
- Phase 1 NEM;

- Phase 1 Value Stack;
- Phase 2 Value Stack;
- Remote net metering;
- Remote crediting;
- Community Distributed Generation;
- Net crediting;
- Customer Benefit Contribution Charge (CBC);
- Standby Service; and
- Multiple Savings Rates.

In addition, the Company has programs generally designed for larger DERs not eligible for VDER – Standby Service and Buyback Service; however, no customers are currently served under these programs.

2) *Future Implementation and Planning*

Future implementation efforts are underway for several different programs, including:

- **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 25 MW) 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 Adopting a Host Community Benefit Program*,⁷³ issued on February 11, 2021. The utilities await further approval by the Commission of the Implementation Plans and tariff leaves.
- **Volumetric Net Crediting.** Central Hudson began offering Net Crediting (also known as Consolidated Billing) for monetary Value Stack customers in March 2021, providing an alternate payment and crediting methodology for CDG Hosts and CDG Satellites that eliminated the need for 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 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. The utilities are currently working with DPS Staff and stakeholders to develop an alternative Net Crediting program for these types of projects. Programming has been completed but continues to be tested and enhanced for January 2026.

⁷³ Case 20-E-0249, In the Matter of a Renewable Energy Facility Host Community Benefit Program, Order Adopting a Host Community Benefit Program (Issued February 11, 2021).

- **Statewide Solar for All (S-SFA).** S-SFA is a New York State utility bill assistance program for income-eligible households to take advantage of community solar. The program aims to make clean solar energy accessible to low-income households that reside within a Disadvantaged Community. It combines the Energy Affordability Program with community solar initiatives to deliver bill credits to eligible participants. The program's goal is to provide at least \$40 in annual savings to over 800,000 households across the state. It also supports the growth of community solar and energy storage projects, ensuring equitable access to renewable energy.
- **Renewable Energy Access and Community Help (REACH).** The REACH program focuses on providing electric bill credits to low-income households residing in Disadvantaged Communities, ensuring they benefit from renewable energy projects. This initiative aligns with New York's clean energy goals and supports vulnerable communities through credits funded by renewable energy revenues.

It is important to note that setting up, testing, and maintaining each program can be increasingly complex, especially when considering interactions with other programs. The Company continues to devote time and resources to support each of these programs from design, programming, and implementation to ongoing IT and administrative maintenance. It 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, Retail Choice and Community Choice Aggregators (CCAs).

4. RISKS AND MITIGATION

The primary continued risk to timely implementation of these programs is the comparative challenge of making the complex changes to billing that are often needed. New programs or program enhancements involve changes to the billing system. Most of New York's complex billing programs cannot be met with commercially available customer information systems (CISs) without custom programming, and each new change can interact with other recent changes or other complex billing rules to add complexity.

For example, just for a single residential service classification, a customer could have the option of 1) having on-site DER, 2) subscribing to a CDG or 3) being a satellite of an Remote Net Meter. For each type of DER participation that customer could be compensated via: 1) net metering, 2) Phase One NEM or 3) Value Stack (Phase One or Phase Two). That same customer could also participate in additional programs or be subject to other charges requiring any of the following complex billing rules: 1) they purchase their supply from an ESCO, 2) they opt for budget billing, or 3) they are subject to the CBC. The more than 50 permutations of complex billing rules possible by the scenarios described would only be further complicated, for example, if the customer participated in multiple Remote Crediting projects or had their own on-site system in addition to Remote Crediting participation.

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. Another consideration is that throughout the implementation process, 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 adoption rates before the automation process presents additional challenges. The Company mitigates the risk of delay by engaging additional employees to complete the work and communicating with stakeholders and regulators about the process to establish a complete understanding of the steps and timeline involved.

5. STAKEHOLDER ENGAGEMENT

The Company recognizes that stakeholder engagement is an important part of customer satisfaction, developing inclusive regulatory policy, and achieving desired policy outcomes. Since the last DSIP filing, the Company has hosted or participated in many stakeholder engagement sessions to continually provide information to customers and industry participants. Past and planned presentations, webinars, and workshops have centered on various utility program topics, such as net crediting, value stack, and remote crediting. Collaboration between the departments has been helpful. Billing works with DER, the Consumer Outreach Department, and New Business, which also seeks to reach out and educate customers on issues and understanding gaps.

The Joint Utilities participate in monthly meetings for the CDG Billing and Crediting Working Group. The Joint Utilities also participated in the stakeholder conference on CDG billing and crediting hosted by the Commission on February 27, 2023. As directed by the Commission, stakeholders proposed a negative revenue adjustment mechanism to be tied directly to the utilities' CDG crediting and billing performance. Department of Public Service Staff will prepare a proposal for performance tracking and identify next steps for the matter.

6. ADDITIONAL DETAIL

1) Describe the various DER-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, RNM, CDG, and VDER.

The Company offers the aforementioned VDER-related billing and compensation programs, which began with Net Energy Metering and Remote Net Metering, expanded to Community Distributed Generation in 2015. These programs have evolved, beginning in 2017, to implement a VDER tariff to transition from NEM to Value Stack Phases One and Two, and to introduce several new compensation programs since then that modify or combine existing program rules.

In 2021, Remote Crediting was introduced, offering an opportunity for existing Remote Net Metering projects compensated via the Value Stack, as well as for CDG projects, to convert to Remote Crediting. Remote Crediting is like CDG but: 1) limits the number of subscribers, 2) allows subscribers to also have onsite solar, and 3) provides subscribers with the ability to subscribe to multiple projects.

In 2022, the Customer Benefit Contribution Charge (CBC) was introduced pursuant to the *Order Establishing Net Metering Successor Tariff* (Net Metering Order)⁷⁴ issued July 16, 2020. for projects interconnecting on or after January 1, 2022. The CBC is a \$/kW charge on the bills of mass market customers with onsite DER and is assessed on the size of their DER system in kW DC. The CBC recovers the costs of certain public benefit programs.

⁷⁴ Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Order Establishing New Metering Tariff (issued July 16, 2020).

Finally, effective July 1, 2023, the Company offered an alternate version of Value Stack compensation for DERs participating in the wholesale market. DERs selling their energy and/or capacity directly to the NYISO may continue receiving the remaining components of Value Stack compensation without the energy and/or capacity components, to avoid duplicate compensation. These changes were filed by Central Hudson in order to conform with FERC Order 2222, as discussed above.

CDG full automation was achieved in January 2024, which has evolved and fully automated billing has been performed since that time.

Standby and Multiple Savings Rates were added in May 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.

Expanded use, and associated billing/compensation of DERs in the Company's service territory, are generally supported by either: 1) advanced metering infrastructure for onsite projects requiring net meters or meters capable of recording hourly consumption, and 2) billing system functionality to automatically calculate, bill and/or track applicable costs or credits associated with onsite billing/compensation programs or participation in remote or community crediting programs. Quite often, this billing system functionality requires custom billing system coding by a utility, as there are no commercially available CISs that contain the necessary programming to deliver all the unique requirements to implement the various customer billing/compensation programs directed by the Commission. Such design and development is then followed by unit testing and full system regression testing by users familiar with the complex billing program rules, which can, at times, lead to the identification of issues that require coding revisions, and a subsequent round of testing, as was the case with recent program automation for CDG and CBC.

For future planned program changes, such as the anticipated S-SFA and REACH program, adequate development and testing time are needed to correctly implement changes in a complex web of programs as discussed above.

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 (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.

As of the date of this DSIP filing, the Company does not have any interconnected customers who are eligible for WDS or WVS compensation. The Company will be utilizing existing resources and leveraging existing and proposed processes for Standby Service and Buyback Service to assist with the programming and implementation of WDS. The existing processes and programming for VDER will be leveraged to implement WVS.

The telemetry and cybersecurity process has been established and published to assist developers with the construction process. The telemetry requirements document is located on Central Hudson's website.

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.

As of the date of this DSIP filing, the Company has completed its CDG billing automation and files stipulation reports to that effect. Approximately 16,000 Central Hudson customers subscribe to CDG and are billed under a fully automated process. The Company continues to work with its development partners to resolve and identify any issues while working to improve and streamline the overall process.

5) For each type of DER billing and compensation, including CDG and wholesale market participation, describe the current information system constraints preventing full automation of DER billing and compensation.

Standby and Buyback rates filed in Case 15-E-0751, as well as other DER automation enhancements such as S-SFA and REACH, require access to the master data billing object in SAP for development purposes. Access to this programming element is exclusive and coordinated by priority, and full testing with other programs is needed during that period. This can result in a delay in full automation and the use of semi-automated solutions in the interim.

6) Describe how DER billing and compensation affects other programs such as budget billing, time-of-use rates, and consolidated billing for Energy Service Companies (ESCOs).

Billing and compensation for the various DER programs offered must also consider interaction with other complex billing rules from the perspective of program enrollment/de-enrollment, billing/crediting, tracking/reporting of data, and bill display. The introduction of each new DER program will require testing of multiple scenarios combining these complex programs to ensure the interaction of complex rules from each program yields the desired billing/compensation results. Furthermore, as the utility is often the entity responsible for reporting data to multiple third-party entities involved in these complex billing programs, the Company at times finds itself in a position of needing to provide additional stakeholder education to inform third-party entities on how other complex billing programs may affect the data they receive on a particular customer that may participate in multiple programs.

7) Describe the utility's means and methods – existing and planned – for monitoring and testing new or modified customer billing and compensation functions.

The Company's Billing Process Exception Management workflow in its SAP CIS allows for the identification and monitoring of billing exceptions for billing functions automated in the Company's billing system. New or modified billing and compensation functions require full unit testing and system regression testing, including testing multiple scenarios and interactions with other complex billing rules, as previously discussed.

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 Company participates in many stakeholder engagement sessions with customers and industry participants. The Company plans to continue to participate in such engagement sessions, including webinars, workshops, and working group sessions. In addition, the Company has a dedicated DER team that manages relationships with DER developers/operators and acts as the main point of contact at Central Hudson for these projects. Furthermore, the Company maintains a dedicated DER section on its website with detailed information and additional information for customers on programs available to them and the applicable program rules.

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.

a) CDG host to CH:

The host can reach out directly to CDGBilling@cenhud.com or by phone to present any concerns or inquiries. The objective is to provide a response within 24 hours. If additional time is required, the host will be notified.

b) Subscriber to CH:

Customers will reach out to the contact center (either by phone or email) or to the Distributed Generation (DG) email (dg@cenhud.com). When reaching out to the contact center directly (either email, phone, or through the chat), there is a ticket system for escalated calls, re-routing for bill corrections, or a specialty desk request in place to track interactions in the contact center directly. There is also the ability to schedule a callback if the customer does not want to wait on hold.

K. DER INTERCONNECTIONS

1. KEY TAKEAWAYS

Central Hudson continues to see significant interconnection activity on both the distribution and transmission systems. With the recent NYISO interconnection reform as required by FERC 2023, Central Hudson has seen a record number of projects as the Connecting Transmission Owner (CTO) compared to prior years, as part of the initial Transition Cluster Study process. Central Hudson prides itself on efforts

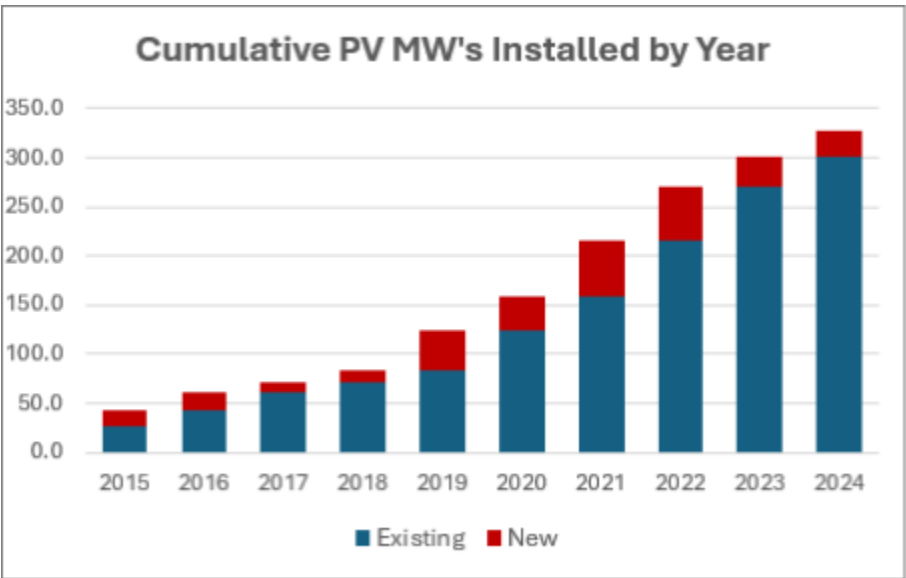
to meet all regulatory timelines, as well as provides flexibility to developers/applicants where possible, to support the integration of DER. Some examples of this include utilizing substation transformer 24-hour load cycles vs. nameplate, which allows for higher thermal ratings, providing low-cost solutions such as low-cost DTT vs. substation transformer upgrades due to N-1 conditions or volt-var and volt-watt smart inverter settings, proactively providing multiple options within studies such as system downsizing options where high infrastructure upgrade costs may be identified, etc.

Central Hudson has remained an active member of various working groups related to interconnections, such as the Interconnection Technical Working Group and Interconnection Policy Working Group. There have been numerous initiatives and achievements within these teams, as detailed in this section below. By year-end, the Company expects to have the interconnection process for utility projects (projects greater than 5 MW not under the NYISO) built into the Company’s Interconnection Online Application Portal (IOAP) to improve visibility for these projects and streamline the process for all stakeholders. With the Company’s move to CYME load flow software, Central Hudson has begun using this software to review DER interconnections and hopes to find ways to improve processes as a result of features within CYME that did not exist within the load flow software previously used. For future implementation, Central Hudson will seek to re-establish automation of preliminary screens within CYME by integrating CYME with the Company’s IOAP.

2. CONTEXT AND BACKGROUND

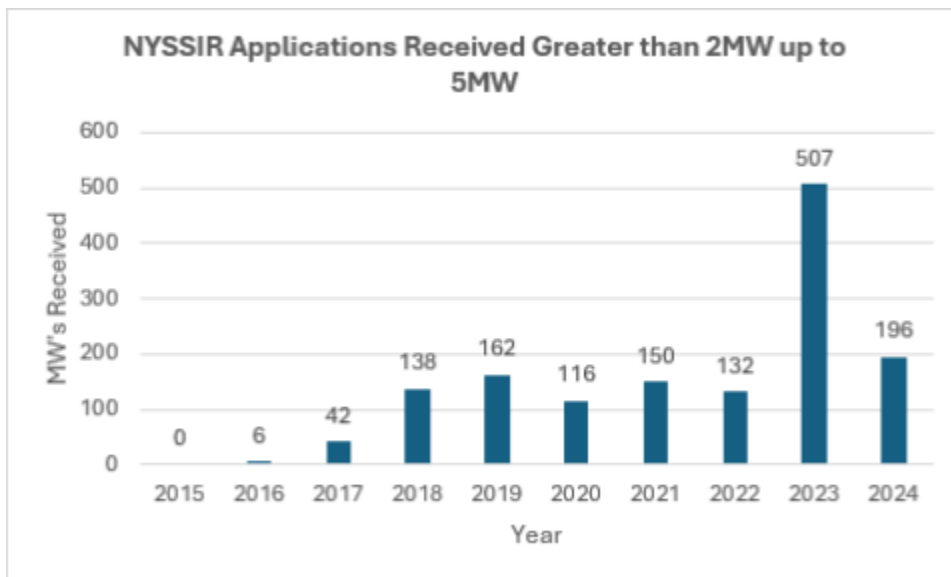
Since the 2023 DSIP filing, Central Hudson has continued to process distribution interconnection applications within the required timelines specified in the New York State Standardized Interconnection Requirements. Figure 39 below shows the cumulative growth in MW for solar photovoltaic installed from 2015–2024 through the NYSSIR. The majority of the Distributed Energy Resources applications within the service territory are solar photovoltaic ; however, Central Hudson is also experiencing an increase in Energy Storage System applications. In 2024, of the 32.21 MW installed, 81.7% were PV, 0.36% were ESS, 6.2% were Hybrid (PV + ESS) and 11.6% were synchronous generators.

Figure 55: NYSSIR PV MW Installed 2015–2024



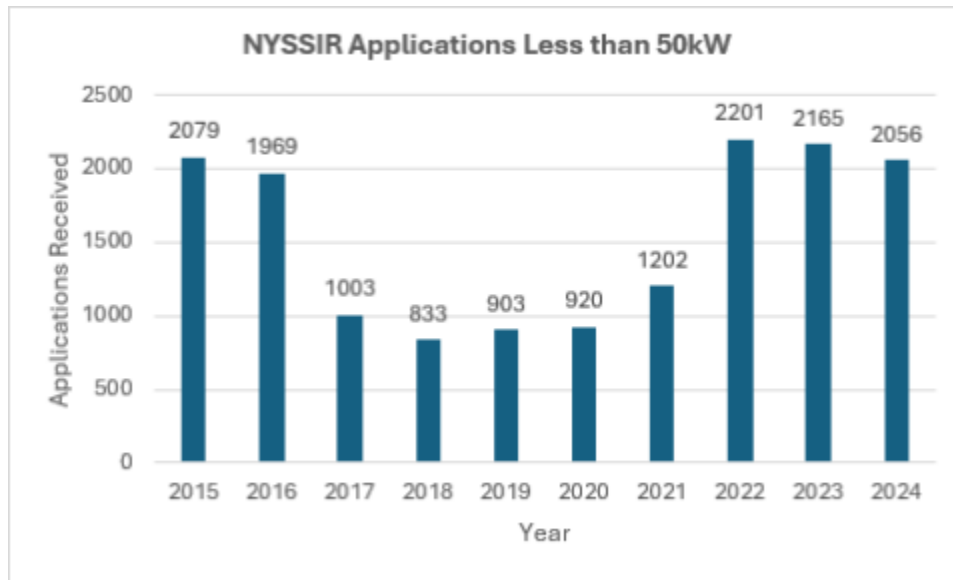
Since the 2023 DSIP, Central Hudson has continued to see a relatively high volume of large applications. Figure 40 below illustrates the total number of MWs of interconnection applications that Central Hudson has received under the NYSSIR for system sizes between 2MW and 5MW from 2015-2024. Although Central Hudson saw a substantial amount of MWs received in 2023 (507MW) compared to prior years, the majority of these did not move to completion. Of the 507 MW, 21 of the applications (105MW) withdrew prior to providing a completed application and ultimately receiving a queue position. Another 76 projects (356MW) also eventually withdrew.

Figure 56: NYSSIR Applications Received Greater Than 2 MW up to 5 MW



It is also worth noting that since 2022, Central Hudson has received greater than 2,000 interconnection applications per year. Some suspected drivers include residential customers applying for PV interconnections to gain energy independence due to energy supply cost volatility, as well as new residents to the Central Hudson territory who have purchased homes since 2021 and were eager to install solar panels. Figure 57 below illustrates the total number of interconnection applications under 50 kW that Central Hudson has received under the NYSSIR between 2015–2024.

Figure 57: NYSSIR Applications Less Than 50 kW



In addition to applications submitted through the NYSSIR, Central Hudson has recently seen a large increase in NYISO interconnection requests as part of the newly reformed interconnection process. Prior to 2024, Central Hudson received an average of nine applications per year. In 2024, the NYISO initiated a reform that significantly revamped the interconnection process, providing a reduced timeline, more transparency and improved queue management. This reform was in response to FERC Order 2023, and 2023a. This interconnection reform process was modified with input and feedback from both NY Transmission Owners (TOs), including Central Hudson, as well as stakeholders. The first NYISO Cluster Study process, identified as the Transition Cluster Study, had an Application Window that opened August 1, 2024, through November 15, 2024. Central Hudson received 28 applications as the Connecting Transmission Owner (CTO) as part of the application window. The second stage, the Cluster Engagement window ran from November 16, 2024, through February 18, 2025, and the Cluster Study Phase 1 Process commenced February 26, 2025. As some projects withdrew from the initial application stage/engagement window, Central Hudson currently has 21 projects as the Connecting Transmission Owner progressing within the Cluster Study Phase 1 anticipated to be completed in August 2025. Cluster Study Phase 2 is anticipated to be completed in the summer of 2026. Since the Transition Cluster study process was initiated, FERC ruled on this new process filed by the NYISO under Order 2023 and 2023a, accepting most of the NYISO's proposals though modifying some, namely the proposed study delay penalty proposal. Central Hudson will continue working with the NYISO to ensure all required steps are followed and completed within the required timeframes. In addition to applications, the NYISO process still includes a pre-application process. Table 41 below illustrates the number of pre-application requests received over the last ten years.

Table 41: NYISO Interconnection and Pre-Application Requests

Year	Pre-Application Requests
2009	0
2010	0
2011	0

2012	0
2013	0
2014	0
2015	0
2016	0
2017	8
2018	5
2019	9
2020	7
2021	1
2022	8
2023	1
2024	17

While the majority of interconnection activity has been under the NYSSIR and NYISO processes, Central Hudson has also seen an interest in applications greater than 5 MW that fall outside of the NYSSIR and NYISO, and within the Company's Utility Process. Table 42 lists the number of applications received since 2018.

Table 42: Utility Projects Interconnection Application Requests

Year	# of Applications Received
2018	1
2019	10
2020	3
2021	3
2022	1
2023	1
2024	3

While NYISO projects follow a separate process and have primarily proposed to interconnect to the buses, in the weaker portions of the transmission system, these substation- and transmission-level interconnections can limit the hosting capacity of DERs on feeders, even in locations where the hosting capacity of the feeders has not been exceeded. The Company has experienced high penetration levels in localized areas of the service territory. Central Hudson has continued to apply the Coordination of Inclusion Rules for Interconnection Queues ("Inclusion Rules"), to each of the three queues in areas with high DER penetration.

Since the 2023 DSIP update, Central Hudson has continued to maintain and improve the Interconnection Online Application Portal (IOAP), described further below in Section E. This portal was initially established to meet the requirements of Phase 1 Automating Application Management within the Public Service Commission's March 9, 2017 DSIP Order. The IOAP continues to successfully run and allows DER developers to submit interconnection applications electronically.

In addition to performing the day-to-day responsibilities associated with interconnections, Central Hudson also has an active role in collaborative working groups, including the ITWG and IPWG. Since the 2023 DSIP, these groups have met on a monthly basis, focusing on modifying interconnections requirements and processes based on industry concerns and benchmarking with other utilities outside of New York. These groups have also worked together to develop various joint guidelines and regulatory filings, and have allowed for modifications to existing interconnection requirements including:

- Providing bi-directional EV chargers with a waiver for UL 1741 SB certification; initially set to expire in the summer of 2023, the JU allowed for two extensions, with the current expiration on July 1, 2025.
- Collaborating with EPRI to provide smart inverter settings using EPRI's Common File Format (CFF), which have been posted publicly to both EPRI's website and Central Hudson's DG website.
- Providing updates to DER technical cost matrix on an annual basis as well as providing detailed clarity and visibility into the cost estimation methodologies and reconciliation techniques.
- Providing DER developers with information on preferred charge and discharge schedules for battery energy storage systems.
- Identifying amendments to Energy Storage System Application Requirements to provide information in a more coherent manner and thus improve speed of the interconnection process.
- Establishing the requirements based on working with Underwriters Laboratories (UL) to adopt the UL 1741 Certification Requirements Decision for Multimode systems.
- Proposing changes to Screens E (Simplified Penetration Test) and G (Supplemental Penetration Test) within the SIR to provide more clarity to developers on what upgrades may be required to accommodate reverse power flow.
- Defining a scope in which developers may be permitted to self-build interconnection equipment for DG projects.
- Discussing standby letter of credit (SLOC) as an option for higher cost interconnection upgrades in lieu of cash.
- Proposing redlines within the SIR to address Cost Share 2.0 payment timelines based on concerns raised by Industry.
- Discussing construction milestones as well as queue management.

Lastly, since the 2023 DSIP filing, Central Hudson has continued to maintain and improve hosting capacity map, as discussed in the Hosting Capacity section of this DSIP.

3. IMPLEMENTATION PLAN

1) Current Progress

Central Hudson continues to refine and improve the IOAP, using the software and updates provided by Clean Power Research. Since the 2023 DSIP, Central Hudson has implemented the following improvements to the portal: developed a solar compensation eligibility calculator, embedded Appendix K data fields into the Interconnection Application, created a DER Planned Outage Tracker form, added notes fields for both utility and applicant to provide additional feedback, set up a link to attachments to provide visibility internally to vital documents with files too large to email, streamlined the DER Customer Account Transfer process and implemented an update to alleviate Meter Set Request error message.

As the April 21, 2023, Commission *Order Modifying Standardized Interconnection Requirements* directed, Central Hudson updated the application portal to display inverters that have been certified and tested in accordance with the most recent revision of UL 1741, including supplement B (“UL 1741 SB”). Subsequently, Central Hudson implemented the necessary updates associated with the January 18, 2024, PSC Order Approving Interconnection Contract for State Entities.

While Central Hudson, along with the Joint Utilities, has already made significant progress in improving the interconnection process in collaboration with working groups such as the ITWG and IPWG, Central Hudson continues to work with these groups to address developer and stakeholder concerns. The most current and upcoming topics for discussion within these groups include:

- Flexible interconnections, including current pilot/demonstration projects;
- Standby letter of credit forms ;
- Collaborating with inverter manufacturers to adopt the CFF;
- Waiving UL 1741 SB for bi-directional EV chargers until July 1, 2025;
- Remaining cognizant of technical standard development activities and new DER architectures;
- Requiring certificate of compliance for UL 1741 CRD for Multimode by June 30, 2025;
- Making edits to the SIR where necessary to enable a greater volume of interconnected DERs;
- Establishing storage charge and discharge schedules, to help developers maximize economic value for BESS;
- Providing developers with the latest information on interconnection costs via presentations within the ITWG/IPWG and the cost matrix;
- Continued discussions on construction milestones and queue management; and
- Continued discussions on self-build policies and implementation.

Central Hudson currently works with DER developers/applicants in numerous ways to provide flexibility and enable a higher penetration of DERs. These include:

- Utilizing substation transformer ratings based on the 24-hour load cycle, in lieu of the transformer nameplate, which results in higher thermal ratings;
- Providing low-cost direct transfer trip solutions for contingency situations that occur on an infrequent basis, to prevent limitations on hosting capacity (i.e., N-1 for two transformer stations and looped transmission systems);
- Using smart inverter settings (volt-var and volt-watt) in lieu of traditional infrastructure upgrades;
- Enabling interconnection on a phased/nameplate limitation approach (if possible) for long-lead time upgrades;
- Assigning a dedicated project manager who works closely with developers to align DER construction timelines and Central Hudson upgrades;
- Providing a quick response time to all stakeholders—from general to complex technical inquiries—via dedicated DER phone line and email address;
- Being proactive in providing multiple options within impact studies, where applicable (i.e., full nameplate requirements along with downsize options if high infrastructure upgrade costs are identified at full nameplate); and
- Utilizing engineering judgement to streamline projects under preliminary or supplemental screens to avoid costly impact studies or infrastructure upgrades.

Since the 2023 DSIP, Central Hudson refreshed the Company's Interconnection Requirements December 2023. The document is publicly posted on the Company's Distributed Generation website for reference by developers and is also filed with FERC as part of the Form 715 filing. Central Hudson plans to continue to update these guidelines as needed.

Since the 2023 DSIP update, the Joint Utilities have continued to mandate the requirement for inverter-based interconnection applications submitted after January 1, 2023, to have smart inverter functionality by requiring UL-1741 Supplement B certification and specific smart inverter settings related to reactive power support (volt-var curve), voltage and frequency ride through capability, enter service criteria, and frequency droop. As previously mentioned, the Company has provided these settings within EPRI's Common File Format and has also incorporated these into the Central Hudson's Interconnection Requirements documentation. As smart inverter settings are dynamic and affect the process for studying DER systems as part of the **Coordinated Electric System Interconnection Review (CESIR)**, Central Hudson's move to CYME load flow software has helped improve the modeling capabilities of inverter-based resources with smart functionality.

Since the 2023 DSIP, Central Hudson has been evaluating and designing a low-cost monitoring device that provides a promising solution for 100 kW–499 kW DER systems both standalone and behind the meter. This R&D project leverages Central Hudson's existing Sensus communication network technology. Once the R&D is completed, Central Hudson would look to standardize this low-cost monitoring device for future DER installations in the 100 kW–499 kW range, to provide better visibility into how these systems operate (without impacting economics of DER projects), which is currently limited to-date. For systems greater than 5 MW that fall outside of the NYSSIR and NYISO processes, Central Hudson currently has a DER Project Manager to oversee these Utility Projects. The application process for these

projects can be found on the Company's DG website. While the Utility Process is not subject to NYSSIR requirements, Central Hudson is currently in the process of working to establish a new PowerClerk program to accept these applications through the IOAP for ease of submitting an application for developers but will also provide efficiencies and better tracking for Central Hudson. Central Hudson will begin mapping workflows and processes for the Utility Projects starting in the second half of 2025.

Lastly, since the 2023 DSIP, Central Hudson has yet to receive projects participating within the Wholesale Market Aggregation as enabled by FERC 2222. While the application and requirements fall under NYISO jurisdiction, Central Hudson has established an internal process for reviewing the eligibility of proposed aggregations, as well as ensuring the safety and reliability of the electric system due to aggregations. The Company also maintains a landing page specific to FERC 2222 available on the Company's Distributed Generation website. The website provides a high-level overview of wholesale market aggregation as well as details on transmission node IDs, telemetry requirements, and contact information for questions.

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.

Based on average of the prior 5 years (2020–2024), the following provides statistics on Central Hudson's processing timelines and applicant timelines as part of the processes tracked within the SIR Inventory filing, filed on the 15th of each month.

Table 43: DER Interconnection Utility Timeline Metrics

01/01/2020 - 12/31/2024								
Utility Timelines								
System Size	Application Review Duration (10 BDs)		Preliminary Screening Analysis Duration (15 BDs)		CESIR Study Duration (60-100 BDs)		Final Acceptance Review Duration (5 BDs) ¹	
≤50kW	Qty	%	Qty	%	Qty	%	Qty	%
Met deadline	8,498	100.0%	3	100.0%	1	100.0%	7,133	94.2%
Over deadline	0	0.0%	0	0.0%	0	0.0%	443	5.8%
Total Qty	8,498		3		1		7,576	
Average Days	6		14		60		4	
50kW < x ≤ 300kW	Qty	%	Qty	%	Qty	%	Qty	%
Met deadline	77	100.0%	76	100.0%	3	N/A	45	97.8%
Over deadline	0	0.0%	0	0.0%	0	N/A	1	2.2%
Total Qty	77		76		3		46	
Average Days	6		13		60		4	
300kW < x ≤ 5.0MW	Qty	%	Qty	%	Qty	%		%
Met deadline	255	100.0%	254	100.0%	114	100.0%	11	100.0%
Over deadline	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total Qty	255		254		114		11	
Average Days	5		12		62		3	
Total	Qty	%	Qty	%	Qty	%	Qty	%
Met deadline	8,830	100.0%	333	100.0%	118	100.0%	7,189	94.2%
Over deadline	0	0.0%	0	0.0%	0	0.0%	444	5.8%
Total Qty	8,830		333		118		7,633	
Average Days	6		13		61		4	

¹Meter Set – 10 Business Days; generally submitted the same day as Final Acceptance Review – 5 Business Days

As illustrated in the table above, Central Hudson meets all utility timelines as required by the NYSSIR, with a nuance to note for Final Acceptance Review for systems 50 kW or less. While the statistics for these suggest timelines are not met, this is due to the overlap of parallel timelines in the NYSSIR, as the net meter set request is generally submitted the same day as the Final Acceptance Review. Therefore, the net meter set is completed within the 10-Business-Day timeline, as permitted in the NYSSIR; however, this exceeds the 5-Business-Day Final Acceptance Review for systems 50 kW or less.

Table 44: DER Interconnection Applicant Timeline Metrics

01/01/2020 - 12/31/2024										
Applicant Timelines										
System Size	CESIR Payment Duration (10 BDs)		Commence CESIR Duration (30 BDs)		Partial 25% Payment Duration (90 BDs)		Full Payment Duration (90 or 120 BDs) ²		Project Construction Duration (365 Days) ³	
≤50kW	Qty	%	Qty	%	Qty	%	Qty	%	Qty	%
Met deadline	0	0.0%	0	0.0%	0	N/A	587	99.3%	7,575	99.8%
Over deadline	1	100.0%	1	100.0%	0	N/A	4	0.7%	16	0.2%
Total Qty	1		1		0		591		7,591	
Average Days	14		79				11		48	
50kW < x ≤ 300kW	Qty	%	Qty	%	Qty	%	Qty	%	Qty	%
Met deadline	0	0.0%	0	0.0%	3	75.0%	15	93.8%	36	78.3%
Over deadline	3	100.0%	3	100.0%	1	25.0%	1	6.3%	10	21.7%
Total Qty	3		3		4		16		46	
Average Days	14		64		65		44		234	
300kW < x ≤ 5.0MW	Qty	%	Qty	%	Qty	%	Qty	%	Qty	%
Met deadline	94	72.3%	49	40.8%	55	93.2%	34	82.9%	7	63.6%
Over deadline	36	27.7%	71	59.2%	4	6.8%	7	17.1%	4	36.4%
Total Qty	130		120		59		41		11	
Average Days	12		38		77		116		412	
Total	Qty	%	Qty	%	Qty	%	Qty	%	Qty	%
Met deadline	94	70.1%	49	39.5%	58	92.1%	636	98.1%	7,618	99.6%
Over deadline	40	29.9%	75	60.5%	5	7.9%	12	1.9%	30	0.4%
Total Qty	134		124		63		648		7,648	
Average Days	13		60		71		57		231	

²100% Payment - 90 Business Days; Balance 75% Payment - 120 Business Days

³Less than or equal to 50 kW Projects Constructed prior to application submission - 585 Final interconnection requests submitted within 1 week of Application approval, 1,252 submitted within 2 weeks, and 2,040 within 3 weeks

As illustrated in the table above, 70% of projects made their CESIR payment on time, and 40% of projects submitted a complete design package to commence the CESIR within the SIR timeline. Payments are generally made on or near the deadline date; therefore, payments are not posted by the due date. Regarding construction timelines, on average, systems less than or equal to 50 kW take 48 days to construct, between 50 kW and 300 kW an average of 234 days to construct and for 300 kW to 5 MW an average of 412 days to construct.

Finally, since the 2023 DSIP, Central Hudson's DER Group responsible for project management/construction oversight for both SIR and Utility projects, along with billing (CDG and remote crediting), were transferred to the Electric Planning & Interconnections team. This reorganization has consolidated DER efforts into a single group and created synergies in the administrative and billing functions across all three interconnection processes.

2) Future Implementation and Planning

Future work regarding interconnections will require integration with distribution planning functions as well as further integration with utility systems. This level of integration, however, requires the completion of other ongoing initiatives and feedback from stakeholders. This includes integration of the Company's Interconnection Online Application Portal with CYME load flow software to automate preliminary screens under the SIR. Additionally, Hosting capacity as indicated in Section III.B, as well as stakeholder prioritization of DER concerns, will drive future requirements regarding interconnections.

As the JU continues to interconnect DER across the state, available hosting capacity may diminish, and future interconnections may require more costly electric system upgrades. While Cost Share 2.0 was established to reduce the burden of high interconnection costs borne by one developer, flexible interconnections have also been raised by developers as a potential solution. While each utility and developer may define flexible interconnections differently, on the surface, the concept of flexible interconnections allows the utility to curtail the power output of an interconnection when grid constraints or violations are identified, i.e., curtail DER by 500 kW when a substation transformer's reverse power flow thermal limit is approaching. Enabling a flexible interconnection with curtailment capability may eliminate the costly upgrade of the substation transformer and still allow the DG to interconnect; however, its complexity requires a significant change to the way DERs are currently handled and studied as part of the NYSSIR interconnection process today, as well as requires an economic determination by the developer.

In addition, in order to offer Flexible Interconnections across the service territory, a Distribution Energy Resource Management System (DERMS) will be required. Central Hudson is commissioning an Advanced Distribution Management System (ADMS) and included in the roadmap is the anticipated commencement of the DERMS initiative starting in 2027. Understanding that implementing a DERMS is needed in the future, in 2021 Central Hudson joined an R&D pilot project in partnership with EPRI, Smarter Grid Solutions (SGS), GE, and Nexamp to evaluate corrective vs. predictive DERMS as well as demonstrate the DERMS capabilities via a field demo. EPRI oversaw the project and received funding from NYSERDA via PON 4128. GE demonstrated a predictive DERMS within the EPRI test lab environment, and SGS demonstrated the corrective DERMS through a field demo between Central Hudson and the PV site owner, Nexamp. Since the 2023 DSIP, this project completed the field demo testing in November 2024, and final reporting was completed in December 2024. The results and lessons learned from this R&D project will help inform Central Hudson of the steps required to implement a DERMS as well as consider flexible interconnections as a solution in the future.

In addition to discussing flexible interconnection as part of the ITWG, the discussion of energy storage will continue to be a topic. The JU and ITWG will continue to dive into the predominant use cases of energy storage, balancing the complexity that comes along with studying each individual energy storage system under their own operational schedule vs. identifying specified time periods for storage assets. The goal of these discussions is to enable higher penetrations of energy storage onto the electric system, while also ensuring utilities can successfully manage and track these systems.

The JU will continue efforts and discussions related to the use of smart inverters on the distribution system, including identifying any potential smart inverter setting adjustments that may arise as the JU become more familiar with how these settings affect the electric grid. As previously indicated, the JU are working with EPRI and stakeholders to implement the adoption of EPRI's CFF for sharing smart inverter

settings. The JU believe that both the utilities and developers will benefit if manufacturers were to adopt the CFF, as it would lead to quicker verification of inverter settings and reduced man-hours per project, which in turn shortens overall interconnection timelines. Following up from these conversations, the JU plans to implement a requirement for CFF by January 1, 2026.

Central Hudson will internally require additional time to work through the requirements related to integration of DER systems with DMS/DERMS. Additional research and considerations are also required with regard to cybersecurity concerns.

Similar to current implementation efforts, 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 and DMS/DERMS functionality are anticipated to provide additional flexibility and higher integration of DERs.

Central Hudson's implementation of the CYME software will provide efficiencies in analyzing DER interconnections, including smart inverters, applicable time-series analysis, as well as hosting capacity analysis, which all support the integration of DER. As part of enabling flexible interconnection in the future, there is significant work involved in both the policy and technical side. This includes investments in a DERMS, as well as changes to the NYSSIR in contractual obligations and study requirements.

While some of the initial conversations on flexible interconnections have begun as part of the ITWG and IPWG, this will require continued efforts over the next few years. Central Hudson's DERMS initiative is anticipated to commence in 2027. Timing related to the integration of CYME and IOAP includes scoping anticipated in the second half of 2025 with implementation in 2026.

The Coordinated Grid Planning Process (CGPP) and DSIP are filings with overlapping but distinct scopes. The CGPP will detail the evolution of distribution planning processes needed to meet Climate Leadership and Community Protection Act (CLCPA) goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes the implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs.

Planned capital investments, including technology platform investments and how they will be leveraged, will be included in the DSIP (e.g., AMI, automation, ADMS, etc.) and the results of executing the processes will be used to inform the CGPP. Additionally, an understanding of the existing DER, particularly those sites already interconnected or considered firm, will be an important input into the analysis as part of the CGPP.

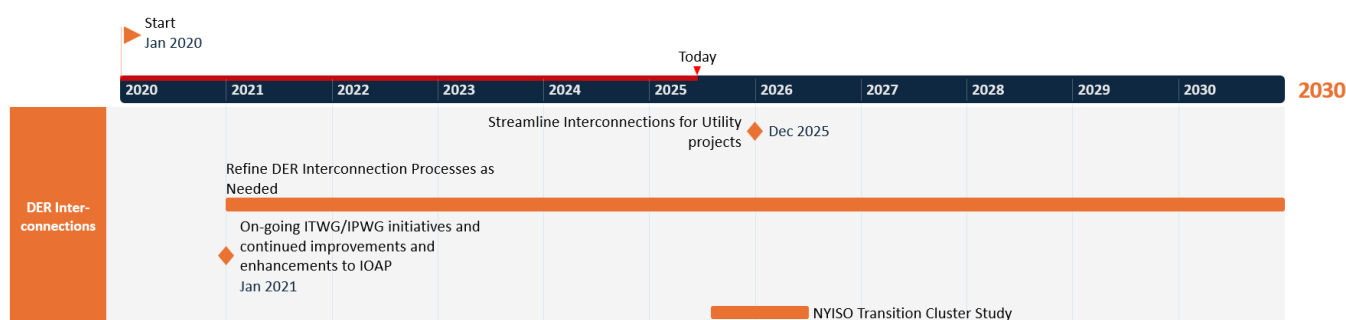
The CGPP is aimed at developing a "CLCPA-focused planning process," including "the State's bulk transmission, local transmission, and distribution planning processes." The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution (LT&D) and bulk system studies with NYSERDA's renewable generation and storage procurements; and improve forecasting of renewable generation development for specific

locations on the LT&D and bulk transmission grid. As part of the CGPP stages, one of the key inputs to the CGPP is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council (EPPAC). While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP, thus, may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects, once approved, will be incorporated and used to inform the normal DSIP and interconnection processes. This includes ensuring any upgrades identified as part of the CGPP that DER interconnections may benefit from are included within appropriate interconnection analyses; as well as, vice versa, ensuring any DER interconnection upgrades identified within systems are appropriately incorporated as part of CGPP analysis. Additionally, DER queue information is taken into consideration as part of CGPP efforts. As of this DSIP writing, the CGPP is currently in Stage 3 (Local Assessment) of the 6-Stage process.

3) Integrated Implementation Timeline

Figure 58 provides a high-level perspective of the DER interconnection specific. However, there are several other initiatives such as integrating the interconnection portal with CYME load flow software, implementation of hosting capacity maps, and data sharing that overlap substantially with DER interconnections. Figure 11 (Section II) provides a comprehensive overview.

Figure 58: DER Interconnections Timeline



4. RISKS AND MITIGATION

Application volume for interconnections continues to vary significantly depending on regulatory changes, new initiatives, or customer demand. Drivers for volume fluctuations include NYISERDA incentives, policy changes, economics, and technology. As anticipating the volume at any given point is challenging, there are potential risks in maintaining the appropriate level of resources to be able to handle a rush of applications. Additionally, as previously mentioned, Central Hudson has seen continued volume in smaller applications, less than 50 kW. These applications increased in complexity with the UL-1741 SB requirements after January 1, 2023. In addition, the rise in interest in battery storage integration and hybrid (ESS + PV) systems continues to pose new challenges for the Company, in both interconnection review and future planning. As the number of smart inverters and energy storage projects increase, the complexity of the CESIR study process will also increase. The JU may need to also develop new procedures to verify ESS settings, control schemes, and ensure that these are appropriately documented.

Central Hudson's move to CYME load flow is anticipated to support the complexity of studying these systems. The JU will also continue to stay in touch with each other, DPS, industry, and other stakeholders to proactively identify and address issues.

Over the years, the Company has managed the fluctuation in applications by maintaining flexibility in shifting internal resources within the Company, as well as externally, to be able to support the interconnection processes. However, a rise in larger applications, as well as NYISO projects, will require greater participation with additional engineering groups within the Company. This creates a challenging work planning scenario. Based on CLCPA goals, it is anticipated that the Company will continue to experience an increase in the level of proposed and completed interconnections to the system on both the distribution and transmission levels.

In addition to the incremental work associated with the actual interconnections, the Company continues to invest resources in associated processes and systems. This type of work includes the development and enhancement of hosting capacity maps and continued alterations to the Company's IOAP to stay in sync with NYSSIR updates and reporting requirements. These factors are increasing the resource requirements required to process, review, and study these interconnections.

With the introduction of new technologies and equipment, such as EVs and V2G and battery storage paired with microgrid interconnect devices, there is risk and uncertainty in trusting the power control systems and operation of these devices, ensuring they do not interfere with required settings or have an unintended operation that could impact the safety or reliability of the electric grid. Central Hudson, along with the JU, will work to mitigate these risks by identifying opportunities for process improvements, working with NYSERDA and other utilities across the US, as well as industry organization such as UL and EPRI to assess new technologies and verify operational concepts. Additionally, the groups will work to push for standardization and certification of these new technologies that enable higher penetration with reduced risk.

5. STAKEHOLDER INTERFACE

Stakeholder interface and feedback have continued to be a significant focus for interconnections. The ITWG meets on a monthly basis to provide stakeholders with the ability to discuss topics of concern regarding interconnections, specifically relating to technical aspects. The IPWG group has also continued to meet on a monthly basis and provides DER developers the ability to voice administrative or policy-related issues. ITWG and IPWG meetings are open to the public and consist of representatives from each of the NY JU, DPS Staff, DPS consultants, NYSERDA, project developer/industry representation, as well as trade groups, associations, and equipment manufacturers, as necessary.

While these groups enable discussions and changes related to updating regulatory documents like the NYSSIR, they also facilitate mutual agreement and standardization of technical requirements. These forums provide industry members with the ability to raise and discuss any technical or policy issues they are facing, pertinent to DER interconnection. The meetings also provide DPS Staff with the ability to identify topics of interest and areas of prioritization in the near and long term. In addition, the Joint Utilities have held numerous Hosting Capacity stakeholder engagement meetings. These meetings have led to the progression of the hosting capacity maps discussed in Hosting Capacity. Central Hudson will remain active within the ITWG and IPWG. Topics of interest, which will be discussed on upcoming working group agendas, are included above.

The JU leads for the ITWG and IPWG 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 determine ways to address these issues. The JU members meet on a weekly basis to discuss relevant topics and deliverables as part of the upcoming monthly ITWG and IPWG meetings, as well as to inform the JU lead as part of DPS Staff and Industry Liaison call.

Relevant materials are posted online prior to ITWG/IPWG meetings and are available for download. The JU will 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 DER, the JU will seek to continue to receive information from industry regarding specific pain points and justification for new requests.

After new practices or process updates are implemented as part of ITWG and IPWG discussions, these topics are typically revisited shortly after implementation to identify the success of the changes or the need to continue to refine solutions to meet the needs of all participants.

As part of NYISO's reformed interconnection process, stakeholders, including TOs, had input into the new structure. This modified process, which is currently undergoing the Transition Cluster Study period, was updated to provide a more streamlined process, reducing overall study timelines, providing more visibility upfront, and studying impacts from all systems in one process (i.e., elimination of small versus large generator procedures).

Central Hudson hosts an annual Solar+ Summit, which provides DER developers and industry professionals with information on the technical and procedural aspects of interconnecting with the utility, industry updates, available programs, and incentives. The event also provides networking opportunities with industry professionals. At the conclusion of each Solar+ Summit, a survey is provided for feedback from attendees and is utilized for future planning purposes, including specific topics of interest that professionals would like to see and hear about.

Central Hudson typically holds a DSIP webinar summarizing the content included within each of the topical sections of the DSIP, along with major initiatives or implementations. This session provides stakeholders with an opportunity to attend, listen, and ask questions. This webinar is held shortly after the DSIP filing, and additionally, the Company provides ad hoc DSIP engagement with interested stakeholders via email or meeting touchpoints over the course of the year about DSIP-related topics. The JU also holds a DSIP enablement webinar biannually, and quarterly, provides newsletters to stakeholders. The JU also has a website, which is DSIP-focused, and includes various references and resources for stakeholders, and is updated on a rolling basis.

Central Hudson has direct email and phone contacts for DER interconnection questions, including a DG Ombudsperson that stakeholders can directly reach out in order to resolve concerns. The following are emails included on the Company's DG website for inquiries related to DERs: dg@cenhud.com, pvmetering@cenhud.com, dgombudsman@cenhud.com, wholesaleaggregations@cenhud.com.

6. ADDITIONAL DETAIL

1) A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.

Central Hudson's Interconnection Online Application Portal (IOAP) can be found by accessing the following direct link: <https://cenhuddg.powerclerk.com/MvcAccount/Login>, or by visiting Central Hudson's Distributed Generation page at <https://www.cenhud.com/dg>.

Central Hudson's PowerClerk software, created by Clean Power Research provides a streamlined, user-friendly experience. Based on the interconnection portal gaps identified in the Initial DSIP, the new IOAP, using PowerClerk, addressed these gaps and provides better features for the application process, and enables the applicant to have more visibility into the process. New updates to the IOAP since the 2023 DSIP include, but are not limited to:

- Developed a formula on the Utility application review form to calculate solar project compensation based on its technology, NEM Type, Load Type, and kW
- Incorporated Appendix K data fields into the Interconnection Application form, rather than uploading a PDF attachment
- Developed and implemented the DER Planned Outage Tracker form
- Added "notes to applicant" field in external forms to provide further clarification to Applicants (preliminary screens, supplemental screens, and CESIR results)
- Updated PV System form element to only include SB inverters, to provide clarity to Applicants if their proposed inverter is compliant with current standards
- Added attachment field for Inverter Setting screenshots, and a link to Central Hudson's current required settings
- Added new State Agencies interconnection contract to the portal (APPENDIX A-2)
- Made updates to provide visibility internally to vital documents when a project enters construction
 - Created new form with System Design, Site Plan, Construction Worksheet, and CESIR Results; form accessible internally without the need to log into PowerClerk
- Revamped the DER Customer Account Transfer process
 - Leveraged existing API to import new customer data, and worked with programming to update automated email notifications to include vital information (meter number & premise)
- Implemented an update to improve the Meter Set Request
- Added the ability for the Applicant to provide feedback/comments to the utility

2) 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: (1) DER type, size, and location (2) DER developer (3) DER owner-operator (4) DER operator (5) Connected substation, circuit, phase, and tap (6) DER's remote monitoring, measurement, and control capabilities (7) DER's primary and secondary (where applicable) purposes (8) DER's current interconnection status (operational, construction in progress, construction scheduled, or interconnection requested), and its actual/planned in-service date.

Central Hudson's IOAP provides DER developers with the ability to submit applications anytime, at their convenience. The IOAP itself provides the appropriate safeguards to ensure that only developers who are given authority to act on a customer's behalf can view a particular customer's information. The PowerClerk software also uses secure login with appropriate encryption to ensure the privacy of customer data. Employees within the Electric Planning and Interconnections group actively monitor applications as they come in daily and provide updates to the IOAP as part of the normal NYSSIR process, to ensure the IOAP is maintained with up-to-date information. The following information is available within the IOAP:

- DER type, size, and location;
- Net-metering type proposed by applicant and associated compensation eligibility;
- DER developer, agent, or contractor;
- The connected substation and circuit;
- Current interconnection status

The bulleted information above is also posted monthly on the New York State Department of Public Service website under Matter Number 13-00205 and is known as the Monthly SIR Inventory Report. This informational report redacts customer-confidential information and can be downloaded for public use. This New York State Department of Public Service website also includes a link to the NYISO Planning Services & Requests website, which contains links to interconnection documents and the interconnection queue; the NYISO's interconnection queue links back to the New York State Department of Public Service NYSSIR inventory website.

Central Hudson does not track instances where the DER owner and DER operator may be different entities. Third-party lease agreements are between the DER developer and utility customer and do not impact the interconnection process, particularly when the utility customer provides the DER developer with authority to act on their behalf. The IOAP also does not provide developers or the general public with information on the primary and secondary purposes of DER system, as the primary means for interconnection for the majority of applications received under the NYSSIR are to offset load and receive compensation per the Value of Distributed Energy Resources. However, Central Hudson's IOAP does track when the use of more than one generator is provided, such as a battery storage system installed for backup, as well as the type of net-metering system, including Community DG or remote crediting.

Central Hudson's Solar PV Hosting Capacity Map and Energy Storage Hosting Capacity Map are public resources available to developers or stakeholders for use in determining a distribution circuit's potential hosting capacity within Central Hudson's territory. In addition to hosting capacity, the map also provides pop-up information to indicate what substation, circuit, and operating voltage currently exist at each feeder location. The following information is also available within the pop-up: interconnected and in-queue DG information for the feeder and substation, substation transformer peak load information, and 3V0 upgrade status.

Monitoring and control capabilities for each individual DER system are not provided as public information. However, current monitoring and control requirements can be found on the NYS Public Service Commission's Website under the Interconnection Technical Working Group. As of September 2017, these conditions require DER systems with nameplate ratings of 500 kW and above to have monitoring and control capabilities, which can be satisfied by installing a Point of Common Coupling (PCC) Electronic Recloser at the DER site. For systems smaller than this, monitoring and basic control may be required depending on system conditions and technical evaluations. The NYISO has additional requirements for resources participating in NYISO markets. Details of these requirements and processes may be found in the NYISO's Transmission Expansion and Interconnection Manual, as well as NYISO Open Access Transmission Tariff Attachments X, S, and Z.

3) The utility's means and methods for tracking and managing its DER interconnection application process to ensure achievement of the performance timelines established in New York State's Standardized Interconnection Requirements.

With Central Hudson's IOAP software, Central Hudson has mapped out the entire interconnection process, from the initial application submittal to final interconnection and ultimately reconciliation. Through the use of various workflows and forms, the IOAP provides timestamps and application statuses to ensure applications are tracked and managed in a timely manner and as required by the NYSSIR. The utility login page of the IOAP provides a layout and breakdown of all applications statuses and type, such as application reviews, pre-applications, and CESIR study that allow Central Hudson's employees to easily track the approaching deadlines for each of these projects. The IOAP is also set up to provide internal and external email reminders for upcoming due dates, based on the timelines listed in the NYSSIR. Employees within the Electric Planning and Interconnections group actively monitor applications as they come in on a daily basis and provide updates to the IOAP as part of the normal NYSSIR process to ensure the IOAP is maintained with up-to-date information.

To ensure each member within the group, including new employees, has an understanding of NYSSIR timelines and importance of consistently meeting them, Central Hudson has developed detailed documentation on the process flow, including current automations within the IOAP, as well as a guideline on reviewing applications under the NYSSIR for training purposes. As the NYSSIR is updated based on ITWG/IPWG collaborations, these revisions are reviewed thoroughly and the IOAP is updated accordingly.

4) 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.

Central Hudson's IOAP allows applicants and other appropriate stakeholders to create an IOAP account in order to log in and view the status of their application in real-time. Automated emails are also sent to applicants to inform them of when the application changes statuses, for example, when it moves from application under review to preliminary screening analysis in progress. When applications are deemed incomplete, details are provided within the IOAP to let the applicant know which documents are deficient as well as the reasoning behind this. The IOAP status also clarifies if the next steps are the responsibility of the developer or the utility.

In addition to the IOAP, Central Hudson also maintains a centralized email and phone number for applicants or DER developers to contact with questions or concerns. This contact information can be found on the IOAP landing page or by visiting Central Hudson's Distributed Generation website.

The NYISO Interconnection Queue indicates the status of projects that applied for interconnection through the NYISO Interconnection Process and the NYISO also maintains an interconnection portal in which applicants/DER developers as well as NY TOs can log in and access information.

5) The utility's processes, resources, and standards for constructing approved DER interconnections.

Central Hudson follows the procedures and requirements listed within the NYSSIR. Through the use of the IOAP, the customer has the option to submit a pre-application or application as the initial step to move forward with a DER interconnection. For the application review, Central Hudson currently has two employees and one contractor available to review applications for completeness and manage the interconnection administration process, including application questions and calls. For questions regarding billing and/or net-metering eligibility, the Company has one employee designated as the primary point of contact. Central Hudson also has one employee designated to manage and maintain the IOAP.

For systems greater than 50 kW, which are subject to technical screening, Central Hudson currently has four employees available who are able to perform these technical screens. For applications that require a CESIR, the Company currently contracts these studies out to two consultant resources; however, assistance and additional review are provided by employees within Central Hudson's Electric Planning & Interconnections Group and System Protection Group, and input on cost estimates is provided by the Company's Estimating Group and Substation Engineering Group.

In addition to the interconnection requirements outlined within the NYSSIR, Central Hudson utilizes two additional documents for interconnection requirements: the Interconnection Guidelines, which were last updated in December 2023, and Central Hudson's Requirements for Electric Installations. Both of these documents are publicly available on the Company's Distributed Generation website. The Interconnection Guidelines include information regarding the technical requirements DER systems must meet before receiving approval for interconnection, as well as information on the interconnection process. As a part of ITWG discussions and outcomes, some interconnection requirements have also been standardized between the Joint Utilities of New York. This includes requirements for Unintentional Islanding and

Monitoring and Control, a standardized template for completing preliminary screening, and CESIR studies. There is also JU reference material related to storage metering configurations and schedules, along with CESIR cost drivers and typical construction upgrade estimates. These documents can be found on the NYS DPS's ITWG website.

For projects interconnecting through the NYISO, the NYISO's Transmission Expansion and Interconnection Manual provides details on the NYISO's processes. NYISO Open Access Transmission Tariff (OATT) Attachments P and HH are also helpful in understanding the NYISO processes. These documents contain NYISO-specific requirements that are in addition to Central Hudson requirements.

For projects undergoing the Utility Process, the application process and requirements for these projects can be found on Central Hudson's DG website.

6) The utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels

For systems less than 50 kW, where the typical upgrade is limited to a service transformer upgrade, the applicant can pay for the transformer upgrade and obtain information on its construction status via the IOAP or by contacting the centralized DG phone and e-mail. For applications that do not require upgrades to interconnect or new service, the applicants are automatically approved to construct their DER system once the application is deemed complete, and they only need to contact the utility through the IOAP again to request a meter change and submit final approval documentation.

For applications greater than 50 kW that require new service or utility upgrades, these customers are provided with the contact information for a Central Hudson Project Manager. The Project Manager remains the primary point of contact for questions regarding construction and next steps, including estimated construction timelines. The Project Manager remains the liaison between the DER developer and all appropriate groups within the Company who may have a role in the construction process.

Once a project provides utility system upgrade payments (both partial and full), an automated email is sent from the IOAP to the Project Manager to inform them of this status change and to initiate appropriate next steps within the process. All real-time and current statuses of the application can also be found within the IOAP. On a monthly basis, the Electric Planning & Interconnections Group provides a status report for systems greater than 50 kW. As DER system construction is nearing completion, the Project Manager will inform the appropriate groups within Central Hudson in order to coordinate a timely completion on any remaining Central Hudson system upgrades.

For utility projects, these projects are assigned a Project Manager who is responsible for tracking and managing construction from the initial application through to final interconnection.

For projects interconnecting through the NYISO, the NYISO maintains an Interconnection Portal and Interconnection Queue on their website that provides information on each proposed project.

7) Describe how and when the utility will deliver and maintain its DER interconnection information to the IEDR?

Central Hudson is currently sending the following data related to DER interconnections to the IEDR on a monthly basis:

- Installed DER
 - DER Project ID
 - DER Type
 - DER Nameplate Rating
 - DER Developer Name
 - DER Interconnection Location
 - Project City and Zip Code
 - Substation and Feeder
 - DER Interconnection cost
 - DER Operating Company/Name
- Pending DER
 - DER Project ID
 - DER Type
 - DER Nameplate Rating
 - DER Developer Name
 - DER Interconnection Location
 - Project City and Zip Code
 - Substation and Feeder
 - DER Interconnection cost
 - DER Operating Company/Name
 - Application Start and End Dates and Calculated Durations
 - Application Approved Date
 - Construction Payment Dates

Central Hudson coordinates any changes to IDER fields with the IEDR implementation consultants, as needed.

L. ADVANCED METERING INFRASTRUCTURE

1. KEY TAKEAWAYS

Central Hudson has investigated the benefits and costs of implementing Advanced Metering Infrastructure (AMI), in accordance with the *Order Establishing the Benefit Cost Analysis Framework*.⁷⁵ The Company's recently completed AMI assessment is included in this DSIP as Appendix B, in which AMI deployment was evaluated through a benefit-cost analysis (BCA) framework considering the societal, utility, and customer perspectives.

Central Hudson initially assessed the cost effectiveness of deploying AMI in 2016, which at that time showed that AMI was cost ineffective. Following the Company's recent transition from bi-monthly meter reading to monthly reading, an upgrade of the Company's CIS, and consideration of other technological advancements, the Company reassessed the cost effectiveness of AMI. This was followed by a formal RFP to collect updated cost assumptions from vendors as well as a detailed internal review of cost and avoided cost assumptions. The Company developed the updated BCA for widespread AMI deployment, supported by these updated assumptions. The Company has also included a partial list of the operations and information quality benefits which can be made available to customers with an AMI-based system.

AMI metering can significantly enhance the quality of service available to Central Hudson's customers by supporting accurate, timely billing and real-time insights into their energy use. With AMI, greater usage detail is available which could provide customers with greater understanding of their consumption, increase their ability to conserve energy, and improve satisfaction. This technology also enables faster outage detection and access to cost savings programs like time-of-use rates and demand response. AMI empowers customers to make informed energy decisions while improving reliability, transparency and convenience.

Central Hudson will be developing an AMI implementation plan, the results of which will be used to further refine the AMI BCA presented in Appendix B.

2. CONTEXT AND BACKGROUND

Advanced Metering Infrastructure (AMI) provides grid-edge measurement, data acquisition, and control capabilities which are beneficial to several important functions in a future distribution system. Granular time-series data from smart meters and other intelligent devices at customers' premises enables advanced analyses, operational improvements, and customer engagement strategies which benefit both 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.

In addition to improving the customer experience, AMI data can provide critical tools and insights that improve the integration of electric vehicles, building electrification, and DERs. With the increase of DERs including future electrification impacts, increased granularity of data will become more critical for planning purposes. AMI data analytics can be used to detect the adoption of EVs and building

⁷⁵ CASE 14-M-0101 - Order Establishing the Benefit Cost Analysis Framework, Issued and Effective January 21, 2016; Order Adopting Distributed System Implementation Plan Guidance, Issued and Effective April 20, 2016.

electrification and enable more precise data for distribution planning on the impact of EVs on pole top/pad mount transformer sizing. It allows customers, or parties customers have authorized, to access interval data to analyze usage and provide relevant customer specific options and recommendations.

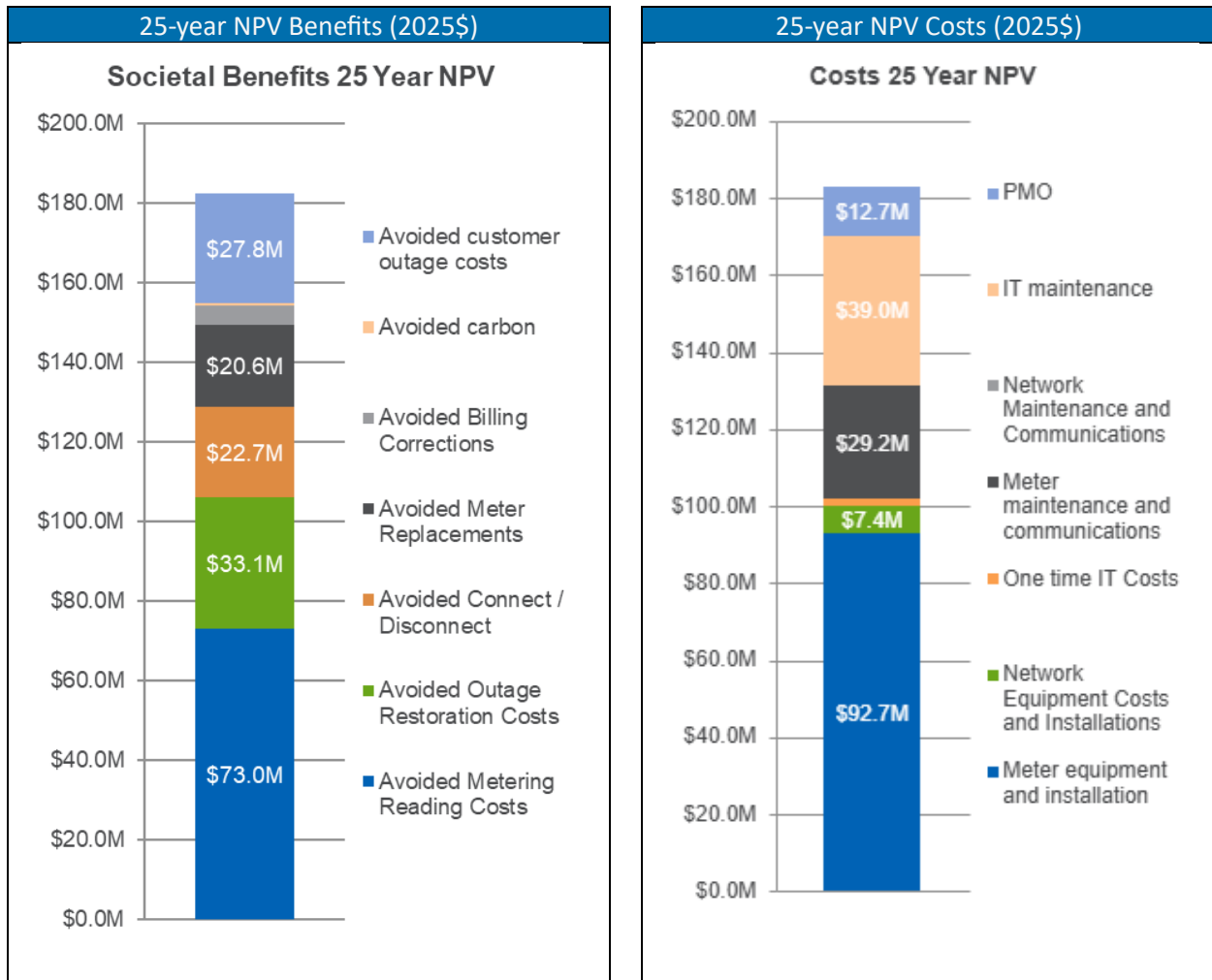
Pursuant to Commission requirements, Central Hudson’s meter reading frequency has recently changed from a mainly bi-monthly to monthly cadence, in recognition that this enhances customer value. In addition, the cost of AMI meters and deployment have changed as the industry has gained more experience with meter deployments. Recognizing the changes since the 2016 BCA was completed, the Company performed a preliminary BCA screen in January 2024 which indicated that cost-effectiveness of AMI had improved. Central Hudson followed this with a formal RFP to collect updated cost assumptions from vendors as well as a detailed internal review of cost and avoided cost assumptions. Further, a thorough literature review of recent AMI business cases, both in New York and neighboring states, was performed to inform updates to the benefit and cost categories. Central Hudson has developed a new BCA for widespread AMI deployment, supported by these updated cost assumptions. The updated BCA is summarized here, in this topical section of the DSIP.

Table 45 summarizes the net benefits and the benefit cost ratio for the operational benefit cost analysis. As demonstrated by these summaries, full AMI deployment would be cost-effective for Central Hudson customers from the societal perspective. The societal cost test shows a benefit cost ratio of 1.00. Figure 59 shows the detailed breakdown of cost and benefit categories for the societal cost test for the operational benefit cost analysis. The right panel shows the breakdown of costs. The panel on the left shows the breakdown of the four operational benefit categories. Appendix B provides additional details about the cost and benefit categories, the data sources, assumptions, and results.

Table 45: Operational AMI Benefit and Cost Summary

Benefit Cost Analysis (20-year NPV, 2025 \$000)	Societal Test	Utility Test	Customer Impact Test
Benefits	\$182,560.7	\$129,883.9	\$137,636.2
Costs	\$182,847.1	\$169,448.5	\$169,448.5
Net Benefits	(\$286.4)	(\$39,564.6)	(\$31,812.3)
B/C Ratio	1.00	0.77	0.81

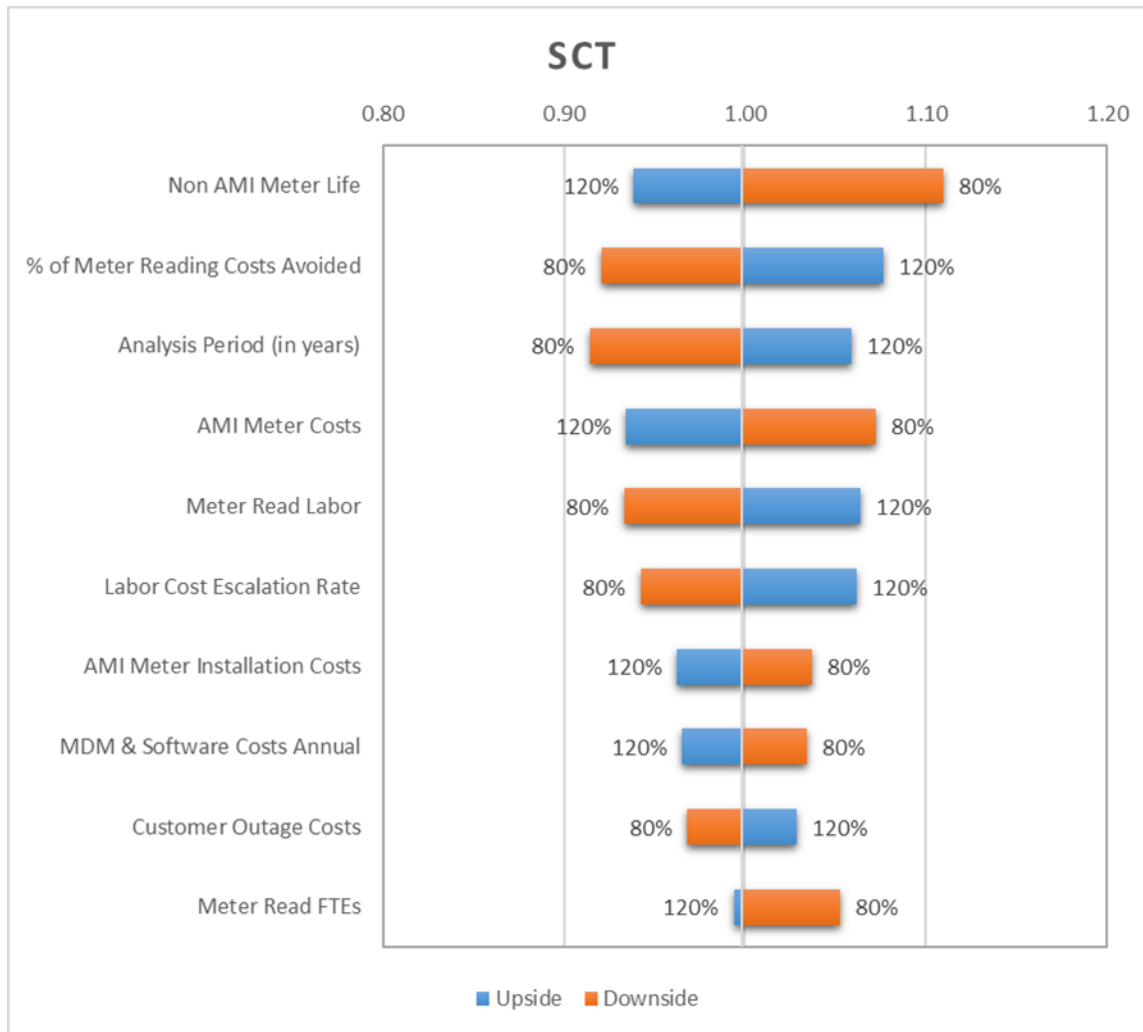
Figure 59: Operational Benefit and Cost Details, Full Deployment, Societal Test



The Company also analyzed the key drivers of cost-effectiveness through a systematic sensitivity analysis designed to identify the inputs that contribute most to net benefits. This is accomplished by varying each component by 20% while holding all other inputs constant. The goal is to identify which inputs have the greatest impact on the results and whether the results will change substantially or directionally by varying or fine-tuning inputs. The key finding from the sensitivity analysis is that each individual input has only a small impact on the result.

Figure 60 shows the sensitivity results for the assumption inputs with the greatest impact on the societal cost test. The top 10 assumptions can be said to be the top 10 drivers of the result. The midpoint where the blue and orange lines meet is the societal test ratio of 1.00. The conclusion that full AMI deployment is cost-effective is supported by the sensitivity analysis.

Figure 60: Top 10 Drivers of Full Deployment Societal Benefit Cost Results



The 2025 benefit cost analysis was designed to quantify benefits that can be tangibly quantified. However, there are key qualitative benefits that could not be quantified but provide clear value to Central Hudson customers that will directly enable Central Hudson to further support state policy goals. These include the potential for:

- Improved customer satisfaction due to automated outage reporting, better outage detection and communication, and shorter restoration times.
- Customer avoided time and effort in submitting meter reading pictures and concerns about billing accuracy.
- Improved customer ability to understand energy usage patterns and manage energy usage.
- An easier account close out or new service experience for customers due to remote connection and disconnection capabilities.

- Increase system-wide demand response capacity: Central Hudson currently uses interval metering to support a demand response program for customers in NWA areas. Through this program, the Company installs an interval meter and sends out notifications to customers to reduce energy usage during periods of high demand. The program is cost effective, pay-for-performance, and offers ultimate flexibility to the customer in the type of loads available for curtailment. Performance is determined by interval data.
- Better insight into energy demand behaviors: High consumption equipment such as EVs and heat pumps and coincident use on peak load times. AMI can help identify these loads aiding in targeted outreach efforts and increasing DR capacity.
- Measuring demand reduction impacts associated with EE efforts such as weatherization and behavioral programs. These programs are known to provide impactful and cost-effective load reductions. AMI metering would significantly increase our ability to more precisely determine demand reductions associated with these efforts.
- Enable more refined right sizing of distribution system investments: AMI will also help improve temporal-spatial visibility on the distribution system which is currently limited to substation and feeder SCADA data and other DA system components. This supports planning functions by providing the ability to disaggregate loads and DERs to improve forecasting efforts, identify low voltage pockets and load balancing needs to improve system plans, including volt/var functionality. This can in turn facilitate more precise and granular identification of system investments or non-wires alternative solutions.
- Leveraging AMI data with machine learning to enable the Company to monitor equipment asset health and prevent failures.
- Provide automated natural gas leak detection through the installation of additional sensors.

3. IMPLEMENTATION PLAN

Central Hudson understands that AMI is a gateway technology that supports advanced analyses, innovative rate designs, demand-side management and customer engagement strategies that benefit both the customers and the grid. Refer to the Context and Background section above for more details on current progress. Based on the new BCA showing that widespread AMI deployment would be cost-effective, the Company will be developing an AMI implementation plan. The implementation plan will help the Company refine costs and benefits further.

4. RISKS AND MITIGATION

The risks associated with implementation of this recommendation stem from uncertainty with the system integration, potential cost impacts of tariffs, and the competition for resource assignment, including premature reassignment of resources to complete this project to the detriment of previously prioritized projects, and incomplete identification of environmental factors and operations/business requirements in the case of inadequate assignment of resources due to competing priorities. A full risk mitigation plan will be conducted as part of the AMI deployment implementation plan.

With a significant portion of deployment occurring in the field with the actual installation of meters, Central Hudson’s commitment to customer and employee safety as top priority must remain paramount. Additionally, the Company must engage in robust stakeholder engagement and a communication campaign to ensure accurate information is conveyed. In addition, Central Hudson will need to provide opt-out options for customers that have health, privacy, and security concerns. While Central Hudson maintains a comprehensive cybersecurity program as described in the Data Sharing section, it will be critical to adequately address any cybersecurity concerns, to minimize the risk associated with increased digital communications and access to data that accompany AMI deployment.

Table 46: AMI Deployment Risks and Potential Mitigation Strategies

Potential Risk	Potential Mitigation Strategies
System integration	Lay out detailed system integration plans with architecture roadmap for resources
Territory topography / remote locations of service points	Service level agreement with vendor to ensure cell coverage in remote locations
Potential cost impacts of tariffs and/or supply chain constraints	Lock in contracting before price increases Price sensitivity BCA assessment Contingency budget for potential increases
Resource constraints	Third party fixed fee contracts with hard deadlines and performance based incentives and penalties for non-performance

5. STAKEHOLDER INTERFACE

Central Hudson understands that customer engagement is a critical part of AMI deployment, and a large component of an AMI roll-out would incorporate customer-facing outreach and education. However, given that the Company is currently only preparing to develop an implementation plan for AMI, Central Hudson cannot provide detailed answers to DSIP 2023 Guidance questions on AMI at this time. As part of pursuing regulatory approval for AMI deployment, stakeholders, including Central Hudson customers, will have the opportunity to review and comment on Central Hudson’s AMI benefit cost analysis and implementation plan including customer outreach and education components.

6. ADDITIONAL DETAIL

1) Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.

AMI has not been deployed at Central Hudson. Please refer to the content above for a more detailed summary of the most up-to-date AMI assessment.

However, Central Hudson has deployed approximately 1,400 interval meters throughout its service territory for specific use cases. For example, the Company implemented a REV demonstration project that provided optional and residential advanced metering and data services, via options known as

Insights +.⁷⁶ Between 2017 and 2020, Central Hudson offered a subscription-based service that includes the installation of an advanced meter, which captures 15-minute interval customer load data and communicates this information over a cellular network. This enhanced data provided subscribing customers with the ability to view daily and hourly energy consumption, correlate energy consumption with average daily temperature, set bill and usage alerts, and participate in various rate structures/programs. While the Demonstration Project ended in December of 2020, most of the deployed advanced meters are still in service.

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 has not been deployed at Central Hudson. However, the limited deployment of advanced interval meters on the Central Hudson system has enabled the following initial capabilities:

- Measurement and Verification (M&V): Central Hudson and its program partner, Itron, utilize a statistical sample set of advanced meters for measurement and verification of load reductions achieved as part of the Targeted Demand Management / Non-Wires Alternative program. This program also utilizes smart measurement devices including telemetry-enabled thermostats and direct load controllers.
- Load Research: Load research data has been primarily used to construct load profiles for retail access and cost of service purposes. However, the Company has significantly increased its utilization of this data for rate design purposes, including the design of the alternative Residential TOU rate, proposed standby and NEM successor rate designs, and value stack considerations.
- Value Stack: The data from the advanced meters meets the criteria for the application of value stack compensation, and the hosted Itron meter data management (MDM) system can accommodate the additional meters at no additional system cost.
- Residential TOU: Central Hudson offers this program, the details of which can be found at <https://www.cenhud.com/en/my-energy/my-energy-options/time-of-use-billing/>.

3) Describe the AMI-acquired data and information that is planned to be available through the IEDR.

AMI-acquired data is not currently available through the Integrated Energy Data Resource (IEDR) due to the relatively limited scale of advanced meter deployment to date.

⁷⁶ Demonstration Project Implementation Plan Q4 2020 Status Update

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.

AMI has not been deployed at Central Hudson. This DSIP contains the most up-to-date information regarding the recently completed AMI BCA assessment. The company would develop a stakeholder communication plan as part of an AMI implementation plan.

5) Provide a summary of plans and timelines for future expansion and/or enhancement of AMI functions.

Central Hudson plans to develop an AMI implementation plan that would inform further refinement of the AMI BCA provided in the appendix of the DSIP.

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.

AMI has not been deployed at Central Hudson. The company has deployed limited quantities of advanced internal meters.

Interval data is stored in the Itron MDM system and then exported to the Company's billing system. Accounts that require interval data, such as Value Stack CDG projects, are billed using the interval data. These accounts are not downloaded into the meter reading system to be read by meter readers.

Currently, Central Hudson does not use AMI-acquired data for asset management, grid planning, or grid operations due to limited deployment to-date. Though these benefits were not clearly quantifiable for the AMI BCA, Central Hudson does plan to enhance its planning and operations if AMI is fully deployed in its territory, as described in the "Context and Background" section.

M. BENEFICIAL LOCATIONS FOR DERs AND NON-WIRE ALTERNATIVES

1. KEY TAKEAWAYS

Since filing its initial DSIPs, Central Hudson has put in place a robust process for identifying opportunities for Non-Wire-Alternatives (NWAs). This process involves the development of forecasts to look for areas where growth exceeds current system capabilities, and the application of criteria to monitor for opportunities to target procurement and programmatic activities to support the development of DER to defer infrastructure development. Central Hudson currently has three NWA projects, located within Fishkill Plains/Shenandoah, the Northwest Corridor (i.e., Northwest 115/69, Northwest 69), and Merritt Park. T&D projects have been deferred for five, seven, and seven years, respectively, to date, and include over 15% of load areas. Central Hudson is now quickly approaching a point where upgrades in these areas cannot be deferred for much longer. Central Hudson has a process to quantify the risk of overloads over time and identify locations suitable for NWAs. These candidate locations are referred to as beneficial locations and include areas that are not yet in the five-year T&D Capital Plan window but have a greater than 10% probability of overload by 2035. These sites will be monitored and will undergo a

detailed planning engineering review, and when needed, an NWA feasibility assessment. Appendix E provides additional information on the beneficial locations.

2. CONTEXT AND BACKGROUND

Non-wires alternative (NWA) solicitations are an important mechanism for bringing distributed energy resources (DERs) onto the system. They offer opportunities for developers to propose innovative solutions to meet a clearly defined system need, while also driving customer benefits. Collectively, the Joint Utilities have undertaken significant efforts to advance NWA processes and have released a number of NWA solicitations to the market. A key underlying component of this process is the identification of beneficial locations for DERs and NWAs.

As part of the initial DSIP filing in 2016, Central Hudson worked with consultants to develop a methodology utilizing probabilistic forecasting to determine location-specific transmission and distribution avoided costs. This study recognized that to avoid or defer infrastructure upgrades, DERs need to ramp up at the right time and right place. In addition, the DERs procured must target the right hours, with the right amount of availability and the right level of certainty so that infrastructure investments can be deferred. Areas with sufficient load-serving capability and areas where local, coincident peaks are declining are generally not well suited for NWA projects. Likewise, locations may not be suitable for non-wire projects if the infrastructure investments must take place either because of aging or failed equipment or because of the need to improve reliability and modernize the grid.

Beneficial locations are areas where loads are growing, but there is limited room to accommodate growth. The results of Central Hudson's Avoided T&D Cost studies to date have indicated that, with a few exceptions, most of Central Hudson's locations are either experiencing declining loads or have ample room for growth. Locations with a load growth factor above 100% are experiencing growth, and locations where the loading (peak demand /load-serving capability) was closer to 100% had less room for growth. This approach, however, is overly simplistic. It does not reflect that, all else equal, a location with a 3% annual growth rate will begin to exceed its rating in one-third of the time as a location with a 1% growth rate. It also does not factor in uncertainty and the reality that many growth trajectories are possible, and the growth pattern is less certain further into the future.

While locations can benefit from DERs, in some instances, Central Hudson can provide temporary relief through load transfer or other low-cost steps. As part of Central Hudson's planning processes, the Company evaluates alternative solutions to system needs and implements the lowest evaluated cost option. For example, in some cases, load transfers to neighboring areas, if needed, can be completed at a relatively low cost as an alternative to potential capital projects. This may postpone the timing of the upgrades and their inclusion as NWA projects.

As part of the previous DSIP filings and again as part of this DSIP filing, Central Hudson engaged with Demand Side Analytics to further develop the probabilistic forecasting methodology and complete a new study based on current loading data. The results of the 2025 study are included in Appendix E of this filing.

3. IMPLEMENTATION PLAN

1) *Current Progress*

IDENTIFICATION OF BENEFICIAL LOCATIONS FOR NWA

As a general rule, only growth-related T&D investments that are shared across multiple customers can be avoided by DERs or demand management. As loads grow, the excess distribution capacity dwindles. Suppose a customer helps reduce coincident demand, either by injecting power into the distribution grid or by reducing demand. In that case, the unused capacity can accommodate another customer's load growth, thereby helping avoid or defer investments required to meet load growth. Avoided or deferred T&D investments free up capital for other alternate uses, improving the efficient use of resources.

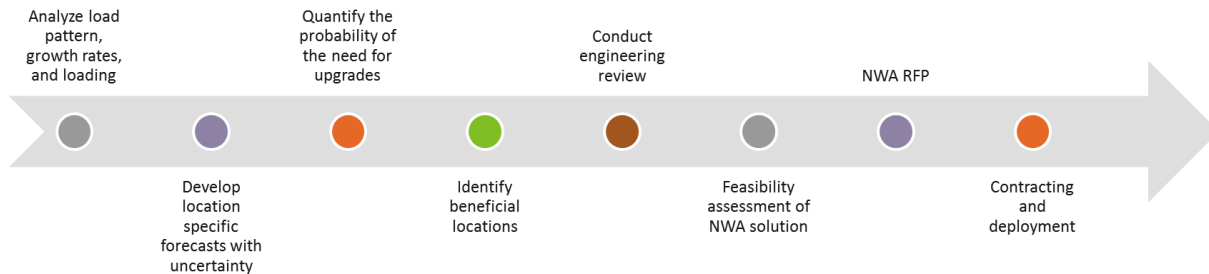
Not all distribution investments are driven by local, coincident peak loads. Some investments are tied to customer interconnection costs and are essentially fixed. Other investments must take place because of ageing or failed equipment, or because of the need to improve reliability and modernize the grid. These investments typically cannot be avoided by managing loads with DERs. The value of T&D deferral varies significantly across local system areas because of:

- Load growth rates and anticipated changes in load curve shapes, which affect whether growth-related upgrades can be avoided and how long they can be deferred;
- The seasonality of the peak load (i.e., summer vs. winter);
- The amount of existing excess capacity or the amount of additional load that can be supported without upgrades;
- The magnitude, timing, and cost of projected system upgrades;
- The design of the distribution system; and
- The ability to make inexpensive operational changes (i.e., switching alternatives) in some cases to address constraints.

In areas with excess capacity – or areas where local, coincident peaks are declining or growing slowly – the value of capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of capacity relief can be quite substantial, especially if it is possible to delay or defer infrastructure upgrades for a substantial time. However, many Central Hudson areas have declining or slowly growing loads, or they have sufficient capacity already built such that investments are not needed in the foreseeable future.

Central Hudson uses a standardized process to identify potential NWA projects, assess their feasibility, and procure resources to modify or limit load growth, as shown in Figure 61.

Figure 61: Central Hudson’s Process for Identifying NWA Projects

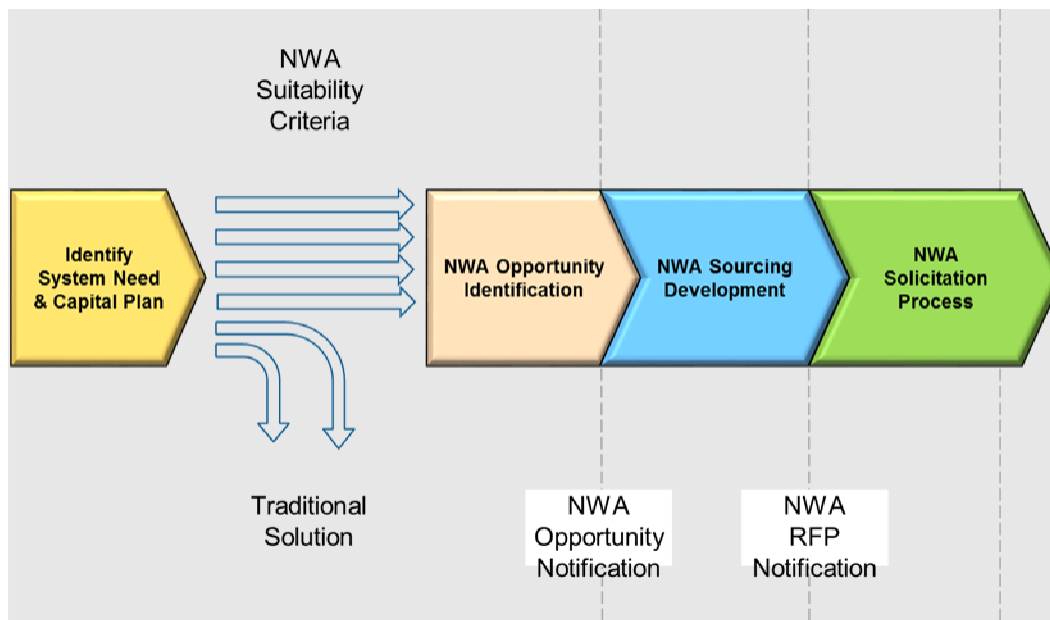


Locations with a 10% or greater likelihood of triggering an infrastructure investment by 2035 (ten years) are classified as beneficial locations and are subject to additional planning and engineering review, and a more detailed NWA feasibility assessment.

NWA IMPLEMENTATION

Through stakeholder engagement, the Joint Utilities provided third parties with greater transparency and visibility into the NWA planning and sourcing processes. The planning process is shown in Figure 62.

Figure 62: Joint Utilities Planning Process and Sourcing Overview



Each utility continues to coordinate with the Joint Utilities to develop RFPs that have a similar structure and supporting information when possible. RFPs provide the details necessary for respondents to develop solutions and craft a proposal and generally include a detailed project overview. The detailed project overviews may include a description of the specific need, area of need, and customer demographic information, including annualized consumption and peak and average billing demand. During the annual planning processes, utilities identify additional NWA projects that may go out for RFPs

in the following year. Table 47 summarizes Central Hudson’s current NWA locations and targets to date. The demand within these existing NWA areas represents approximately 15% of load areas.

Table 47: NWA Solicitations

2017-18 NWA Projects	Targeted Load Relief (MW)	T&D Deferral Period	Date Solicitation Issued	Status
Shenandoah / Fishkill Plains	3.4MW	2025 YE	Nov 2014	Ongoing NWA
Northwest Corridor / Transmission Upgrade	11.6MW	2029 YE	Nov 2014	Ongoing NWA
Merritt Park / (2) Distribution Feeder Upgrades	1MW	2027 YE	Nov 2014	Ongoing NWA

Currently there are three active NWAs implemented jointly as the Company’s “Targeted Demand Response” Program or “CenHud Peak Perks” as identified in Figure 63. Combined, the Company aims to achieve a localized peak load reduction of 16 MW across the three areas.

Developers and other stakeholders can access resources for accessing up-to-date information about non-wire alternative areas on the Company website.⁷⁷ Additional information regarding 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 can be found within the *Joint Utilities Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification*, filed under Case 16-M-0411 on May 8, 2017.

⁷⁷ <https://www.cenhud.com/en/contractors/non-wires-alternative-opportunities/>

Figure 63: Current NWA Project Locations and Targets

TDM Program Targets

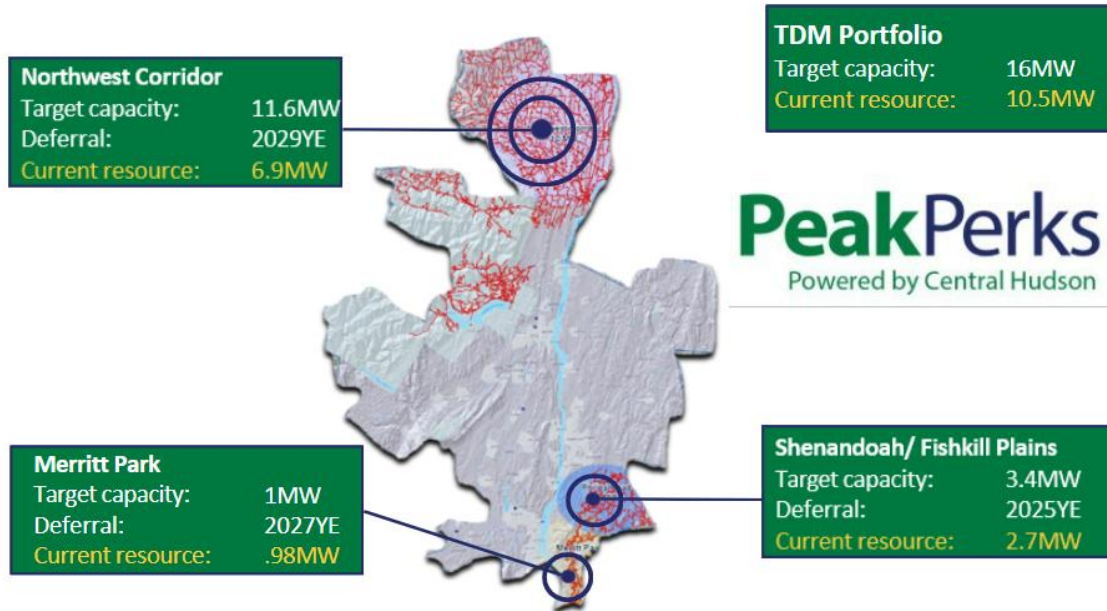


Table 48 illustrates the load reductions available as of January 2022. The Company anticipates achieving the target capacity by the end of 2029.

Table 48: Potential Load Reductions for Current NWA Projects

Program Locations	Residential & Small Commercial	Large Commercial & Industrial	Targeted Energy Efficiency	Avoided Distribution Line Losses ⁷⁸	Total kW available
Fishkill	1,705	0	260	97	2,062
Merritt Park	215	245	7	24	491
Northwest Area	891	3,094	2,287	247	6,519
Total	2,811	3,339	2,554	368	9,072

⁷⁸ Avoided distribution line losses have been calculated by Central Hudson per the Operation Procedure

More detail on this project can be found in Central Hudson Gas & Electric Corporation's 2024 Annual Report for the Targeted Demand Response Program, a Central Hudson Non-Wires Solution.⁷⁹

NWAs benefit stakeholders by leveraging behind-the-meter resources to support the system at large. They provide project developers and customers with new opportunities to participate in the system as prosumers. NWAs also support and improve system reliability and power quality. NWAs generally support the achievement of the goals established by the Climate Leadership and Community Protection Act (CLCPA) and NWAs that entail a battery storage solution and support the State's goal of 6 GW energy storage by 2030.

2) Future Implementation and Planning

a) Identification of Beneficial Locations for DERs and NWAs

Central Hudson believes that the methodologies and processes outlined and followed in the Marginal Cost of Service (MCOS) Study (see Appendix A) represent the leading edge of best practices in the determination of beneficial locations and NWA areas. The process is accurate and repeatable and provides reliable results. The study demonstrates the value of developing T&D avoided cost estimates at a local level using probabilistic methods. While Central Hudson has utilized this methodology in its three prior Avoided T&D Cost studies, it is still evolving and may benefit from future refinements and improvements. Future studies can be further bolstered by conducting additional sensitivity analyses, through the refinement of engineering rules which trigger T&D infrastructure upgrades and by increasing the granularity of the review. Central Hudson is committed to continuing to modify and enhance these methodologies and plans on repeating the analysis with current load data every two years. With continued electrification efforts in the state and the forecasted adoption of EVs, it is expected that this methodology will continue to identify potential additional beneficial locations in the future. There is also the potential shift from summer-peaking to winter-peaking in some areas through electrification (i.e., heat pump adoption), which may cause other areas of the system to be identified.

⁷⁹ <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A0FD8893-0000-C213-9D33-0AB7A04332DB}>

Figure 64: Summer Overload Risk for Substations

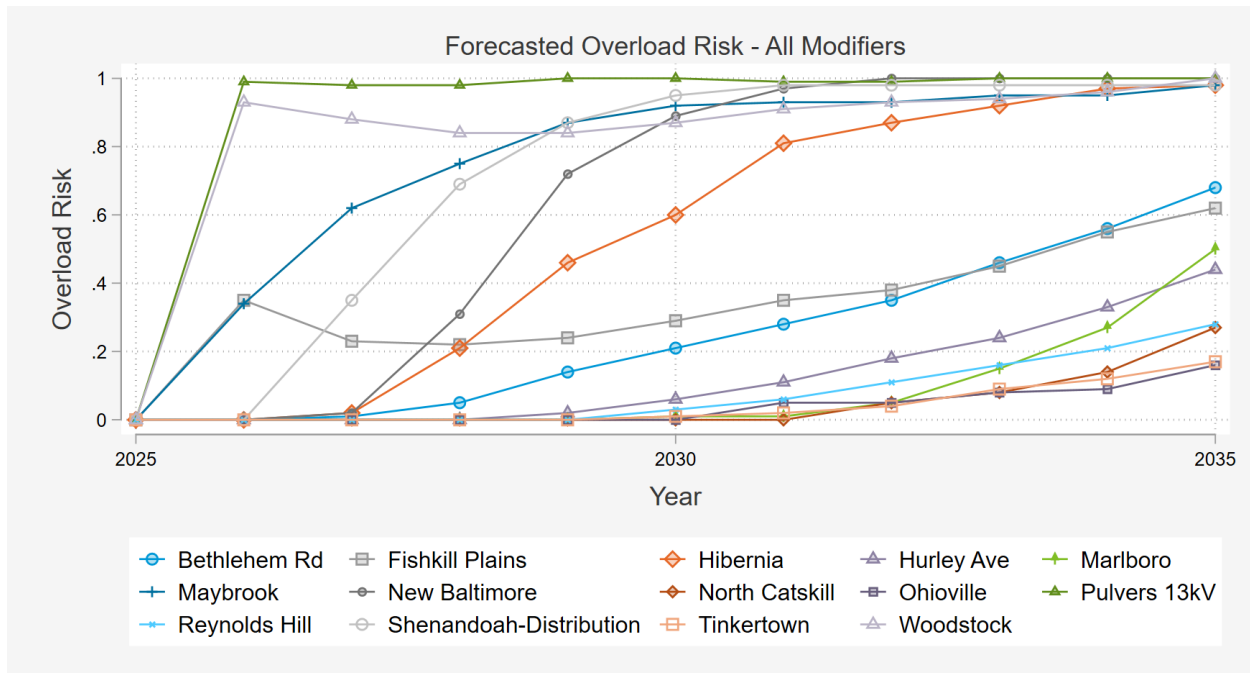
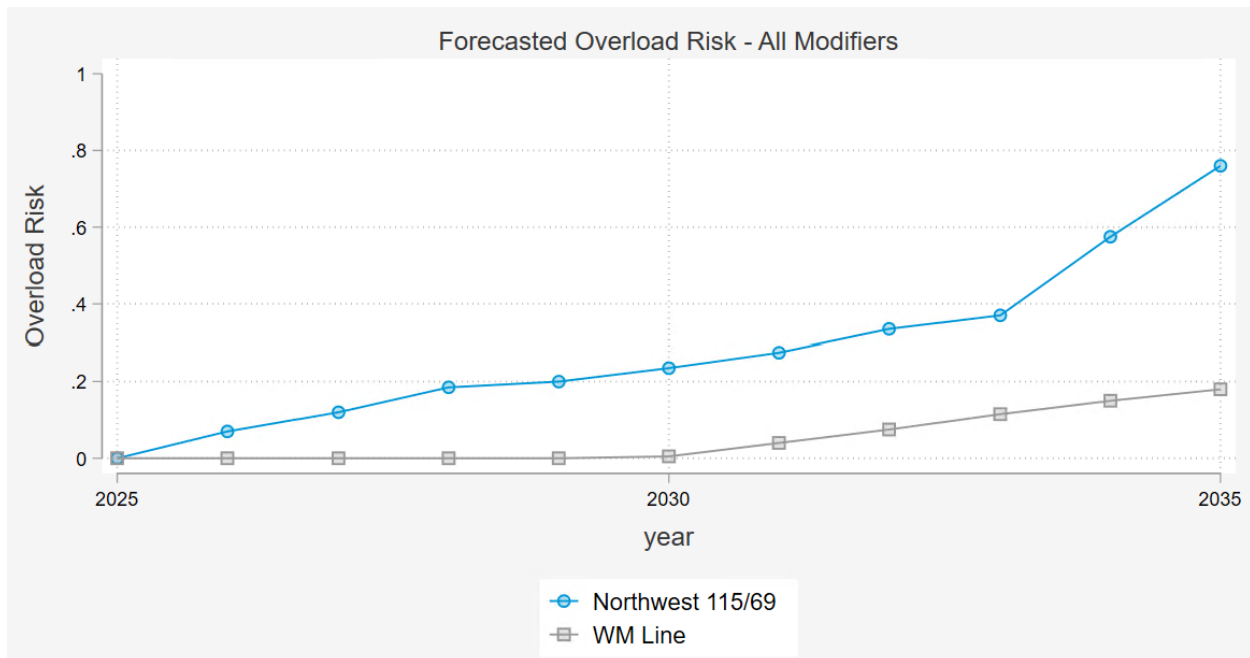


Figure 65: Summer Overload Risk at Transmission Areas



In total, two transmission areas and fourteen substations were identified. Of the fourteen substations identified as having an overload risk greater than 10% by 2035, ten have infrastructure upgrades or load transfers planned for the near term, which are included as part of the Company's five-year capital plan. Of the two transmission areas flagged, one has infrastructure upgrades identified for the near term. The

planned upgrades for these locations incorporate increases in load serving capabilities. In addition, the planned upgrades are required to address infrastructure issues and operational issues or are required due to the development of emergent large lumped industrial loads in the areas.

For areas that lack planned upgrades, the right type of DERs with the right availability may allow for deferral of infrastructure investment, but additional engineering review and an NWA feasibility assessment needs to be conducted. This is the case for the remaining four substations, Bethlehem Rd, Marlboro, North Catskill, and Ohioville, as well as one transmission area, the WM line. Figure 66 and Figure 67 show the four beneficial substation locations and the beneficial transmission location, respectively. These locations peak during different seasons and different hours. DERs would need to address the appropriate seasonal and peaking needs to provide values in each of these locations.

Figure 66: Map of Beneficial Substation Locations for DERs – Substation Summer Overload Risk

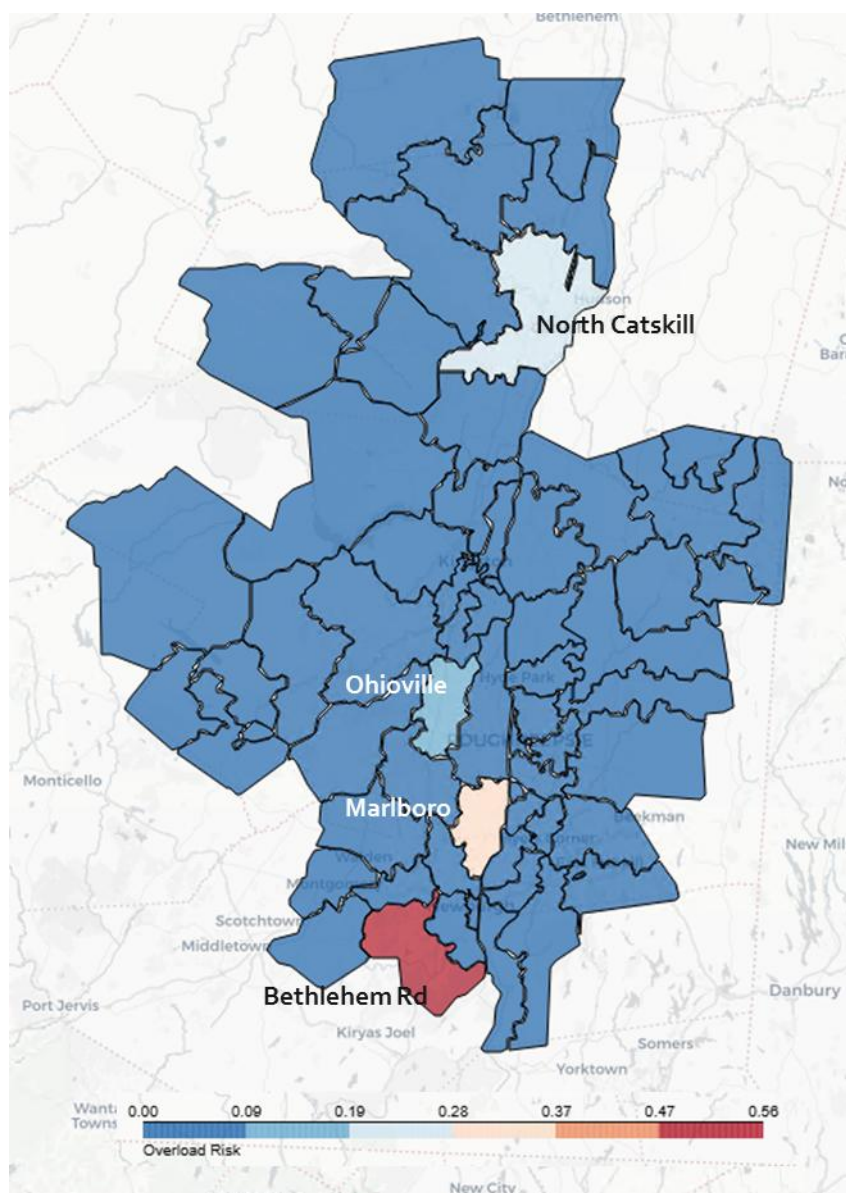
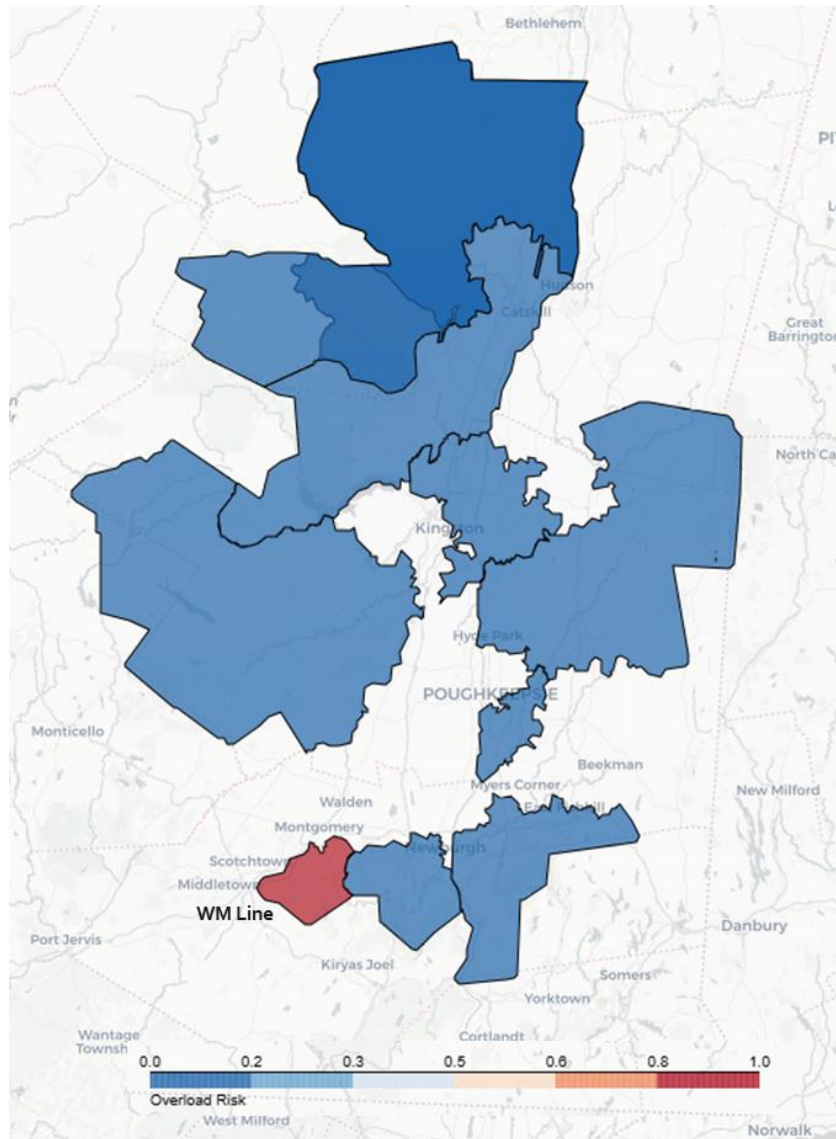


Figure 67: Map of Beneficial Transmission Locations for DERs



Appendix E contains additional detail for each beneficial location, including:

- Accounts and consumption for residential and non-residential customers
- Annual peak load shapes
- Load duration curves
- Historical weather patterns
- Forecast with uncertainty

b) NWA Implementation

The Company continues to integrate DERs into the planning process as a normal course of business and learn from its experiences, starting with the identification of NWA and extending through internal budgeting and accounting, evaluation of proposals, and contracting with successful bidders. As utilities gain experience with NWA solicitations, the Joint Utilities DER Sourcing / NWA Suitability Criteria Working Group will review NWA suitability criteria annually and propose modifications to the criteria, if appropriate. This working group will also engage stakeholders to review any proposed changes to the suitability criteria and provide justifications and objectives for making any changes.

The Joint Utilities continue to share experiences and lessons learned among themselves to achieve a consistent set of best practices and improve their solicitation processes to be more efficient and user-friendly. NWA topical areas reviewed during the meetings include updates on company RFPs and existing projects; availability and potential use of utility property and interconnection cost treatment; opportunities to move towards similar contracts (including terms and conditions) and procurement methods where appropriate in response to the DSIP guidance, this included reviewing best practices in other US states; liability caps in NWA contracts; NW solicitation contract language regarding DE participation in multiple revenue streams; implications of the New York State Storage Roadmap and sharing experiences on deploying two storage projects in response to the March 9 DSIP 207 Order; leveraging existing EE programs to meet localized NWA targets; annual assessment of the NWA suitability criteria as part of the annual planning process and changes or refinements to the criteria (none were identified in 2023); commercial and performance requirements; and non-performance issues of NWA contracts.

The Joint Utilities will continue to invite input from stakeholders through direct discussions and broader stakeholder engagement meetings. As utilities gain more experience with NWAs, the Joint Utilities see great value in working together and with stakeholders to make NWA solicitations consistent, repeatable, and easy-to-use processes for developers.

- Central Hudson will support stakeholder needs by creating pathways that alleviate load concerns at the lowest potential cost, thus reducing pressure upon customers while servicing customer needs. Cost-effective pathways should prioritize the penetration of renewable energy, load flexibility, and CLCPA targets for DACs and environmental justice (EJ) regions. The Company will continue to seek opportunities to support and improve system reliability through our “Targeted Demand Management Program” by identifying areas of load constraint, considering demand management solutions as alternatives to traditional infrastructure development, and employing those solutions where appropriate.
- To progress from the current implementation to the planned future implementation of NWAs, the Company will continue to promote cross-departmental collaboration, optimize relevant BCAs, provide flexibility to allow for adjustments in NWA implementation, and hold implementation contractors accountable through clearly defined metrics. The Company will continue to collaborate with DPS Staff on its latest NWA opportunities and innovation.
- To progress from the current implementation to the planned future implementation of NWAs, the Company will look for support from oncoming state regulation and funding to facilitate project implementation and adoption. Regulatory alignment and funding coupled with the

emerging availability of technology and the proliferation of local distribution chains should create the groundwork necessary for future planning.

Additionally, the Company will look to review future projects that fall outside of the currently established timeline suitability criteria. For example, deferral projects that are expected to commence in less than 18 months, or a shorter timeframe than currently specified for small projects will be evaluated and implemented at the discretion of feasibility determined by the Company.

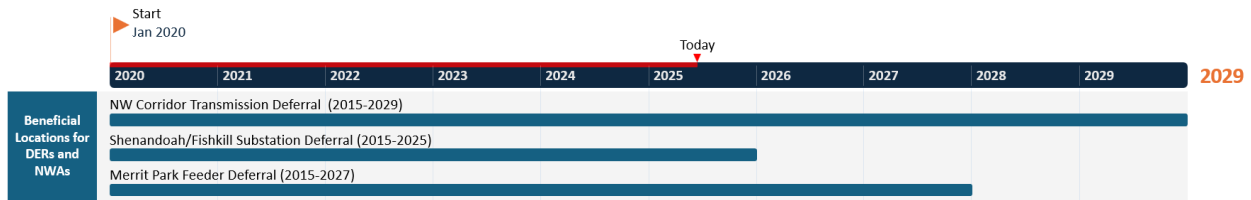
The Coordinated Grid Planning Process (CGPP) and DSIP are filings with overlapping but distinct scope. The CGPP will detail the evolution of distribution planning processes needed to meet Climate Leadership and Community Protection Act (CLCPA) goals, align with transmission planning processes, and ensure that planning is integrated. The DSIP describes implementation of the much broader set of DSP activities and projects, and how those activities holistically align with CGPP and CLCPA goals. The CGPP will be more singularly focused on a process to identify distribution system needs to meet CLCPA State goals and develop a distribution investment plan, including capital projects, to meet those needs. Planned capital investments, including technology platform investments along with NWAs and how they will be leveraged will be included in the DSIP (e.g., AMI, automation, Advanced Distribution Management System [ADMS], etc.) and the results of executing the processes will be used to inform the CGPP.

The CGPP is aimed at developing a “CLCPA-focused planning process,” including “the State’s bulk transmission, local transmission, and distribution planning processes.” The goal is to improve planning processes to better coordinate the studies performed by the Utilities with the NYISO’s bulk-power system planning and generation interconnection processes; improve the integration of Local Transmission and Distribution and bulk system studies with NYSERDA’s renewable generation and storage procurements; and improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid. As part of the CGPP, one of the key inputs to the CGPP is the generation build-out scenarios identified by the Energy Policy Planning Advisory Council. While forecasting practices for the CGPP and DSIP are aligned, the scenarios identified by the EPPAC may result in different forecasts than those completed as part of the DSIP. The output of the CGPP thus may result in the identification of Phase 2 capital projects that are not already identified in current rate plans. Although capital projects identified within the CGPP are intended to be funded under the FERC load ratio share methodology, these Phase 2 projects once approved will be incorporated and used to inform the normal DSIP and planning processes.

3) Integrated Implementation Timeline

Figure 68 shows the timeline for existing NWA projects. As discussed above, Central Hudson has a process in place for early detection of locations with a potential risk of overloads. The process has identified one transmission area, and four substations that will undergo a more detailed engineering review and an NWA feasibility assessment, at which point Central Hudson will decide whether to pursue NWA projects for those locations.

Figure 68: Non-Wire Alternatives Timeline



4. RISKS AND MITIGATION

Any forecasting technique includes inherent risks in terms of overall accuracy. The longer the period included within the forecast window, the higher the risk of inaccuracy. No one knows precisely when loads will exceed design ratings or by how much; however, linear forecasts assume precise knowledge. In practice, actual growth trajectories are rarely linear, and growth patterns trend across time – both load growth and load declines follow cyclical patterns. Forecasts inherently include uncertainty and become more uncertain further into the future. Because a linear forecast assumes exact knowledge, no value is assigned to the years before the linear forecast exceeds the risk tolerance. Probabilistic methods, on the other hand, reflect the potential reality that infrastructure could be triggered earlier. Probabilistic methods will assign value to periods earlier than the linear forecast would dictate based on the probability of triggering an earlier infrastructure upgrade.

Risks are mitigated within the methodology in several ways. The year-by-year growth estimates are estimated using econometric models designed to disentangle year-by-year growth rates from differences in weather patterns, day of week effects, and seasonality. For the most part, the year-by-year estimates of growth are relatively precise. Historical year-by-year growth does not follow a linear pattern and varies around the general trend line. This variation was used to develop the standard error of the forecast, which reflects how year-to-year growth can vary. This variability or uncertainty in the growth pattern is critical to probabilistic forecasting. Because growth and declining loads compound over time, growth patterns can deviate substantially from the straight-line forecast. An area where loads are projected to remain flat can exceed the load-serving capability five to ten years out due to the uncertainty in the forecast, though the likelihood of doing so is lower than for an area that is growing.

Overall, the probabilistic methods quantify the risk mitigation value of managing demand. The estimates produced within the report are based on 200 simulations of potential load growth patterns for each substation and transmission area, respectively. For each simulation, Central Hudson can assess if the relevant design rating is exceeded, identify the timing of infrastructure upgrade, quantify the magnitude of demand reductions needed to avoid the infrastructure upgrade, and calculate what the avoided costs associated with the deferral of infrastructure upgrades would be if demand reductions were in place. The detailed calculations from each of the simulations at each location are used to estimate the expected avoided costs per kW/year. That is, the probabilistic method assigns T&D avoided costs when, for example, only 5% of potential growth trajectories lead to infrastructure upgrades. This approach quantifies the risk mitigation value provided by resources that reduce demand at the right times at each location.

Through NWA's, the Company is deploying potentially new and innovative DER technologies to meet grid needs. Unlike traditional infrastructure projects, these DER solutions do not have the same proven history of reliably performing utility functions. DER solutions carry more performance risk than

traditional utility solutions, and until more experience is gained, those risks cannot be precisely quantified. To mitigate this risk, the Company leverages portfolio solutions to solve NWA needs where possible. Diversification of resource types is the primary strategy to mitigate the risk associated with any individual resource.

5. STAKEHOLDER INTERFACE

Central Hudson actively participates in the “DER Sourcing” Joint Utilities working group, which facilitates the sharing of best practices in DER procurement among New York utilities. The group has organized various workshops to promote the exchange of ideas and gather feedback on existing processes directly from DER developers and other stakeholders.

One notable example is Central Hudson’s annual Solar+ Summit. This event provides DER developers and industry professionals with information on the technical and procedural aspects of interconnecting with the utility, industry updates, available programs, and incentives. At the end of each Solar+ Summit, attendees are given a survey to provide feedback, which is used for future planning. This includes identifying specific topics of interest that professionals want to see and hear about. Additionally, beneficial locations for DER developers may be identified and presented at future Solar+ Summit meetings, when applicable.

This feedback is used to optimize procurement procedures and enhance the participation experience for developers. Central Hudson strives to provide the most detailed information available to prospective DER providers through RFPs. For each solicitation, the company responds to specific questions and discusses topics requested by stakeholders during a pre-bid conference.

6. ADDITIONAL DETAIL

- 1) *Describe where and how developers and other stakeholders can access resources for accessing up to date information about beneficial locations for DERs and/or energy efficiency measures; and efficiently sorting and filtering resources by the type of capability needed, and geographic area*

Developers and stakeholders can access up-to-date information on optimal locations for DERs and energy efficiency measures through Central Hudson’s Hosting Capacity Maps. This tool offers geographic filtering, downloadable datasets, and system-specific data such as feeder load forecasts and available capacity, helping users identify grid-constrained areas suitable for projects.

- 2) *Describe the means and methods for identifying and evaluating locations in the distribution grid where NWA could help reduce, delay, or eliminate the need for upgrading distribution infrastructure.*

Central Hudson produces granular forecasts using probabilistic methods. All locations with a 10% or higher probability of overloads over the next ten years are identified as beneficial locations for DERs and subject to a more detailed engineering review and NWA feasibility assessment. If the initial screening

passes, Central Hudson issues and RFP for NWA services which define the magnitude of resources needed by hour and forecast year to avoid the need for growth-related infrastructure upgrades.

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.

Central Hudson identifies NWA opportunities early through integrated planning, allowing time for internal coordination and timely RFP issuance. Solicitations clearly define system needs and timelines, giving developers a structured process to propose viable solutions. Projects with shorter lead-times are evaluated on a case-by-case basis to maintain flexibility. Ongoing collaboration and lessons learned from the Joint Utilities help streamline and standardize the process, ensuring it aligns with both utility constraints and developer readiness.

4) Describe where and how DER developers and other stakeholders can access up to date information about current NWA project opportunities.

DER developers and stakeholders can access up-to-date information on current NWA project opportunities through Central Hudson's procurement portal and regular stakeholder engagement forums. These include updates on active and upcoming RFPs, project timelines, and requirements. Additional context is provided in DSIP filings and Joint Utilities meetings, which share lessons learned, best practices, and any changes to sustainability criteria. Stakeholders are also engaged directly during the planning process to ensure transparency and alignment with system needs.

5) Describe how the utility considers all aspects of operational criteria and public policy goals when deciding what to procure as part of a NWA solution.

Central Hudson considers both operational criteria and public policy goals when evaluating NWA solutions. This includes assessing system reliability, load constraints, and feasibility through internal planning and benefit-cost analysis. At the same time, the Company prioritizes solutions that support CLCPA goals, including renewable energy adoption, load flexibility, and benefits to disadvantaged communities. Cross-departmental collaboration ensures that selected NWA solutions meet technical needs while aligning with broader state policy goals.

6) 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.

Updates are provided by Central Hudson on completed and active NWA projects through its procurement portal, DSIP filings, and ongoing stakeholder engagement. These updates include project status, lessons learned, and process improvements to ensure transparency and consistency. Additionally, Central Hudson hosts an annual Solar+ Summit, where DER developers and industry stakeholders receive updates on interconnection processes, available programs, and emerging opportunities. Feedback from attendees helps shape future content, and beneficial NWA locations may be highlighted at future events when applicable. The combination of digital resources and direct engagement ensures stakeholders have timely access to relevant NWA project information.

N. MARGINAL COST OF SERVICE OVERVIEW

1. KEY TAKEAWAYS

On August 19, 2024, the Public Service Commission issued an *Order Addressing Marginal Cost of Service Studies* (“MCOS Order”)⁸⁰ that specify the marginal cost of service (MCOS) study methodologies for determining several components of the Value of Distributed Energy Resources (VDER) Value Stack. In 2016, 2018, 2020, and 2023, Central Hudson conducted location-specific avoided transmission and distribution (T&D) cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This 2025 study adopts the traditional NERA methodology, with modifications required by the Commission to better align approaches across utilities.

In Central Hudson’s MCOS study, marginal costs were estimated at three levels: local transmission, substation, and distribution feeder. For each level, all growth-related and multi-value (i.e., growth and reliability) projects in the capital investment plan were included in the analysis. To determine the total marginal cost for each location, Central Hudson aggregated the marginal costs across all three levels.

The key findings from the MCOS study are:

- Many circuits, substations, and local transmission areas are experiencing declining loads or have ample room for growth.
- Transmission and substation-level marginal costs increase over the ten-year timeframe as areas with higher marginal costs have projects with expected in-service dates in the latter half of the planning horizon.

The latest version of Central Hudson’s Marginal Cost of Service Study will be made available at the following publicly accessible web link: <https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips>

2. CONTEXT AND BACKGROUND

One vital role of the electric utility is to ensure that the electricity supply remains reliable. By projecting future demand along with identifying reliability and/or condition-based infrastructure needs, utilities can reinforce the local transmission and distribution systems to maintain power quality and reliability of the system and ultimately avoid costly outages.

In its April 18, 2019 *Order Regarding Value Stack Compensation* in Case 15-E-0751, the Public Service Commission initiated a new proceeding to examine the Joint Utilities’ marginal cost of service (MCOS) studies, which have been used for a variety of purposes, including components of the Value Stack, economic development rates, and the avoided cost benefit associated with energy efficiency load reduction programs. Following a stakeholder process, the Commission issued an order on August 19, 2024, establishing a methodology for estimating marginal costs to inform system-wide applications. This

⁸⁰ Case 19-E-0238, Proceeding on Motion of Commission to Examine Utilities’ Marginal Cost of Service Studies, Order Addressing Marginal Cost of Service Studies (Issued August 19, 2024).

order calls for consistent MCOS study methodologies to reduce the significant variations that previously existed across the Joint Utilities.

The load forecasts leveraged in the MCOS, as described more fully in the DSIP Advanced Forecasting section, were done using econometric forecasts for each of Central Hudson's 272 distribution feeder circuits, 66 substations, and 10 transmission areas. These forecasts incorporate substation-level growth rates, forecasted changes in household growth, and are weather-adjusted for planning conditions. Modeling was performed on an hourly basis to produce forecasts at the feeder circuit level for evolving technologies, including solar, storage, transportation electrification, and building electrification. Central Hudson produced these granular forecasts for the 10-year horizon as required in the MCOS study.

In 2016, 2018, 2020, and 2023, Central Hudson conducted location-specific avoided T&D cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This 2025 study adopts the traditional NERA methodology, incorporating modifications required by the Commission to better align practices across utilities. Compared to previous studies, the 2025 Marginal Cost of Service (MCOS) Study differs in several key areas:

- The study included all growth-related and multi-value projects planned within the 5-year corporate Capital Forecast, along with a handful of capital infrastructure investments currently identified past the 2030 timeframe. Since Central Hudson uses a five-year capital forecast, the proportion of service territory with distribution upgrade needs in years six through ten was assumed to be similar to years one through five.
- Marginal cost estimates are developed using deterministic methods.
- Marginal costs are calculated as the actual planned investment cost net of salvage value divided by the incremental capacity provided by each project and converted into annual revenue requirements per kW of capacity. Most of the capital projects included in the MCOS are multi-value projects driven by reliability/infrastructure needs that would require investments absent any load growth. However, for various reasons, these multi-value projects also increase system capacity.

The study focuses on quantifying the marginal costs of increasing the T&D system capacity so that it can accommodate additional loads. The study focuses on feeder, substation, and local transmission costs and was designed to meet the following objectives:

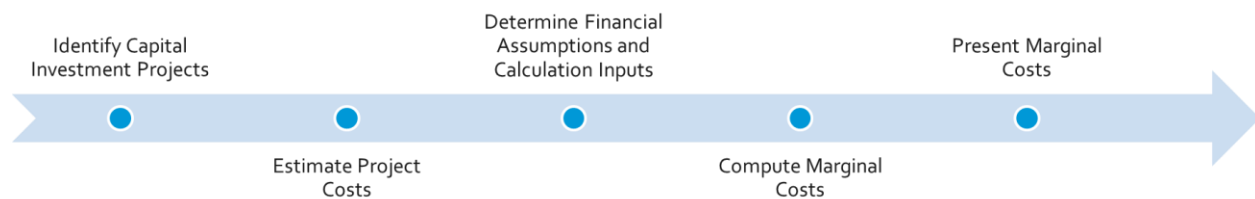
- Analyze the magnitude of expected infrastructure investments at a local level.
- Identify capital investment projects that are growth-related or multi-value.
- Calculate local marginal costs of T&D capacity for projects identified for inclusion in the study, at the local transmission, substation, and distribution feeder levels.
- Estimate the system-wide marginal costs at the local transmission, substation, and distribution feeder.
- Produce avoided T&D costs by substation.

In areas with excess capacity – or areas where local, coincident peaks are declining or growing slowly – the value of capacity relief can be minimal. In areas where a large, growth-related investment is

imminent, the value of capacity relief can be quite substantial, especially if it is possible to delay or defer infrastructure upgrades for a substantial time. However, many Central Hudson areas have declining or slowly growing loads, or they have sufficient capacity already built such that investments are not needed in the foreseeable future. In addition, the annual marginal cost values do not reflect whether resources are delivered at the right hours and right seasons by location.

3. KEY ANALYSIS STEPS

Figure 69: MCOS Key Analysis Steps



The analysis involved five (5) main steps.

1. **Identify Capital Investment Projects.** Central Hudson included all the load growth and multi-value projects in its 5-year capital forecast and a few projects identified past the 5-year timeframe. In addition, Central Hudson included yet-to-be-identified projects in the remaining 10-year timeframe at the average cost per kW of capacity. A total of 9 specific projects were identified, with total capital expenditures of about \$111M over the 2026-2035 horizon. While most of the projects are reliability/infrastructure driven, they also provide for a capacity increase and thus were identified as a multi-value project.
2. **Estimate Project Costs.** The project costs included were consistent with the capital plan. For growth-driven projects (i.e., not multi-value), no salvage value is applied. For multi-value projects, Central Hudson assigned a salvage value of 2.5% for distribution feeder, substation, and local transmission-level investments.
3. **Determine Financial Assumptions and Calculation Inputs** for carrying charge and expense factors.
4. **Compute Marginal Costs.** The calculations simply reflect revenue requirements associated with the capital costs and are presented on \$/kW-year of T&D capacity. The values are in nominal dollars and are included starting the year after the projected project in-service year. The 10-year levelized values reflect the in-service years and the time value of money.
5. **Present Marginal Costs.** The local transmission, substation, and feeder circuit value was stacked at the feeder level and aggregated to the substation level.

Additional considerations in the analysis include:

- In accordance with the MCOS Order's requirement to present costs at a granular level by including the substation serving area, Central Hudson layered marginal costs from local transmission, substation, and feeder circuit levels to the substation level. To allocate local transmission-level marginal costs, each substation within a specific local transmission area was assigned the local transmission-level marginal cost. Circuit-level marginal costs were rolled up to

the substation level by weighing each circuit's marginal cost by its peak load, accounting for differences in circuit size.

- Marginal costs will vary by year depending on the projects being placed into service in that year. In addition to showing marginal costs over each of the ten years, a ten-year levelized marginal cost is presented as the net present value of the investments, factoring in the in-service year of the planned capital projects.
- In accordance with the MCOS Order, the marginal costs summarized in Table 49 are shown at the local transmission, substation, and feeder level for all projects identified within the ten-year planning horizon and are representative of areas with identified projects over the study period.
- In addition, Central Hudson's study presents system-wide marginal costs, inclusive of areas with ample room for load growth. All areas were included in the study and weighed according to their share of Central Hudson's load.

4. RESULTS

Table 49 and Table 50 present the annual and 10-year levelized total marginal cost estimates by local transmission, substation, and distribution feeder. Table 49 reflects total marginal costs in areas with identified projects. As indicated previously, many feeders, substations, and local transmission areas in Central Hudson's territory are experiencing declining loads or have ample room for growth. As a result, the marginal costs applicable to areas with growth-related and multi-value projects are not representative of all areas of Central Hudson's system. The values also should not be stacked (i.e., added across local transmission, substation, and feeder circuit), unless a specific location has upgrade projects scheduled at all three grid levels. Most locations do not have upgrades in the 10-year horizon, or, if they do, have upgrades scheduled for a specific component (e.g., transmission upgrade, but not substation, and feeder).

Table 50 reflects total marginal costs on a system-wide basis, factoring in areas with no marginal costs or yet-to-be-identified projects over the 10-year planning horizon. Such a value would be more appropriate in circumstances where a single marginal cost value is utilized regardless of where in the system a resource is located.

Table 49: Marginal Costs for Areas with Projects by Component (\$ nominal)

Year	Local Transmission	Substation	Feeder Circuit
2026	\$0.00	\$0.00	\$12.37
2027	\$0.00	\$0.52	\$12.63
2028	\$0.00	\$12.65	\$12.63
2029	\$0.00	\$12.65	\$12.63
2030	\$0.00	\$42.84	\$12.63
2031	\$0.00	\$99.50	\$12.63
2032	\$0.00	\$99.50	\$12.63
2033	\$27.92	\$127.47	\$12.63
2034	\$27.92	\$127.47	\$12.63
2035	\$27.92	\$127.47	\$12.63
10-year levelized (\$2025)	\$6.56	\$55.51	\$12.60

Table 50: System-wide Marginal Costs (\$ nominal)

Year	Local Transmission	Substation	Feeder Circuit	Total Marginal Costs
2026	\$0.00	\$0.00	\$3.03	\$3.03
2027	\$0.00	\$0.07	\$3.10	\$3.17
2028	\$0.00	\$1.80	\$3.10	\$4.89
2029	\$0.00	\$1.80	\$3.10	\$4.89
2030	\$0.00	\$6.08	\$3.10	\$9.18
2031	\$0.00	\$14.13	\$3.10	\$17.23
2032	\$0.00	\$14.13	\$3.10	\$17.23
2033	\$11.62	\$18.10	\$3.10	\$32.81
2034	\$11.62	\$18.10	\$3.10	\$32.81
2035	\$11.62	\$18.10	\$3.10	\$32.81
10-year levelized (\$2025)	\$2.73	\$7.88	\$3.09	\$13.70

The order also required marginal costs at the substation level. Figure 70 shows the map of the 10-year levelized total marginal cost at the substation level, which includes the cost at all levels. The total marginal costs represent the sum of marginal costs at the local transmission, substation, and feeder levels, as described earlier.

Figure 70: Map of 10-Year Levelized Marginal Cost by Substation

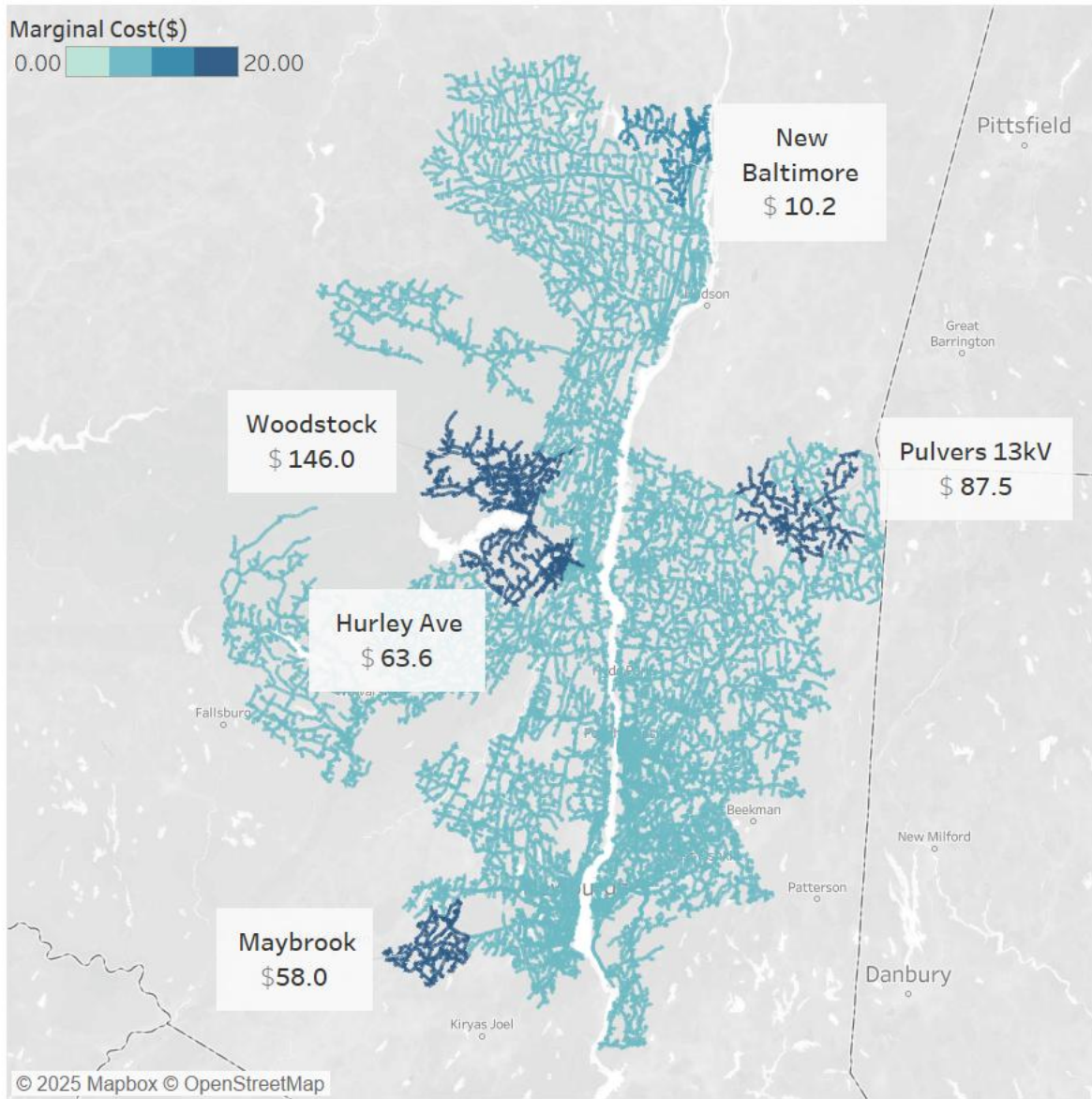


Table 51: 10-Year Levelized Marginal Costs by Substation

Local Transmission	Substation	Local Transmission MC	Substation MC	Feeder MC	Total Marginal Costs
Ellenville	Clinton Ave	\$2.73	\$3.37	\$3.04	\$9.14
	Galeville	\$2.73	\$3.37	\$3.06	\$9.16
	Greenfield Rd	\$2.73	\$3.37	\$3.27	\$9.37
	Grimley Rd X1	\$2.73	\$3.37	\$3.03	\$9.13
	Grimley Rd X2	\$2.73	\$3.37	\$1.77	\$7.86
	High Falls	\$2.73	\$3.37	\$3.07	\$9.17
	Honk Falls	\$2.73	\$3.37	\$3.03	\$9.13
	Kerhonkson	\$2.73	\$3.37	\$3.10	\$9.20

Local Transmission	Substation	Local Transmission MC	Substation MC	Feeder MC	Total Marginal Costs
	Neversink	\$2.73	\$3.37	\$3.05	\$9.15
Hurley-Milan	East Kingston	\$2.73	\$3.37	\$3.03	\$9.13
	Lincoln Park	\$2.73	\$3.37	\$3.10	\$9.20
	Rhinebeck	\$2.73	\$3.37	\$3.22	\$9.32
Mid-Dutchess	Knapps Corners	\$2.73	\$3.37	\$3.23	\$9.33
	Manchester	\$2.73	\$3.37	\$3.03	\$9.13
	Sand Dock-Distribution	\$2.73	\$3.37	\$3.03	\$9.13
	Sand Dock-Industrial	\$2.73	\$3.37	\$3.03	\$9.13
	Spackenkill	\$2.73	\$3.37	\$3.03	\$9.13
Northwest 115/69	North Catskill	\$0.00	\$3.37	\$3.12	\$6.49
	Woodstock	\$0.00	\$142.90	\$3.09	\$145.99
Northwest 69	Saugerties	\$2.73	\$3.37	\$3.14	\$9.24
Pleasant Valley 69	Ancram	\$2.73	\$3.37	\$3.03	\$9.13
	East Park	\$2.73	\$3.37	\$3.03	\$9.13
	Hibernia	\$2.73	\$3.37	\$3.11	\$9.21
	Millerton	\$2.73	\$3.37	\$3.03	\$9.13
	Pulvers 13kV	\$2.73	\$81.54	\$3.28	\$87.55
	Pulvers 34kV	\$2.73	\$3.37	\$3.03	\$9.13
	Smithfield	\$2.73	\$3.37	\$3.03	\$9.13
	Staatsburg	\$2.73	\$3.37	\$3.04	\$9.14
	Stanfordville	\$2.73	\$3.37	\$3.54	\$9.64
	Tinkertown	\$2.73	\$3.37	\$3.05	\$9.15
RD-RJ Lines	Bethlehem Rd	\$0.00	\$3.37	\$3.25	\$6.62
	Union Ave	\$0.00	\$3.37	\$3.23	\$6.60
Southern Dutchess	Forgebrook	\$2.73	\$3.37	\$3.55	\$9.65
	Merritt Park	\$2.73	\$3.37	\$3.20	\$9.30
	Shenandoah-Distribution	\$2.73	\$3.37	\$3.03	\$9.13
	Tioronda	\$2.73	\$3.37	\$3.15	\$9.25
	Wiccopee	\$2.73	\$3.37	\$8.66	\$14.76
Stand Alone	Boulevard	\$2.73	\$3.37	\$3.08	\$9.18
	Coldenham	\$2.73	\$3.37	\$3.06	\$9.16
	East Walden	\$2.73	\$3.37	\$3.03	\$9.13
	Fishkill Plains	\$2.73	\$3.37	\$3.03	\$9.13
	Highland	\$2.73	\$3.37	\$3.06	\$9.15
	Hurley Ave	\$2.73	\$57.70	\$3.17	\$63.60
	Inwood Ave	\$2.73	\$3.37	\$3.11	\$9.21
	Marlboro	\$2.73	\$3.37	\$3.10	\$9.20
	Milan	\$2.73	\$3.37	\$3.04	\$9.14
	Modena	\$2.73	\$3.37	\$3.41	\$9.51
	Myers	\$2.73	\$3.37	\$3.04	\$9.14
	North Chelsea	\$2.73	\$3.37	\$3.30	\$9.40
	Ohioville	\$2.73	\$3.37	\$3.05	\$9.15
	Reynolds Hill	\$2.73	\$3.37	\$3.09	\$9.19
	Sturgeon Pool	\$2.73	\$3.37	\$3.03	\$9.13
	Todd Hill	\$2.73	\$3.37	\$3.38	\$9.48
	West Balmville	\$2.73	\$3.37	\$3.11	\$9.21
WM Line	Maybrook	\$2.73	\$52.25	\$3.06	\$58.03
	Montgomery	\$2.73	\$3.37	\$3.19	\$9.29

Local Transmission	Substation	Local Transmission MC	Substation MC	Feeder MC	Total Marginal Costs
Westerlo Loop	Coxsackie	\$2.73	\$3.37	\$3.16	\$9.25
	Freehold	\$2.73	\$3.37	\$3.21	\$9.31
	Hunter	\$2.73	\$3.37	\$3.03	\$9.13
	Lawrenceville	\$2.73	\$3.37	\$3.03	\$9.13
	New Baltimore	\$2.73	\$4.32	\$3.17	\$10.22
	South Cairo	\$2.73	\$3.37	\$3.19	\$9.29
	Vinegar Hill	\$2.73	\$3.37	\$3.03	\$9.13
	Westerlo	\$2.73	\$3.37	\$3.04	\$9.14



IV. DSIP GOVERNANCE

This section addresses the following:

- Distributed System Platform (DSP) scope, objectives, and participant roles and responsibilities.
- Nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSP work.
- How the work processes are expected to evolve over the next five years.

As has been previously described in Central Hudson's prior DSIP filings, the DSP's scope covers three main functional areas: DER Integration (including Distribution Planning and Distribution Grid Operations), Information Sharing, and Market Services. Central Hudson's 2025 DSIP filing provides an opportunity for the Company to share its progress to date and the roadmap going forward for key initiatives within these three main functional areas.

Organizationally, Central Hudson has aligned functional responsibility under four leaders: the Chief Transformation Officer, the Chief Customer Services Officer, the Vice President of Operations and Safety, and the Vice President of Regulatory Affairs. The following table lists the DSP responsibilities of these leaders.

Table 52: DSIP Leadership and Functions

Leader	DSIP Functional Area	DSP Responsibilities Include
Chief Transformation Officer	DER Integration – Distribution Planning	Integrated planning, load and DER forecasting, hosting capacity, interconnections, and the integration of energy storage and electric vehicles.
Chief Customer Services Officer	Market Services	Customer programs relating to electric vehicles, energy efficiency, clean heat, and Non-Wire Alternatives; customer billing and compensation; the BCA handbook; and the development of service offerings to enhance customer experience.
Vice President of Operations and Safety	DER Integration – Distribution Grid Operations	Grid operations.
Vice President of Regulatory Affairs	All	Providing overall support and guidance for DSP activities. Marginal Cost of Service (MCOS) Study. Market Services pertaining to the interface between the ISO and DSP.

While these leaders and their organizations work collaboratively, Central Hudson believes that functionally separating the planning and operations functions from the market implementation functions remains important. This organizational construct is very similar to how Central Hudson operates today with transmission planning and operations and the wholesale markets.

To best coordinate with the Joint Utilities and receive valuable input from stakeholders, Central Hudson has played a leadership role in collaboration with the Joint Utilities. Central Hudson has also been active under the functional Joint Utilities implementation working, which includes the Interconnection Technical Working Group, Interconnection Policy Working Group, ISO-DSP Working Group, Integrated Planning Working Group, and electric vehicle and other working groups. To ensure that these work efforts stay coordinated, representatives from the Energy Policy and Regulatory Group follow and provide regulatory support and guidance to the SMEs that participate in these various working groups. These coordinated efforts have been invaluable in providing a streamlined forum for stakeholder participation, utility collaboration, sharing experiences, and receiving valuable input from the JU's consultants, who have the benefit of pulling in experiences from other jurisdictions.

Current progress toward the DSP has been significant. Regarding grid operations, the Company is in the midst of a multi-year implementation of its foundational investments, which include Distribution Automation, Distribution Management System, and Network Strategy communication backbone. Aligned

with the completion of these investments has been the buildout and staffing of the new transmission and distribution operation center. Due to the complexity of managing and operating a distribution system with a significant penetration of DERs and two-way power flows, Central Hudson has recognized the need to put in place new control center capabilities as well as develop the resources and the procedures necessary to operate this much more dynamic and complex grid. Regarding integrated distribution planning, the Company has put in place the DER forecasting capabilities and customer alternatives, including non-wires solicitations, described throughout this document. Regarding the integration of markets, Central Hudson has worked closely with the Joint Utilities in engaging with the NYISO in its efforts to establish the DER Aggregation market in New York. These collaborations have resulted in clear DER Aggregation processes, roles and responsibilities, and hand-offs between utilities and the NYISO, and this information is now captured in published NYISO manuals. The Company has also implemented a range of customer programs related to beneficial electrification, energy efficiency, and demand response. Additionally, Central Hudson has implemented a new Customer Information System, which provides a modern and scalable platform that can support advancements in future billing and compensation options for DER, if sufficient time and resources are allowed for programming (most of New York's complex billing programs cannot be met with commercially available customer information systems without custom programming).

Refinements in all these areas will continue to occur over the next five years, and as the DSP market evolves, there will be an added emphasis on implementing enabling actions, processes, and investments that build on the DSIP progress made to date and push forward toward offering customers additional behind-the-meter and front-of-the-meter flexible options, as envisioned by the Grid of the Future proceeding.