Paul A. Colbert
Associate General Counsel
Regulatory Affairs

June 30, 2020

Hon. Michelle L. Phillips
Secretary to the Commission
New York State Public Service Commission
Agency Building 3
Albany, NY 12223-1350

Re: Case 16-M-0411 - *In the Matter of Distributed System Implementation Plans*

Case 14-M-0101 - *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*

Dear Secretary Phillips:

Central Hudson Gas & Electric Corporation ("Central Hudson") submits its Distributed System Implementation Plan ("DSIP") and associated appendices for filing in the above-referenced cases. Central Hudson files the DSIP pursuant to the New York State Public Service Commission's Order Adopting Distributed System Implementation Plan Guidance issued and effective April 20, 2016 ("Order").

Please contact the undersigned at (845)486-5831 or pcolbert@cenhud.com with any questions regarding this matter.

Respectfully submitted,

/s/Paul A. Colbert

Paul A. Colbert
Associate General Counsel
Regulatory Affairs

284 South Avenue
Poughkeepsie, NY 12601

(845) 452-2000
Phone: (845) 486-5831 Cell: (614) 296-4779
Email: pcolbert@cenhud.com
www.CentralHudson.com

Central Hudson Distributed System Implementation Plan

Revised June 30, 2020

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Central Hudson Distributed System Implementation Plan

Revised June 30, 2020

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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
AICPA	Certified Public Accountants
ALT	Automatic Load Transfer
AMI	Advanced Metering Infrastructure
ASCR	Aluminum Conductor Steel-Reinforced Cable
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BCA	Benefit Cost Analysis
CCA	Community Choice Aggregators
CDD	Cooling Degree Days
Central Hudson (Company)	Central Hudson Gas and Electric Corporation
CEII	Critical Energy Infrastructure Information
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CIS	Customer Information System
CLCPA	Climate Leadership and Community Protection Act
Commission or PSC	Public Service Commission
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DERs	Distributed Energy Resources
DLP	Data Loss Prevention
DMS	Distribution Management System
DPS	Department of Public Service
DR	Demand Response
DRV	Demand Reduction Value
DSIP	Distributed System Implementation Plan
DSO	Distribution System Operations

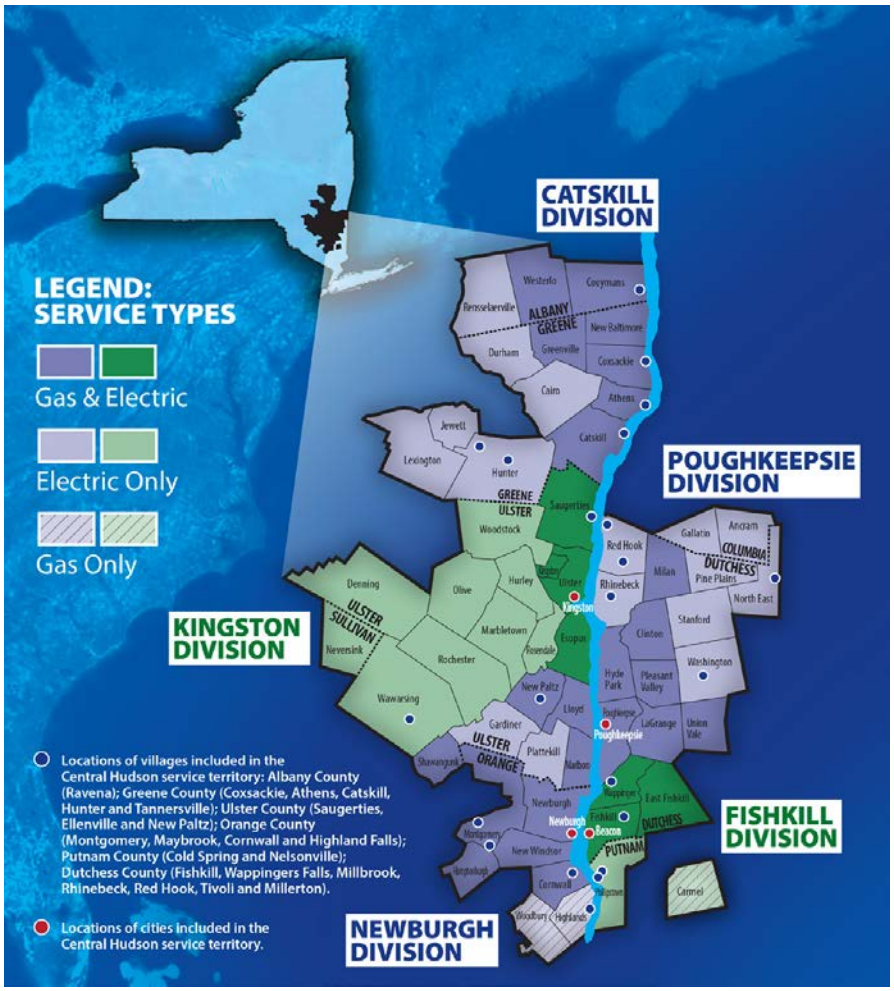
ACRONYM	DEFINITION
DSP	Distributed System Platform
EAM	Earnings Adjustment Mechanism
EDI	Electronic Data Interchange
EE	Energy Efficiency
EMS	Energy Management System
ESCO	Energy Service Companies
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAT	Factory Acceptance Testing
FLISR	Fault Location, Isolation, and Service Restoration
GAPP	Generally Accepted Privacy Principles
GIS	Geographic Information System
HDD	Heating Degree Days
IED	Intelligent Electronic Device
IPWG	Interconnection Policy Working Group
ISM	Integrated System Model
ITWG	Interconnection Technical Working Group
JU	Joint Utilities
JUNY	Joint Utilities of New York
LSC	Load Serving Capabilities
LSRV	Locational System Relief Value
M&V	Measurement & Verification
MDM	Meter Data Management
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NMS	Network Monitoring System
NWA	Non-wire Alternative
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research & Development Authority
NYSSIR	New York State Standardized Interconnection Requirements
O&M	Operations and Maintenance
OMS	Outage Management System
OTS	Operator Training Simulator

ACRONYM	DEFINITION
PCC	Primary Control Center
PDS	Program Development System
PHEV	Plugin Hybrid Electric Vehicle
PV	Photovoltaic
QAS	Quality Assurance System
REV	Reforming the Energy Vision
SAT	System Acceptance Testing
SCADA	Supervisory Control and Data Acquisition
SIEM	System Information and Event Management
T&D	Transmission and Distribution
UBP	Uniform Business Practices
VDER	Value of Distributed Energy Resources
VVO	Volt/VAr Optimization

I. Executive Summary

Central Hudson Gas and 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 electric and gas transmission and distribution (T&D) services to approximately 307,000 electric customers and 82,000 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 is comprised of approximately 9,400 miles of transmission and distribution lines.

Figure 1: Central Hudson Service Territory



As a result of slowdowns in the regional and state economy (not related to COVID-19), energy efficiency (EE) programs, and the integration of primarily small-scale photovoltaic (PV) systems, the electric system peak has shown a steady decline in recent years. The actual system peak in 2019 was 1,109 MW (1,092 MW on a normalized basis). Due to the continued forecasted economic weakness in the Hudson Valley, the normalized peak forecast for 2025 is projected at 1,146 MW; when the effects of DER are included the system peak drops to 1,114 MW. For comparison, Central Hudson's all-time electric system peak demand of 1,295 MW was set in 2006. As a result of the observed and forecasted reduction in system demand growth, the majority of the Company's electric capital expenditures remain focused on replacing existing infrastructure based on condition assessment and Grid Modernization efforts.

The Company has continued its effort towards implementing several large scale transformational projects designed to improve the intelligence of its system and provide tangible benefits to its customers. These efforts include the installation of a Distribution Management System (DMS), increased levels of Distribution Automation (DA), and 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). These deployments were approved in the Company's prior rate cases and are foundational to meet the targets of the Climate Leadership and Community Protection Act (CLCPA) and Reforming the Energy Vision (REV).

In addition, the Company has embarked on the transformation of its Customer Information System, called Project Phoenix, which will bring industry-leading functionality to Central Hudson's business processes by improving the customer experience, supporting emerging customer expectations, and laying the groundwork for future capabilities compelled by the CLCPA.

Finally, the Company has completed an expansion of its existing Primary Control Center in 2019 to accommodate the growing needs of the Distribution System Operation Center and is implementing the design and construction of a new Primary Control Center that will be able to fully accommodate the needs of the Distribution System Operation Center as the DA and DMS efforts are completed.

As Central Hudson continues to plan for investments that will enable the CLCPA and REV goals, the Company is mindful of the impacts of these investments in light of the COVID-19 pandemic. The scope and timing of the plans portrayed in this DSIP filing may be purposefully altered to lower the impacts to consumers during the economic recovery.

The original Order Adopting Distributed System Implementation Plan (DSIP) Guidance, 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 (DSP). 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 that Order, New York State has set forth some of the boldest clean energy policies in the nation to reduce carbon emissions and address climate change. One of the foundational elements of the State's REV initiative is increasing the amount of distributed energy resources – such as wind, solar, and battery storage – and increasing energy efficiency. In July 2019, under Gov. Andrew Cuomo's leadership, 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.

Central Hudson is committed to a cleaner energy future by supporting the CLCPA targets and Reforming the Energy Vision (REV) policies — 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 a part of the solution.

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 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, DPS Staff, and stakeholders. The Joint Utilities are working collaboratively to progress the DSPs as consistently as possible across the state while recognizing the inherent differences of each of the utility's systems. 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 future 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 efforts, pilot programs, and other innovations, including the investments in DA, ADMS, Network Strategy, an electric

geographic information system (GIS) project, Project Phoenix, and various research programs related to forecasting, Storage, and 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, Energy Efficiency Integration and Innovation, Distribution System Data, Customer Data, Cyber Security, DER Interconnections, Advanced Metering Infrastructure, Hosting Capacity, Beneficial Locations for DERs and Non-Wires Alternatives, and Procuring Non-Wires Alternatives.

Section IV Other DSIP Information: Included in this section is 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 a number of detailed subsections that provide further information and support for our efforts and direction, including Load and DER forecasting, the Avoided T&D Cost Study, the BCA Handbook, Central Hudson Long Range System Plan, and Tools and Other Resources for customers and developers.

Central Hudson, through its implementation of the DSIPs, has made significant improvements in the areas of Distributed Energy Resource (DER) Integration, Information Sharing, and Market Services. Additionally, significant improvements have been made in the focus areas of Distribution System Planning, Grid Operations, and Market Operations.

Foundational Investments to a Smarter Grid

In the Initial DSIP and its prior and subsequent rate plans, Central Hudson outlined a number of Foundational Investments as part of its Grid Modernization Program designed to improve system reliability, improve system and customer efficiency, further enable DER integration, defer distribution capital investment by leveraging redundancy, and position itself for the transition from a static to a dynamic distribution operating system. Central Hudson's Grid Modernization Program is comprised of six major components:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)
2. ESRI System Model Geographic Information System (GIS) – providing a single consolidated mapping and visualization platform

3. Distribution Management System (DMS) – the centralized software “brains”

4. Distribution System Operations (DSO) – the organization responsible for the use of the DMS

5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS

6. Substation Metering Infrastructure – Substation feeder metering upgrades required for accurate DMS power flow calculations

Central Hudson continues on this integrated Grid Modernization Program to develop Network Communications and a Distribution Management System, install Distribution Automation equipment and monitoring, and create ESRI-based GIS models of the distribution system. Central Hudson has successfully implemented its Distribution Automation in two of its five operating areas and is on a path to complete this implementation system-wide by 2023. In addition to the hardware and software efforts, Central Hudson has also developed a plan to address the personnel and operations needs through the development of a Transmission and Distribution System Operations control center and training academy. This dual-purpose facility will allow for the full development of the facilities and staff needed to implement the Grid Operations aspect of the DSP. This will be a primary the focus of Central Hudson’s enabling investment in the DSP over the next five years.

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 forecast and planning process to a more probabilistic granular hourly load forecasting and planning process. As part of this DSIP update, Central Hudson has continued to advance this effort through the development of a more probabilistic and granular DER forecast for Energy Efficiency, Electric Vehicles, Distributed Generation, and Storage. In addition, the Company has continued to make significant progress on system modeling, capturing components across all areas of the system including: conductor size and length, protective elements, phasing, and key customer transformer information. This information continues to be updated in the OMS and GIS systems, and in turn, the Planning load flow models. The data is critical in the rollout of devices and needed system reinforcements for the implementation of Distribution Automation.

Satisfying the Developers' Data Needs

Central Hudson, primarily working in conjunction with the Joint Utilities, continues to make improvements in the areas of accessible Customer and System Data. Central Hudson has made great strides in developing and providing public access to Customer and System Data. The Company has developed various GIS map-based data portals that provide access to granular 8760 load data (both historical and forecasted) and Hosting Capacity data. In addition to these portals, data maps including beneficial locations and Non-Wire Alternative areas, as well as links to other resources such as reliability data, capital plans, DSIP plans, DER interconnections, and aggregated customer data, have all been developed and made publically available through Central Hudson's website or the Joint Utilities' website. Central Hudson will continue to work with the Joint Utilities and stakeholders to further refine the data provided and how this data is made accessible. During the past two years, the Joint Utilities have been working together to develop a greater understanding of system data needs and studying use cases, however; these discussions have not resulted in significant changes in the amount of available data nor the way this data is accessed. Central Hudson looks forward to working collaboratively with DPS Staff and NYSERDA in the implementation of an Integrated Energy Data Resource to help achieve a useful and valuable resource.

Improving the Interconnection of DER

Central Hudson has also made progress in Hosting Capacity and DER Integration, along with the other Joint Utilities. Central Hudson played a lead role in the development of the Hosting Capacity Roadmap by refining the information provided in the roadmap, adding new data elements that were requested by stakeholders, and providing a consistent format to be used across the utilities. Central Hudson also continues to support the efforts in DER Integration on both the Integration Policy Working Group and Integration Technical Working Group. Through these efforts, Central Hudson has developed a method for managing the SIR queue, created consistent requirements for interconnection, and implemented and improved the PowerClerk portal for interconnection applications. These efforts resulted in greater clarity for developers in the state, allowing for much more efficient DER development. Although capital projects that also provide an opportunity to increase hosting capacity are considered in the Capital Investment Plan as an additional benefit, there currently exists no specific planning process for increasing hosting capacity. As a part of this DSIP filing, DER forecasts were developed at the substation and transmission levels separate from net loads as an additional step towards further integrating DERs into the planning process. Central Hudson looks forward to working with the PSC, NYSERDA, and Joint Utilities in developing a focused planning process to increase DER integration.

Addressing Cyber Security

Regarding Cyber Security, Central Hudson recognizes the importance of maintaining system integrity during this expansion of functionality related to DERs and the DSP. To address these concerns, Central Hudson has developed a Cyber Security of Operational Technology (CSOT) methodology, which takes a CIP Standards approach to non-CIP assets – applying the same principles as CIP, but not within the CIP program. This ensures that the same Cyber Security standards that are used for other critical utility systems are consistently applied to the DSP.

Advancing New Forms of DER

In the areas of Energy Storage Integration, Electric Vehicle Integration, and Electric Heat Transformation, consistent with the actions by the Commission, Central Hudson has begun a new strategic focus to advance the understanding of the role of the utility in these markets. Central Hudson has been active in the various policy cases and joint utility activities in these areas and will continue to actively participate in the PSC Cases. As for Electric Vehicle Integration, Central Hudson worked externally with the Joint Utilities to implement the Direct Current Fast Charger (DCFC) Incentive program and is working collaboratively with DPS Staff on Electric Vehicles and other beneficial electrification. With what has been learned over the past few years and this new strategic focus, Central Hudson is poised to progress on both of these aspects of the DER market at a rapid pace.

Investing in Infrastructure

Central Hudson's service territory continues to show an overall reduction in system peak with few areas showing any 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 is able to 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.

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 as appropriate. Since the inception of its Non-Wire Alternative program in 2014, Central Hudson has identified and/or implemented four Non-Wire Alternative projects covering approximately 16% of our load areas. While this has led to the deferral of capital projects related to growth in those areas and an increase in DERs, it has also resulted in a continued reduction in the broader system Locational System Relief Value and the Demand Reduction Value.

In summary, Central Hudson continues to progress the DSP through its individual efforts as well as the collective efforts of the Joint Utilities. The Company remains fully supportive of working with the stakeholders, the Commission, and the other utilities on improving transparency and data sharing. Additionally, Central Hudson strives to meet the objectives of the REV 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

Central Hudson and the Joint Utilities have focused Distributed System Platform (DSP) implementation efforts on three core aspects of the platform: Distributed Energy Resource (DER) Integration, Information Sharing, and Market Services. These core aspects include the basic focus areas from the DSIP: Distribution System Planning, Grid Operations, and Market Operations. The progress achieved in these areas and described in this DSIP will benefit customers and market participants by (1) providing more and better information that helps them to make informed market choices, (2) stimulating DER deployment by facilitating the realization of DERs value, and (3) implementing planning and operational methodologies and infrastructure that allows continued safe and reliable system operation at higher DER penetration levels.

The results of this current "DSP 1.0" version of the DSP will be more DERs on the system and across New York and the potential for improved system efficiency, more resource diversity, lower emissions of greenhouse gases, and the animation of market services. DERs will have better access to market value through multiple market mechanisms, and in turn, the system will benefit from an enhanced ability of DERs to provide grid services.

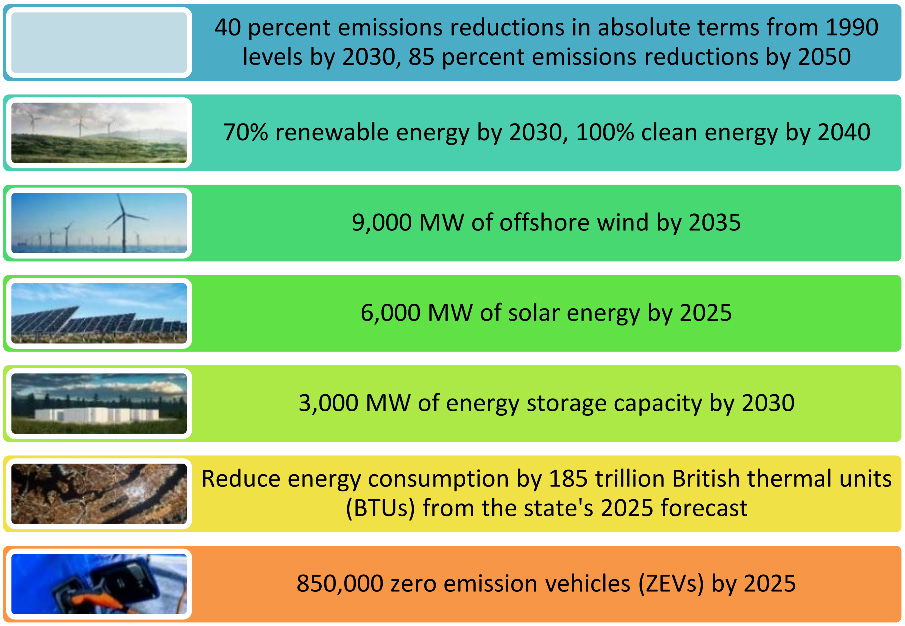
The progress outlined in this DSIP will also advance Central Hudson and the Joint Utilities toward the longer-term vision of the DSP and beyond, as discussed below.

B. Long Term Vision

1. Summary

Since the 2018 DSIP, the clean energy policy focus in New York has shifted from an emphasis on distribution-connected, small-scale energy resources to advancing de-carbonization through larger, utility-scale resources such as offshore wind. The passage of the Climate Leadership and Community Protection Act (CLCPA) in June 2019 encapsulated this transition. The CLCPA codifies as New York State law multiple targets and policies designed to drive the state toward net-zero greenhouse gas (GHG) emissions over the coming decades.

Figure 2: Summary of CLCPA Goals plus Zero Emission Vehicle Regulation Targets



Central Hudson is committed to driving the development of the clean energy economy in New York. The role of the utility in achieving the CLCPA's clean energy transition for the New York State energy grid is more important than ever before, including functions at both the distribution and transmission level.

The Company's DSP vision continues to focus on facilitating the growth of distribution-level clean energy resources by providing three interrelated DSP services – DER integration, market services, and information sharing. Through these services, DSPs will deliver value for electricity customers and market participants through expanded customer choice, greater leveraging of DER as a system resource, and enhanced access to value streams that compensate DER for their realized distribution and wholesale value. The Company will stage investments to develop a DSP that manages a fully integrated grid and provides safe, reliable, efficient, and clean electricity to customers. As presented in its DSIP updates, Central Hudson has continued to make progress in enhancing its capabilities to provide services in all three areas.

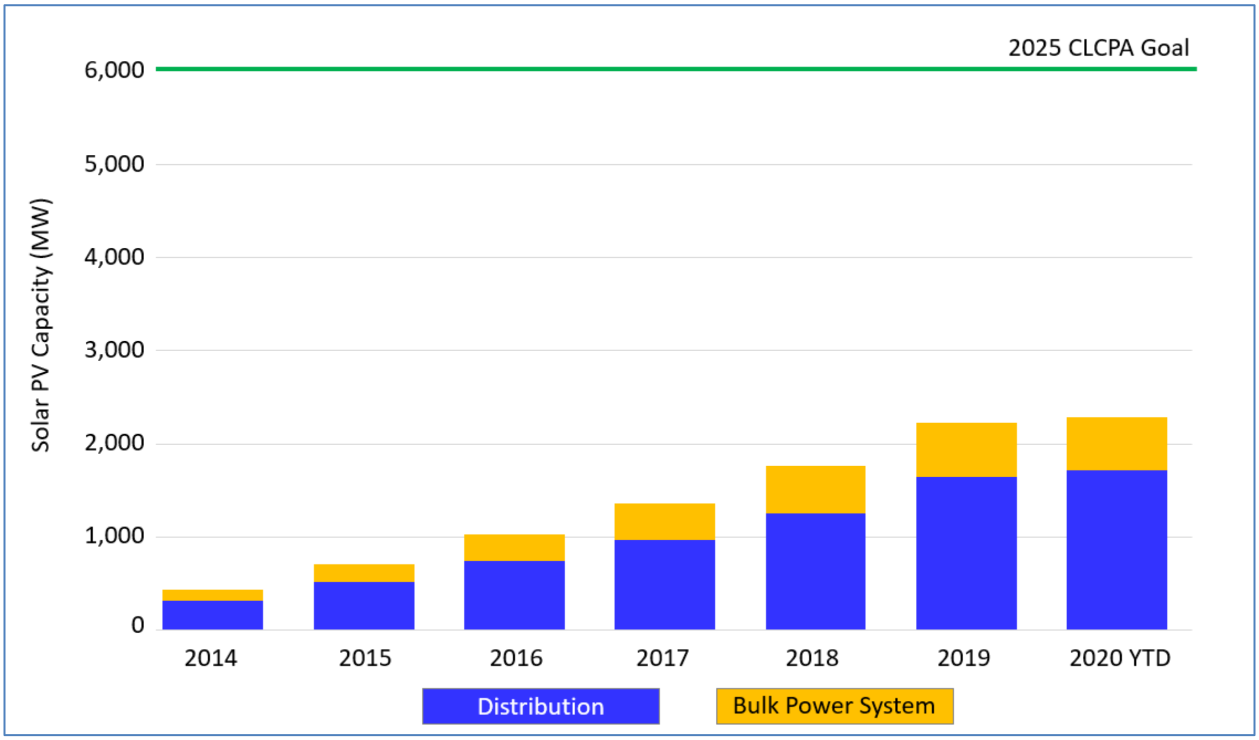
The CLCPA also accelerates and expands beyond the REV trajectory, placing an increased emphasis on large-scale renewables, beneficial electrification, and serving disadvantaged communities. The Company's vision is adapting accordingly. While Central Hudson has long supported and planned for growth in renewable generation at both the distribution and transmission level, the CLCPA clarifies how New York will reduce carbon emissions throughout the economy as it utilizes a vastly higher penetration of clean resources like solar PV and wind, a significant portion of which will be interconnected to the transmission system. Transitioning away from the combustion of fossils fuels by electrifying much of the State's transportation and space heating to utilize increasing renewable generation will also provide a significant portion of the State's carbon reductions. This transition to large-scale electrification will put upward pressure on electricity demand, especially in the winter. Additionally, expanded adoption of flexible resources like energy storage and electric vehicles will create a more dynamic system and requires more advanced DSP management capabilities.

Watershed State Clean Energy Goals Emphasize the Importance of DSP Capabilities

As captured in Figure 2, targets set by the CLCPA and other associated state policies are aimed at the deployment of specific technologies that will impact the resource mix in New York and enable a cleaner energy future. The Company's vision now contemplates these targets, and it expects that supporting investments to achieve them will accelerate, leveraging the DSP building blocks the utilities have implemented and are in the process of implementing. Because of the investments Central Hudson has made to expand DSP capabilities, Central Hudson is well-positioned to continue building on this foundation in the coming years through multi-value projects that create benefits for the distribution system, and support expanded bulk system transmission capacity and market opportunities, where the majority of growth will need to occur to attain most targets.

Figure 3 illustrates this trajectory for solar PV – both the progress that the Joint Utilities have driven on the distribution system toward meeting the CLCPA goal of 6,000 MW of solar PV by 2025, as well as the need for DSPs to facilitate greatly increased bulk system solar capacity in the next five years. The utilities' collective efforts to streamline interconnection, enhance planning processes, and deploy enabling grid technologies have enabled significant growth of solar PV on the distribution system, approximately 500% from 2015 through 2020. Yet even at that robust growth rate, the pathway to the 2025 goal requires even more significant growth in bulk-level resources. The Company's vision for the DSP incorporates this evolving understanding of the need to continue supporting ever more advanced distribution system DER integration and operation while enhancing capabilities to integrate and manage renewable generation resources across all system levels.

Figure 3: New York's Progress towards CLCPA Goal of 6,000 MW of Solar PV by 2025



There is a similar set of needs for other CLCPA technology targets. For example, the Company's efforts to advance electric vehicles (EV) demonstrations, pilot projects, and charging infrastructure awareness among customers, regional groups, associations, and governments have helped lead to New York State's light-duty EV population growing to nearly 50,000 vehicles. These steps have served as critical foundations and should continue, but will not be sufficient to maintain similar growth rates in the coming years or to achieve Zero Emission Vehicle Regulation ("ZEV") targets. Furthermore, given that transportation remains a major contributor to the State's GHG and criteria pollutant emissions, EVs are also a critical component in achieving CLCPA targets.

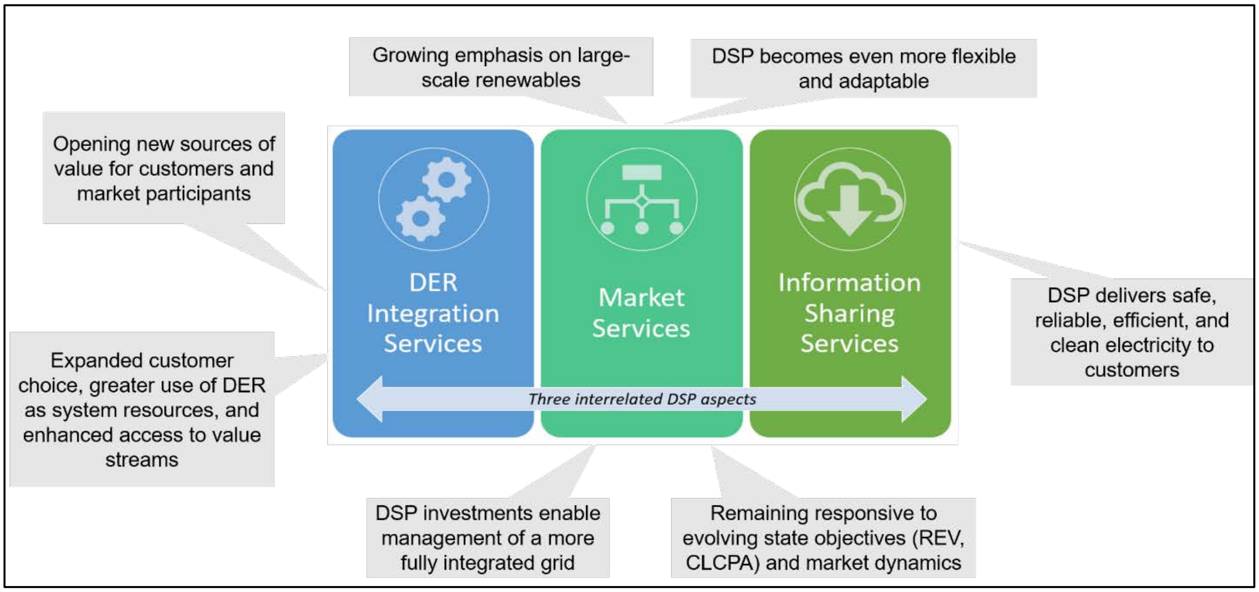
The Company envisions increased strategic investment in electric infrastructure needed to support most of the State's proposed EV charger gap to expand EV adoption in underserved market segments. The Joint Utilities anticipate a need to play a more active role in supporting the strategic deployment of EV charging infrastructure, managing EV loads to provide system benefits, and creating broad customer awareness of transportation electrification benefits. Utility investments can also support emerging opportunities in medium and heavy-duty vehicle electrification, generating benefits for communities that have disproportionately faced the brunt of transportation emissions. The Joint Utilities are currently working with DPS on approaches to create flexibility to ensure that future transportation electrification programs achieve State goals, support the diverse interests of EV charging service providers and EV charging site hosts, and provide benefits to all utility customers.

Given the expected growth across clean energy technologies, the Company has also 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.

Core to Central Hudson's DSP vision is the goal of attaining clean energy targets at the lowest possible cost for customers. As such, 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 put in place, the DSP market services will evolve from tariff- and procurement-based mechanisms to more competitive and cost-efficient market mechanisms.

Being able to fully achieve these goals and deliver a clean energy future for New York requires an expanded set of DSP capabilities that builds on the foundation established in recent years. As described in the 2018 DSIP, these enhanced capabilities encompass three interrelated aspects of the DSP: (1) DER integration services, (2) market services, and (3) information sharing services. See Figure 4.

Figure 4: 5 Year Vision for the DSP



Providing Safe, Reliable Electric Service as the System Evolves and Integrates DER

One of the three core aspects of the DSP is DER integration services, which the Joint Utilities define (see 2018 DSIP) as the planning and operational enhancements that promote streamlined interconnection and efficient integration of DER into operations while maintaining the safety and reliability of energy delivery.

Central Hudson's vision is to further enable the secure, safe, and rapid integration of DER, and to enable dynamic network management and interface with DERs.

The long-term DSP vision includes more seamless DER integration into all aspects of system planning and operations. Beginning with interconnection, continued improvements to streamline the process will allow DER to receive interconnection approval faster and include tailored requirements to specific DER types and locations. In the future, the Company will be able to use flexible interconnection agreements to more actively manage operations of new DER in response to dynamic system conditions under high penetration scenarios. Although the development of a framework for adapting to new DER behavior and penetration levels will likely go beyond the five-year timeframe of this DSIP, the Company is taking near-term steps to enable this type of active network management and deliver cost savings to the DER owner, while simultaneously providing the DSP with greater operational flexibility.

In addition to an enhanced interconnection process, Central Hudson also envisions a more robust planning process that preserves system safety and reliability while ushering in a clean energy future. The

DSP will maximize system benefits of an increasing number of DER while enabling the evolution of a more harmonized planning process across the transmission-distribution (T-D) interface to effectively account for the planning impacts of clean energy resources interconnected at all levels of the system.

Enhanced interconnection processes, planning processes, and grid modernization deployment will enable more dynamic operations that fully utilize higher levels of flexible resources to resolve localized constraints. The Company will have greater flexibility to meet the real-time needs of the distribution system by using energy storage and dynamically managing load through a portfolio of DER and system assets. Central Hudson has taken steps to prepare for this increasingly dynamic grid, including analyzing monitoring and control (M&C) and operational system requirements and coordinating with the NYISO to define operational coordination processes needed to facilitate DER wholesale market participation.

Central Hudson also recognizes that smart inverters can play an important role in enabling this vision of active network management, flexible interconnections, and increased DER visibility. Given the significant complexity involved with standardizing smart inverter functionality in New York, the Company is working alongside the other utilities to identify implementation pathways that maximize the system benefits that smart inverters can provide and to expand future collaboration with stakeholders.

Enabling a Robust Marketplace for DER to Access Value at All Levels of the Grid

A second core aspect of the DSP is market services. Central Hudson's vision is for the DSP to support a more competitive, transparent marketplace for distribution-level electric services that delivers efficient outcomes for investment and operation at the lowest cost to customers.

Today, the Company offers DER compensation through broad tariff mechanisms Value of DER (VDER), demand-side-management programs, and direct contracting with resources (i.e. non-wires). Each mechanism played an important role in kick-starting and accelerating DER adoption. The long-term DSP vision evolves from this starting point to a future energy marketplace based more on competitive market signals, leveraging DER participation in the NYISO wholesale markets while enabling an additional market for targeted distribution system value. The development of a more competitive marketplace that delivers the most cost-efficient outcomes for customers depends on highly targeted market opportunities that compensate resources based on verified performance relative to the services and characteristics required. This alignment between the system needs and resource performance effectively signals to customers and DER operators the relative cost and value of the locational and temporal grid services required to maintain reliability, which will enable the DSP to pay or be paid for the appropriate use and potentially support peer-to-peer settlements or transactions. Additionally, effectively targeting market opportunities will support a more harmonized DER marketplace across the transmission-distribution interface that minimizes cost while preserving system safety and reliability.

As technology, planning, operations, and DER penetration levels advance, the Company will layer on additional distribution market services to transition the current compensation mechanisms to a truly dynamic and competitive distribution marketplace.

Forthcoming integration of DERs into the NYISO wholesale markets will serve as a significant step towards realizing the DSP market vision. As DERs begin to participate more fully in the wholesale market, the DSP will play a critical role in ensuring that the NYISO's dispatch of wholesale participatory DER is compatible with distribution system safety and reliability. Within the 5-year time horizon, the Company believes that with enhanced planning, operational capabilities, and evolving market rules, the DSP will begin to take steps toward building more granular and market-based distribution value compensation mechanisms that complement, and do not duplicate, the NYISO wholesale markets and other compensation mechanisms.

Central Hudson believes this vision will be consistent with ongoing stakeholder discussions, including the DPS-led Market Design and Integration Working Group (MDIWG) and the PSC's Value of DER proceeding. There are currently multiple potential future states under consideration. The Joint Utilities remain active participants in these processes and are focused on advancing the vision of promoting pathways to market value for energy resources, as well as achieving price parity for consumption and injection of electricity to guide investments to the most cost-effective resources.

The Company is also continually reviewing and refining the full range of future grid modernization requirements that will be critical for the DSP to deliver a long-term, competitive, and dynamic distribution marketplace. Central Hudson is currently implementing key transformational investments (e.g., Network Communications, ADMS, and grid automation) to further enhance the operational capabilities necessary for this future.

Sharing Useful, Market-Enabling Information that Enhances Customer Value

Information sharing services, the third core aspect of the DSP, are comprised of communications and analytics systems that measure, collect, analyze, manage, and display granular customer and system data. Access to this information enables customer choice and facilitates third-party vendors' and aggregators' participation in markets for DER. These efforts require continued emphasis on preserving customer privacy and security.

In this area of the DSP, Central Hudson's vision is to provide useful information that results in customers receiving greater value, while helping to attain the CLCPA's energy goals. With enhanced levels of visibility into real-time DER and system operations and the resulting expanded repository of customer and DER data, the DSP will be better equipped to provide valuable information that enables market participants to match clean energy resources with customer and utility needs efficiently. These utility efforts – which build off of the significant progress Central Hudson has made to date in expanding the provision of system and customer data – will continue to animate DER markets and enhance the distribution system's role as a core component of an integrated, clean, and flexible electricity system.

Central Hudson is also participating in advancing the concept of a statewide data resource platform as a potential part of its vision for information sharing. The Company believes that enhancing customer value should be the primary objective of this effort and that providing more uniform information across state utilities through a common platform holds the potential to help market participants provide this value. The utilities must work in partnership with DPS and stakeholders to understand critical aspects of a future platform, such as customer willingness to allow utilities to share their anonymized or non-anonymized data for DER developers' market research. Central Hudson is supportive of establishing a collaborative approach to continue to strive for greater energy data uniformity, granularity, and secure and improved access across New York utilities.

2. DSP Progress and Implementation Roadmap

a) DER Integration

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 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. Planning methodologies and processes at the time (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 enablement and management of a high-DER environment.

Since the 2018 DSIP, the Joint Utilities have continued to meet with stakeholders through a variety of stakeholder engagement sessions. This includes, but is not limited to, the ITWG, IPWG, and Hosting Capacity Group. As the ultimate goal of these groups is to streamline processes and enable higher DER deployment on the system, DSP enablement plans continue to evolve based on stakeholder priorities. Through June 2020, the Central Hudson and the Joint Utilities have implemented several key DER Integration initiatives, which are summarized in Figure 5.

Figure 5: Actions and Results in DER Integration through June 2020

Actions		Results
Improved forecasting methodologies	→	Plan the future grid in a cost-effective manner that facilitate increasing levels of DER while safeguarding future reliability
Expanded deployment or demonstration of foundational communications and operations infrastructure: AMI, sensors, DSCADA, Distribution Automation, ADMS	→	Facilitates improved network performance and increased DER integration
Released Stage 3.0 of the hosting capacity displays which added sub-feeder level granularity and existing DER	→	Provides stakeholders with additional detailed information and to create a more streamlined DER interconnection process
Released a stakeholder survey on the full list of potential enhancements to the hosting capacity displays stakeholders have previously requested	→	Allows for third party input into the prioritization into the hosting capacity roadmap enhancements in both the near and long-term
Updated the SIR to include energy storage systems to formalize a state-wide standard process for energy storage interconnections	→	Provides greater certainty, transparency and uniformity to energy storage developers in the interconnection process across New York

Actions		Results
Completed internal and external benchmarking of smart inverter capabilities	→	Identified common understanding of the individual Joint Utilities' efforts to date, and the challenges, lessons learned, and best practices to consider as part of a statewide approach developed with the ITWG and IPWG
Continued REV demonstration and other research projects focused on areas such as: smart inverters, flexible interconnection, and alternative telemetry and communications methods	→	Provides insight regarding deployment at scale to address system needs while delivering exceptional customer value
Coordinating with NYISO, DPS, NPCC, and other stakeholders on bulk power system impacts from DER operations	→	Establishing plans to preserve system safety and reliability while enabling DER value realization across all levels of the electric system
Coordinating with the NYISO and DPS on interconnection coordination matters including queue management, venue mapping and study procedures	→	Established a framework to ensure alignment of DPS and NYISO interconnection processes

As outlined in the 2018 DSIP, Central Hudson continues down its well-established path of developing a smarter and more functional electric distribution system. An advanced distribution system provides the ability to use smart grid devices and functionality, two-way communication and near real time monitoring, along with advanced system modeling and automated response to changing system conditions. Additionally, an ADMS provides the ability to integrate customer-owned DER in such a way as to not only to accommodate the additional DER, but to utilize this DER in such a way as to maximize its value to both the customer and the DSP through improved efficiency and operation of the distribution system.

Central Hudson outlined a number of the Foundational Investments that will allow for this functionality. One area that remains unclear is how liquid a market can develop within the DSP as a result of this new functionality and the increased level of DERs. A dominant factor in the evolution of this market is the value of DERs to the distribution system and whether this value, in a utility service territory where electric load growth is meager, will ever be enough to allow for a DER market to grow beyond tariff based programs or targeted NWA solicitations. Central Hudson will continue to work with the Joint Utilities, Stakeholders, and the PSC to develop a common understanding and definition for the Value of DER and how this value can be best offered to the market. Central Hudson will also work with the Joint Utilities and the NYISO to ensure that any market developed within the DSP is well-coordinated and complementary to the wholesale market administered by the NYISO and regulated by FERC.

In the interim, Central Hudson's vision for the DSP is one where increased functionality, visibility, and control of the distribution system will allow for improved operation, efficiency, reliability, and increased DER interconnection.

While these are outputs described in greater detail in later sections, some highlights are described briefly below.

Since the 2018 DSIP, the Interconnection Technical Working Group has focused on the integration of ESS to further streamline the process and requirements associated with this newer technology. This includes establishing protection and control requirements, standardizing on metering options and configurations for hybrid systems, and improving the level of data requested as part of the ESS application in order to provide the utilities with key information needed to appropriately plan and operate the system, but also providing the Industry with flexibility given some of the market uncertainties with ESS. The Joint Utilities have also worked to further automate the interconnection application process through efforts associated with Phase 2 of the Interconnection Online Application Portal (IOAP). Phase 2 efforts further streamlined the process by automating the preliminary screening analysis within the NYSSIR. This is a milestone in a phased roadmap presented in the Supplemental DSIP to achieve various functionality improvements throughout the interconnection process, with the final "full automation" phase in the future. Additionally, the JU and the ITWG have begun discussions and research, including benchmarking, related to the use and integration of smart inverters.

In order to outline and implement standard operating practices across all levels of the transmission and distribution system, the Joint Utilities have coordinated with the NYISO to propose operational DSP - NYISO coordination protocols. These protocols offer approaches for DSP dual participation as a provider of both local distribution services and wholesale energy in NYISO markets, which could allow DERs to access multiple value streams, without impacting the reliability of the transmission or distribution system.

Additionally, as Central Hudson is seeing a high penetration of DER systems in localized areas of both the transmission and distribution system, the Company in the early stages of a research and development project related to deploying a Distributed Energy Resource Management System (DERMS). The purpose of the DERMS would enable Central Hudson to better manage grid performance with a high penetration of DER, particularly for transmission voltage levels that the NYSIO does not secure.

Central Hudson and the Joint Utilities have also collaborated in shared learning on more advanced forecasting approaches, including the incorporation of probabilistic methodologies. Enhanced forecasting is supporting more granular Marginal Cost of Service studies, which underlie more accurate and updated Locational System Relief Values (LSRV) as part of the Value of DER (VDER) Phase 1 tariff. These improved forecasting initiatives are helping to more accurately align DER compensation with grid value through price signals, one of the core goals of the DSP.

Central Hudson, both individually and in conjunction with the Joint Utilities, will continue to advance and expand both internal and stakeholder-facing shared learning opportunities in the deployment of advanced metering and DER management systems, as well as through the operation of REV demonstration projects exploring flexible interconnection, storage, online marketplaces, and transportation electrification. These initiatives are critical foundations for understanding how to most effectively integrate new technologies, projects, and policies to enable rapidly increasing DER penetration.

Through 2022 and beyond, further advancements in DER integration will drive continued progress towards the next phases of the DSP. Ongoing demonstration and deployment of foundational DSP technologies (such as ADMS including forecasting methods for both load and DER, DERMS, smart inverters, Energy Storage, EV charging infrastructure, and expanded monitoring and control capabilities through direct utility control, third-party aggregators, and the wholesale market operations) will enable active management and coordination of DERs on the distribution system. In addition to these technical factors, IOAP 3.0 and improved coordination with the NYISO and utility interconnection processes will further streamline the DER interconnection process through increased automation, and DER forecasting will become a standard part of Central Hudson's planning process.

b) Market Services

While the distributed system platform must perform multiple functions, a key focus of the Track One and Track Two Orders 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 in 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 advances in the "3 P's" (pricing, programs, and procurement), and the Joint Utilities have implemented a number of steps in each of these areas to accomplish this goal.

At the outset of REV, none of the New York utilities had yet incorporated NWAs into their distribution procurement processes.[1] DERs were limited in their ability to offer services as an alternative to traditional utility infrastructure investments and to offer new services to customers. A significant volume of DERs on the system – mostly distributed photovoltaic systems – were compensated based on net energy metering, a system that represented a useful provisional assessment of value but one that had not yet been finely calibrated to the grid services provided by these resources. Through June 2020, Central Hudson and the other Joint Utilities have implemented several key Market Services initiatives, which are summarized in Figure 6.

Figure 6: JU Actions and Results in Market Services through June 2020

Actions		Results
Identified and developed non-wires opportunities	→	Developing projects and portfolios of DER solutions that provide value to customers; streamlining the non-wires solicitation process across the Joint Utilities
Formalized dispatch and communication protocols and roles and functions between the DSP, NYISO, aggregator, and DER owner	→	Enables DER to access more value through wholesale markets while preserving system safety and reliability

[1] Con Edison's Brooklyn-Queens Demand Management program was proposed in 2014 and Central Hudson's initial NWA's were proposed in its 2014 rate filing.

Actions		Results
Enabled dual participation for DER and energy storage resources	→	Provides opportunity for DER to access value for both distribution-level services and wholesale markets
Expanded implementation of advanced customer programs for demand-side management (EE, DR)	→	Allows for greater DER market participation and increases DSP flexibility to meet system needs
Continued implementation of the Value of DER value stack	→	Provides market signals to DER about the locational and temporal value of operation
Engaged in the DPS Market Design and Integration Working Group (MDIWG)	→	Charting out potential paths forward to enable a New York energy marketplace that achieves clean energy deployment, customer empowerment, and cost savings while providing grid level, distribution level and edge level services
Stakeholder engagement in non-wires alternatives process including hosting both Joint Utilities and Company-specific webinars	→	Increased awareness of open RFPs, awarded projects, lessons learned, and utility BCA approaches to improve developer experience and drive competitive bids and customer value
Defined suitable, unused, and undedicated utility land as directed by the Storage Order; developed a mechanism for standardizing the valuation of unused utility land to be included in BCA handbooks and non-wires alternative opportunities	→	Creates visibility for bidders into the potential use of utility land, if available for NWS, delivering value to customers through lower-cost solutions

Actions		Results
Initiated procurement of at least 350 MW of energy storage utilizing NYSERDA's bridge incentive funding, catalyzing expanded storage deployment	→	Supports the state's ambitious clean energy goals; RFP results announced April 2020
The Joint Utilities collaborated with NYSERDA on Energy Efficiency (EE) statewide implementation plans for heat pumps and Low-Medium Income (LMI) customers	→	United vision and plan for increasing EE efforts; plans filed in March and May 2020; and stakeholder conferences held on LMI
Explained Allocated Cost of Service (ACOS) methodologies at technical conferences and through filed descriptions in case 15-E-0751	→	Increased clarity for customers and other stakeholders on costs allocated on a shared and local basis for the purpose of creating Standby Rates
Explained marginal cost of service studies filed as proposed basis for value to the distribution system in case 19-E-0283	→	Provide a more accurate compensation for DER, including EE, DLM, and DER on the Value Stack Tariff for avoided distribution value
Developed EV direct current fast charging (DCFC) incentive programs using a similar approach across the Joint Utilities	→	Encourages deployment of public direct current fast charging stations to facilitate wider adoption of EVs

Since the release of the Supplemental DSIP, the Joint Utilities have provided NWA suitability criteria that followed common guidelines developed in discussions with stakeholders and were also individually tailored to each utility. Utilities and stakeholders agreed that such criteria could help all parties by identifying the best opportunities for NWAs, allowing for more efficient use of time and resources. The Joint Utilities submitted a filing in May 2017 describing how future utility planning procedures would apply the proposed NWA Suitability Criteria and identifying projects in each utility's five-year capital plan that meet these criteria. Central Hudson has focused on targeting local infrastructure upgrades through

NWAs. To date, Central Hudson's active NWA projects account for approximately 16% of its service territory based on percent of load.

In procurement, the Joint Utilities have made substantial progress, as informed by discussions with stakeholders. Multiple stakeholder meetings detailing the proposed NWA sourcing process both before and since the Supplemental DSIP have generated important feedback on stakeholders' desired timeframes for notification of NWA opportunities, as well as standardization of required data and requirements in response to requests-for-proposals (RFPs). Incorporating this feedback, the Joint Utilities produced a set of NWA Suitability Criteria as a standard framework for evaluating potential utility NWA investments, as well as a more detailed filing on the DER sourcing process. The Joint Utilities are continuing to work toward increased standardization and simplification of that process.

As a result, four NWA opportunities have been identified in Central Hudson's service territory since the inception of this process improvement, and information about these opportunities has become available sooner and through centralized online locations. Developers can now expect to see increasing standardization of the elements of RFPs, making responding easier and faster. These NWA opportunities have been offered as technology-neutral, and as energy storage becomes more cost-effective or able to access value from the wholesale markets, Central Hudson expects to see energy storage added to the more traditional technologies of Demand Response, Energy Efficiency, and Distributed Generation.

In pricing, as noted above, the Joint Utilities have worked to incorporate multiple work streams, including new forecasting techniques and an understanding of NWA suitability to provide inputs to the VDER Value Stack working group. This group is advancing the work within that proceeding to craft a tariff that is more aligned with DER grid value and provide greater certainty of bankable revenue streams that support the financing of projects. The Joint Utilities have also put forward a longer-term vision for the relationship and role in the marketplace between NWAs and tariffs like VDER, to help clarify the pathways through which DERs can be developed and compensated.

The Joint Utilities have also worked on market services regarding specific DER technologies. One area of focus has been supporting the adoption of electric vehicles and the deployment of electric vehicle supply equipment (EVSE). Central Hudson had instituted a new strategic focus on EVs and will be developing internal program leadership and a cross-functional team to advance utility infrastructure and rate design discussions, vehicle charging equipment needs, and advocacy and education for both company employees and the public. On April 24, 2018, the Commission commenced a proceeding to consider the role of electric utilities in providing infrastructure and rate design to accommodate the needs and electricity demand of EVs and EVSE. In addition, on May 31, 2018, the Governor announced a new $250 million electric vehicle expansion initiative, EVolve NY, with the New York Power Authority. Since that time, the Joint Utilities have implemented the DCFC incentive program, incentivizing more than 1000 DCFC plugs from 2019 through 2025. In addition, in early 2020 the DPS Staff issued a white paper for a potential make ready program for light duty vehicle DCFC and Level 2 charging. Central Hudson has been working with the DPS Staff, NYSERDA, the Joint Utilities, and Stakeholders to refine the program described in the whitepaper and develop a statewide charging infrastructure program to assist in enabling the electrification of the transportation sector.

In addition to Electric Vehicles, Central Hudson is very supportive of utilizing clean electric heating technologies as a carbon reduction strategy. The Company launched its first heat pump conversion program in 2018 and has achieved early success.

According to the Energy Efficiency Order, utility-specific mechanisms within electric rates or surcharges would be used to fund its heat pump programs. Central Hudson's current proposed heat pump program budget of $30.2M over the period of 2020-2025 is forecasted to enable the Company to achieve approximately 12,000 installations. Although the bill impact of this initiative may appear manageable in the short term, the Company is concerned about the long-term sustainability of funding this and other beneficial electrification initiatives primarily through electric bills. Additional advancements in market services up to and beyond 2020 will continue to progress the DSP's role in enabling and appropriately compensating DER participation through various market mechanisms. One such mechanism is VDER Phase Two, in which compensation for distribution value will be enhanced beyond the current version of DRV/LSRV components. The market platform will also facilitate higher DER value through direct or aggregated participation in NYISO wholesale markets, a more standardized NWA procurement process, more flexible interconnection, and near-real-time distribution-level services. Further enhancements to probabilistic load and DER forecasting methods, along with greater temporal and locational granularity of data, will allow market participants to more effectively realize value from DER investments and transactions through the DSP.

c) Information Sharing

Expanded access to more transparent, granular, and accessible data sources empowers retail consumers, developers, and other stakeholders to make smarter decisions in 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, as aligned with developer needs at the time. Because DERs did not yet constitute a significant proportion of system load or capacity, 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. Through June 2020, the Joint Utilities have implemented several key Information Sharing initiatives, which are summarized in Figure 7.

Figure 7: Actions and Results in Information Sharing Through June 2020

Actions		Results
Updated individual utility data portals including system data, LSRV, NWA, hosting capacity stage 3.0	→	Improved data access and granularity to increase value of data driven by stakeholder and developer feedback
Established statewide terms and conditions for the use of aggregated whole building data shared with owners or agents	→	Developed common statewide approach which facilitates business opportunities for third parties while maintaining customer data security and privacy
Implementation of Green Button Connect (GBC), or similar; and proposed GBC terms and conditions	→	Increased data access through easier and more granular mechanisms to share customer data for customers or authorized third parties, and established terms and conditions for use of such data to maintain customer privacy
Began submitting Utility Energy Registry (UER) bi-annual data reports to NYSERDA	→	Increased data access by sharing aggregated zip code or municipality monthly energy usage data to the public UER
Created a standard data security agreement (DSA)	→	Increased data access and privacy by improving energy data security practices
Coordinated implementation of new data pilots	→	Informed utilities about ongoing utility-specific data pilots for knowledge sharing with NYSERDA which may expand statewide deployment
Continued to support the strategic use of energy data through conversations with Staff and stakeholders	→	The Commission opened a new proceeding (20-M-0082) to comprehensively coordinate data related efforts in the state

Over the past two years, the Joint Utilities, guided by stakeholder engagement, including focused outreach to understand developer use cases, have developed and implemented a comprehensive set of information sharing enhancements. These include the creation of centralized portals both on the Joint Utilities' website and through REV Connect to provide system data and access to NWA and other RFP opportunities. These portals enable increased access to and usability of stakeholder-requested information and enhance efficiency for developers seeking to participate in NWA and other opportunities.

The Joint Utilities have also made progress in achieving greater uniformity and shared understanding of privacy standards, including the 4/50 data privacy standard for whole building aggregated data, which the Commission approved in its April 19th, 2018, UER Order.[2] This alignment secures individuals' utility data, fulfilling the critical need to protect customer privacy while also simplifying planning for stakeholders, who can now anticipate and design approaches based on a shared privacy standard.

The Joint Utilities have also collaborated to address other priorities related to information sharing, stemming from the Supplemental DSIP filing and related Orders, which are building blocks towards more evolved information sharing services within the DSP.

The Joint Utilities system data working group has advanced through the second step of a three-step process to review and standardize the formatting of publicly available data. Once completed, this more uniform approach will assist developers and other stakeholders who have identified shared formats as a priority. The group has also completed other important steps, such as proposing an annual needs assessment, classifying data based on the sensitivity of the information, and working collaboratively with stakeholders regarding requests for additional data elements. 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 in the development of System Data Portals for DER developers to gather valuable system data. In addition, during the past two years, the Joint Utilities have been working together to develop a greater understanding of system data needs and studying use cases, however these discussions have not resulted in significant changes in the amount of available data nor in the way this data is accessed.

To propose the next steps to enable access to useful energy data, on May 29, 2020, the DPS Staff released a whitepaper - Recommendation to Implement an Integrated Energy Data Resource. Central Hudson looks forward to working collaboratively with DPS Staff and NYSERDA to help achieve a useful and valuable resource.

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[2] This standard dictates that a building must have at least 4 residents, with no resident accounting for more than 50% of the building's annual energy consumption, in order to allow aggregated data to be collected and shared.

The customer data working group has also completed several steps, including developing approaches for aggregated building data collection and dissemination – some of which were addressed in the 4/50 privacy standard proposal – as well as a process to track aggregated data requests and responses, allowing for more efficient identification and response to non-standard, high-value data requests from stakeholders.

On May 29, 2020, the DPS Staff issued a whitepaper regarding a Data Access Framework. As proposed by Staff, the Data Access Framework would serve as a single source for data access policies and provides uniform and consistent guidance on what is needed for access to, and the availability of, energy-related data. In addition, the proposed Data Access Framework would provide a more workable approach that is designed to provide access to data, while preserving all the necessary protections, to fully enable the intentions of the Commission. Central Hudson looks forward to working collaboratively with DPS Staff on the development of the Data Access Framework, allowing customers interested in sharing accessing and sharing their data to be able to do so in a safe and reliable manner.

In addition, the forecasting implementation team has worked to fulfill ongoing tasks related to information sharing, including coordination with NYISO and soliciting input from stakeholders on potential use cases for forecast data. This work has included alignment on understanding the use cases for 8760, or hourly substation-level load and DER forecasts, which are provided shortly following this filing. Central Hudson has been providing this level of detail since the 2016 DSIP filing and continues to make improvements in its DER forecasting that are reflected in this year's updates.

Increased access to data sources and standardized, easily understandable formats will characterize information sharing through 2020 and beyond. Additional value-added data services will be established, and Stage 4 hosting capacity visualizations will enable streamlined interconnection of new DER projects.

C. Innovation

Central Hudson continues to look for innovative opportunities to engage customers, explore new business models, partner with third-party service providers, develop and refine market price signals, and deploy foundational technologies in order to continue the evolution into the DSP and support the State's Energy Policy Goals. Efforts in these areas are described below.

Engaging Customers with CenHub[3]

Central Hudson's first demonstration project, CenHub, was proposed on July 1, 2015, in compliance with Ordering Clause 4 of the Commission's Order Adopting Regulatory Policy Framework and Implementation Plan (issued and effective February 26, 2015). CenHub's primary purposes were to increase customer engagement with electricity and natural gas use and to provide an economically efficient energy efficiency delivery mechanism. CenHub provides customers with extensive functionality including but not limited to:

- A customer portal with personalized electric energy usage dashboard;
- Personalized messaging, energy saving tips, and recommended actions;
- The ability to purchase products and services through an online marketplace and automatically apply rebates at checkout; and
- Cross-promotion of programs that meet the specific needs of the individual customer

Central Hudson is also aware of the growing expectations of customers based on their interactions with other industries and businesses. Looking across industries, there are trends that can be leveraged to design solutions that align with today's customer expectations, as illustrated in Figure 8.

Figure 8: Customer Experience Industry Trends

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[3] CenHub was split/rebranded during a recent web redesign. The store is still marketed as the CenHub store, however the account portal is no longer separately branded as CenHub.

On April 3, 2016, the CenHub Platform was made available to Central Hudson's customers and has seamlessly provided information, decision-making support, and access to incentives and rebates for a host of energy efficient products and services. At this time, 51% of Central Hudson's customers have engaged with the CenHub Platform. Per Central Hudson's current Rate Plan,[4] CenHub graduated from its status as a demonstration project and is now funded through base rates. During the term of the current rate plan, CenHub is expected to continue evolving and engaging customers through:

- improving the mobile platform;
- increasing the number of self-service options;
- providing a personalized dashboard;
- engaging with DER providers to develop third-party partnership portals;
- providing personal usage disaggregation;
- providing municipalities with additional information regarding the aggregated customer information; and
- providing calculators to support customer decisions regarding energy efficiency, voluntary time-of-use, and environmentally beneficial electrification.

These changes to the CenHub platform will increase customer convenience and control by improving the means by which they can manage their energy use and increasing the transparency of the associated financial and environmental impacts while directly supporting the State's Energy Policy Goals.

Engaging Customers with Ongoing Demonstration Projects

Insights+ is a subscription based offering provided on the CenHub Platform since June 6, 2017. Specifically, the Insights+ offering is a continuing demonstration project that comes with the installation of an advanced meter that captures 15-minute interval customer load data and communicates this

[4] Case 17-E-0459, et. al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas and Electric Corporation for Electric Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Current Rate Plan"), (issued June 14, 2018), Appendix Y.

information over cellular networks. This subscription is available to residential customers only at a cost of $4.99 per month. Customers can receive a reduced subscription cost of $1.99 per month if they sign up for the Voluntary Time of Use rate along with Insights+. At this time, approximately 150 customers have subscribed to the Insights+ service.

Beyond the Insights+ demonstration project scope, the Company has expanded the use of the Insights+ meters to assist in accomplishing other operational objectives:

- Measurement and Verification (M&V): Itron utilizes a statistical sample set of Insights+ meters for M&V as part of the Peak Perks NWA program. Itron pays the monthly meter fee and the customer receives the Insights+ service as part of their Peak Perks program participation incentives. Currently, approximately 420 customers are provided with Insights+ data through the Peak Perks program.

- Value Stack: The Insights+ meter data meets the criteria for value stack, and the hosted Itron Meter Data Management (“MDM”) can accommodate the additional meters at no additional system cost.

- Time of Use: The Insights+ meters capture data for our original Time of Use intervals as well as our new Voluntary Time of Use intervals. They also provide enhanced visual displays that differentiate time of use time periods and peak and off-peak usage analytics.

Innovative Market Price Signals and Programs

Central Hudson has refined or developed innovative customer facing programs or price signals in the interim period since the last DSIP filing. Several examples are discussed below.

Central Hudson has utilized the results of its Avoided T&D Study, which was introduced within the 2016 DSIP, in many innovative ways in order to create consistent price signals across many diverse technologies and programs. As such, the Avoided T&D Study provides the basis for the following:

- Value Stack Pricing: The Demand Reduction Value (DRV) and the Locational System Relief Values (LSRV) are based on the Avoided T&D Study.

- Energy Efficiency: The distribution system value within the Benefit Cost Analysis Handbook provides the basis for assigning value to Energy Efficiency measures that provide demand reduction coincident with the system peak demand.

- **Demand Response Programs**: Central Hudson is modifying its existing Dynamic Load Management ("DLM") program to include "Auto" and "Term" DLM categories which are better aligned with the operational characteristics of energy storage resources. These additional categories would provide higher compensation over a fixed term of three years for an enrolled capacity amount. Participating resources will be required to support higher performance factors, quick response times, broader availability, and multi-year participation commitments.

- **Voluntary Time of Use (VTOU) rate**: The Avoided T&D Study provides the basis for the differential between the peak and off-peak prices within the VTOU rate that was approved by the Commission on November 16, 2017, within Case 17-E-0369.

Additionally, Central Hudson has committed an incremental $43.2 million to support the achievement of approximately 255,000 MMBtu of energy savings through heat pump electrification. Heat pumps represent approximately 2% of the heating and cooling market in New York State, as well as 2% of the heating market within the Company's service territory. Heat pump technologies present a great opportunity in meeting the ambitious statewide greenhouse gas reduction goals due to their ability to provide efficient heating and cooling for residences and businesses alike. Central Hudson aims to complete approximately 12,000 heat pump installations by 2025, with a total energy savings of 255,000 MMBtu.

Finally, Central Hudson is collaborating with Joint Utilities and NYSERDA to develop coordinated statewide efficiency initiatives targeting low and moderate income (LMI) customers. Statewide, over 40% of households qualify as low-to-moderate-income. This collaboration includes defining the LMI market, determining key performance indicators, and developing initiative descriptions. Central Hudson has taken an active role in the development of each of the initiatives presented in the LMI implementation plan (LMI IP). The Company also seeks to ensure all LMI customers have equal access to all programs regardless of 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.

D. Grid Modernization and the DSP Technology Platform

Central Hudson proposes system investments in alignment with state objectives to provide safe and reliable service and create net positive customer value. In recent years, many such investments in utility systems both in New York and elsewhere have been associated with grid modernization efforts and have also been described as foundational to the DSP, or DSP-enabling.

Grid modernization investments are investments that improve the reliability, resiliency, efficiency, and automation of the transmission and distribution system. Such investments generally include various groupings of assets: the sensors, communications networks, and data repositories that enable enhanced visibility and understanding of the behavior of the network; technologies and equipment that facilitate greater customer engagement regarding energy usage and alternatives; and the underlying systems, data management, and analytics that facilitate situational awareness, asset management, contingency and risk analysis, outage management, and restoration. These necessary core investments underpin the required focus on grid reliability and resiliency of any grid investment strategy. They provide the basis for increased operational flexibility, can enable efforts toward achieving state policy goals, such as the integration of various types of DERs, and are beneficial for any resource mix.

Central Hudson, along with the other New York utilities, has been proposing and implementing investments that meet this definition of grid modernization since before the commencement of REV and continue to do so. Upon the initiation of REV, the utilities have worked to align planned and proposed investments with identified REV objectives. Because REV goals are subsumed within overall state energy and environmental policy goals, all grid modernization investments planned and proposed by the Company are aligned with REV, though not necessarily driven by REV.

Many grid modernization investments have mutually reinforcing benefits, such as those that provide reliability or operational benefits while also supporting DER integration, and therefore contribute to meeting multiple objectives. This is why many current Stage 1 investments are described as "foundational" in the context of the DSP. Foundational Investments are a subset of grid modernization investments that enable grid capabilities to provide or support applications that increase reliability, resiliency, safety, and enhanced situational awareness and operational flexibility. These Foundational Investments are required to enable more advanced functions related to DSP enablement and DER integration. Foundational Investments are, therefore, "no regrets" actions that can support both current and future functions, such as integration and utilization of DERs, in a modular fashion.

Future functions, which typically fall into Stage 2, are variously described as DSP enablement, DER integration, DER utilization, or value capture activities. DSP enablement is an overarching term that, in the grid investment context, refers to ensuring that the DSP can manage the growing penetration of DERs for both bulk system and distribution operations while maintaining safety and reliability. This description has significant overlap with enabling DER integration, which refers to ensuring that the grid can integrate DERs with the necessary communication, cyber security, and physical security protocols, in order for DERs to be included in system planning grid operation processes. DSP enablement also allows the DSP to improve DER utilization and value capture, which means that the DSP can make use of DERs to meet system resource needs and enhance system efficiency while providing system and economic benefits.

DSP capabilities are achieved through a set of investments that advance reliability and operational efficiency (i.e., foundational investments) or allow for DER integration and DER value capture (i.e., DSP-enabling investments). This DSIP contains plans for grid modernization investments that advance New York policy objectives and enable DSP capabilities. The foundational and DSP-enabling investments that Central Hudson and the other New York Utilities have outlined would enable it to meet the following New York policy objectives:

- Drive Affordability
- Increase Reliability and Resiliency
- Enable Customer Choice
- Improve Asset Condition and Operational Capability
- Maximize System Efficiency
- Incorporate Evolving Technology
- Enhance DER Integration
- Adopt Clean Technologies
- Reduce Carbon Emissions
- Animate Operational Markets

Consistent with the definitions above, in the SDSIP,[5] the Joint Utilities characterized the technology investments that occur in Stage 1 (Grid Modernization) as those that confer benefits in reliability and operational efficiency. The technology investments that occur in Stage 2 (Operational Markets) are those that confer the benefits of DER integration or value capture. The investments that enable capabilities that

[5] Case 16-M-0411 In the Matter of Distributed System Implementation Plans (“DSIP”), Joint Utilities of New York, *Supplemental Distribution System Implementation Plan,* November 1, 2016.

confer system and customer benefits in Stage 1 and also enable future DSP functions in Stage 2 and beyond are considered foundational.

Table 1 summarizes several technology investments.

Table 1: Investments Characterization (S-DSIP 2016)

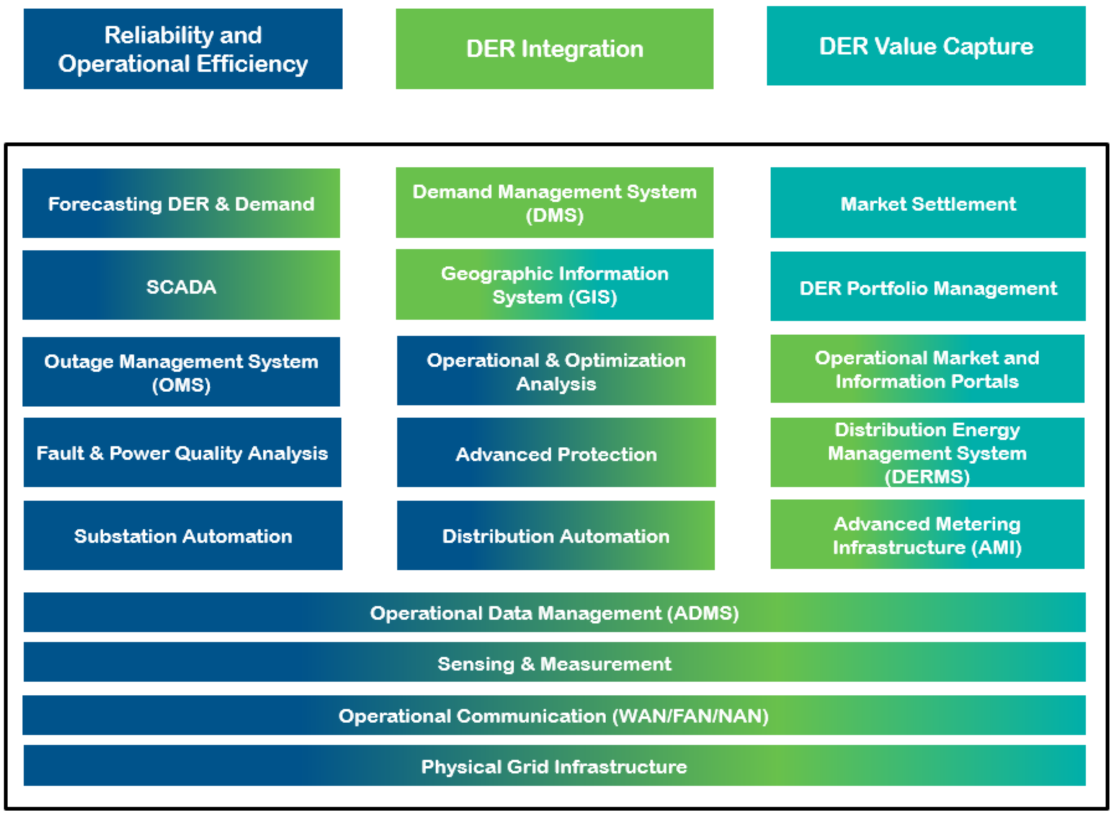
Investments	Stage 1: Grid Modernization	Stage 2: Operational Market	
	Reliability & Operational Efficiency	Enable DER Integration	DER Value Capture
Advanced Metering Infrastructure	✓	✓	✓
Distribution Automation	✓	✓	
Advanced Distribution Management System	✓	✓	✓
Distributed Energy Resource Management System		✓	✓
Data Analytics		✓	✓
Geographic Information System (GIS)	✓	✓	
Communications Infrastructure	✓	✓	✓
System Data Platform		✓	✓
Volt/VAR Optimization/Conservation Voltage Reduction	✓	✓	✓
Note: Central Hudson agrees that in some cases AMI could be considered a Foundational Investment but based on previous BCAs had determined that system-wide implementation of AMI was not cost beneficial. Central Hudson will continue to evaluate AMI. Without a full deployment of AMI Central Hudson already has visibility into more than 30% of the energy sales through the HPP and Demand Metering. Central Hudson will utilize advanced metering as a customer option or as a component in other smart grid investments.			

Taken together, these investments support the functions and capabilities of the DSP, which Central Hudson has defined as the set of people, processes, and systems that enable the utility to integrate DERs, share information, and provide market services while preserving safe and reliable system operation.

The Department of Energy's Office of Electricity Delivery and Energy Reliability (DOE-OE), in collaboration with the California Public Utilities Commission and the New York Public Service Commission, has developed a comprehensive set of functional requirements for a next generation distributed system platform (DSPx) to enable the full participation of DERs in the provision of electricity services. The Joint

Utilities have aligned their definitions and characterizations of platform investments and functions with the DSPx initiative. A representation of the functions of the distributed system platform, and how they map to Stage 1 and 2, or both, under the DSPx framework is shown in Figure 9. Additionally, the figure demonstrates how the core components and applications of the platform are supported by a mix of foundational and DSP-enabling investments in Stage 1 and Stage 2.

Figure 9: Grid Investments in Relation to Grid Functions



Grid Investments Cost Effectiveness Framework

The DSPx Decision Guide[6] identifies a framework for determining the cost-effectiveness of grid investments based on a primary purpose. The Guide acknowledges the complex nature of this exercise since some investments may have benefits driven by multiple grid functions, as demonstrated above (Table 1 and Figure 9). Furthermore, investments may involve different technologies aimed at achieving the same set of capabilities required of the DSP. Therefore, the implementation of different specific technologies may involve different technical use cases, all of which can support a single business use case. Nonetheless, the framework provides a useful approach to describing the types of purposes that drive investment through four general categories of grid expenditures (see Table 2).

Table 2: DSPx Grid Expenditure Cost-Effectiveness Framework

No.	Expenditure Purpose	Methodology
1	Grid expenditures to replace aging infrastructure, new customer service connections, relocation of infrastructures for roadwork or the like, and storm damage repairs.	Least-cost, best-fit or other traditional method recognizing the opportunity to avoid replacing like-for-like and instead incorporate new technology
2	Grid expenditures required to maintain reliable operations in a grid with much higher levels of distributed resources connected behind and in front of the customer meter that may be socialized across all customers.	Least-cost, best-fit for core platform, or Traditional Utility Cost-Customer Benefit based on improvement derived from technology.
3	Grid expenditures proposed to enable public policy and/or incremental system and societal benefits to be paid by all customers.	Integrated Power System & Societal Benefit-Cost (e.g., EPRI and NY REV BCA)
4	Grid expenditures that will be paid for directly by customers participating in DER programs via a self-supporting margin neutral opt-in DER tariff, or as part of project specific incremental interconnection costs, for example.	These are "opt-in" or self-supporting costs, or costs that only benefit a customer's project and do not require regulatory benefit-cost justification.

[6] U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume III: Decision Guide ("DSPx"),* June 28, 2017.

III. DSIP Update Topical Sections

A. Integrated Planning

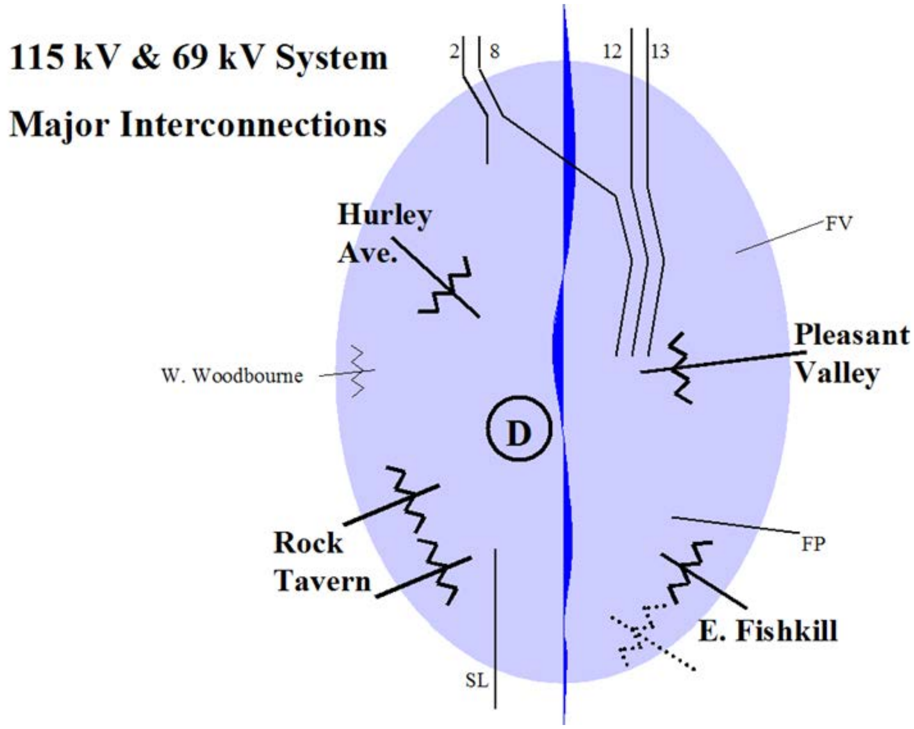
1. Context and Background

Introduction

Central Hudson's service territory includes a total of approximately 64 distribution load serving substations, 59 of which are fed from the transmission system, and approximately 270 circuit feeders. For planning purposes, substations are grouped into ten load areas, and most load transfers occur between substations and circuit feeders in the same area. Central Hudson also operates and plans its interconnected transmission system within the service territory. There are also a total of eleven transmissions areas, or load pockets, where transmission lines and generators affect power flow. During 2019, Central Hudson served approximately 261,100 electric residential customers and 43,950 electric non-residential customers. Combined, they were billed for 4,898 GWh of electricity and produced a peak demand of 1,109 MW.

Central Hudson's electric transmission system is tied to the bulk electric transmission system at the 345 kV voltage level operated by the New York Independent System Operator (NYISO). These interconnections are at four major substations that are shown, along with the major 115 kV & 69 kV interconnections supplying Central Hudson's electric transmission system, in Figure 10.

Figure 10: Major Interconnections



These interconnections also include connection to the transmission systems of National Grid, New York State Electric & Gas, Consolidated Edison, New York Power Authority, Eversource, and First Energy. 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. At this time, Central Hudson's System LSC is 1,480 MW[7]. 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 2025 of 1,146 MW (and 1,114 MW with DER).

The distribution system includes all assets outside of the substation fence operating at 34.5 kV and below. However, load transfers within the distribution system are sometimes utilized to manage substation and transmission infrastructure, operational and thermal constraints, and the transmission and substation

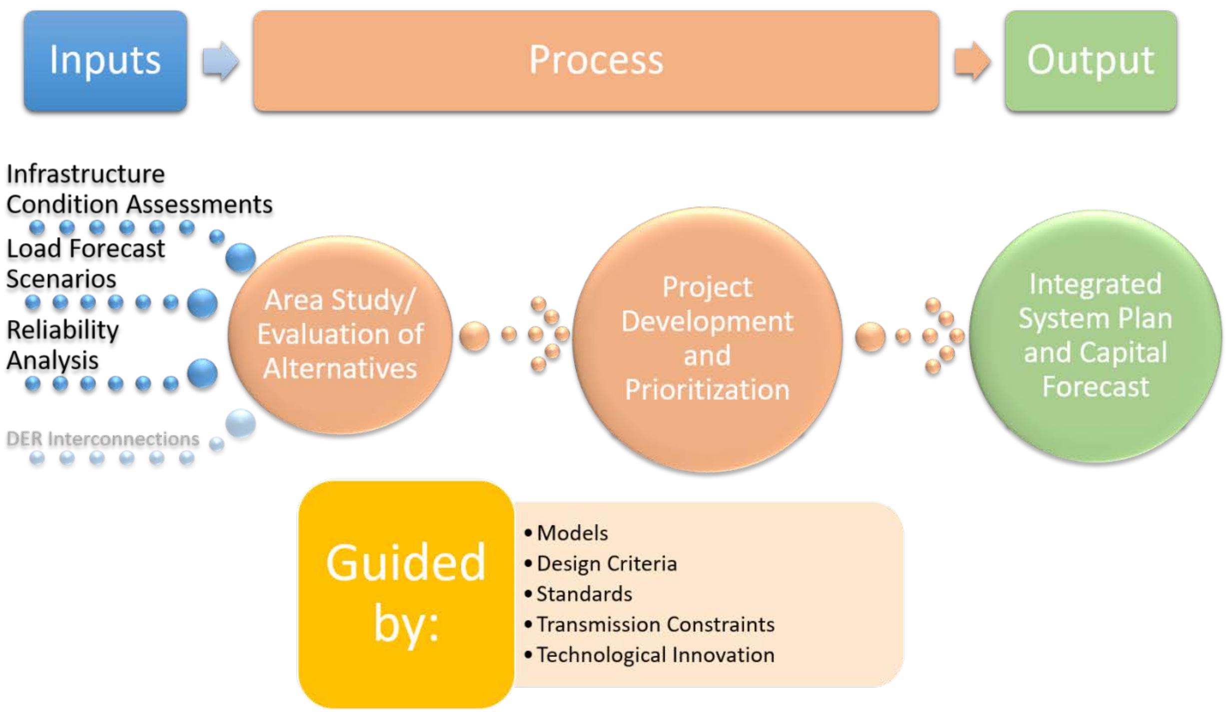
[7] Based on the 115 kV East Fishkill – Fishkill Plains HF line at Summer Long Term Emergency (LTE) Rating following the loss of the 115 kV East Fishkill – Shenandoah EF Line with no internal generation.

systems that provide the backbone to the distribution system. Therefore, the integrated planning process includes both transmission and distribution components, as well as distributed energy resources.

The System Planning function at Central Hudson has served customers well by safely planning for a 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 maintenance processes and programs, the primary outputs of the planning process are an Integrated Long Range Electric System Plan (Appendix C) and Capital Investment Forecast.

Figure 11 illustrates the current components of the Integrated Distribution System Planning process at Central Hudson and how they flow together. Discussion on these components follows the figure. More detail regarding specific components of the process can be found in Central Hudson Gas & Electric's Electric System Planning Guides, issued in October 2013.

Figure 11: Integrated Distribution System Planning Process



Inputs

Inputs to the planning process are described below:

1. Infrastructure Condition Assessment

   Central Hudson complies with the Electric Safety Standards Order[8], 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 C for additional detail) to manage replacement programs associated with individual asset classes. Trends of failing equipment are also considered. As any 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 and DERs, including improvement in hosting capacity;
   - Current standards;
   - Transmission constraints; and
   - Other scheduled projects in the same vicinity.

[8] 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).

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 properly designing infrastructure and reliability based projects for the long term. Currently, net peak load is the primary consideration, but, as discussed throughout the remainder of this section and in Section III.B, the process is evolving to consider forecasts of distributed energy resources (DERs), as well as multiple scenarios.

3. Reliability Analysis

Central Hudson maintains reliability criteria for the planning and operation of its electric transmission and distribution (T&D) 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 (NPCC) 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-001-4 – 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, issued October 2013, as well as Section IV of the Central Hudson Initial Distributed System Implementation Plan[9]. Analysis is completed based upon these criteria, and if the criteria are not met, project alternatives are evaluated as part of the Integrated Planning Process.

4. DER Interconnections

Although proposed DER interconnections are reviewed by the Distribution Planning department, they are not a direct part of the current Integrated Planning Process (other than to consider on-going project construction due to DERs). However, infrastructure projects that also provide an opportunity to increase hosting capacity are considered in the Capital Investment Plan. Additionally, as a part of this DSIP filing, DER forecasts were developed at the substation and

[9] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Central Hudson Gas & Electric Corporation’s Distributed System Implementation Plan (“Initial DSIP”), (filed June 30, 2016).

transmission levels separate from net loads as an additional step towards further integrating DERs into the planning process.

Process

Depending upon the extent of additional considerations, a final integrated plan may be developed along a continuum from an informal meeting with appropriate stakeholders to a formal, comprehensive Area Study. The result is the development of recommendations to maintain and improve reliability of service and support the capital budget plan. At any level of formality, the process relies on local system knowledge and experience, and it includes an evaluation of project alternatives, the age and condition of the infrastructure, and an assessment of electric service reliability. Projects are prioritized based upon the Capital Prioritization Guidelines[10].

While Central Hudson's electric capital plan is predominately comprised of condition-based infrastructure type projects, a number of these existing projects also provide incremental hosting capacity benefits. As new project needs are studied, renewable penetration levels and potential hosting capacity improvements are included in the analysis to determine the recommended solution. While DER is currently included as a criteria within the capital prioritization plans, in order to meet NY State's renewable goals, this process will continue to evolve to further integrate DER into the planning and prioritization process. Study work has begun to help identify additional potential projects that would facilitate the attainment of these goals based on system constraints and forecasted renewable penetration levels.

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;
- Performing analysis of reliability and power quality data and leveraging the use of new technology to continuously improve the T&D systems;

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[10] *Ibid,* Appendix G.

- 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;
- Evaluating DER applications and determining what system upgrades will be required to facilitate interconnection; and
- Developing a capital forecast and identifying where a non-wires alternative may be considered based upon suitability criteria.

Outputs

After projects are prioritized, they are incorporated into the annual Capital Forecast, and non-wires alternative(s) are pursued as appropriate. Additionally, system-wide asset management and capital plans are documented in the Long Range Electric System Plan (Appendix C).

Historically, electric grids were engineered to accommodate the flow of electricity from centralized generation to end users. Generation, transmission and distribution infrastructure was sized to meet the aggregate demand of end users when it was forecast to be at its highest (peak demand) while allowing for forced outages. At the system level, electricity supply must meet demand instantaneously with sufficient reserve (spinning, quick-start, etc.) levels to avoid outages due to the loss of generation. Substation transformer and distribution infrastructure, however, was, and generally still is, sized based on local peaks, which can be quite diverse and often are not coincident with system peaks that drive generation infrastructure.

While the core System Planning functions will continue to maintain and improve the safety and reliability of the electric system, sophisticated technology and changing customer expectations are increasing the complexity of this role. The Integration of DERs at both the transmission and distribution levels, and alternatives to traditional utility investments, must be included in the Integrated System Planning Process. Stakeholders are expecting higher levels of reliability and resiliency, along with information transparency. Forecasting methodologies must evolve to an integrated approach that is probabilistic in nature; foundational investments, such as distribution automation, must continue to progress; asset management must be improved as infrastructure ages; and system modeling must become more granular and be refreshed at a much faster rate.

Foundational Technologies

To embark on the efforts described in the previous section, key investments in Foundational Technologies are required. Enabled by more sophisticated system modeling, investments in these technologies will allow for the integration of DERs and a smarter grid. These investments also require a significant Distribution Planning effort to determine required upgrades to the distribution grid and software systems. Distribution Automation (DA) has been the focus of foundational investments from an integrated planning perspective. Externally, the evolution of decentralized, automated devices, along with the commercialization and integration of sophisticated modeling, geographic information systems mapping, and Distribution Management Systems have helped propel DA solutions. Internally, DA has gained momentum as a solution to address system considerations resulting from the exponential growth of solar among the Company's customer base. Additionally, DA will address infrastructure replacement due to age and condition, increasing levels of limited redundancy and operational flexibility, and reliance on communication systems providers whose core business models have shifted away from hard-wired lines.

A centralized approach with modern modeling techniques will also improve system efficiency and defer capital investments by leveraging the distribution system for redundancy and upgrading infrastructure that has reached the end of its useful life. Further benefits include improved reliability and power quality, integration of DERs, reduced system losses, and enhanced switching safety. To achieve the benefits described, Central Hudson had identified several gaps in its current approach. Figure 12 shows the gaps identified, along with a desired future state.

Figure 12: Identified Gaps and Future State

Gaps Identified:

- Peak day system model with asset gaps
- No remote control of distribution devices
- Decentralized communications with many platforms
- Asset communications driven by vendor
- Does not integrate customer-owned devices

Transition began in 2011 via Pilot Projects and Cross-Functional Teams

Future State:

- Real time system model with detailed asset information
- Two-way communication with control via Operations Center
- Centralized communications through single platform
- Central Hudson led communications via vendor partnership
- Integrates customer-owned DERs

To test a more integrated approach, Central Hudson partnered with a vendor and NYSERDA to develop an Integrated System Model focused on 8760 analysis, including both the transmission and distribution system. The Company tested and developed conservation voltage reduction (CVR), a prototype for a DMS, and Fault Location Isolation and Service Restoration (FLISR) to avoid an outage to over 8,000 customers fed by a substation served by a radial transmission line through challenging terrain, avoiding transmission system investments by better leveraging the distribution system. Central Hudson began a pilot CVR trial on one feeder in 2012 and a second feeder in 2013, using a "day on, day off" approach with a variety of customer load groups. Applying the results along with studies completed in several national labs, Central Hudson anticipates a 1.39-1.73% reduction in energy usage, in addition to loss reduction. Tools such as solar impact analysis and efficiency benefit analysis were developed through the process, and the pilot as a whole helped inform the process of selecting a vendor for the Distribution Management System (DMS).

With successful pilots in progress, Central Hudson fine-tuned and began implementing its integrated Grid Modernization strategy. This program is developing a DMS to improve reliability, system safety, and system efficiency. Central Hudson is creating detailed electric models in the ESRI GIS system to use as the asset database. It will also have links to the DMS and Engineering Planning tools, which will, in turn, link to the Outage Management System (OMS), as well as a designer tool to synchronize proposed changes and actual as-built maps between Engineering, Design, and Operating groups. Over 800 Intelligent

Electronic Devices (IED; e.g. electronic reclosers, switched capacitors, and voltage regulating devices) and sensors are being installed through DA and other programs, which will provide real-time data to the DMS so that it can make centralized decisions based on current system conditions rather than anticipated peak loads. DERs also must be monitored, and in some cases, controlled, as a critical input to the DMS per the requirements established by the Interconnection Technical Working Group[11]. Along with system-wide implementation, there is a large infrastructure improvement plan to create robust mainline feeders that can be looped through switching to restore customers after an outage or optimize and balance feeders during normal operations, as well as improve hosting capacity.

The Grid Modernization Strategy is also foundational to REV. VVO and FLISR modules that will be included in the DMS are consistent with the REV policy goals of improving efficiency, reliability, and resiliency. Once fully deployed, the system will consider the impact of DERs in switching and voltage optimization decisions utilizing generation profiles. The DMS is being developed so DERs can be integrated into the system for monitoring and control through additional modules as needed, as well as weather forecasting, to improve resource diversity and animating markets in the future. While the monitoring, control, and market mechanisms surrounding DERs are still being defined through other REV proceedings, the DMS will be critical to any level of coordination, as well as the safety and reliability of the electric distribution system, as its complexity increases. In addition, the ability to add AMI at the customer level is being incorporated into the Network Communications Strategy.

Central Hudson's Grid Modernization Strategy is comprised of six critical components:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)

2. ESRI System Model Geographic Information System (GIS) – provides a single consolidated mapping and visualization system

3. Distribution Management System (DMS) – the centralized software "brains"

4. Distribution System Operations (DSO) – the organization responsible for the use of the DMS

5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS

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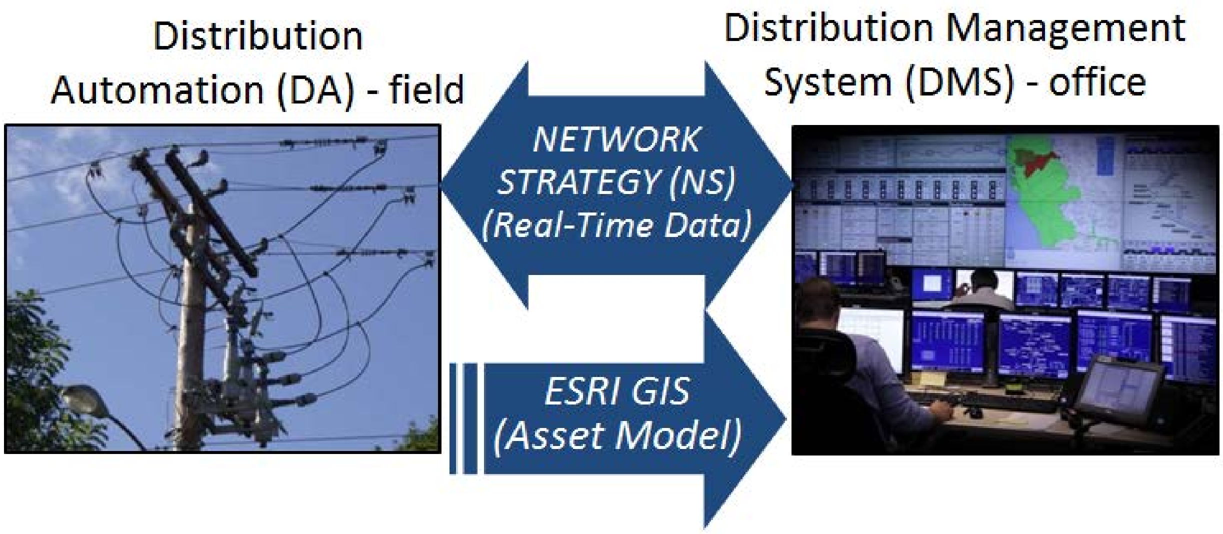
[11] *Monitoring and Control Requirements for Solar PV Projects in NY,* September 1, 2017.

6. Substation Metering Infrastructure– substation feeder metering upgrades required for accurate DMS power flow calculations.

Figure 13 illustrates how these projects interact, along with the underpinning ESRI Geographic Information System (GIS) Asset Model.

Figure 13: Smart Grid Projects



The Planning aspects of DA and the asset model will be discussed in this section. For additional details on the Grid Modernization strategy, please see Section III.C.

a. **Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2016;**

Since the initial DSIP filing in 2016, the Company has made progress in transitioning to a more integrated planning process. Traditionally, Central Hudson applied a deterministic approach to the development of a peak load forecast. Central Hudson also engaged a vendor to deliver a robust probabilistic load forecasting tool and conduct a multi-day workshop to review the process in detail (see Advanced Forecasting, Section III.B). The Company also added two additional team members to the Electric Distribution Planning area, who assist with integrating DERs into the process.

The Company has also placed a significant focus on system modeling. During 2016, the Company contracted with two vendors to perform a field assessment of critical connectivity modeling components across all areas of the system not previously completed: conductor size and length, protective elements, phasing, and key customer transformer information. This information was input to the OMS and GIS system, and in turn, planning load flow models. The data was critical in modeling and planning the rollout of distribution automation device locations and reconductoring requirements. Central Hudson will maintain this data going forward. This data was also critical for the completion of the Stage 2 hosting capacity analysis described in further detail in Section III.B. While the Distribution Engineering group initially took the lead on improving system modeling, these efforts have transitioned to the Work and Asset Management group as part of the Grid Modernization Strategy. This group works closely with the DMS Model Manager to ensure a successful integration of the GIS data into the DMS model.

The first three years of the Distribution Automation plan were approved as detailed in the Order Approving Rate Plan, issued and effective June 17, 2015[12], with a contingency of meeting milestones that Central Hudson and Department of Public Service Staff mutually agreed on. Due to Central Hudson's success during the prior rate plan, the current rate plan, which commenced on July 1, 2018[13], included full funding to continue with the implementation of not only Distribution Automation, but the DMS and Network Communications Strategy as well. As a result, two additional Distribution Planning Engineers were hired, one Junior Engineer in January 2017 and another Junior Engineer in June 2020. These individuals' primary focus is to assist with further planning of DA projects and additional cleansing of distribution system models.

Central Hudson's service territory is comprised of five operating districts. All components of DA will be modeled, analyzed, planned, field designed, and constructed in parallel on a district by district basis, with the process separated into two phases for some districts. As available, devices will be simultaneously integrated with the network communication radios and DMS. Vendors were selected for each component, and construction standards have been developed. However, the ongoing evaluation of emerging products and technologies may result in continuous improvement, particularly in the sensor area. Additional products, such as solid state transformers or static VAR compensators that allow for

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[12] Case 14-E-0318, et. al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas and Electric Corporation for Electric Service ("Prior Rate Case")*, Order Approving Rate Plan, (issued June 17, 2015), page 16.

[13] Case 17-E-0459, et. al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas and Electric Corporation for Electric Service*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Current Rate Plan"), (issued June 14, 2018), Appendix Y.

voltage control, will be continuously monitored for economic applicability on Central Hudson's system, to further enable feeder voltage reduction or mitigate impacts of solar PV installations.

2. Implementation Plan

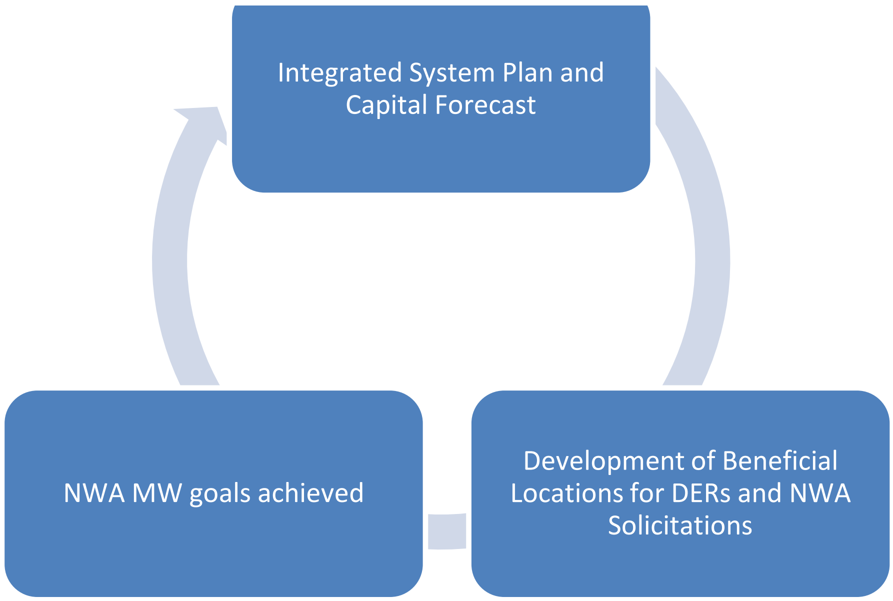
a) Current Progress

As described above, Central Hudson's Planning Engineers have been trained on the probabilistic planning process, and the distribution system models have been updated to complete the necessary hosting capacity and distribution automation analysis. These models can incorporate a simulation of any hour in the year. Details regarding the DA schedule can be found in Section III.C.

The planning process does not end with the development of a Capital Forecast[14]. As illustrated in Figure 13, the output of the Distribution Planning process has expanded from the Integrated Capital Budget to include beneficial locations to install DERs, which will become more ingrained in the process as the Company gains experience with and evaluates the results of existing non-wires alternative projects. Once acceptable criteria are developed, the capital plan will result in the development of beneficial locations to install DERs, along with solicitations for NWAs to defer or eliminate the need for some of the identified capital investments. Note that this is not currently presented in conjunction with hosting capacity maps, which will have their own roadmap described in Section III.L. Hosting Capacity will identify areas where interconnection is easier but will not necessarily coincide with beneficial locations to alleviate a system constraint.

[14] Case 17-E-0459/17-G-0460, Central Hudson Gas & Electric Corporation’s Compliance Filing of its 2021-2025 Corporate Capital Forecast, (filed July 1, 2020).

Figure 14: Capital Forecast development with NWAs



Finally, as described in Section N, stakeholders now have access to 8760 load data, where available, in addition to NWA solicitations.

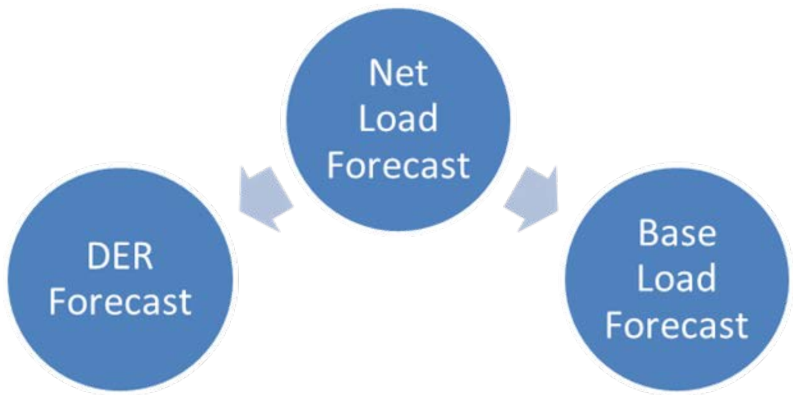
Additionally, while the overall planning process tends to focus on longer-term system needs, both Planners and Electric Operations Engineers are responsible for reviewing near-term requirements of new service requests for individual spot loads. The Company is currently in the early stages of evaluating its ability to use EPRI's DRIVE tool to streamline the review for these types of load requests. This effort may also lead to further use of the tool for other aspects of planning functions, along with the medium-term efforts described further in Section III.L Hosting Capacity. For example, the DRIVE tool could assist with the planning and integration of DER, such as energy storage and EVs. Additional information on EPRI's DRIVE tool can also be found in Section III.L Hosting Capacity as well within the Initial DSIP.

b) Future Implementation and Planning

While the Integrated T&D System Planning Process functions to provide for the safety and reliability of the system will remain, the tools applied and the complexity of the process is rapidly evolving. Currently, the interconnection of DERs is evaluated separately from the long-term T&D Planning process. With the increased intermittency associated with many DERs, the application of a linear forecast, even with engineering knowledge and judgment, will be insufficient to recognize the range of potential generation and load scenarios.

As discussed previously, Central Hudson is transitioning its 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 DERs and base load, as shown in Figure 15.

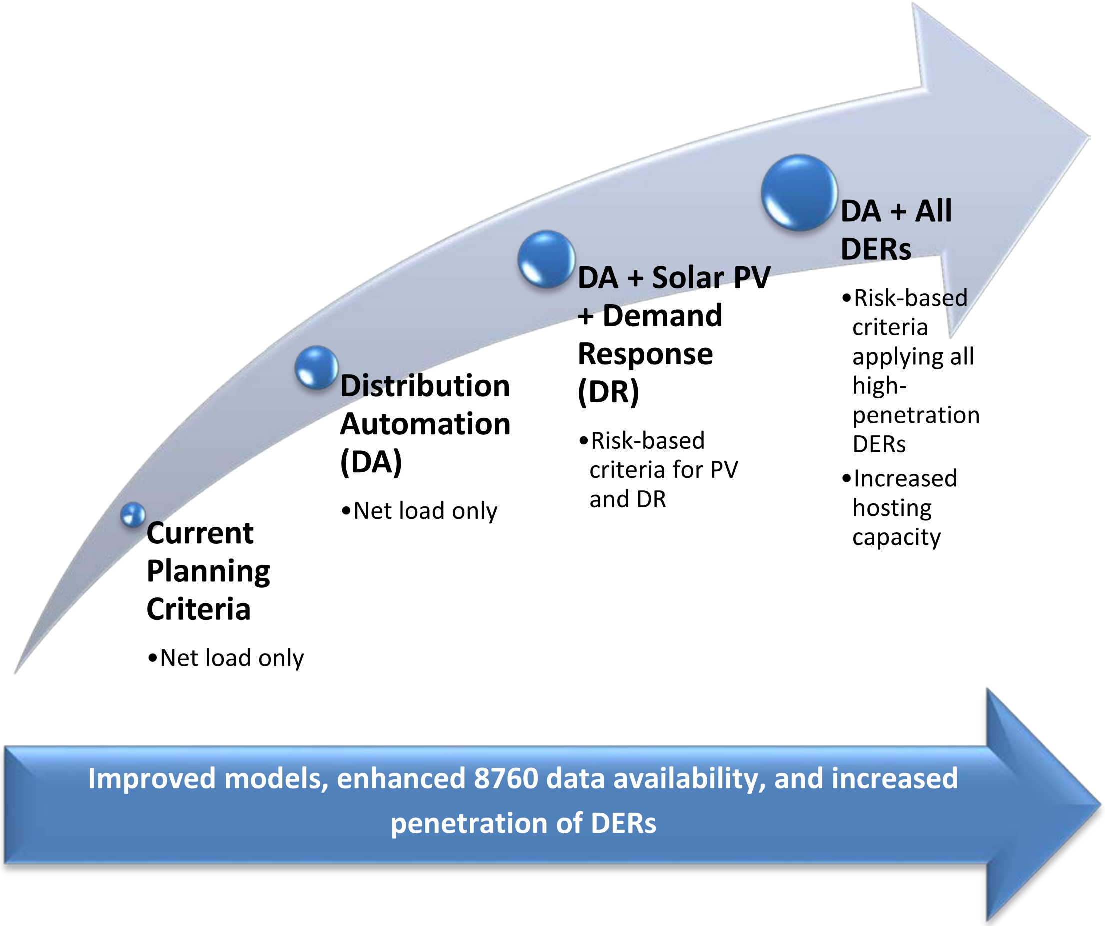
Figure 15: Forecasts Must Separate DERs and Base (Gross) Loads



During this transition to a probabilistic approach, when an area of need is identified through traditional planning methodology, base load and DER forecasts are being developed with separate scenarios for each. DER 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. Still, their aggregate impact over time will be important to consider and will also inform the interconnection process of the future. 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 as well as DER integration studies where DER interconnected penetration levels are high.

This information is applied to understand the system needs and scenarios and to develop alternatives and a final solution. 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 16 provides a roadmap of this evolution.

Figure 16: Evolution of T&D Planning Criteria



At this time, Central Hudson has moved beyond the traditional current planning criteria and has implemented probabilistic forecasting, using more granular data, and more sophisticated models.

On a similar note, Operating Criteria will need to evolve to integrate the Foundational Investments (i.e., DA and DMS) as well as DERs, and DA rollout will continue. This is discussed further in Section III.C. Modeling will continue to improve as the ESRI platform, DMS, and system planning tools become more tightly integrated and as distribution designer software ties to the platform to accelerate the closure of new work orders, so that a more "real time" model is available.

Table 3 summarizes the gaps in today's Integrated Planning Process and the steps and timelines to address them. While the overall planning process will not change from Figure 16, it will become significantly more complex. Completion of the roadmap will require hiring additional technical resources to develop sophisticated analytical and software application skills, uniquely blended with power system knowledge.

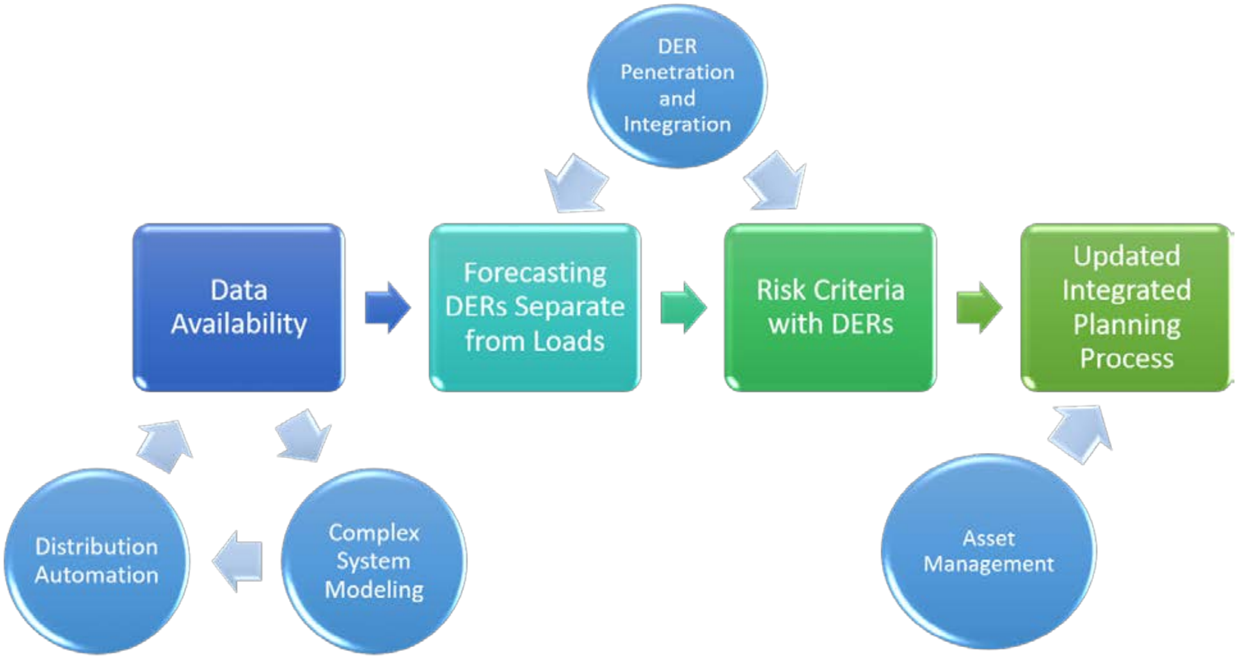
Table 3: Integrated System Planning Gaps and Roadmap

Action Item	2020	2021	2022	2023	2024	2025	2026+
Improve 8760 Data Availability							
Load	>95%	>98%	>98%	>98%	>98%	>99%	100%
Distributed Generation	>500kW	>500kW	>500kW; possible smart inverter availability	>500kW; smart inverter availability	>500kW; smart inverter availability	>500kW; smart inverter availability	>500kW; smart inverter availability
Electric Vehicles	✓	✓	✓	✓	✓	✓	✓
Battery Storage	>500kW	>500kW	>500kW; possible smart inverter availability	>500kW; smart inverter availability	>500kW; smart inverter availability	>500kW; smart inverter availability	>500kW; smart inverter availability
Develop Substation Level Probabilistic Forecasting by Load/Generation Type							
Load, Solar, Energy Efficiency, and Electric Vehicles	Vendor ✓	Central Hudson ✓	Central Hudson ✓	Central Hudson ✓			
Other DERs	As Needed						
NYISO Market Considerations		✓	✓	✓	✓		
Integrate into Planning Process	✓	✓	Other DERs As Needed	Other DERs As Needed	Other DERs As Needed		
Improve System Modeling Capabilities							
Improve 8760 Modeling Capabilities	✓	✓	✓	✓			
Implement Designer Software to improve Work Order Process	✓	✓					
Improve model based upon real-time DMS data	On-Going						
Integrate T&D constraints	✓	✓					
Improve Asset Management and Reliability Analysis							
Maintain Cascade for Distribution Assets	✓	On-Going					
Leverage analytical tools along with mapping features	✓	✓	✓				

Develop Risk-Based Planning Design Criteria					
Solar PV, Energy Efficiency and Demand Response	✓	✓	✓		
Battery Storage		✓	✓		
Electric Vehicles		✓	✓		
Other DERs			As Needed		
Scenario Planning		✓	✓	✓	
	Note: Requires Consideration of Operating Procedures				
Integrate DER Interconnections					
Maintain Technical Guidelines				On-Going	
Develop Operating Guidelines				On-Going per Section III.C	
Complete Hosting Capacity Roadmap				On-Going per Section III.M	
Complete Distribution Automation Project	✓	✓	✓	✓	
Update Integrated Planning Process				✓	✓

Figure 17 illustrates the interdependencies of these items. While some of these items are being completed as a part of this DSIP update (e.g., substation-level probabilistic forecasts for load, solar, and energy efficiency), they are not yet integrated into the planning process and therefore do not have a future date associated with them.

Figure 17: Interdependency of Planning Process Roadmap Items



3. 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 process of the future is dependent upon the System Forecasting process, which will be driven not only by uncertainty in base system loads, but also uncertainty regarding the connection of DERs. The utility has very limited control over most elements that drive when a DER will interconnect to the grid or whether a project will ultimately be completed. Policy decisions or pricing changes can impact a forecast overnight. Moreover, many DERs (such as solar photovoltaics) operate intermittently and have limited restrictions on when they may disconnect and the notifications required, both temporarily and permanently, further challenging the forecasts. Also, DERs participating in NYISO markets may be driven by economic signals that need to be balanced with local distribution system reliability.

To mitigate the risk, the Company is transitioning to a probabilistic based forecasting methodology, which separates DERs from base load forecasts. This allows the Company to better assess scenarios of forecast uncertainty for up to ten years in advance and consider a plan that may be required for those cases. 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 amply capacity. The risk is concentrated on a limited number of locations that are growing and have limited capacity to accommodate additional growth. Although peak load forecasts were critical in the past, minimum load forecasts are now crucial to understand when equipment may be back fed or when 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. Therefore, an 8760 forecast has been completed for all substations, and Central Hudson will continue to produce these forecasts in the future. Additionally, operational processes and procedures will also mitigate the risk as the Distribution Management System (DMS) can be used to control DERs when needed. As the DMS is further developed, processes and procedures 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, but due diligence, progress to date, and the continuation of current processes until an appropriate cutover time has mitigated some of that risk.

4. Stakeholder Interface

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

For facilities that fall outside of the NYISO's jurisdiction, the stakeholder interface with the Integrated Planning process primarily includes the inputs and outputs of the process, rather than the process itself. Stakeholder engagement regarding load forecasting is described further in Section III.B. DER Interconnections and Hosting Capacity analysis and their potential ties to the Integrated Planning process, are described further in Sections III.J and III.L. Additionally, much of the System Data used to drive the Integrated System Plan is publically available, as described in Section III.F.

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 publically available. Projects which meet the NWA Suitability Criteria are considered through the NWA Procurement Process described in Section III.N.

5. Additional Detail

a) 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.

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

Central Hudson has transitioned to probabilistic, granular forecasting. By design, the approach includes:

1. Tracking of when, where, and who adopts individual DERs.
2. Using the data on adoption to fit adoption diffusion curves and forecast aggregate adoption with uncertainty.
3. Estimating the propensity of customers to adopt different types of DERs at granular level, typically for individual premises.
4. Assessing the impact of the adoption of DERs on individual substation and transmission areas. This is grounded on layering hourly (8760) DER load shapes on substation and transmission area loads.

For most DERs – energy efficiency, solar, and electric vehicles – 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, and geographic location. The estimates reflect the interrelated effects of DERs. For example, customers with distributed solar are more likely to adopt electric vehicles and vice-versa. Section III.B provides additional detail regarding Central Hudson's T&D and DER forecasting methodology. These probabilistic forecasting methodologies must be integrated into Central Hudson's planning process per the roadmap in Table 3.

c) How the utility 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 (1) 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 spot checked every month 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 Public Service Commission on a monthly basis. 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 (2) infrastructure assessments, the Electric System Planning Guides document the analysis that is required. Finally, (3) reliability data is heavily scrutinized to reconcile outage information and report the information to the Public Service Commission every month. Annually, a detailed System Reliability Report is filed with the Public Service Commission that includes data by distribution feeder.

The process for developing the Capital Investment Forecast is documented in the Capital Prioritization Guidelines[15]. Figure 18, which is included in the aforementioned guidelines and reproduced below, illustrates the development timeline.

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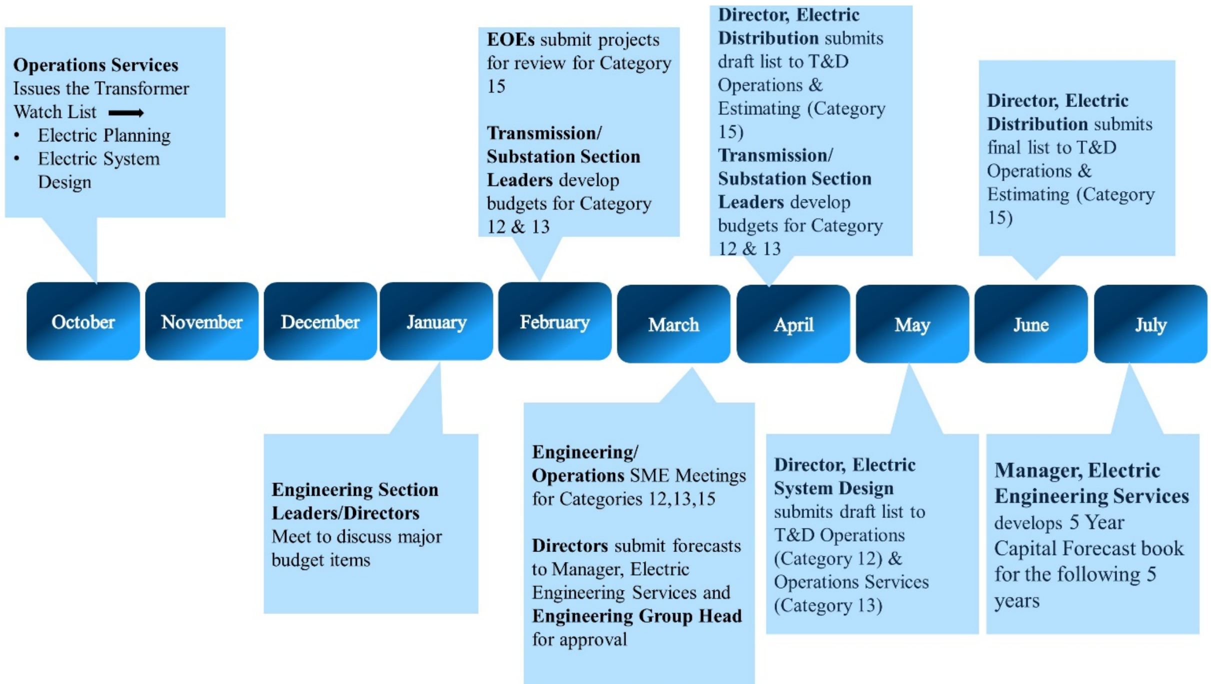
[15] *Initial DSIP*, Appendix G.

Figure 18: Electric Capital Forecast Development Timeline



d) 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, when key inputs are based on assumptions, or when there is substantial uncertainty around critical drivers of results. Since Central Hudson is transitioning to a probabilistic approach where feasible, Central Hudson will not typically apply this analysis.

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, were 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 an important role for technologies in a nascent stage or experiencing truly disruptive innovation(s). Because historical data for those technologies is limited, any current projections rely on assumptions or data from proxy technologies. For example, for electric vehicles, Central Hudson employed data on the adoption of proxy technology, green vehicles overall, which includes hybrids, EVs, and plug-in hybrids. To explore the potential of higher penetration rates, the models were pressure tested by assuming that the penetration of electric and plug-in electric vehicles would double that of hybrids. A similar approach will be employed for battery storage once enough data is available.

e) How the utility would timely adjust its integrated system plan if future trends differ significantly with predictions, both in the short-term and in the long-term.

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 load does 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 as Appendix G to the Initial DSIP filing.

In the longer term, the probabilistic-based forecasting methodology will provide 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. But 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 load does not materialize, or a traditional solution may have to be accelerated if load grows more quickly than anticipated or DERs do not come to fruition as expected.

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

The integration of aging infrastructure into the Integrated Planning Process is described at the beginning of this Section, including reference to the Long Range Electric System Plan in Appendix C that is an output of the process. Although Central Hudson's long term experience is not specific to electric vehicles (EV) 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. As EVs are in the early stages of development and the Company has latent capacity available on its system, it would not be prudent to overinvest in anticipation of EVs and other technologies that are undergoing electrification. Section III.E describes the initial steps the Company is taking to begin developing a framework for the future as EV penetration increases. As a part of the Current Rate Plan, Central Hudson continues to advocate for beneficial electrification, especially for programs and rate design that encourages improved load factor and system efficiency, such as expanding the use of geothermal technology as well as actively funding heat pump electrification projects. The Company continues to monitor other technologies considering electrification through participation in Electric Power Research Institute programs.

g) 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 must be considered as a part of the forecasting process. A system-wide forecast is developed at the corporate level, both with and without the impacts of energy efficiency, which can then be allocated to the substation level. The range of forecasts will allow System Planners to monitor longer-term system needs and develop planning alternatives depending upon how much of the energy efficiency comes to fruition. Additional detail regarding Energy Efficiency Integration and Innovation can be found in Section III.F.

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

Central Hudson actively participates and has a leadership role within the Electric Power Research Institute's Distribution Planning and Operations program. Through attendance at semi-annual conferences, Planning interest group meetings, and webinars, the Company stays abreast of the latest developments in System Planning and integrate 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 the 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.

B. Advanced Forecasting

1. 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 re-routed in case of prolonged or temporary outages.

The electricity industry is experiencing rapid technological change, particularly with the introduction of distributed energy resources. 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:

- Customer growth and migration patterns;
- Behavioral changes regarding how and when customers use electricity;
- The adoption of distributed solar including community solar;
- The adoption of electric vehicles;
- The introduction of battery storage;
- The natural adoption of energy efficiency;
- 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 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 the impact on the electric grid challenging to predict. Almost by definition, disruptive technologies are difficult to identify and predict in advance.

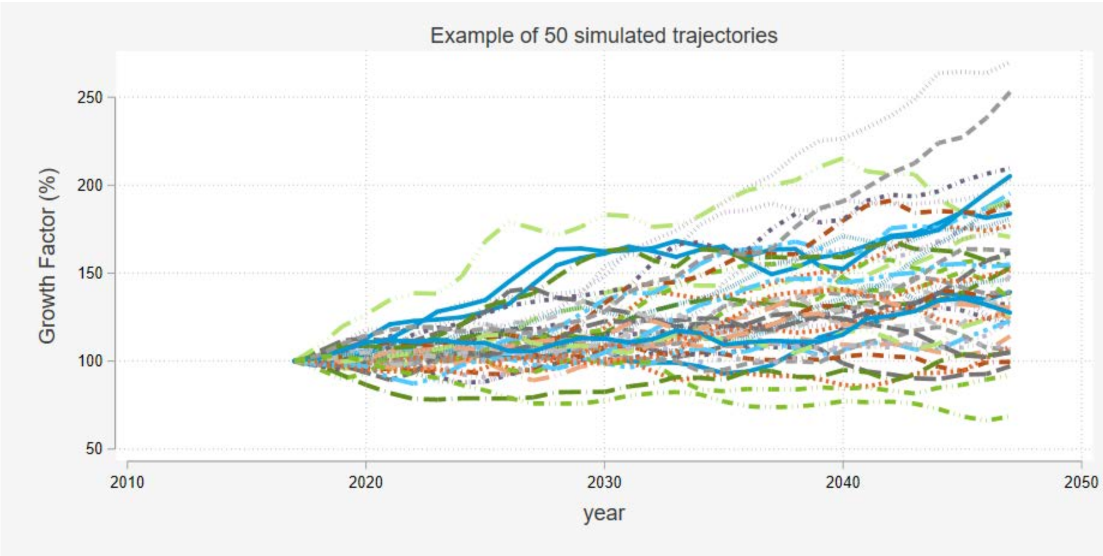
Forecasting Principles

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 across 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.

Figure 19 illustrates the critical role of probabilistic, location-specific forecasts. This type of forecasting requires estimating historical load growth patterns and simulating potential load growth trajectories thousands of times, as shown in the top panel. Some outcomes are far more likely than others and are summarized into probabilistic bands that identify the likelihood of load growth falling within specific confidence bands.

Figure 19: Probabilistic Planning Reflects Greater Uncertainty Further Into the Future



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

1. Forecast T&D loads and adoption of specific DERs;
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.

System Level Forecasts

Central Hudson's Initial DSIP filing provided a comprehensive discussion of the system-wide forecast prepared by the Company, 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. While the overall forecasting process has not changed since the 2016 DSIP filing, continued refinements in the econometric models, updates to the data used to develop the forecasts, and methodological modifications for addressing DER have been made.

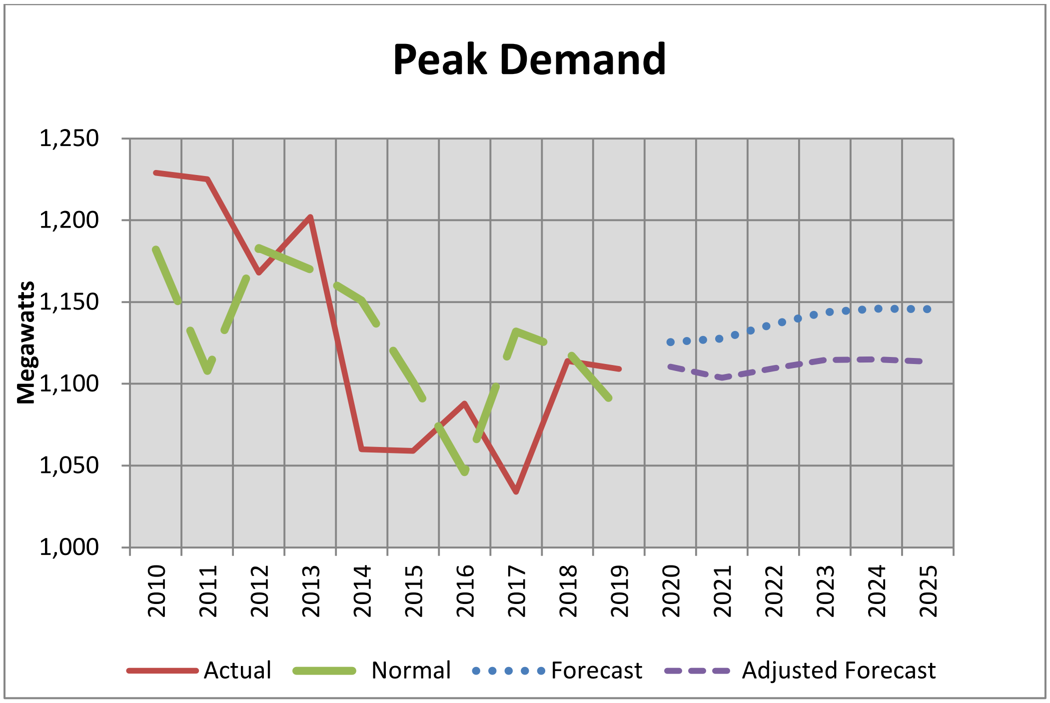
While forecasts of monthly customers, sales and revenue, and annual peak demand are developed on request, they are also routinely developed on an annual, scheduled basis for integration along financial, accounting, energy procurement, regulatory and system planning purposes. The majority of the sales projections and the peak demand projection are developed through econometric analysis.

Historically, both EE and DERs, more specifically PV interconnected to the distribution system, were addressed external to the sales modeling process. This prevented the sales regression models from assuming that the historical EE and PV growth patterns would continue in the future, thus allowing the growth patterns to be altered and applied as a post forecast adjustment. The results of recent analyses indicate that EE cumulative savings are expected to continue on the same trajectory as historic cumulative savings. As a result, the most recent sales and annual peak demand forecasts do not contain explicit EE adjustments instead the forecasts are shaped by the historic EE savings embedded in actual billing and peak system data. The forecasts also formally address initial statewide efforts to stimulate electrification through implementation of a heat pump program and continued, albeit very modest, penetration of electric vehicle transportation.

The top down System Level Forecast reflects a level of DER that was derived from various sources that differs from the sources and assumptions that were used in the development of the granular level forecast. One of the primary differences stems from the focus of the System Level Forecast on billed sales and peak metered load in contrast to the focus of the granular level forecast on the loading of individual components of the Company's electric system. As a result, there is a difference in how DERs are reflected in each of the forecasts. For example, DERs that are subject to net energy metering reduce the system wide forecast of billed sales and metered peak, while DERs subject to monetary compensation for exports, such as community distributed generation (CDG), do not impact metered consumption. In contrast, the granular level forecast addresses the system loading impacts of the various DERs.

The Company continues to see significant solar penetration resulting from regulatory action such as: the extension of Phase One net energy metering, establishment of the CDG program, and the implementation of a value stack approach to monetary compensation. Moreover, demand response, through both system-wide and location-targeted initiatives, and electrification, mainly in the heating and transportation sectors, are increasingly affecting system throughput. As a result, the Company continues to assess the frequency, method, and content of its system sales and demand forecasts to provide more accurate and timely information to address estimation of sales impacts resulting from these various initiatives. Figure 20 provides the current 5 Year System Level Forecast.

Figure 20: Peak Demand (MW)



While the aforementioned system-wide forecasts and the location-specific forecasts discussed below continue to be developed independently of each other, they are both utilized within the integrated planning process. The bottom-up, location-specific forecasts are cross-checked against the system-wide forecasts to ensure that any differences are reconciled or explained due to either line losses or to substations that are not included in the forecast due to inferior or unavailable hourly data. Optimally, the most accurate system-wide forecast would be produced from synchronizing the location-specific forecasts for all substations. However, meter installation requirements and subsequent collection of sufficient historic data to estimate local load growth shifts this potential outcome to the future.

Location-Specific Forecasts

The integration of DERs requires significant changes to how distribution planning takes place and how it is coordinated with system forecasts. In the recent past, 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.

A potential key barrier, however, is that not all feeders and substations have meters collecting hourly or sub-hourly data. Once meters are installed, several years of data need to be collected to estimate local annual growth trends. For Central Hudson, this barrier has been eliminated through ongoing infrastructure replacement programs. Currently, Central Hudson has hourly metering data available for approximately 95% of its cumulative system load, with plans to reach close to 99% within the next two years.

Location-Specific Forecast Methodology

The forecasting process can be summarized in four main steps. These steps are:

1. **Clean and fill the data**. Historically, data quality for substations and circuit locations has been a barrier to their use for more granular load forecasting due to lack of metering, meter data gaps, and abnormal system operations or configurations. This step required extensive use of data analytics to identify and remove load transfers, outages, data gaps, and data recording errors. Load transfers were of particular importance since they can be confused with load decreases or growth. After identifying anomalous data, gaps were filled with synthetic data predicted from neighboring areas' loads and temperature conditions. For five substations with no interval data at all, we estimated growth patterns based on annual sales of customers at these locations.

2. **Estimate historical load growth trends and noise**. The objective was to estimate historical load growth for each year in 2014–2019 in percentage terms. The year-to-year growth patterns were then used to assess the growth trend and the variability of load growth patterns; the degree of growth in a given year was related to growth during the prior year – technically known as autocorrelation. The econometric models were purposefully designed to both estimate historical load growth and allow for the weather normalization of loads for 1-in-2 weather peaking conditions. The key to this process was to model the natural log of the daily peak loads as the dependent variable and include time-specific coefficients to estimate the percent change in loads, after controlling for other factors. By using the natural log as the dependent variable, the time-specific coefficients estimate the annual percent change in loads after controlling for differences in weather conditions, day of week effects, and seasonality.

3. **Weather adjust loads for 1-in-2 conditions**. Based on historical patterns, years 2013 and 2015, respectively, reflect the 1-in-2 and 1-in-10 weather conditions. Econometric models were used to weather normalize the loads and remove the inherent variation of weather across years.

4. **Simulate potential load growth trajectories**. The load growth forecasts were developed using probabilistic methods – Monte Carlo simulations – that produced the range of possible load growth outcomes by year. This exercise simulates the reality that the near term forecast has less uncertainty than forecasts ten years in the future. A total of 5,000 simulations were performed for each transmission area and substation. Each simulation produced a distinct growth trajectory that took into account the historical trend, variability in growth patterns, and the fact that growth patterns are auto-correlated.

Transmission Historical Loads and Forecasts

The historical peak demands, room for growth, and growth trajectories vary widely across transmission areas. Most areas are experiencing declining loads, but a few areas are growing. Actual historical peak demand levels are first summarized, followed by the presentation of weather normalized historical peaks and forecasts for each location.

Table 4 shows the historical peaks and growth rates for each of Central Hudson's ten transmission areas. Table 5 shows weather normalized historical and forecasted peaks. Locations with a loading factors closer to 100% have less room for growth. Most transmission areas are experiencing declining loads or limited growth or else have low loading factors. However, two transmission areas – Northwest 115-69kV and Northwest 69kV (which is a subset of Northwest 115-69kV) – are currently loaded above 80% and are experiencing positive growth of 1-2% per year. Loading will be changing meaningfully in 2025 with the planned changes to load-serving capability not related to growth. Of these two areas, only the Northwest 115-69kV area is at risk of triggering an infrastructure investment by the end of 2030 (the ten-year study period) in the absence of further load relief. Note that this risk is primarily driven by the changes to load-serving capability.

Table 4: Transmission Area Historical Load Growth Estimates (2014-2019)

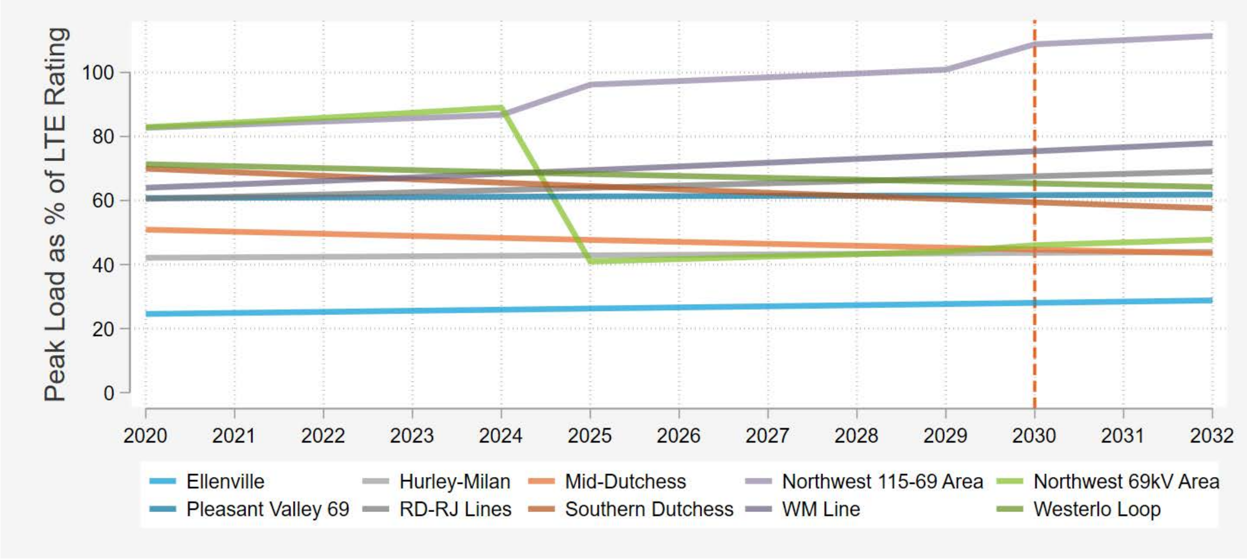
Transmission Area	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Ellenville	251.0	58.0	61.1	64.1	60.7	62.3	61.4	24.5%	1.3%	1.5%
Hurley-Milan	193.0	81.8	80.7	80.4	79.0	83.4	80.5	42.1%	0.4%	1.1%
Mid-Dutchess	230.0	118.8	117.0	113.5	113.0	110.6	108.1	51.1%	-1.3%	0.9%
NW 115-69 Area	149.6	126.7	119.4	125.7	127.4	132.2	128.6	82.5%	1.2%	1.3%
NW 69 Area	116.1	102.3	99.5	98.3	104.2	105.5	106.9	82.5%	1.8%	1.3%
Pleasant Valley 69	107.0	72.4	67.8	73.6	71.2	69.8	59.4	60.7%	0.2%	2.0%
RD-RJ Lines	144.0	87.2	88.5	89.0	89.7	89.5	92.8	60.3%	1.1%	1.4%
Southern Dutchess	211.0	146.8	145.3	141.2	137.6	139.3	139.2	70.3%	-1.6%	0.7%
WM Line	68.0	41.8	43.5	45.2	43.4	48.8	40.2	63.7%	1.7%	1.9%
Westerlo Loop	83.6	67.7	66.6	66.2	64.1	57.4	62.6	71.5%	-0.9%	1.3%

Table 5: Transmission Area Normalized Peak Load Estimates, Historical (2015-2019) and Forecast (2020-2025)

Transmission Area	Historical 1 in 2 Annual Peak (MVA)					Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Ellenville	58.4	59.1	59.9	60.7	61.5	61.7	62.5	63.4	64.2	65.1	65.9	251.0
Hurley-Milan	80.1	80.4	80.7	80.9	81.2	81.3	81.6	81.9	82.2	82.5	82.8	193.0
Mid-Dutchess	123.8	122.2	120.7	119.1	117.5	117.1	115.6	114.1	112.6	111.2	109.7	230.0
NW 115-69 Area	117.7	119.1	120.5	122.0	123.4	123.9	125.3	126.9	128.4	129.9	131.5	149.6
NW 69 Area	89.2	90.8	92.5	94.1	95.8	96.3	98.1	99.8	101.7	103.5	105.4	116.1
Pleasant Valley 69	64.7	64.8	64.8	64.9	65.0	65.0	65.1	65.2	65.3	65.5	65.6	107.0
RD-RJ Lines	83.2	84.1	85.0	86.0	86.9	87.2	88.1	89.1	90.1	91.1	92.1	144.0
Southern Dutchess	158.3	155.7	153.2	150.8	148.3	147.6	145.2	142.9	140.6	138.3	136.1	211.0
WM Line	40.6	41.3	41.9	42.6	43.3	43.5	44.2	45.0	45.7	46.5	47.2	68.0
Westerlo Loop	62.0	61.5	60.9	60.4	59.8	59.7	59.1	58.6	58.1	57.6	57.1	83.6
System	**995.5**	**1006.9**	**1019.8**	**1033.3**	**1046.4**	**1050.5**	**1064.9**	**1080.2**	**1094.1**	**1107.1**	**1121.4**	**N/A**

Figure 21 shows expected (50th percentile) forecasted transmission area loads as a percentage of the LTE rating, including sharp changes from year to year represent changes to ratings and/or NWA expirations. Because most transmission areas are experiencing declining loads or limited growth, the risk of repeatedly exceeding LTE ratings and triggering an infrastructure upgrade is minimal. Even under more extreme load growth (90th percentile, not shown), only the Northwest 115-69kV area is at risk of triggering investment.

Figure 21: Transmission Area Forecast – Peak Load as Percent of Rating, Expected Case



Appendix B further discusses the transmission area forecasts and how they were used to identify locations with T&D deferral potential.

Substation Historical Loads and Forecasts

Central Hudson developed hourly (8760) forecasts for its ten distinct transmission areas and all distribution load-serving substations. Some substations either lacked data or had lower quality data, which prevented the estimation of location-specific forecasts for all substations. Table 6 through Table 13 compare the historical loading factor and growth rate for each of Central Hudson's substations with at least three years of hourly historical data. Locations with a loading factor closer to 100% have less room for growth. Note that five substations, indicated with an asterisk (*), are either not metered or don't have sufficient historical meter data for modeling purposes, and for these locations, annual customer usage data was used to estimate the historical growth rates. Table 14 shows historical and forecasted peak loads for all substations, normalized to 1 in 2 weather conditions.

Table 6: Ellenville Load Group – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Clinton Ave	7.7	1.4	1.4	1.4	1.4	1.5	1.6	17.6%	3.6%	1.2%
Greenfield Rd	15.4	6.6	6.5	6.9	6.8	7.5	7.2	44.3%	2.5%	1.3%
Grimley Rd	7.2	4.1	4.4	5.2	5.0	4.9	5.4	61.0%	1.8%	2.4%
High Falls	34.5	17.1	17.1	18.1	18.0	18.8	17.7	51.1%	1.0%	1.4%
Honk Falls	18.2	5.9	5.8	5.7	5.6	5.6	5.3	33.2%	-1.8%	1.2%
Kerhonkson	44.6	8.7	8.4	9.9	9.4	9.9	10.6	20.8%	2.7%	1.3%
Neversink	4.9	3.2	3.1	3.3	3.6	3.3	3.5	63.3%	0.3%	0.5%
Sturgeon Pool	29.7	2.2	2.2	2.2	2.4	2.6	2.7	7.7%	1.9%	1.5%
Overall	N/A	**45.8**	**46.2**	**50.7**	**47.6**	**52.5**	**50.5**	**0.5%**	**1.5%**	**1.1%**

Table 7: Fishkill Load Group – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Fishkill Plains	49.9	37.0	36.6	37.1	35.2	36.1	37.4	73.8%	1.2%	1.8%
Forgebrook	47.8	26.4	26.2	25.7	24.2	25.3	25.0	55.6%	-0.2%	1.3%
Knapps Corners	47.8	19.3	19.2	19.5	18.4	18.3	18.1	41.2%	-1.6%	1.4%
Merritt Park	52.2	30.8	32.0	31.9	31.2	32.6	30.7	62.0%	-0.5%	1.4%
Myers Corners	35.1	20.8	21.1	20.4	19.3	19.5	18.9	59.7%	-1.5%	1.1%
North Chelsea	48.3	19.0	19.5	19.3	19.4	19.3	18.0	40.5%	0.1%	1.7%
Sand Dock-D	8.0	4.3	4.4	4.8	4.6	5.4	4.9	54.8%	2.8%	1.7%
Shenandoah-D	12.7	11.0	11.3	11.1	10.9	13.3	12.3	95.0%	1.4%	1.6%
Tioronda	25.7	13.2	13.8	14.9	14.3	14.8	15.0	53.8%	1.5%	1.6%
Overall	N/A	**178.2**	**179.4**	**179.0**	**174.7**	**175.4**	**174.1**	**1.9%**	**-0.1%**	**1.3%**

Table 8: Kingston-Saugerties Load Group – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Boulevard	35.0	20.5	20.6	19.8	18.4	20.1	18.9	59.3%	-3.8%	1.4%
East Kingston	48.0	12.0	12.1	12.2	11.7	11.4	11.4	25.1%	-0.4%	1.6%
Hurley Ave	23.1	17.6	17.0	17.3	16.8	18.4	18.2	76.2%	1.3%	1.6%
Lincoln Park	84.0	40.4	41.1	40.3	38.3	39.2	38.8	49.3%	-1.3%	1.0%
Saugerties	54.1	21.1	20.7	22.1	20.8	21.6	20.0	38.0%	-0.1%	1.5%
Woodstock	19.1	20.5	20.2	20.1	20.9	20.2	20.9	96.3%	1.7%	1.4%
Overall	N/A	**126.0**	**126.1**	**127.5**	**120.1**	**124.6**	**123.2**	**1.3%**	**-0.8%**	**1.1%**

Table 9: Modena Load Group Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Galeville	28.7	9.1	11.0	10.4	12.1	11.4	10.7	36.9%	1.8%	2.0%
Highland	32.9	17.1	17.1	18.1	18.0	18.8	17.7	54.8%	0.9%	1.4%
Modena	25.9	12.1	12.5	13.4	13.3	13.8	13.3	51.1%	2.1%	1.8%
Ohioville	29.7	24.2	22.9	20.1	22.0	24.4	21.9	72.4%	-0.2%	1.3%
Overall	N/A	**61.2**	**61.9**	**59.6**	**62.4**	**66.2**	**63.0**	**0.6%**	**1.2%**	**1.4%**

Table 10: Newburgh Load Group – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Bethlehem Rd	47.8	34.5	35.6	36.0	36.2	36.2	33.9	72.3%	-0.3%	1.3%
Coldenham	47.8	33.6	30.8	30.6	31.2	29.4	30.3	63.8%	-1.9%	1.5%
East Walden	26.2	14.1	14.7	14.1	13.7	15.1	14.7	54.6%	1.0%	2.1%
Marlboro	30.9	18.4	19.6	19.7	19.5	21.8	21.1	59.6%	2.3%	1.8%
Maybrook	24.0	14.6	17.8	18.9	18.6	20.5	18.2	68.2%	4.1%	2.8%
Montgomery	2.8	1.4	1.5	1.4	1.4	1.4	1.5	50.5%	0.8%	1.3%
Union Ave	94.5	53.1	53.4	54.2	53.6	56.3	60.7	54.6%	2.1%	1.6%
West Balmville	47.8	33.1	35.2	35.0	34.3	35.0	34.9	71.7%	0.6%	1.4%
Overall	N/A	**196.5**	**206.4**	**205.2**	**202.6**	**203.3**	**203.7**	**2.0%**	**0.8%**	**1.3%**

Table 11: Northeastern Dutchess Load Group – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
East Park	24.2	11.9	12.5	11.9	12.3	12.8	12.6	52.7%	1.1%	1.8%
Hibernia	17.8	10.5	10.6	10.0	10.8	12.1	12.4	55.9%	2.8%	2.7%
Milan	25.9	6.4	6.1	6.6	6.8	7.4	7.7	25.7%	2.1%	1.4%
Millerton	8.3	5.3	5.0	5.0	5.2	5.4	5.0	60.1%	1.0%	1.5%
Pulvers 13	5.8	4.5	4.4	4.7	4.9	4.9	5.0	78.1%	2.1%	1.5%
Pulvers 34	17.2	2.8	2.8	2.9	2.8	3.0	2.9	15.0%	1.0%	1.4%
Rhinebeck	47.8	28.4	28.0	28.7	26.5	28.5	29.9	60.1%	0.2%	1.3%
Smithfield	5.8	1.5	1.5	1.4	1.4	1.4	1.3	24.4%	-2.2%	1.3%
Staatsburg	26.5	8.6	8.0	8.7	8.3	9.2	9.1	32.9%	1.7%	1.7%
Stanfordville	6.3	3.1	3.0	3.4	3.9	3.5	3.5	53.1%	1.2%	2.3%
Tinkertown	19.1	13.1	13.1	14.8	13.6	14.4	13.7	71.4%	1.1%	1.9%
Overall	N/A	**93.1**	**92.0**	**93.3**	**91.6**	**97.8**	**98.4**	**1.0%**	**1.1%**	**1.2%**

Table 12: Northwest Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Coxsackie	16.4	11.8	11.9	11.8	12.4	13.3	11.4	67.7%	2.9%	1.7%
Freehold	15.7	6.4	6.3	6.3	6.5	7.5	6.9	40.5%	1.6%	1.6%
Hunter	19.5	14.2	13.4	14.7	11.1	10.1	10.7	41.3%	-5.2%	5.1%
Lawrenceville	22.1	17.2	15.1	16.9	13.2	13.3	12.5	40.5%	-4.5%	4.7%
New Baltimore	25.8	9.4	9.2	9.3	9.3	10.4	11.4	34.9%	5.6%	2.0%
North Catskill	35.1	23.8	23.1	24.1	22.7	24.2	23.0	67.2%	0.4%	1.3%
South Cairo	19.9	11.6	11.7	11.2	11.4	11.9	11.6	54.7%	2.6%	1.3%
Vinegar Hill	20.7	9.1	9.7	9.8	10.1	9.9	9.5	43.4%	0.3%	3.6%
Westerlo	27.0	8.6	8.2	8.9	8.2	8.0	8.1	29.9%	1.1%	2.4%
Overall	N/A	**99.6**	**94.4**	**97.5**	**100.2**	**94.3**	**92.9**	**0.9%**	**0.4%**	**1.6%**

Table 13: Poughkeepsie Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Inwood Ave	47.8	25.3	24.6	26.3	26.2	24.9	24.4	50.0%	0.4%	2.0%
Manchester	47.8	29.2	28.8	33.7	32.9	32.4	31.4	64.6%	1.0%	1.4%
Reynolds Hill	47.8	34.6	32.8	35.6	34.1	36.1	36.0	69.0%	1.6%	1.0%
Spackenkill	47.8	31.4	31.3	31.1	30.5	29.8	30.8	63.9%	-0.7%	1.5%
Todd Hill	47.8	21.1	22.0	20.9	21.4	21.7	21.2	45.3%	0.4%	1.6%
Overall	N/A	**137.3**	**137.3**	**140.1**	**139.2**	**137.2**	**136.2**	**1.4%**	**0.5%**	**1.2%**

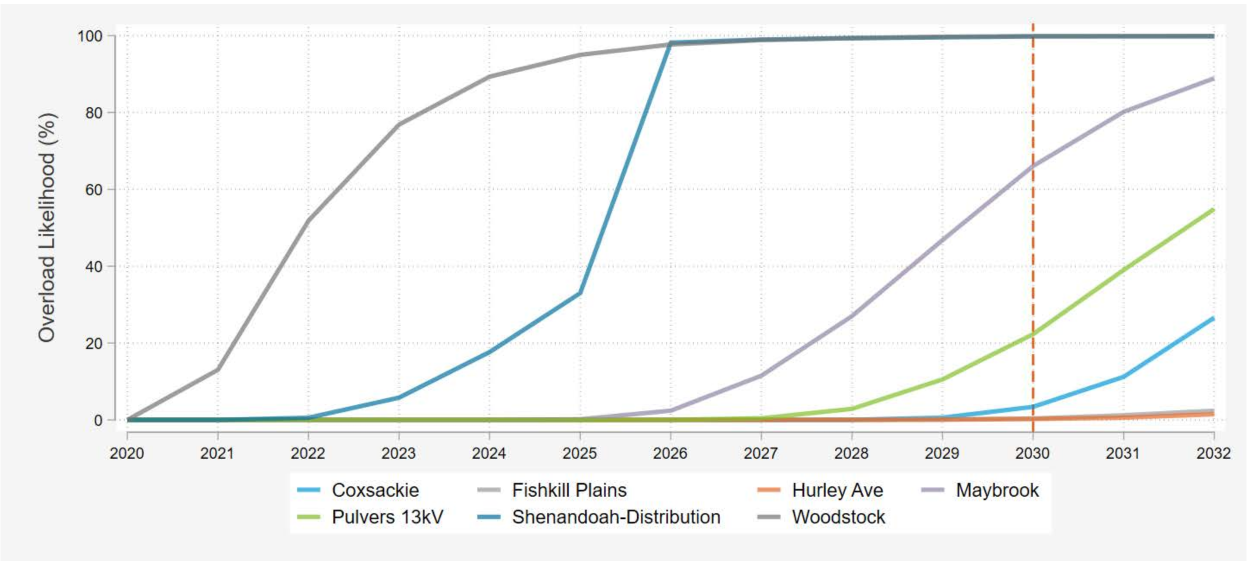
Table 14: Substation Normalized Peak Load Estimates, Historical (2015-2019) and Forecast (2020-2025)

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)					Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Ellenville	Clinton Ave	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.6	1.6	7.7
	Greenfield Rd*	6.2	6.3	6.5	6.7	6.8	6.9	7.0	7.2	7.4	7.6	7.8	15.4
	Grimley Rd	4.1	4.2	4.2	4.3	4.4	4.4	4.5	4.6	4.7	4.7	4.8	7.2
	High Falls	16.9	17.1	17.3	17.5	17.6	17.7	17.9	18.1	18.3	18.4	18.6	34.5
	Honk Falls	6.5	6.4	6.3	6.2	6.1	6.0	5.9	5.8	5.7	5.6	5.5	18.2
	Kerhonkson	8.4	8.6	8.8	9.0	9.3	9.3	9.6	9.8	10.1	10.4	10.7	44.6
	Neversink*	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	4.9
	Sturgeon Pool	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	29.7
	Total	**46.5**	**47.3**	**48.0**	**48.7**	**49.5**	**49.7**	**50.5**	**51.2**	**52.0**	**52.9**	**53.7**	**N/A**
Fishkill	Fishkill Plains	35.1	35.6	36.0	36.4	36.8	36.9	37.4	37.8	38.3	38.7	39.2	49.9
	Forgebrook	26.8	26.7	26.7	26.6	26.6	26.5	26.5	26.4	26.4	26.3	26.3	47.8
	Knapps Corners	21.0	20.7	20.4	20.0	19.7	19.6	19.3	19.0	18.7	18.4	18.1	47.8
	Merritt Park	33.1	32.9	32.7	32.5	32.4	32.3	32.1	32.0	31.8	31.6	31.5	52.2
	Myers Corners	22.3	21.9	21.6	21.3	20.9	20.8	20.5	20.2	19.9	19.6	19.3	35.1
	North Chelsea	19.5	19.5	19.5	19.5	19.5	19.6	19.6	19.6	19.6	19.6	19.6	48.3
	Sand Dock-D	3.9	4.0	4.1	4.3	4.4	4.4	4.5	4.7	4.8	4.9	5.1	8.0
	Shenandoah-D	11.5	11.6	11.8	11.9	12.1	12.1	12.3	12.5	12.6	12.8	13.0	12.7
	Tioronda	13.1	13.3	13.4	13.6	13.8	13.9	14.1	14.3	14.5	14.7	14.9	25.7
	Total	**186.3**	**186.1**	**185.8**	**185.7**	**185.4**	**185.4**	**185.2**	**185.0**	**184.8**	**184.6**	**184.4**	**N/A**
Kingston-Saugerties	Boulevard	24.2	23.3	22.4	21.6	20.7	20.5	19.7	19.0	18.3	17.6	17.0	35.0
	East Kingston	12.3	12.2	12.2	12.1	12.1	12.0	12.0	12.0	11.9	11.9	11.8	48.0
	Hurley Ave	16.7	17.0	17.2	17.4	17.6	17.7	17.9	18.1	18.4	18.6	18.9	23.1
	Lincoln Park	43.7	43.1	42.5	42.0	41.4	41.2	40.7	40.2	39.6	39.1	38.6	84.0
	Saugerties	20.6	20.6	20.6	20.6	20.6	20.6	20.5	20.5	20.5	20.5	20.5	54.1
	Woodstock	17.2	17.5	17.8	18.1	18.4	18.5	18.8	19.1	19.4	19.8	20.1	19.1
	Total	**133.1**	**131.9**	**130.9**	**129.8**	**128.7**	**128.4**	**127.4**	**126.3**	**125.3**	**124.3**	**123.2**	**N/A**
Modena	Galeville	9.9	10.1	10.2	10.4	10.6	10.7	10.8	11.0	11.2	11.4	11.6	28.7
	Highland	17.4	17.6	17.7	17.9	18.0	18.1	18.2	18.4	18.6	18.8	18.9	32.9
	Modena	12.2	12.4	12.7	12.9	13.2	13.3	13.6	13.9	14.2	14.5	14.8	25.9
	Ohioville	21.7	21.7	21.6	21.6	21.5	21.5	21.5	21.4	21.4	21.3	21.3	29.7
	Total	**59.2**	**59.9**	**60.6**	**61.3**	**62.0**	**62.2**	**62.9**	**63.6**	**64.3**	**65.1**	**65.8**	**N/A**
Newburgh	Bethlehem Rd	35.1	35.0	34.8	34.7	34.6	34.5	34.4	34.3	34.2	34.1	34.0	47.8
	Coldenham	32.9	32.3	31.7	31.1	30.5	30.3	29.8	29.2	28.7	28.1	27.6	47.8
	East Walden	13.8	13.9	14.0	14.2	14.3	14.3	14.5	14.6	14.8	14.9	15.1	26.2
	Marlboro	16.8	17.2	17.6	18.0	18.4	18.6	19.0	19.5	19.9	20.4	20.9	30.9
	Maybrook	13.9	14.5	15.1	15.7	16.4	16.6	17.3	18.0	18.8	19.5	20.3	24.0
	Montgomery*	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	2.8
	Union Ave	47.4	48.4	49.5	50.5	51.6	51.9	53.1	54.2	55.4	56.6	57.8	94.5

	West Balmville	33.5	33.7	33.9	34.1	34.3	34.3	34.5	34.7	34.9	35.1	35.3	47.8
	Total	**193.8**	**195.2**	**196.7**	**198.2**	**199.7**	**200.2**	**201.7**	**203.3**	**204.9**	**206.5**	**208.2**	**N/A**
Northeastern Dutchess	East Park	12.2	12.3	12.5	12.6	12.8	12.8	12.9	13.1	13.2	13.4	13.6	24.2
	Hibernia	8.9	9.2	9.4	9.7	9.9	10.0	10.3	10.6	10.9	11.2	11.5	17.8
	Milan	6.1	6.2	6.4	6.5	6.7	6.7	6.8	7.0	7.1	7.3	7.4	25.9
	Millerton	4.8	4.8	4.9	4.9	5.0	5.0	5.0	5.1	5.1	5.2	5.3	8.3
	Pulvers 13	4.2	4.3	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.8
	Pulvers 34	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	17.2
	Rhinebeck	28.6	28.6	28.6	28.7	28.7	28.7	28.8	28.8	28.9	28.9	29.0	47.8
	Smithfield	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	5.8
	Staatsburg	8.2	8.3	8.4	8.6	8.7	8.8	8.9	9.1	9.2	9.4	9.5	26.5
	Stanfordville	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.6	6.3
	Tinkertown	13.1	13.2	13.3	13.5	13.6	13.7	13.8	14.0	14.2	14.3	14.5	19.1
	Total	**92.2**	**93.2**	**94.2**	**95.2**	**96.2**	**96.5**	**97.5**	**98.6**	**99.6**	**100.7**	**101.8**	**N/A**
Northwest	Coxsackie*	9.9	10.2	10.5	10.8	11.1	11.2	11.5	11.9	12.2	12.6	13.0	16.4
	Freehold	6.0	6.1	6.2	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.9	15.7
	Hunter	10.0	9.5	9.0	8.5	8.1	7.9	7.5	7.1	6.8	6.4	6.1	19.5
	Lawrenceville	10.8	10.3	9.9	9.4	9.0	8.8	8.5	8.1	7.7	7.4	7.0	22.1
	New Baltimore	7.2	7.7	8.1	8.5	9.0	9.2	9.7	10.2	10.8	11.4	12.0	25.8
	North Catskill	23.2	23.3	23.4	23.5	23.6	23.6	23.7	23.8	23.9	23.9	24.0	35.1
	South Cairo*	9.8	10.1	10.4	10.6	10.9	11.0	11.3	11.6	11.9	12.2	12.5	19.9
	Vinegar Hill	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	20.7
	Westerlo	7.8	7.8	7.9	8.0	8.1	8.1	8.2	8.3	8.4	8.4	8.5	27.0
	Total	**85.9**	**86.3**	**86.7**	**87.1**	**87.4**	**87.5**	**87.9**	**88.3**	**88.7**	**89.1**	**89.5**	**N/A**
Poughkeepsie-D	Inwood Ave	23.5	23.6	23.7	23.8	23.9	23.9	24.0	24.1	24.2	24.3	24.4	47.8
	Manchester	29.7	30.0	30.3	30.6	30.9	31.0	31.3	31.6	31.9	32.2	32.5	47.8
	Reynolds Hill	30.9	31.4	31.9	32.5	33.0	33.1	33.7	34.2	34.8	35.3	35.9	47.8
	Spackenkill	31.5	31.2	31.0	30.8	30.5	30.5	30.3	30.1	29.8	29.6	29.4	47.8
	Todd Hill	21.3	21.4	21.5	21.6	21.6	21.7	21.8	21.8	21.9	22.0	22.1	47.8
	Total	**133.3**	**134.0**	**134.6**	**135.3**	**135.9**	**136.1**	**136.8**	**137.5**	**138.2**	**138.9**	**139.5**	**N/A**

Figure 22 summarizes the likelihood that loads will exceed long term emergency ratings by year for seven substations – Coxsackie, Fishkill Plains, Hurley Ave, Maybrook, Pulvers 13kV, Shenandoah-Distribution, and Woodstock. All other substations either have ample room for growth or are experiencing declining loads. Of the substations with overload risks, three locations – Coxsackie, Fishkill Plains, and Hurley Ave – have less than 5% overload risk in 2030, while overloads in three other locations – Maybrook, Pulvers 13kV, and Woodstock – can be addressed through low-cost load transfers to neighboring substations. This leaves only the Shenandoah-Distribution substation (shown in dark blue in the figure below) with a risk to trigger infrastructure investment, leaving an opportunity for beneficial DERs.

Figure 22: Probability of Loads Exceeding Design Ratings



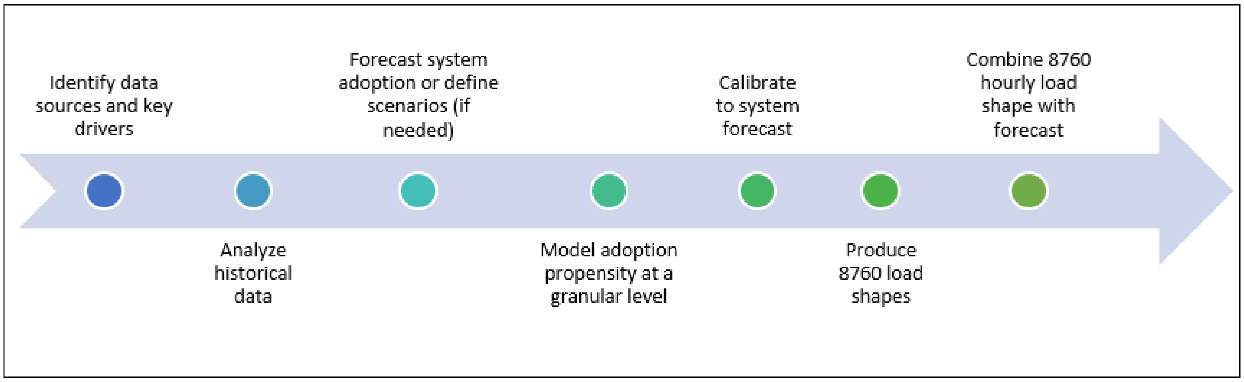
Appendix B further discusses the substation forecasts and how they were used to identify locations with T&D deferral potential.

Forecasting Distributed Energy Resources

The adoption of distributed energy resources by customers outside the planning process introduces significant uncertainty and creates a challenge for long-term planning. As a result, load forecasts must now incorporate predictions of DER growth, which require careful tracking, frequent model refining, and forecast updating. Further, the adoption of different DERs varies by location, necessitating granular estimates to anticipate system impacts.

Figure 23 provides a high level overview of the forecasting process for DERs. Central Hudson has applied this process for distributed solar, electric vehicle adoption, and energy efficiency, producing forecasts and 8760 load impacts for each load-serving substation in its territory.

Figure 23: DER Forecast Process



The nuances of the forecasts vary slightly for different DERs, but the process is similar. The steps are discussed in more detail below.

1. **Identify data sources and key drivers**. In some instances, Central Hudson has comprehensive data regarding where DERs are located, the magnitude of the resources, and when those resources were deployed – energy efficiency, solar, and battery storage are instances where Central Hudson has full data. In other cases, such as EVs, Central Hudson only has partial visibility into information about when, where, and how many electric vehicles and plug-in hybrids were adopted and must rely on external data sources such as New York vehicle registration data, which includes details regarding all registered vehicles in New York and the zip code, but not the specific address, where the vehicle is registered. The drivers of adoptions also vary by the type of DER in question. For solar and storage, the main driver is customer preferences, followed by the introduction of solar leasing and power purchase agreement models. For energy efficiency, the focus was on program based energy efficiency – where Central Hudson offers incentives, discounts, or rebates – which is driven by policy objectives and regulated budgets. The naturally occurring (non-program based) energy efficiency is absorbed in the load growth forecasts.

2. **Analyze historical data**. For each DER, Central Hudson analyzed how penetration grew over time, the dispersion of the resources, and, where appropriate, the historical performance of Central Hudson at meeting policy goals. In some instances, such as electric vehicles, the

distribution of key inputs, such as vehicles across years and the replacement rates, were also analyzed.

3. **Forecast system adoption**. Where and when possible, Central Hudson relied on fitting innovation diffusion curves to historical data – a non-linear regression often referred to as S-curves. When implemented properly, innovation diffusion curves use historical data to estimate, with uncertainty, the future trajectory of cumulative adoptions and the overall market adoption rate. Fitting innovation diffusion curves requires a sufficient history of adoption. An innovation diffusion curve was used to predict community solar new applications, while for the residential and non-residential solar segments – which have experienced multiple years of steady growth in installations – time-series models were used instead. For DERs in their nascent stages or those experiencing truly disruptive innovation, fitting innovation diffusion curves is not always feasible. For instance, Central Hudson tied battery storage adoption – which has occurred only in the past two years – to future solar adoption since batteries are rarely installed on their own. In the case of electric vehicles, Central Hudson employed data on the adoption of proxy technology – green vehicles overall, which includes hybrids, EVs, and plug-in hybrids – and data on vehicle replacement rates and the distribution across model years to estimate overall adoption over time. Because electric vehicles have the potential to achieve deeper penetration than hybrids, scenarios were modeled assuming similar penetration as hybrid and twice the penetration of hybrids. For energy efficiency, where explicit quantity goals are in place, the historical track record in achieving those goals and the volatility observed were employed to produce forecasts with uncertainty.

4. **Model adoption propensity at a granular level (dispersion modeling)**. Estimating where and how much of specific DERs are likely to be adopted is critical for assessing how they will influence distribution and transmission loads and infrastructure upgrades. This requires modeling customer adoption at the granular level, ideally for individual premises. For most DERs – energy efficiency, solar, storage, and electric vehicles – data was available that enabled Central Hudson to predict which customers had a higher propensity for adoption based on characteristics such as energy use patterns, weather sensitivity, customer size, participation in other programs, and geographic location. Not all variables were predictive, so different models were employed for different DERs. The process enabled scoring of customers into groups with a higher or lower likelihood of adoption, which in turn allowed for

the estimation of whether expected adoption rates are higher or lower for specific substation or transmission areas.

5. **Calibrate the granular adoption rates to the aggregate forecast**. For each forecast year, the adoption of DERs was calibrated to add up to the aggregate forecast with uncertainty. The goal was to accurately reflect the current penetration of DERs and expect growth on a year by year basis.

6. **Produce 8760 hourly load shapes for different DERs**. The main objective of the study was to understand how DERs and electric vehicle adoption are expected to influence distribution and transmission loads. A critical step, therefore, was to model hourly load shapes of DERs under T&D planning conditions, which are defined by a normal or 1-in-2 weather year. The 8760 hourly load shapes were produced for solar, storage, electric vehicles, and various types of energy efficiency, by building type and end use. The data sources and methodology for producing those load shapes are detailed in the appendices to Central Hudson's 2016 DSIP filing.

7. **Combine 8760 load shapes with granular DER adoption forecasts**. To understand the expected impact of DERs on transmission and distribution loads, the expected DER adoption for each year at each substation was multiplied by the 8760 load shapes, producing an estimate of the hourly impacts on distribution loads. The substation DER forecasts were then aggregated to understand the impact on specific transmission areas.

Appendix B provides additional detail regarding the development of granular, spatial, and temporal forecasts by DER. The tables below show the 5 year DER forecasts for EE, PV, and EV granular by load area. Load areas are groups of adjacent substations with loads that can be transferred between the substations.

Table 15 shows the peak savings coincident with the local peak of each load area. For comparison, the weather normalized energy efficiency demand savings are shown. The estimates show cumulative energy efficiency savings since 2009. Energy efficiency programs to date have delivered approximately 80 MW of peak savings. By 2025, peak savings from energy efficiency are projected to total slightly less the 150 MW, or an incremental 80 MW of peak savings. Because of differences in when local peaks occur, the sum of individual loads areas does not equal the system coincident peak savings.

Table 15: Coincident Peak Energy Efficiency Demand Savings Forecasts by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	1.2	1.8	1.9	2.2	2.8	4.6	5.4	6.2	7.0	8.0	8.9
Fishkill-D	7	19	10.0	7.1	7.6	8.4	9.6	14.1	16.7	19.5	22.5	25.9	29.1
Kingston-Saugerties	7	17	3.3	4.7	5.5	6.6	8.4	12.7	14.9	17.2	19.6	22.1	24.7
Modena	7	18	3.2	2.7	3.8	4.0	4.5	6.5	7.5	8.5	9.6	11.0	12.0
Newburgh	7	17	7.3	8.7	10.5	11.5	14.3	19.8	23.2	25.9	29.0	32.7	36.0
Northeastern Dutchess	7	19	2.9	3.4	4.2	4.5	5.1	8.1	9.5	10.9	12.3	14.2	16.0
Northwest	1	18	1.2	1.0	1.7	2.7	3.5	4.1	5.0	5.8	6.6	7.3	7.9
Poughkeepsie-D	9	17	1.7	2.3	2.8	3.7	4.3	5.2	6.2	7.2	7.9	8.9	9.6
System	**7**	**17**[16]	**40.5**	**40.1**	**46.8**	**52.8**	**62.6**	**90.5**	**105.9**	**120.8**	**130.2**	**148.1**	**164.9**

Table 16 shows the solar output coincident with the local peak of each load area. Several of the load areas peak later in the day than the Central Hudson system, and one area peaks in the winter. The solar production does not necessarily coincide with the local peaks, which are more diverse. Because solar production is substantially higher in the early afternoon, a difference of a couple hours can yield significant differences in production.

Table 16: Coincident Peak Solar Production Forecasts by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.3	0.5	0.3	0.9	0.8	2.2	2.3	2.3	2.7	3.2	3.5
Fishkill-D	7	19	0.6	0.8	0.6	1.7	1.7	2.1	2.2	2.5	2.8	3.4	3.7
Kingston-Saugerties	7	17	1.9	2.7	2.5	5.1	5.4	7.3	8.5	19.7	21.3	23.2	25.2
Modena	7	18	1.3	1.4	1.3	2.5	1.8	2.3	2.7	3.0	3.5	4.3	4.8
Newburgh	7	17	3.5	5.4	4.6	8.1	7.4	9.4	10.3	11.1	15.5	19.7	22.4
Northeastern Dutchess	7	19	0.9	0.9	0.7	1.3	1.2	1.6	2.0	2.2	2.5	2.8	3.0
Northwest	1	18	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3
Poughkeepsie-D	9	17	1.2	1.2	2.0	0.8	3.7	2.8	3.0	3.7	4.3	4.7	5.0
System	**7**	**17**[17]	**13.9**	**21.9**	**18.8**	**37.1**	**34.2**	**48.2**	**63.2**	**81.2**	**63.9**	**74.8**	**83.2**

[16] System peak hour shifts to HE 18 starting in 2023.
[17] System peak hour shifts to HE 18 starting in 2023.

Table 17 shows the storage output coincident with the local peak of each load area. Several of the load areas peak later in the day than the Central Hudson system, and one area peaks in the winter. The timing of storage discharge is assumed to be driven by wholesale market prices and not to be entirely coincident with local peaks, which are more diverse.

Table 17: Coincident Peak Storage Production (Discharge) Forecasts by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.5	1.3
Fishkill-D	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.4	0.7	1.5
Kingston-Saugerties	7	17	0.0	0.0	0.0	0.0	0.1	0.1	0.8	2.6	2.9	4.2	5.1
Modena	7	18	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.9	1.1	1.4
Newburgh	7	17	0.0	0.0	0.0	0.0	0.0	0.1	0.1	1.1	1.6	2.7	3.7
Northeastern Dutchess	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.7
Northwest	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.6	1.8
Poughkeepsie-D	9	17	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.5	0.6	0.8	0.8
System	**7**	**17**[18]	**0.0**	**0.0**	**0.0**	**0.1**	**0.3**	**1.1**	**2.0**	**6.5**	**9.7**	**16.2**	**21.4**

Figure 24 shows the base cumulative forecast of electric vehicle loads on the Central Hudson peak day. The graph shows the year-by-year change in electric vehicle home charging loads. Data regarding electric vehicle charging outside of homes was not available. It is anticipated that rate designs will incentivize off peak charging. As a result, the vast majority of electric vehicle load will occur late at night or in early morning hours (due to automated timers), and because of this, they improve utilization of existing T&D resources and rarely lead to substation or transmission reinforcements. Their contribution to peak is therefore expected to be minimal or near zero.   See Table 18.

[18] System peak hour shifts to HE 18 starting in 2023.

Figure 24: Electric Vehicle Load Forecast

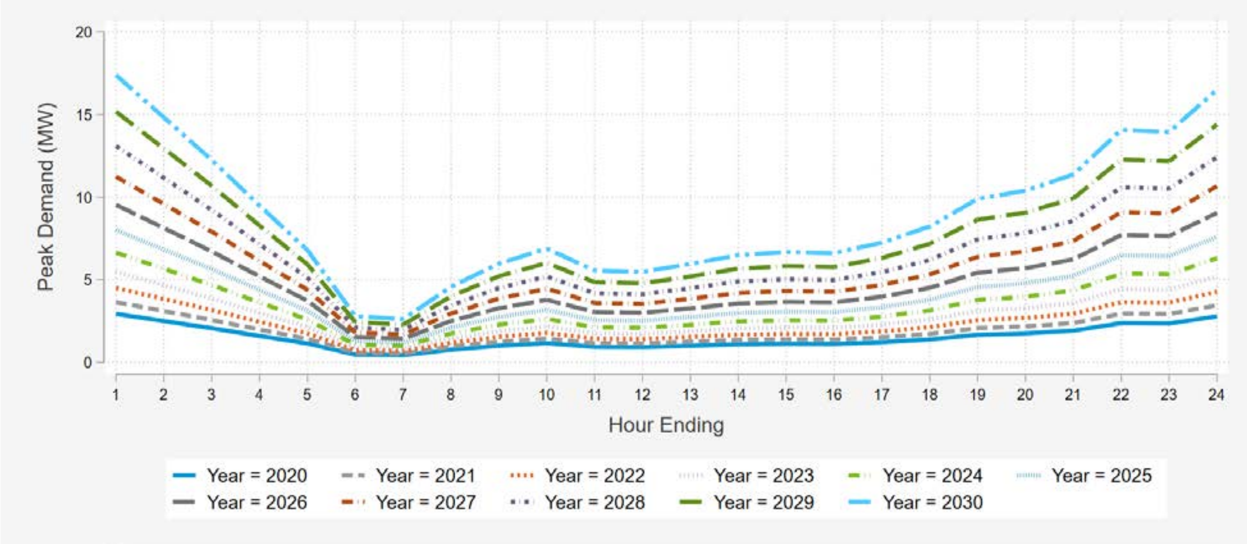


Table 18: Coincident Peak Electric Vehicle Loads by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3
Fishkill-D	7	19	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.6
Kingston-Saugerties	7	17	0.1	0.1	0.1	0.2	0.3	0.4	0.3	0.4	0.5	0.6	1.0
Modena	7	18	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.6
Newburgh	7	17	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.6
Northeastern Dutchess	7	19	0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.6
Northwest	1	18	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3
Poughkeepsie-D	9	17	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
System	**7**	**17**[19]	**0.2**	**0.3**	**0.5**	**0.8**	**1.3**	**1.6**	**1.5**	**1.9**	**2.6**	**3.1**	**4.5**

For planning, it is important to understand the peak contribution of additional resources. While the contribution to the single peak hour is a useful summary, in practice, DER needs to be available for multiple hours. For this purpose, Central Hudson calculated conversion factors to enable conversion of potential DERs into local peak contribution. The interpretation of each conversion factor differs with the type of resource since some resources are typically measured in terms of energy (MWh) and others in

[19] System peak hour shifts to HE 18 starting in 2023.

terms of nameplate capacity (MW). Table 19 shows the interpretation for these two types of conversion factors

Table 19: Methodology for Applying Peak Contribution Conversion Factors for Potential DERs

Type of DER	Metric	How to Calculate Peak Contribution	Interpretation
EE and EVs	MWh	MW = conversion factor x (total annual MWh / 8760 hours per year)	Percent of average hourly demand. Essentially this is a peak coincidence factor for annual average hourly savings (EE) or charging (EV). The conversion factor incorporates the forecasted mix of EE measures and the forecasted mix of EV sizes and charging patterns (home versus charging station charging).
Solar and Storage	MW	MW = Conversion factor x nameplate capacity	Percent of capacity. Simply apply the peak contribution factor to nameplate capacity to estimate expected local peak contribution. For solar, the conversion factor incorporates performance which falls short of the optimal performance due to positioning, roof angle, shade, failed inverters, and other factors. For storage, the conversion factor incorporates operational discharge limits. For example, discharge rates beyond 85% of capacity are typically avoided due to negative effects on battery system longevity.

Table 20 shows the peak contribution conversion factors for each load area and system-wide. The conversion factors for the top single hour can be used to estimate peak contribution to the single peak hour at each location. Also shown are conversion factors weighted for the top 100 hours at each location. This value is more appropriate for estimating DER peak contribution because resources are needed for more than a single hour to shave the load duration curve and avoid overloads.

Table 20: Peak Contribution Conversion Factors by Load Area and DER

Load Area	Peak Month	Peak Hour	Top Single Hour				Top 100 Hours			
			EE	EV	Solar	Storage	EE	EV	Solar	Storage
Ellenville	7	19	1.53	1.10	0.18	0.32	2.16	1.15	0.11	0.53
Fishkill-D	7	19	1.45	0.90	0.23	0.36	2.08	0.90	0.11	0.54
Kingston-Saugerties	7	17	1.60	1.13	0.32	0.37	2.47	1.36	0.40	0.58
Modena	7	18	1.58	1.17	0.22	0.35	2.55	1.38	0.23	0.56
Newburgh	7	17	1.46	0.89	0.26	0.36	2.26	0.90	0.36	0.55
Northeastern Dutchess	7	19	1.44	1.05	0.16	0.30	2.29	1.12	0.11	0.53
Northwest	1	18	1.08	1.00	0.02	0.16	1.09	0.97	0.00	0.15
Poughkeepsie-D	9	17	1.46	0.97	0.23	0.35	1.10	0.79	0.25	0.42
System	**7**	**17**[20]	**1.52**	**1.02**	**0.26**	**0.35**	**2.30**	**1.14**	**0.24**	**0.56**

2. Implementation Plan

a) Current Progress

The implementation plan for T&D forecasting of loads and DERs as outlined in prior DSIPs is complete. The granular data on existing resources and forecasted loads will be publicly posted by August 2020.

Table 21: Implementation Plan

Implementation Step	T&D Loads	Distributed Solar	Energy Efficiency	Electric Vehicles	Battery Storage
1. Identify data sources	100%	100%	100%	100%	100%
2. Develop granular forecasting methodology	100%	100%	100%	100%	100%
3. Test methodology	100%	100%	100%	100%	100%

[20] System peak hour shifts to HE 18 starting in 2023.

	Implementation Step	T&D Loads	Distributed Solar	Energy Efficiency	Electric Vehicles	Battery Storage
4.	Scale methodology for all substations and transmission areas	100%	100%	100%	100%	100%
5.	Produce forecasts	100%	100%	100%	100%	100%
6.	Make forecasts publicly available	August 2020	August 2020	August 2020	August 2020	August 2020

b) Future Implementation and Planning

Central Hudson's plan is to further refine the process for producing forecasts and to automate it, to the extent possible, starting in 2021. There are two areas where additional refinements are needed:

1. Improvements in data cleaning and tracking of load transfers. While the current approach automates several aspects of data cleaning, it relies on visual inspections of patterns to ensure the load transfers and metering issues are not classified as legitimate changes in loads (and vice-versa). The forecasting process cannot be fully automated without refining the data cleaning algorithms and making better use of load transfer records.

2. Estimating historical gross loads. As part of the DSIP, Central Hudson attempted to explicitly model the effects of solar adoption and energy efficiency on T&D loads using time series data. This proved to be challenging due to the high correlation between New York economic growth and energy efficiency (correlation of 0.95) and solar adoption (correlation of 0.84). Economic conditions have exhibited continuous improvement since the start of the analysis in 2010, which happens to coincide with the growth in energy efficiency implementation and solar adoption. The factors are so tightly woven that it is difficult to disentangle them with confidence. Thus, the approach for estimating growth in gross loads needs to be refined.

3. Risks and Mitigation

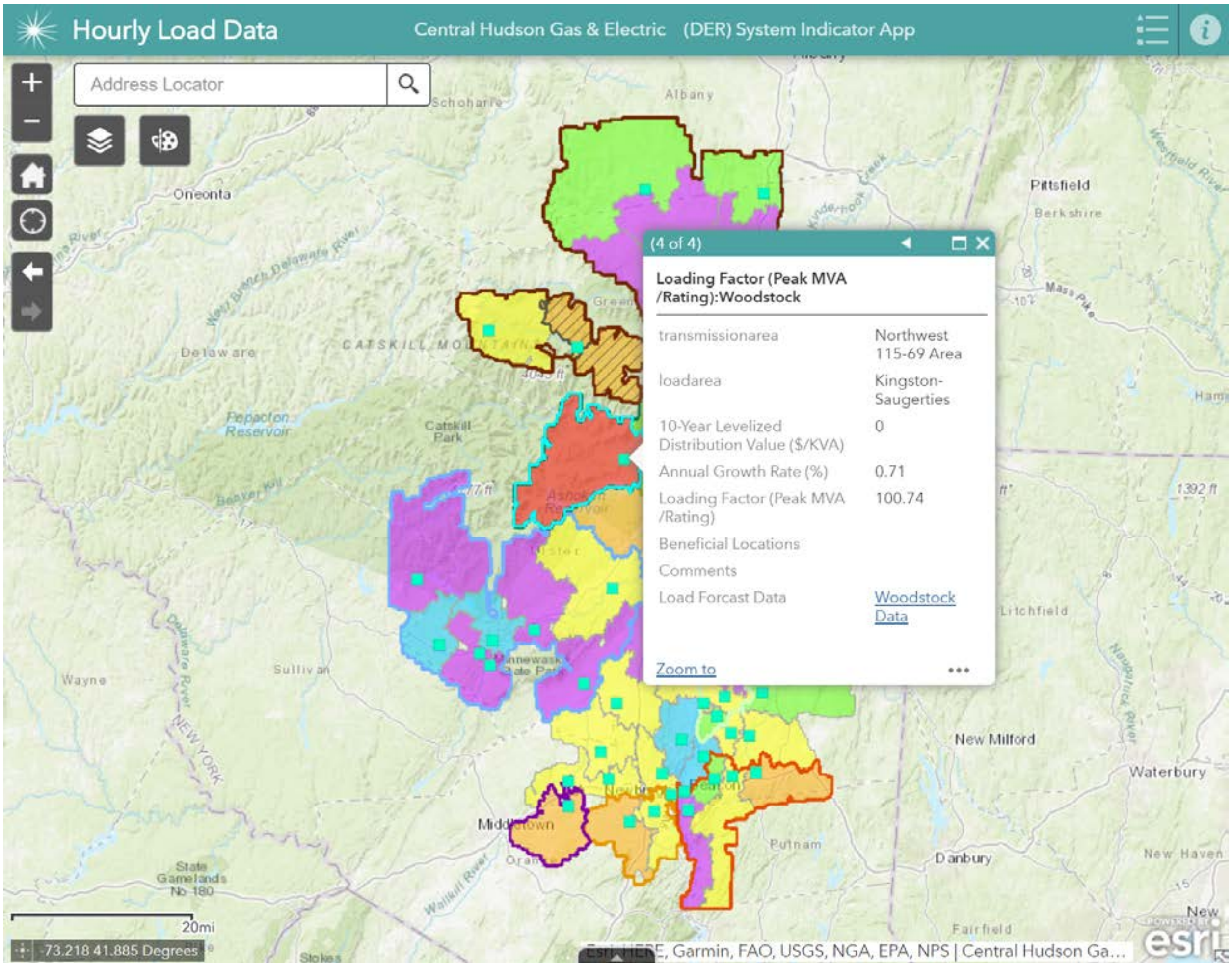
There are a few steps that can be undertaken to ensure that load forecasts are accurate:

- Beyond what is currently available for PV and Company administered EE and DR programs, set up processes to track installation and adoption of other types of DERs and their specific locations;
- Set up processes to track when and where DERs were dispatched (e.g., battery storage or DR) and the magnitude of the resources dispatched;
- Track if actual adoption of DERs differed from the historical forecasts;
- Update locational forecasts and location-specific avoided T&D costs on a bi-annual basis; and
- Explicitly model uncertainty of forecast loads and incremental DERs. While tracking can help improve accuracy, it is just as important to be explicit about uncertainty so that locational forecasts reflect the full range of potential growth patterns.

4. Stakeholder Interface

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 25, are interactive. The main display is a choropleth map, often referred to as 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 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 data as a CSV file.

Figure 25: Central Hudson Stakeholder Interface



5. Additional Detail

a) 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. The System Data Portal provides substation and transmission area load and supply forecast for five years on an hourly basis.

b) 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 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.

c) 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.

d) 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.

e) 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, Energy Storage, and the various solar markets.

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

Central Hudson now 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 DSIP filing. Central Hudson has continued to advance these methodologies since this time, as outlined in this section and within Appendices B (Load and DER Forecasts) and D (Location Specific T & D Cost Report). The use of probabilistic methods has been integrated into Central Hudson's normal forecasting and planning process.

g) Describe how the utility's existing/planned advanced forecasting capabilities anticipate the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency.

Central Hudson's existing probabilistic forecasting methods incorporate existing DERs into the forecasts capturing the inter-related effects. In addition, the use of this probabilistic forecasting approach on load and DER forecasting produces a wide range of forecast possibilities that incorporate the impacts of variability, codependence, and accuracy.

h) 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 still primarily granular transmission area, substation, and circuit level peak load forecasts. The transition to probabilistic hourly load forecasts for load and DER will also allow Central Hudson's planning process to transition to utilize 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.

i) Describe the utility'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 publically 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 at least three years of valid hourly load data from 57 of our 62 distribution load-serving substations encompassing approximately 95% 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.

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

See this Section above and Appendices B and D for the details on the methods used to produce substation level load and DER forecasts.

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

See this Section above and Appendices B and D for details on the levels of accuracy of the various components of the load and DER forecasts.

l) 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 hourly load basis. This will provide 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).

m) 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 does not use sensitivity analyses in this method.

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 is transitioning to a probabilistic approach, where feasible, and will not typically apply this analysis.

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 an important role for technologies in a nascent stage or experiencing truly disruptive innovation(s). Because historical data for those technologies is limited, any current projections rely on assumptions or on data from proxy technologies. For example, for electric vehicles, Central Hudson employed data on the adoption of proxy technology - green vehicles overall, which includes hybrids, EVs, and plug-in hybrids. To explore the potential of higher penetration rates, the models were pressure tested by assuming penetration of electric and plug-in electric vehicles would double that of hybrids.

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

As previously mentioned, Central Hudson utilizes self-generated datasets or publically 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) but has not solicited direct input from DER developers to further inform its forecasting efforts.

o) Describe how the utility 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 a number of 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 in the area of 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.

p) 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 of eliminated.

Central Hudson already separately forecasts DER, including EE, ES, EV, and PV, outside of the load model, but will continue to refine its forecasting methodologies and the accuracy of these forecasts, first through continued market experience using traditional methods to predict market adoption and saturation, and second, to develop more granular forecasts by technology and market to further define the expected DER impacts.

C. Grid Operations

1. 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 DERs' ability 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 in order to preserve distribution system safety and reliability. Critical to these efforts are a set of foundational investments that will support DSP capabilities. Central Hudson's Grid Modernization Program is comprised of six critical project:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)
2. ESRI System Model Geographic Information System (GIS) – provides a single consolidated mapping and visualization system
3. Distribution Management System (DMS) – the centralized software "brains"
4. Distribution System Operations (DSO) – the organization responsible for monitoring and controlling the electric distribution system through the use of the DMS
5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS
6. Substation Metering Infrastructure– Substation feeder metering upgrades required for accurate ADMS power flow calculations.

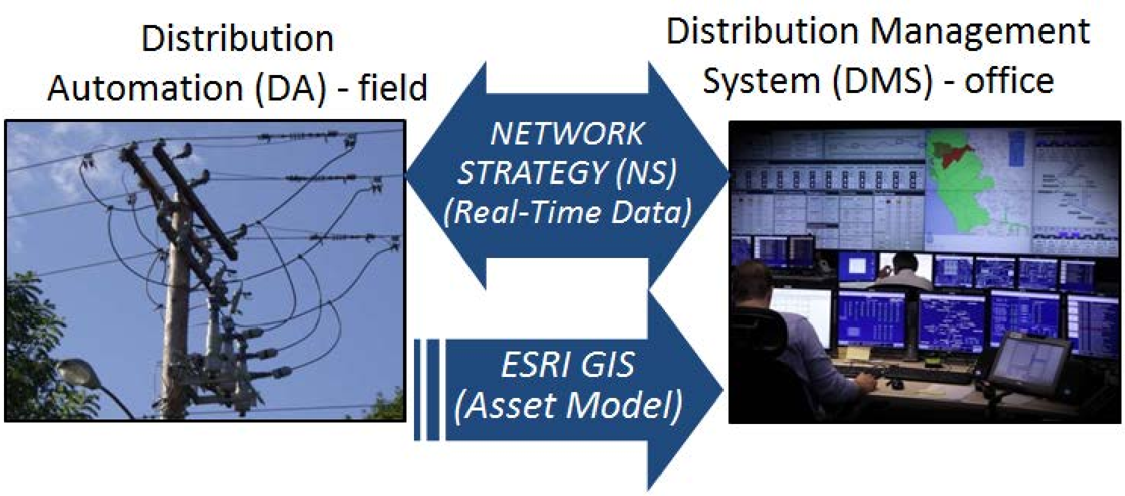
Over 800 Intelligent Electronic Devices (IED; e.g. electronic reclosers, switched capacitors and voltage regulating devices) and sensors are being installed through DA and other projects. These devices provide real time data to the DMS, which enables it to make centralized decisions based on current system conditions rather than anticipated peak loads. DERs also must be monitored, and in some cases, controlled, as a critical input to the DMS. The Network Communications Strategy equipment enables communication between the DA equipment and the DMS. These critical components are described in detail below.

As described above, GIS is a key project of Central Hudson's Grid Modernization Program. 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 physical location and other operating characteristics. 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.

Distribution System Operations staff will utilize DA devices to regularly feed live electrical system data into the DMS, as shown by Figure 26. GIS will support a number of 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 SCADA devices, including distribution feeder breakers, substation load tap changers and DERs.

Figure 26: Interplay between Central Hudson's DA and DMS



The continued implementation of these supporting technologies and systems will enable Central Hudson to produce more robust system models that incorporate the impact of DERs and ultimately allow it to utilize DERs better to provide value to the grid and customers. In the near term, Central Hudson's Grid Modernization Program aims to accommodate DERs through increased monitoring and, in some cases, control. Over the longer term, Central Hudson may seek to dispatch DERs in real time to preserve distribution system safety and reliability or provide other services of value to the grid.

In addition to its individual efforts to accommodate DERs, the Company has helped establish DER M&C requirements through its active role in the Joint Utilities Monitoring and Control (M&C) Working Group. These requirements aim to minimize developer costs while preserving system safety and reliability. Central Hudson's efforts to increase M&C directly supports the Company's goals of integrating DERs, maintaining power quality, optimizing system operations, and enhancing grid resiliency. Additionally, enhanced M&C can increase the dispatchability of DERs, which in turn can promote system efficiencies and support the ability of DERs to provide their full value to the system. Overall, an appropriate level of M&C is required to ensure that new DER interconnections will not jeopardize system safety or reliability.

The focus on M&C also has touchpoints with other groups Central Hudson participates in: (1) the Joint Utilities ISO-DSP Coordination Working Group, (2) the DPS- and NYSERDA-led Interconnection Technical Working Group (ITWG) and (3) the NYISO Market Issues Working Group (MIWG). Central Hudson continues to engage in these groups to harmonize M&C requirements, to the extent possible, for varying DER market and operational use cases to promote a consistent approach throughout the State.

Finally, Central Hudson and the Joint Utilities continue to engage with NYISO, both through direct interaction and the NYISO stakeholder process, on defining operational coordination requirements for wholesale-participatory DERs, including roles, responsibilities, and procedures.

2. Implementation Plan

a) Current Progress

Today, the distribution system is operated on a decentralized basis. Each of the Company's five operating districts has operational responsibilities for their respective geographic-based operating regions. The system operates predominantly in an 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.

As additional DERs are integrated into the system, there is limited visibility regarding the status of these resources. The continued operation of the distribution system in this decentralized approach will result in operating issues that limit the ability to integrate increasing levels of DER without significant system upgrades. While this mode of operation has allowed the system to work safely and reliably for many years, new system requirements such as bi-directional power flow and better utilization of existing infrastructure call for changes to existing grid operations.

In order 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 will result from these DERs. Recognizing this, the Company embarked on the development of a Grid Modernization Program, which includes investments in six foundational projects: DA, ESRI GIS, DMS, DSO, NS, and AMI. The deployment of these systems is currently underway and the details of these deployments are described below.

The DA components of the Grid Modernization Program include distribution system infrastructure upgrades and the installation of IEDs and sensors. The distribution system infrastructure upgrades will develop ties between adjacent feeders or upgrade existing ties with larger conductors. Coupled with IEDs, additional sensors, and the intelligence of the ADMS, 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. Central Hudson also will address two radial transmission feeders that do not meet the design criteria of 7 MVA of unreserved load. Rather than provide a redundant transmission feed, a 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.

To achieve the benefits of DA, two key applications will be implemented along with the infrastructure upgrades: VVO and FLISR. The installation of substation-level AMI data, which includes per phase data reporting, is necessary to implement both VVO and FLSIR schemes accurately.

(1) Volt/VAR Optimization

The concept of VVO revolves around the implementation of voltage reduction and optimization of reactive power flow to improve power quality and efficiency. Applying sophisticated, detailed distribution system models, switched and fixed 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, making these savings transparent to the customer other than lower kWh usage.

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 are accounting 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 CVR 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 voltage implementation. 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.

(2) Fault Location, Isolation, and Service Restoration

Central Hudson has been utilizing ALT teams for approximately fourteen years. 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 consider data from a much wider geographic basis. 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 will 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 not currently available.

(3) Other Functionality

The addition of stronger tie points will enable Distribution System Engineers to employ the same devices that are applied to FLISR 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 System Engineer will remotely initiate switching to manage these situations.

Since the 2018 DSIP, Central Hudson has completed the construction of DA devices for the Fishkill and Newburgh Districts and approximately half of the Poughkeepsie District. DA plans for the Catskill District were completed in 2019 with partial construction underway in 2020. Table 22 illustrates the accomplishments through June 2020.

Table 22: Distribution Automation Roll-out through 2020

District	2015 Q3–Q4	2016 Q1–Q2	2016 Q3–Q4	2017 Q1-Q2	2017 Q3-Q4	2018 Q1-Q2	2018 Q3-Q4	2019 Q1-Q2	2019 Q3-Q4	2020 Q1-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	D, C	C	C	C	C		
Newburgh Phase 2			P, D	D, C	D, C	D, C	C	C	C	C
Poughkeepsie Phase 1					P, D	D, C	D, C	D, C	D, C	D, C
Poughkeepsie Phase 2						P	P	D, C	D, C	D, C
Catskill								P	P, D	D
Kingston Phase 1										P
P = Planning; D = Design (field); C = Construction; I = Implemented										

The DMS components of the Grid Modernization Program include:

- Distribution level SCADA (Supervisory Control and Data Acquisition),

- Advanced System Modeling,
- Near Real-time Load Flow, and
- Contingency Analysis Capabilities.

Central Hudson is installing a DMS to implement applications, including VVO and FLISR, while providing an intelligent centralized control center to manage distribution assets in a more coordinated manner. Central Hudson will use the data acquisition and supervisory control capabilities of the new DMS to monitor and control both electric and gas distribution systems and improve the overall efficiency of operations. In addition to providing greater visibility and control of our distribution system, the DMS will help facilitate and manage a higher penetration level of DERs.

While the DMS is anticipated to support further integration of DER systems, current DMS algorithms related to VVO and FLISR do not currently incorporate DER as part of these schemes. Additionally, the level of control of these systems needs to be further understood, including when a hybrid approach of decentralized vs. centralized control of DER is appropriate. As a result, Central Hudson is jointly working on a NYSERDA PON with EPRI, Schneider Electric, and a PV partner, to test advanced inverter functionalities within the DMS. The goal of this project is to understand how VVO and FLSIR algorithms should be updated to accurately incorporate DER as well as better understand hybrid control strategies. This project involves testing of these strategies via modeling simulations along with a live demonstration project within Central Hudson's territory.

Project Architecture

The DMS is comprised of a distributed computing environment with open system architecture. The architecture and configuration of the system is described in the sections that follow.

The DMS has five separate environments: Primary Control Center (PCC), Backup Control Center, Quality Assurance, Program Development, and Operator Training Simulator (OTS). 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 Quality Assurance and Program Development environments are used to perform database and display maintenance activities and to test new patches/releases received from the Vendor.

Primary Control Center System

The PCC system is the primary real-time environment of the DMS. The platform provides the SCADA capability, which provides the interfaces and functionality required to monitor and control the distribution system. This system also hosts the advanced applications that provide the functionality needed to ensure the efficient and reliable operation of the distribution system.

The PCC is a high availability system characterized by high-speed data collection and presentation functions. The PCC is a fault-tolerant system with redundant server architecture. All storage devices are redundant and hot-swappable so that no downtime is incurred for replacing a failed disk.

Backup Control Center System

The Backup Control Center system includes all of the functions and features provided with the PCC system, is a replica of the PCC system hardware, and as an operating control system must have 24/7 redundancy.

Quality Assurance System

The Quality Assurance System (QAS) supports the development and testing of all components of the DMS. This system provides a platform for testing system upgrades, system patches, network model updates, and other features. The hardware and software in this system are closely modeled to the PCC system.

The QAS is used to test all new components and modifications of existing DMS applications. The QAS has the capability to receive real-time data (i.e., from the EMS and DA devices) concurrently with the PCC system. This process does not interfere with or degrade the performance of the DMS. Control commands issued from the QAS are communicated to field devices only if those devices are directly and solely attached to the QAS.

Program Development System

The Program Development System (PDS) supports display creation, tune-up, and configuration of the DMS. The PDS has substation one-line diagram generation capabilities and also includes all of the administration tools. The PDS is used to help in the validation of the SCADA and DMS databases, system upgrades, system patches, network model updates, network connectivity, land-based completeness, substation one-line diagram accuracy, and applications accuracy.

The PDS supports:

- Database and display development tools,
- Substation one-lines development tools,
- Data acquisition to perform testing with field devices using Sensus or DNP3/IP, and
- Distribution Network Applications.

The PDS is configured as a non-redundant, stand-alone system. The PDS is of the same server and console hardware as in the Production environment. The PDS retains its individual identity, although it is networked with the other components of the DMS.

Operator Training Simulator

An OTS facilitates personnel training for the operation of the DMS. The OTS provides introductory-level training as well as advanced instruction and includes all of the necessary user interfaces and computing capability to train individual operators and/or an entire control room crew.

The DMS will interface with numerous external systems that have been implemented by Central Hudson, some of which are noted below.

Geographic Information System

The DMS will interface with Central Hudson's enterprise GIS to import the as-built geographically connected representation of the electric distribution network and land-based map data.

The enterprise GIS consists of two Oracle database servers with GIS data logically split up amongst various schemas. Gas transmission, gas distribution, electric transmission, electric distribution and land-based map data are all stored in the two databases in various schemas.

The Electric Distribution GIS contains a connected geometric model of all facilities from the substation breakers down to the customer transformers and service points. The data is stored in the standard Telvent/Schneider Electric ArcFM Distribution Data model. The geometric representation is as geographically accurate as possible, with allowances made for separation between devices so that independent connectivity can be maintained.

In addition to electric data, the GIS also contains a large amount of base mapping data and gas transmission/distribution data. It contains a comprehensive, land-based map dataset with streets, railroads, hydro features, political districts, operating districts, circuit map grids, and other features. Central Hudson maintains and updates the street data as well to incorporate new developments and road rebuilds. Tax parcel and building footprint data from the counties are also contained in the GIS land data. Elevation rasters, aerial orthoimagery, and many more reference data layers are available.

Outage Management System

The DMS will interface with Central Hudson's existing OMS. The DMS will receive outage information from the OMS and send IED device status to the OMS. The existing OMS is based on GE's PowerOn Version 4.3 and resides on the corporate network. The long range plan is to replace the existing OMS with a system which will operate within the DMS.

Energy Management System

The ADMS will interface with the existing EMS to exchange real-time operational data for substations. Remote Terminal Units acquire data from substations and provide controls to substation devices. The majority of Remote Terminal Units are connected to the EMS such that all data and controls for substations are available via the EMS.

The operational data and available controls include data and controls for equipment that will be under the jurisdiction of the Transmission System Operators. Therefore, the DMS will not have direct access to the substations.

In addition to measurements, statuses, and controls, the DMS and the EMS are being developed to exchange operational information such as quality codes and tags.

The DMS also contains an Infrastructure Environment. The Infrastructure Environment supports Cyber Security applications, such as antivirus protections, security event logging and Disaster Recovery applications including backup and restore.

Central Hudson has developed internal cybersecurity policies modeled after North American Electric Reliability Corporation's (NERC) Critical Infrastructure Protection (CIP) Version 5 Standards and Requirements for the DMS and Network Strategy projects. Applicable standards were modified, as necessary, to align more closely with the Company's performance and business objectives. The DMS will be compliant with all relevant cybersecurity standards and requirements.

Project Schedule

The new DMS is being implemented in a phased approach as it relies on the completion of the five other critical 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 2017 and the beginning of integration with the EMS system.

The plan of implementation 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.

Network Communications Strategy

The Network Communication Strategy components of the Grid Modernization Program include:

- Tier 1 (High Capacity Backbone),
- Tier 2 (Medium Capacity Network),
- Tier 3 (Low Capacity Network - Future),
- Network Routers to support MPLS and TDM, and
- Network Monitoring Systems.

Background

The Company formed a task force in April 2011 to review communication issues and develop recommendations for improvement. The Network Strategy Team developed the following problem statement: "A well-defined plan to leverage technologies for current and future communication needs does not exist. This absence has led to a patchwork of infrastructure and technologies that lacks adequate documentation and results in poor reliability for some applications. A long-term, cost effective strategy is needed to establish robust systems that provide reliable and secure communications."

Scope

The scope of Network Strategy is communication among 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, mobile radio towers, and large customer meter installations. Technical applications such as SCADA, transmission line protection, security (video and card access), will use the network, as well as general traffic supporting internet use and Voice over Internet Protocol. Network Strategy will also enable Central Hudson to broadly implement DA. Additionally, the network acts as the underlying two-way communications system between the DMS and IEDs in the field. Although the system is designed with expansion capability to allow for communication with smart meters, Central Hudson has no current plans to build out that capability.

Topology Overview

Central Hudson's planned topology is a tiered network. Tier 1 is the high bandwidth backbone connecting the most critical substations as well as other strategic sites. Tier 1 will be a combination of existing and new fiber optic cables and microwave connections. Most of the sites on the Tier 1 network will also serve as gateways for connection to the Tier 2 network. Tier 2 is the medium bandwidth network. Tier 2 will be a mesh radio network for communication with DA equipment, electric substations, gas regulator stations, and large customer meter installations. The system is designed with the provision for a future Tier 3 low bandwidth network that could reach to additional endpoints on the network.

Tier 1

As noted, Tier 1 is the high bandwidth backbone connecting the highest-priority sites in the system. Tier 1 will be a combination of existing and new fiber optic cables and microwave connections.

The Physical Layer (Layer 1) for the Tier 1 network is a fiber optic cable and licensed wireless point to point microwave operating at either 6 GHz or 11 GHz. The current plan for the Tier 1 Network includes approximately 70 nodes. The nominal capacity of the microwave is 350 MB/s. Several specific paths of microwave associated with the connection between the PCC and the Alternate Control Center have nominal capacities of 700 MB/s. The nominal capacity for the fiber optic cable links will be 1,000 MB/s.

The Data Link Layer (Layer 2) for the Tier 1 network is Ethernet. The Network Layer (Layer 3) for the Tier 1 network is Multiprotocol Label Switching (MPLS). Together, these operate at Layer 2.5. Physically, the Company has chosen to use the Aviat CTR 8611 microwave router to implement Multiprotocol Label Switching for the fiber optic and microwave Tier 1 Network. This enables the deployment of Layer 2

Virtual Private LAN Service for certain critical applications such as SCADA and Layer 3 IP for less critical applications such as Voice over Internet Protocol.

Tier 2

Tier 2 is the medium bandwidth network. Tier 2 will be a mesh radio network for communication with DA equipment, electric substations, gas regulator stations, and large customer meter installations. Gateways for connection to the Tier 2 network would be located at the endpoints or nodes of the Tier 1 Network.

The Physical Layer (Layer 1) for the Tier 2 network is an unlicensed wireless point to multi-point mesh radio operating at both 2.4 GHz and 5.8 GHz. The range for the 2.4 GHz radio is 2,400 – 2,473 kHz and the range for the 5.8 GHz radio is 5,150 – 5,850 kHz. The current plan for the Tier 2 Network includes approximately 3,000 nodes. The nominal capacity of the Tier 2 radios is 50 MB/s at the gateways, dropping down to 2 MB/s at the endpoints of the mesh.

Tier 3

As mentioned above, Tier 3 is envisioned to be a low bandwidth network. The Company does not have any current plans to construct a Tier 3 network. One possible design for the Tier 3 network would be a mesh radio network similar to the Tier 2 network. Most likely, this network would be operated at either 900 MHz or 2.4 GHz. The Tier 2 locations would be used as gateways for the Tier 3 network. The remainder of the Tier 3 network mesh radios could be located within electric meters to support an AMI system.

Network Monitoring System

As part of the Pilot Project, a Network Monitoring System (NMS) was established at the South Road Headquarters in Poughkeepsie, NY. 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 Tier 1 microwave equipment, the Tier 1 Multiprotocol Label Switching system, and the Tier 2 radio mesh system. The NMS provides for remote configuration of the Network Strategy Tier 1 and Tier 2 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. Central Hudson plans to establish an alternate NMS at the Alternate Control Center in Newburgh, NY, by the end of 2020.

Cyber Security

Central Hudson developed internal cybersecurity policies modeled after NERC CIP Version 5 Standards and Requirements for the DMS and Network Strategy projects. Applicable standards were modified, as necessary, to align more closely with the Company's performance and business objectives. The Network Strategy Project will be compliant with all relevant cybersecurity standards and requirements.

Project Schedule

In 2014, Central Hudson initiated a pilot project for Network Strategy. The Tier 1 component of the pilot project included the construction of microwave links between the South Road Headquarters in Poughkeepsie, NY, and the Hurley Avenue Substation in Kingston, NY. This connection included three separate microwave links and two intermediate locations. The microwave connection went into service in January 2015. The Tier 2 component of the pilot project included the installation of 18 mesh radios in the Town of Ulster, NY. The company tested two different manufacturers and three different radio frequencies, including both licensed and unlicensed frequencies. This work was completed in 2015.

In 2015, Central Hudson began construction of the Tier 1 Network. Six microwave links were installed to expand the existing microwave portion of the network and connect to several existing fiber optic cable portions of the network in the Fishkill District. In 2016, Central Hudson added distribution ADSS fiber in the Newburgh and Poughkeepsie Districts and in 2017 added transmission OPGW fiber in the Newburgh District.

In 2016, Central Hudson began construction of the Tier 2 Network in the Fishkill District. Construction of the Tier 2 Network is closely linked with the development of the DA program.

Table 23 illustrates the accomplishments through June 2020. In this table, Phase 1 is defined as the planning, design, and construction of the DA endpoints. The location of these nodes is defined by the DA endpoints plus or minus one or two distribution circuit spans (i.e., one pole over if necessary for signal strength). Phase 2 is defined as the planning, design, and construction of the nodes needed to help the mesh network form. These nodes are referred to as Helper Nodes. The location of these nodes is much more involved and includes path studies and field signal strength measurements. The time of year for this design work is critical as well. A location for a Helper Node may look good in the winter and then not perform well in the summer when there are leaves on the trees.

Table 23: Tier 2 Network Roll-out through June 2020

District	2015 Q3–Q4	2016 Q1–Q2	2016 Q3–Q4	2017- Q1-Q2	2017 Q3-Q4	2018 Q1-Q2	2018 Q3-Q4	2019 Q1-Q2	2019 Q3-Q4	2020 Q1-Q2
Kingston Pilot Area	P, D	P, D	C							
Fishkill Phase 1	P, D	P, D	C	C						
Fishkill Phase 2				P, D	P, D, C					
Newburgh Phase 1					P, D	C	C			
Newburgh Phase 2						P, D	D, C	C		
Poughkeepsie Phase 1						P, D	D, C	D, C	D, C	C
Poughkeepsie Phase 2							P, D	D, C	D, C	C
Catskill								P, D	D, C	D, C
P = Planning; D = Design (field); C = Construction Complete										

Central Hudson is continuing the process of developing Distribution System Operations as outlined in the Distribution System Operations Whitepaper (originally developed prior to the 2016 DSIP and updated for the 2018 DSIP). Above all, the mission of Distribution System Operations is to provide for the safe and reliable operation of the distribution system. This includes minimizing the impacts of DERs on the safe and reliable operation of the distribution system. Distribution System Operations is the organization responsible for the use of the Distribution Management System. The Distribution System Operations Whitepaper addressed staffing, position descriptions, the Operational Authority of the distribution system, and how operations will be conducted in normal and emergency operating modes.

Central Hudson has made significant 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 through its involvement with the Joint Utilities M&C Working Group and ITWG.

Central Hudson's Grid Modernization Program

The Company's Grid Modernization Program will enable it to enhance M&C capabilities and accommodate increasing levels of DERs. While the development of advanced M&C capabilities is in its nascent stages, it will allow the Company to more effectively utilize DERs based on existing or forecasted system conditions.

In the Initial DSIP, and further outlined above, Central Hudson detailed its plans for various enabling technologies to support DSP capabilities, including monitoring systems, control systems, and distribution infrastructure upgrades. As mentioned above, the Company's planned investments in various DA technologies, including devices (i.e., reclosers, regulators, and switched capacitors), circuit mainline reinforcements, circuit monitoring, and distributed telemetry, will enable the DMS to receive real-time data. As a result, the DMS will be able to use applications like Volt/VAR control and FLISR to further accommodate, and eventually actively utilize, DERs. Central Hudson anticipates ultimately automating the execution of distribution switching orders for unplanned work (i.e., fault restoration) with the DMS using the FLISR application. Additionally, it plans on adding a work request/switching model to the DMS by 2022.

To promote the integrity and safe operation of the DMS, the Company will afford it the same cybersecurity protection as it does for the Energy Management System (EMS). Central Hudson will protect Operational Technology Assets with its Cyber Security for Operational Technology, which is closely modeled after the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards.

Central Hudson is also investing more broadly in its Distribution System Operations to enhance its ability to fully leverage these supporting technologies and systems.

Lower-Cost M&C Efforts

Central Hudson has been meeting with the Joint Utilities M&C Working Group since 2017 to understand and define M&C requirements that support safe and reliable operation of the distribution system. Through this working group, the Joint Utilities have discussed implementation issues, lower-cost M&C solutions, and the possibility of integrating new M&C technologies. The M&C Working Group produced several technical documents for ITWG consideration, including proposed interim requirements for anti-islanding and M&C informed by benchmarking against other utilities and direct operational experience.

Through discussions with stakeholders, the M&C Working Group recognizes that M&C requirements have the potential to strain project economics, particularly for smaller projects. In follow-up Working Group discussions, the Joint Utilities have identified three primary drivers of M&C cost:

- Available communication methodologies in a geographic area;

- Engineering, design and drafting; and
- Site installation, back office integration, testing and commissioning.

The Joint Utilities believe the most significant opportunity for reducing M&C cost will come through the standardization of design and/or functionality for equivalent business and technical use cases. Achieving this level of standardization will result in fewer engineering, design, drafting, installing, testing, and commissioning hours while also allowing for economies of scale.

To facilitate M&C cost reductions, the Working Group recently benchmarked potential low-cost M&C solutions and engaged in focused, internal discussions with subject matter experts in metering, telemetry, security requirements, and engineering, installation, and commissioning (EIC). These efforts produced four main takeaways:

1. 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).
2. 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.
3. 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.
4. The utilities have an opportunity to standardize low-cost M&C solutions during future pilots and R&D energy storage projects. This will allow the utilities to test these solutions in a controlled environment prior to authorizing them for commercial interconnection applications.

The Joint Utilities have discussed smart inverter capabilities for possible integration into M&C pilots for low-cost solutions. However, these functions have not been widely implemented or standardized. Before utilizing these devices for monitoring and control, we will need to make further progress on issues around cybersecurity, functionality, and standardization. Upon ratification of the IEEE 1547.1-2018 testing standard, the Joint Utilities will require newly-installed smart inverters to be over-the-air firmware upgradeable.

The company maintains that lower cost M&C can be achieved through effective leveraging of foundation technology investments of Distribution Automation, Distribution Management System and Network Communications Systems. Additionally, Central Hudson is also currently supporting a NYSERDA PON led by Quanta Technologies related to the design, testing, and commercialization of a next generation DER gateway that further supports identifying lower cost M&C options, particularly for smaller DER < 500kW.

b) Future Implementation and Planning

Central Hudson, as detailed in the previous section, will continue its implementation efforts for key enabling technologies, such as DA, DMS, OMS, and the Network Communications Strategy projects.

Distribution Automation will continue to be rolled out per the schedule shown in Table 26. Based on the prior 2018 DSIP, as a result of an ongoing research and development project Central Hudson is working on with EPRI and the Company’s DMS vendor, completion of the Kingston and Catskill DA phases were swapped.

Table 24: Distribution Automation Roll-out after July 2020

District	2020	2021	2022	2023
Poughkeepsie Phase 1	C	C, I		
Poughkeepsie Phase 2	C, I			
Catskill	P, D, C	D, C	D, C, I	
Kingston Phase 1	P	D, C	D, C, I	
Kingston Phase 2	P	P, D, C	D, C	C, I
P = Planning; D = Design (field); C = Construction; I = Implemented				

The DMS will continue to be rolled out per the schedule shown in Table 25.

Table 25: Future Objectives

Objectives	Dates
Completion of Fishkill Model and integration of SCADA points DA and EMS	Q2 2021
DMS Upgrade	Q2 2021
Completion of Newburgh Model and integration of SCADA points DA and EMS	Q2 2022
Completion of Poughkeepsie Model and integration of SCADA points DA and EMS	Q1 2023
OMS Upgrade and Integration with DMS	Q4 2023
Completion of Catskill Model and integration of SCADA points DA and EMS	Q1 2024
Completion of Kingston Model and integration of SCADA points DA and EMS	Q4 2024

Network Communication Strategy will continue to be rolled out per the schedule shown in Table 26.

Table 26: Tier 2 Network Roll-out after July 2020

District	2020	2021	2022	2023
Poughkeepsie Phase 2	P, D	C, I		
Catskill		P, D	C, I	
Kingston			P,D,C	C,I
P = Planning; D = Design (field); C = Construction; I = Implemented				

The transition to Distribution System Operations will include the addition of one Distribution System Engineer and twelve Distribution System Operators. This will create the need for both additional office space in the Distribution Control Center and additional workstation space to hold the necessary computer monitors. This extra space must be included as part of the overall considerations for this project.

In 2018, Central Hudson renovated Building 810, Floor S1 at its Poughkeepsie Headquarters, to serve as its Initial Distribution System Operations Primary Control Center (PCC). The Transmission System Operations Primary Control Center is currently located in Building 810 on Floor S2. The current available space in Building 810 on the S1 floor is 2,350 square feet. A study performed in 2017 estimated that 7,245 square feet were needed for Distribution System Operations (not including space for support staff, data center space, or mechanical space). In addition, the low ceiling height in this room does not allow for a map board that would be used to improve situational awareness. The Initial Distribution System

Operations PCC, although lacking in space for the long term, will serve to help with developing an understanding of what works and what doesn't work. Lessons learned from this Initial PCC will help shape the design of subsequent facilities that will host Distribution System Operations.

In 2020, Central Hudson started construction on a new Training Academy; construction of the adjoining Primary Control Center is planned to begin in 2022. Construction of the Primary Control Center is expected to take twelve months, followed by twelve months of commissioning. The PCC will be operational for Transmission System Operations starting in January 2024 and for Distribution System Operations in July 2024. At that time, the facilities in Poughkeepsie will become the Transmission and Distribution Alternate Control Centers and the current Alternate Control Center in Newburgh will be retired. Figure 27 summarizes the progression of investments Central Hudson plans on making to construct a permanent Primary Control Center (PCC) for Distribution and Transmission System Operations.

Figure 27: Timeline for PCC Construction for T&D System Operations

2018
- Renovations at Poughkeepsie headquarters to serve as an Initial Distribution System Operations Primary Control Center

2020
- Begin construction of a new Training Academy

2021
- Complete construction of the Training Academy

2022
- Begin construction of a permanent PCC for Transmission and Distribution System Operations

2024
- PCC operational for Transmission System Operations starting in January
- PCC operational for Distribution System Operations starting in July

In addition to its company-specific efforts, Central Hudson will continue to participate in the M&C Working Group to provide support and input into relevant forums (e.g., ITWG, ISO-DSP Coordination Working Group, and NYISO's MIWG). Additionally, the Working Group will continue focusing on opportunities to implement low-cost M&C solutions for DERs within utility pilots, including harmonizing requirements across different market and operations use cases. Through the continued efforts of this Working Group, Central Hudson remains committed to identifying M&C requirements that balance cost savings for DER developers and improved utilization of DERs while preserving system safety and reliability.

Central Hudson and the Joint Utilities will further address grid operations topics through the development of a separate Market Design and Integration Report, which "identifies, describes, and explains their jointly planned market organization and functions along with the policies, processes, and resources needed to support them." Additionally, the Joint Utilities have been instructed to form a working group with NYISO, DPS, and NYSERDA to complete a set of tasks on various topics, including grid operations, in order to align with the 2018 DSIP and NYSERDA energy storage roadmap. Central Hudson, as part of the Joint Utilities, will remain actively engaged to inform the development of the Market Design and Integration report.

3. Risks and Mitigation

In order 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 towards enabling 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.

Staffing is going to be challenging. The Distribution System Operator positions are anticipated to be very technical and may require a four-year engineering degree. The Distribution System Operators will be required to work on a rotating shift schedule. Experience with other rotating shift schedule positions has shown that not all candidates find this desirable, which limits the applicant pool. If necessary, Central Hudson will expand recruitment efforts to increase the candidate pool and consider additional benefits to make the positions more desirable.

Space limitations will be an issue for the short term. Although the Company has long term plans to construct a Distribution System Operations Primary Control Center (PCC), this will not be available until July 2024. In the short term, the Company will use space at the newly-expanded Distribution System Operation Center at the South Road headquarters.

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 (CSOT) and is in the process of implementing these standards throughout the enterprise. More detail on the CSOT initiative is discussed in Section III.I on Cyber Security.

4. Stakeholder Interface

The Joint Utilities engaged with stakeholders to define M&C requirements and 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.

The Joint Utilities hosted a stakeholder engagement session in October 2017 to communicate the progress made through working with NYISO on coordination issues and to gather additional input. Defining new operational coordination requirements between the DSP, NYISO, DER aggregators, and individual DERs makes greater DER integration and market participation possible, including expanding the ability of DERs to access and be compensated for multiple value streams. Each utility will not only need to expand its historical level of coordination with NYISO, but also build upon, and in some cases establish, new forms of coordination with DER aggregators and individual DERs. In the Order on Distributed System Implementation Plan Filings ("DSIP Order"), the Commission highlights that "many complex and nearly continuous interactions will need to occur among NYISO, the DSPs and DER operators." The Joint Utilities agree and have worked with NYISO, DPS Staff, and stakeholders to define required information exchanges and operational coordination among the various entities.

In the effort to continue developing low cost alternatives to M&C, the Joint Utilities held several internally meetings with the various SMEs in: metering; telemetry; security requirements; engineering; installation and commissioning. The Joint Utilities have several ongoing pilot projects and R&D at various stages of evaluation focused on developing low-cost M&C solutions. The Joint Utilities updated its benchmarked M&C solutions and costs and understanding of new unexplored solutions. This included the March 2019 SME workshop and inverter and non-inverter based low-cost M&C benchmarking. Overall, as means to communicate status to stakeholders, the Joint Utility group provided an interim update to the ITWG regarding low-cost M&C pilots and demos currently being conducted at each utility.

Central Hudson has been promoting its foundational technology investments, including Distribution Automation, the Distribution Management System, and its Network Communication Strategy programs at various forums such as the 2019 Renewable Energy Conference, the Company's DSIP stakeholder conference, the Mid-Hudson Regional Renewable Energy Forum, and the Joint Utility Stakeholder Conferences.

Central Hudson also reviewed its foundational technology investments with the PSC and other stakeholders during its last rate filing in Case 17-E-0459. During this, stakeholders had opportunities to review, question, and comment on the Company's plans. Included in those plans are the capital investments in foundational technologies as well as the planned Training Academy / Primary Control Center.

5. Additional Detail

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

The utility's primary responsibility is to preserve distribution system safety and reliability. The utility 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 distribution system programs (e.g., demand response) and procurements (i.e., NWA), the utility requires participants (i.e., DER aggregators) to sign a contractual agreement that defines the roles and responsibilities for both the utility and DER aggregator. For example, contracts typically specify the amount of advanced notification the utility will provide the DER aggregator prior to an event, and separately they define all reporting and settlement requirements for the DER aggregator.

In the event that a DER begins to participate in a NYISO wholesale market, the Joint Utilities have developed a Draft DSP Communications and Coordination Manual to define 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. For example, as part of NYISO's bidding and scheduling process, the DSP will analyze the dispatch feasibility of individual DERs and DER aggregations (as provided by the DER aggregator) to ensure wholesale market participation does not jeopardize system safety or reliability. The Joint Utilities have also developed a Draft DSP-Aggregator Agreement for NYISO Pilot Program to further define the roles and responsibilities between the DSP and DER aggregators.

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 of 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.

b) Describe other role and responsibility models considered and explain the reasons for choosing the planned model.

The types of roles and responsibilities defined within the utility'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 utility in coordination with third parties. As more DERs are integrated into the distribution system, the utility will look to refine and update their 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 held a stakeholder engagement session in October 2017 to update stakeholders on progress they have made in their coordination with NYISO and will continue to update stakeholders on future progress. Similarly, input received through the NYISO stakeholder process has informed the development of these currently defined roles and responsibilities.

c) 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 on 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 need 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 developed a Draft DSP Communications and Coordination Manual to define the coordination requirements between the DSP, NYISO, DER aggregator, and the individual DER. As DERs more actively participate in the wholesale market, there may need to be enhanced coordination across four major functions: (1) registration, (2) planning, (3) operations, and (4) settlement. The Joint Utilities have also developed a Draft DSP-Aggregator Agreement for NYISO Pilot Program to (1) close the operating and communication gap between the utility interconnection agreements or tariffs and NYISO tariffs and (2) provide DER aggregators with transparency into how they need to coordinate with the DSP to maximize the ability of DER aggregations to deliver value across different services. While this may be used initially as part of the NYISO pilot program, the agreement is meant to inform the development of needed DSP-DER aggregator operational coordination once the NYISO fully implements its DER participation model.

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 getting 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.

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

(1) organizations;

(2) operating policies and processes;

(3) information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch and control, etc.;

(4) data communications infrastructure;

(5) grid sensors and control devices;

(6) grid infrastructure components such as switches, power flow controllers, and solid-state transformers;

(7) cyber security measures for protecting grid operations from cybersecurity threats; and,

(8) cyber recovery measures for restoring grid cyber operations following cyber disruptions.

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 the output or voltage of especially the larger system will be critical.

Cybersecurity measures for protecting grid operations are addressed in Section III.I.

e) Describe the utility resources and capabilities which enable automated Volt-VAR Optimization (VVO). The information provided should:

(1) identify where automated VVO is currently deployed in the utility's system;

(2) in both technical and economic terms, provide the energy loss and demand reductions achieved with the utility's existing automated VVO capabilities;

(3) describe in detail the utility's approach to evaluating the business case for implementing automated VVO on a distribution circuit;

(4) provide a preliminary benefit/cost analysis (using preliminary cost and benefit estimates) for adding/enhancing automated VVO capabilities throughout the utility's distribution system;

(5) provide the utility's plan and schedule for expanding its automated VVO capabilities;

(6) describe the utility's planned approach for securely utilizing DERs for VVO functions; and,

(7) in both technical and economic terms, provide the predicted energy loss and demand reductions resulting from the expanded automated VVO capabilities.

Central Hudson presented a business case for Distribution Automation, inclusive of Volt-VAR optimization, as a part of its 2014 Electric Rate Case. The business case was made from a customer perspective, using a weighted average cost of capital, discount rate, O&M, property taxes, depreciation schedule, inflation rate, and capacity pricing forecasts and procurement requirements available at the time of the study. A 20-year net present value of costs and benefits was calculated and ranged from $7.2 million to $16.7 million, with sensitivity analysis completed on the energy reduction component. These costs and benefits are described below:

- The investment (cost) portion of the business case included: distribution automation hardware, distribution line reconductoring, substation metering and controller upgrades, a Distribution Management System, and Network Communication system inclusive of Tier 1 fiber/microwave and Tier 2 2.4/5.8 GHz radios. These investments were to be made over a 5-year time period at a 20-year net present value cost of $82.9 million.
- The benefits portion of the business case includes: energy reduction, loss reduction, capacity reduction, and avoided transmission system investments. Carbon reduction value was also considered but not required for a net positive investment for customers. These benefits

ramped up over a 7-year time period to approximately 80% of our customers. Total 20-year net present value of benefits ranged from $90.1 million to $99.6 million, with the major components being:

- Capital avoidance of building two transmission lines ($42.9 million): The avoided transmission system investments include leveraging distribution automation to address two radial transmission feeders that will not meet the design criteria of 7 MVA of unreserved load, in the event of loss of those transmission lines. By adding distribution automation hardware and reconductoring lines where needed, a distribution system solution can be achieved at a fraction of the cost of building a second transmission line in each case. Although some of these benefits extend beyond VVO, they were important components of the overall business case to make the necessary investments to implement VVO.

- Energy, capacity and loss reduction savings ($47.3 million - $56.8 million): This included a 20-year net present value of energy savings of $34.2 million to $41.1 million and 20-year net present value of capacity savings of $13.1 million to $15.7 million for Central Hudson's customers. This economic analysis was based upon an energy savings of 1.39% to 1.73%, gradually deployed over approximately 80% of our customer base. The percentage savings was based upon analysis of day-on, day-off pilot testing conducted by the Company for residential and commercial customers over more than one year. An additional 0.3% reduction in energy is anticipated based on loss reduction. Central Hudson is a summer peaking utility and anticipates nearly the same reduction in summer peak demand (98% of energy reduction) as overall energy savings. The Company maintains compliance with all existing CVR Orders but has not quantified the benefits of doing so since they are a base component of operating our business.

As shown earlier in this section, the Distribution Automation devices (regulators and switched capacitors) required for VVO are currently deployed in the Fishkill District and Newburgh Districts. The schedule for installation of devices throughout the remainder of the service territory is listed earlier in this section, with an anticipated completion date of Q2 2023. As a part of site acceptance testing of Central Hudson's DMS, VVO was tested at our Fishkill Plains Substation. Early in the process, testing was run as frequently as possible to gather additional data on the benefits of VVO over varying load and field conditions. This testing was paused as the Company worked through communications issues related to the Sensus devices and the need to begin the cutover to the Network Strategy system. Testing will resume in each area once the communication systems are in place and end to end communication has been tested.

Full implementation of VVO will follow our DMS rollout schedule and the schedule for the addition of the Distribution System Operators. Addition of substations to the current testing will also require completion of the ESRI model as described earlier in this section.

The interactions of VVO with DERs is also considered in the deployment. Particularly when generating electricity, DERs cause voltage to rise on Central Hudson's system, offsetting some of the benefits of CVR. Therefore, the initial activities of using DERs to control voltage will be focused on reducing the cost to developers to mitigate high voltage, which traditionally requires reconductoring or a dedicated feeder. The Company will frequently allow a static change in power factor settings of inverters today to maintain lower voltages, although the addition of a switched capacitor to offset the negative power factor impacts is sometimes required, offsetting some of the benefits. And although used for other operational purposes today, the Company has the ability to Monitor and Control DERs per the requirements developed by the Interconnection Technical Working Group (ITWG).

To begin testing direct control of third party owned devices such as DER inverters, Central Hudson piloted smart inverter control through a solar plus battery storage project that is detailed in Section III.D. As described earlier in this section, as well as in Section III.I (Cybersecurity), the Company will continue to monitor and participate in smart inverter advancement activities and evaluate how they can be securely integrated into the DMS over the longer term as needed.

f) Describe the utility's approach and ability to implement advanced capabilities:

(1) Identify the existing level of system monitoring and distribution automation.

The Energy Management System (EMS) 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.

(2) 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. Additional

Fishkill District circuits will be added coincident with the development of the GIS model that supports the GIS. This will be continued in the remaining four districts as the distribution automation devices and network communication are installed and the GIS models are developed. The Company plans to eventually implement monitoring of the entire distribution system in the DMS.

(3) Describe the means and methods used for deploying additional monitoring and/or distribution automation in the utility'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 2021-2025 Capital Forecast.

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

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

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

Significant progress has been made in the commissioning of the DMS. Central Hudson has completed the 90 Day Final Acceptance period in February 2018 and completed the DMS Phase II Acceptance Testing of Advanced Applications in March 2018. This testing concluded with documented Acceptance Test Procedures (ATPs) and a summary report of Advanced Application testing with detailed action item report summarizing issues found and timelines for expected resolutions. These were filed with the Commission in March 2018.

The DMS had been used to test for Volt/VAR control of distribution circuits, but this practice has been paused for the communications cutover. The circuits in Fishkill remain controllable. The Company has modeled the Fishkill District and is in the process of completing the GIS model for the Poughkeepsie. Integration of the SCADA points for the DA equipment installed in Fishkill is ongoing. These efforts will continue over the next several years as the remaining operating districts are added to the DMS.

The current use of the DMS is helping to shape grid operations policies and procedures. Building off of the Distribution System Operations Whitepaper, the experience with the DMS will help to advance the development of these policies and procedures.

Staffing added since the 2018 DSIP includes the DMS Model Manager and Distribution System Engineer. Policies/procedures have been under development with the Associate Director – Distribution System operations, in conjunction with the Distribution System Engineer.   Plans to hire a Senior Distribution Operator in Q4 of 2020 will aid in policy/procedure development, as well as training plan development for future Operators. The Company is currently developing more formal charter for Grid Modernization effort with the focus on creating a core team and result in additional dedicated staffing for the project.

The DMS is currently being used to advance the development of the GIS model. The ADMS is used to verify GIS model accuracy and connectivity. The ability for power flow calculation to converge in the DMS is used to verify the GIS model, reports of severely under loaded or overloaded transformers, for example, are utilized to identify where customer service point records are not accurate. The addition of the DMS Model Manager position in August 2018 helped with advancing this development.

The DMS is currently also used as a training tool. With the addition of the Distribution System Engineer and the DMS Model Manager, the DMS is a critical component of their development plan. The Senior Distribution Operator will assume the role of the Distribution System Engineer and will be responsible for the training of the Distribution System Operators starting in 2022 and will have primary responsibility for the use of the DTS in the DMS.

(6) Describe how ADMS capabilities will increase and improve over time;

Over time, additional circuits will be modeled and monitored, which will allow for the eventual use of FLISR, closed loop VVO, and monitoring and control of DERs. The timing of this will be tied to the addition of Distribution System Operators and the installation of DA equipment and associated network communication equipment. All of these capabilities will be phased in over the next four years as described above. Additionally, as part of the results of the SUNY New Paltz ESS + PV system described further in Section III.D., Central Hudson has identified the importance of and need to develop advanced forecasting capabilities as a future functionality within the ADMS. As a result, the Company is currently supporting a NYSERDA PON jointly with Electrical Distribution Design (EDD) and University of Albany related to forecasting both load and DER systems. The Company has also been performing research to understand the number and distances in which irradiance sensors will need to be installed and fed back into the DMS, in order to forecast solar PV systems accurately.

(7) 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 or 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. Central Hudson is currently in the early stages of a NYSERDA PON working with EPRI related to deploying a DERMS. The goal of this DERMS research will be to better manage grid performance, particularity in instances where DER penetration has caused the system to exceed thermal and voltage limitations. As described in Section III.J (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 seeks to understand if a DERMS solution will be sufficient to address these issues. This effort will also seek to develop and test NYISO and Distribution System Operations coordination frameworks when DER are providing market services.

D. Energy Storage Integration

1. Context and Background

Energy Storage Systems, especially Battery Energy Storage Systems (BESS), are recognized as an important element of the grid of the future. BESSs represent flexible energy resources that have the ability 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).

While Central Hudson has had limited direct experience with energy storage systems, Central Hudson is continually evaluating energy storage deployment and potential use cases. As with all of its investments, 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. 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) have indicated that to date, energy storage systems do not represent lower cost solutions to meet operational or capacity needs on the Central Hudson system. BESSs are projected to continue to drop in cost based on advances in battery manufacturing, technological advances, lessons learned, and overall industry experience. Central Hudson will continue to track the system costs and overall cost effectiveness of these solutions. As costs come down, Central Hudson envisions that BESSs will have a growing role as a flexible resource on both transmission and distribution systems in the future.

2. Implementation Plan

a) Current Progress

Central Hudson has several ongoing initiatives regarding the implementation of BESSs. These initiatives are geared towards integrating BESSs into transmission and distribution systems and gaining additional learnings on the costs, the economic valuation, and the technical applications of BESSs. Each of these initiatives is briefly described below.

- Request For Proposals (RFP) for Bulk Power Energy Storage Scheduling and Dispatch Rights –In September 2019, to meet the requirements of Case 18-E-0130, In the Matter of Energy Storage Deployment Program ("Storage Order"), Central Hudson issued a Request For Proposal (RFP) to procure scheduling and dispatch rights for a total of at least 10MWs of bulk connected energy storage within the service territory. Per the Commission, the project(s) must be operational by December 31, 2022. Eight project proposals were submitted for consideration. Based on the overall evaluation of the submittals, none of the proposals passed Central Hudson's benefit cost analysis. However, there were a number of processes and documents developed and lessons learned as a result of the RFP and evaluation processes that will facilitate the deployment of energy storage on the system. These included:

1. A set of energy storage (ES) RFP documents for future use were developed.

2. An ES RFP solicitation and evaluation process was developed.

3. An ES RFP team of Subject Matter Experts (SMEs) for evaluating bidders' ES project proposals was established. These SMEs cover the following areas:

    a) Bidders' Credit Rating and Financials.

    b) Land and Property.

    c) Project Construction Schedule.

    d) Electric Interconnection.

    e) Legal.

    f) Economic Evaluation.

4. An ES project Economic Evaluation model, with Central Hudson vendors' support for this model was created. This Economic Evaluation model can be used to evaluate and forecast the potential revenue which may be obtained from owning the dispatch rights to an in-front of the meter ES project that participates in the NYISO market. This potential revenue is based on the following revenue categories:

    a) Net Electric Energy Arbitrage revenue.

    b) Ancillary Service revenue.

    c) Electric Capacity revenue.

d) Central Hudson Transmission & Distribution (T&D) Deferral value.

e) NYSERDA funding.

5. From the review of the bidders' ES project proposals, Central Hudson gained firsthand experience, knowledge and a better understanding of the ES systems that are currently available in the marketplace and of these ES systems' electrical and physical characteristics and capabilities.

6. Central Hudson has compiled a list of ES RFP bidders that can be used for future RFP solicitations or for Central Hudson to contact to obtain answers to questions in regards to ES systems.

- New York Energy Storage Study work with Quanta (prepared for NYSERDA) – Central Hudson supported Quanta Technology LLC in their development of the documentation of a procedure for the planning and evaluation of energy storage system (ESS) applications in the electric utility industry. The report will outline procedures and use cases that can be used by utility planners, ESS developers, lenders, and investors in developing ESS solutions. The report summarizes six use cases selected based on utility needs, lesson learned, and each case study's cross-sectional representation. The projects represent a range of program solutions, project siting and sizing processes, and non-wires alternatives (NWAs) comparisons. Central Hudson provided representative system data, use cases and technical assistance during the analysis and development of the procedures. In addition, Central Hudson reviewed and provided input into the final report.

- SUNY New Paltz PV + Battery Storage Research Project – This project represents a research initiative jointly executed among several industry partners: Central Hudson Gas & Electric, New York Power Authority, New York State Energy Research and Development Authority, Electric Power Research Institute, and SolarLiberty. The project incorporates 100kW of Photovoltaics and 100kW/200kWh of lithium-ion batteries at the SUNY New Paltz campus. The installation was designed for technical learnings including smart inverter grid support functions (power factor, volt-VAr, PV smoothing), peak demand reduction capabilities, and operation in microgrid mode. The installation is located on a Central Hudson 13.2kV distribution circuit supplied by the Ohioville Substation. The project is in service, interconnecting to the Central Hudson system in April 2018. System testing was performed for approximately a year and a half (August 2018-March 2020). A summary report of results and findings was completed in March 2020. Final close out of this project includes holding a workshop at the SUNY New Paltz campus to share lessons learned from this demonstration project with NY Stakeholders. This workshop is on hold due to impacts from the COVID-19 pandemic and will be re-scheduled once conditions permit.

- Quanta BESS Study – PV Integration and Reliability Uses Cases – Central Hudson contracted with Quanta Technology LLC to perform a study to determine both the technical feasibility and overall cost effectiveness of utilizing BESSs versus traditional T&D solutions for two specific use cases: (1) BESS-assisted PV interconnection and (2) BESS support for distribution reliability. Central Hudson identified potential opportunities in several locations on the system for analysis with the overall goal of identifying a cost beneficial application for the implementation of an energy storage project.

  The first phase of the project was to complete an analysis to determine the technical feasibility, sizing, and optimal locations for the BESS to adequately address the project needs. The second phase entailed detailing the costs and benefits, including evaluating and incorporating wholesale market benefits where applicable. The final phase included performing a comparison of the BESS solution against more traditional solutions and evaluating the storage options for overall cost benefit.

  For the BESS-assisted PV interconnection use case, both a transmission location with significant proposed transmission and distribution sited PV and two distribution locations with significant distribution sited PV were analyzed. In each case, the optimal size and location of the energy storage was determined to facilitate the PV integration and then optimized and evaluated for wholesale market revenues.

  For the transmission area use case, a 69kV loop with approximately 110MW of proposed wholesale PV was analyzed. Power flow models were developed for the BESS simulations based on Central Hudson's transmission model and Quanta algorithms were used to simulate BESS operation and determine BESS sizing. The battery was sized for N-0 and N-1 overload relief and curtailment avoidance. Both distribution sited and transmission sited storage were analyzed. A transmission sited storage solution was determined to be optimal for this area. The BESS was treated as an Energy Limited Resource participating in NYISO Day-Ahead Energy, Real-Time Energy, and Regulation markets. In general, charging was performed against Day-Ahead market prices and discharging was performed against Real-Time prices. Regulation is against day-ahead prices. The BESS simulation co-optimizes BESS market participation in these products on an hourly basis, optimized across one day at a time, for each of the 365 days of a year. The market model has to observe constraints imposed by the PV integration application: for each day there is an hourly charging obligation from PV in order to avoid overloading according to transmission load flow analysis.

For the distribution-level BESS-assisted PV integration analysis, two locations (Circuits 3024 and 8093) were examined for voltage, flicker, overload, and back feed issues arising from projected installation of large PV facilities. The problems were diagnosed using standard CYME distribution analysis software – load flow and time series analysis as used in PV hosting studies. Operation of a BESS to manage the PV problems was conducted using proprietary Quanta simulation software in Python which is a "wrapper" around the CYME software which simulates BESS control algorithms of each time step in response to circuit voltage conditions and PV output as computed in CYME. Utilizing this methodology, optimal battery sizing and locations were determined for both distribution use cases. The same methodology that was used for the transmission sited BESS was employed to determine the wholesale market revenues for the distribution sited BESS.

The second use case evaluated the use of BESS support for distribution reliability for two different locations (an area on the 2385 distribution circuit and an area on the 3078 distribution circuit) with below average levels of reliability. The optimal size and location for the storage systems were determined for both average and maximum experienced outage durations. For the simulation of the use of storage for reliability improvement, the CYME time series simulation is not needed. Battery charging and discharging losses are estimated at 8%, and circuit losses are negligible as the battery will be located in the outage area. Load growth is assumed to be 2.7% over ten years in the case of 2385 circuit and 1% in the case of 3078 circuit. The size of the BESS is determined from the load profile on a peak day under the assumption that the outage time is either "average" or "maximum", and the energy under the profile for that outage time is what must be supplied for reliability. The BESS were then optimized for wholesale market participation following the identified methodology. However, the market model has to observe constraints imposed by the reliability application: for each day there is a minimum state of charge which must be maintained in order to guarantee the ability to provide reliability for the required time window of average or maximum outages, and there is a minimum day-end state-of-charge required so that the next day co-optimization will have a valid starting point against its minimum state-of-charge requirement.

Once the technical sizing, location and market participation analysis were completed, the five projects (one transmission PV integration, two distribution PV integration, and two distribution reliability), were subjected to a cost-benefit analysis (BCA). The financial analysis considered capital costs including estimated procurement, installation, and applied overheads; operational costs including the cost of energy losses in the charge-discharge cycle, maintenance, depreciation, and property taxes; the estimated market benefits; and return on capital. Central Hudson provided the costs of conventional solutions and Quanta provided estimates of battery costs. The results of the Net Present Value (NPV) calculation of the differences between the BESS and the conventional solutions over a 20 year horizon were compared.

For the BESS-assisted PV integration in transmission location, the BESS was more economical than the traditional T&D solution; however, the ability to curtail the PV output over select time periods represented a significantly more cost effective option and was the recommended solution. The cost of the traditional solution was approximately $45M, the BESS cost was approximately $30M and would potentially generate $727k in annual market revenues. The BESS-assisted PV integration was favorable compared to the cost of the traditional T&D upgrade on both an aggregate cash flow and Net Present Value basis for both primary applications alone and with market benefits included. However, the PV curtailment option of approximately 150MWh curtailment on an annual basis (less than 1% annual loss of energy output) represented approximately $8,700 annual lost revenue. The curtailment is the less costly option overall by a significant margin.

For the BESS-assisted PV integration in distribution locations, the traditional T&D solutions were determined to be more economical than the BESS option. The traditional T&D solutions ranged from $3.9M to $4.7M while the BESS costs ranged from $16M to $20M. The BESSs would potentially generate $47k (circuit 8093 use case) to $240K (circuit 3024 use case) in annual market revenues. Based on these costs/revenues, the distribution system BESS-assisted PV integration cases were not favorable for either location under any scenarios (primary applications alone and with market benefits included).

For the BESS support for reliability use cases, depending on the specific application analyzed (i.e., location, average/maximum outage durations), the BESS solution potentially represented a more cost effective solution than the traditional T&D solution. The traditional T&D solutions ranged from $1.5M to $2.3M. The BESSs ranged from $1.4M to $2.4M system costs with $40k in annual market revenues (Cragsmoor area) to $4.1M to $5.4M system costs with $118k in annual market revenues (Tannersville area). However, when compared utilizing Central Hudson’s current approach to evaluate and rank reliability-based projects, neither the traditional T&D solutions nor the BESS solutions meet the criteria for implementation.

As shown in the results of this pilot project, it is currently challenging to identify a use case that passes a benefit-cost analysis on Central Hudson's system. Neither of the two use cases and none of the five projects evaluated in the study pass a BCA and meet an acceptable threshold for inclusion in Central Hudson's capital program.

- Four Corners Microgrid Project – The Four Corners Microgrid project is part of a 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. The Phase 1 Engineering Design was submitted to the DHS on August 14, 2018. This design included 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. The project will include optionality to use the BESS for other services (i.e., demand reduction, frequency regulation) during parallel operation. Figure 28 below shows a one-line diagram of the effected system; Figure 29 shows a simplified diagram of the microgrid layout.

Figure 28: One-Line

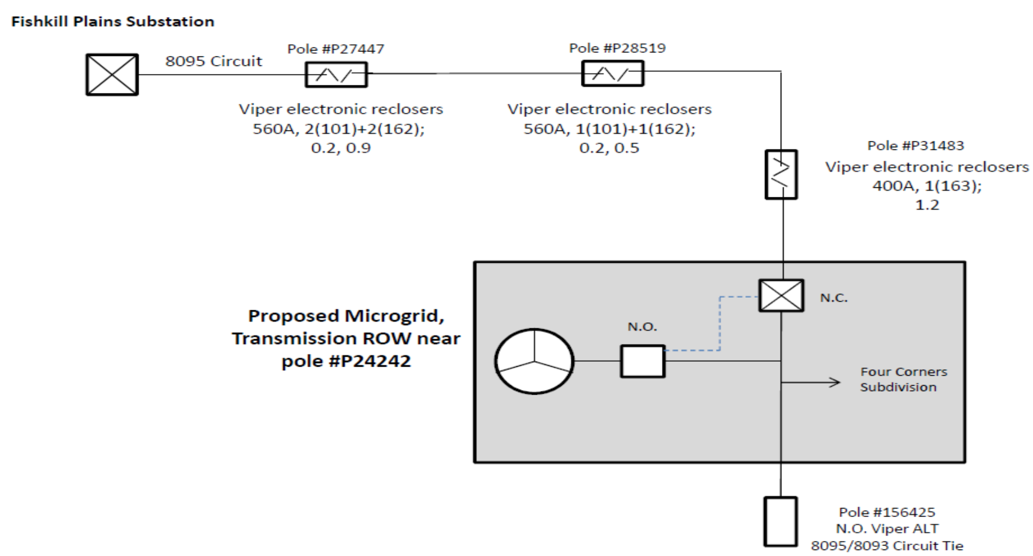
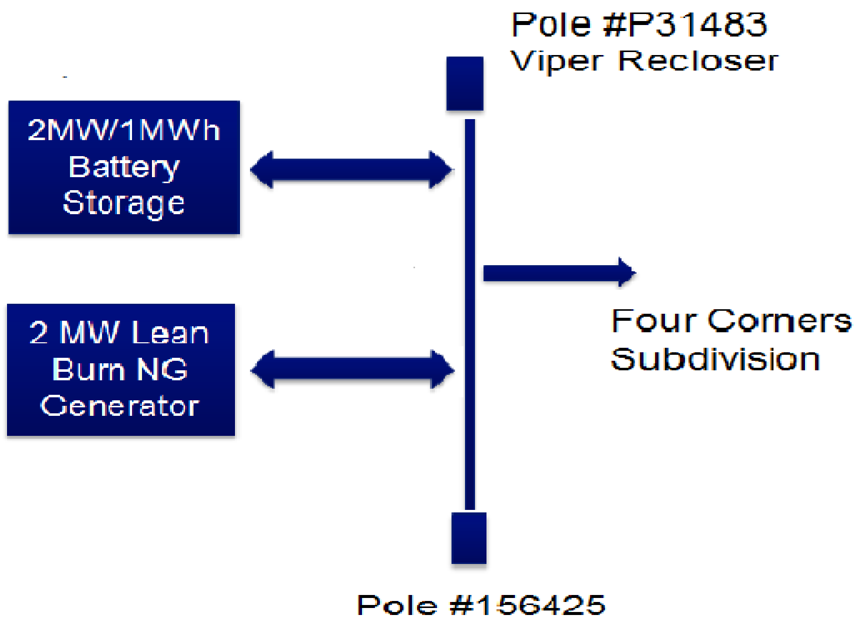


Figure 29: Microgrid Layout



The Phase 1 design was approved by DHS, and on February 15, 2019, Central Hudson received approval from DHS to proceed with Phase II, project construction. In February 2020, Central Hudson issued an RFP for the completion of Phase II permitting and construction work. Bids were received and Central Hudson has engaged with one of the bidders to perform preliminary work based on the proposal. The project is currently scheduled for a completion date of February 2022.

3. Future Implementation and Planning

Central Hudson has two active energy storage projects as indicated above. There are also a number of distribution-level energy storage systems interconnected to the Central Hudson system and several energy storage systems in the NYSSIR, Central Hudson and NYISO queues, including some of significant size (20MW to 200MW range). As discussed previously, in September 2019, Central Hudson issued an RFP to procure at least 10MWs of bulk power energy storage scheduling and dispatch rights. Based on the results of this RFP, the use cases for utility application of storage applications were not able to meet the upfront breakeven installed cost of storage (BICOS) within the service territory. 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.

4. Risks and Mitigation

For all emergent technologies, Central Hudson evaluates the technical risks associated with the technology and also 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 feels 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 the forecasted continued steep and step cost reductions in both battery and balance of systems do not occur or occur at a much slower than anticipated rate, represent higher levels of risk. There are also risks associated with the market revenue forecasts for these installations. The shared learnings among 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 experienced is gained and the applications/markets mature, these risks will be better understood and appropriate mitigation strategies can be developed.

5. Stakeholder Interface

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

- Central Hudson was actively involved with the joint NYSERDA/DPS/Utility working group reviewing the development of the solicitation for Bulk Power Energy Storage Scheduling and Dispatch Rights in each utilities service territory. This included discussions on the NYSERDA Bridge Incentive Program application and the development of a BCA framework to evaluate proposals.

- Central Hudson remains very active in both the Interconnection Technical Working Group (ITWG) and the Interconnection Policy Working Group (IPWG). 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.

Central Hudson was instrumental in making changes to the SIR to accommodate storage systems including both standalone and hybrid systems.

- Central Hudson is very active in NYISO committee workings 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 Storage Roadmap, will be critical to making the use cases for storage economical.
- Central Hudson has worked collaboratively with the New York State Joint Utilities on a number of stakeholder engagement initiatives associated with REV. Section IV outlines the Joint Utilities collaborative efforts on stakeholder engagement in both 2019 and 2020.
- Central Hudson is an active participant in the recently formed DPS lead Utility Infrastructure working group. Kicked off in January 2020, the group is identifying ways to facilitate the CLCPA targets and the goals outlined in the "Accelerated Renewable Energy Growth and Community Benefit Act". The primary goal of the working group is to identify new transmission development and policy changes necessary to facilitate the interconnection of large scale renewables. The working group has been broken down into three work streams – a technical study working group to identify potential required transmission system upgrades; a policy working group to identify changes necessary to facilitate the interconnection work and transmission upgrades; and an advanced technologies working group to identify potential innovative solutions to new to increase system efficiency / asset utilization, grid flexibility and hosting capacity while reducing system costs. In addition to participating on the steering committee, Central Hudson has representatives on all three of these work groups.

6. Additional Detail

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

- Solar PV

- 100kW Princeton Power Smart Inverter
- 100.65kW CSUN Solar Modules

- Battery Storage
  - 100kW Princeton Power Smart Inverter
  - 200kWh Samsung SDI Li-Ion Battery Bank

As indicated, the storage is co-located with a PV system and the project was designed to test the following functionality:

- Smart inverter grid support functions (power factor, volt-VAr, PV smoothing)
- Reduction of electric demand
- Micro-grid mode (Elting Gym on the SUNY New Paltz campus is a Red Cross Shelter).

Overall, this project was effective in demonstrating the use of smart inverters and energy storage systems to provide grid support from distributed PV and ESS resources. This included validating the ability of volt-VAr and Power Factor (PF) to be effective at reducing voltage and variability as well as the ability for an ESS to provide demand savings for customers. This project resulted in numerous findings that have better informed Central Hudson of how smart inverter and energy storage systems perform and operate on the grid. These learnings can be applied moving forward to various utility activities including DER interconnections, planning studies, as well as future operating decisions as part of the DMS. Key findings for the advanced inverter functions include:

- Low light conditions impact the inverters' ability to follow programmed settings. For fixed power factor settings, a more accurate PF is maintained when the system is greater than 20% of its AC nameplate rating.
- The point of measurement has an impact on the ability of the volt-VAr behavior to follow the programmed curve. As a result, if allowing inverters to regulate voltage at their terminals, system designs and settings must consider the offset due to the voltage drop between the inverters and the point of common coupling (PCC). Therefore, for larger systems, it may be prudent for utilities to require power plant controllers in order to ensure more accurate voltage measurement and volt-VAr operation at the PCC.

- When voltage was outside of the programmed dead-band range, measured voltages tended to be closer to reference voltages when volt-VAr functions were active compared to when not active.

- VAr consumption or injection is impacted by the amount of active power outputted by the inverter. Therefore, solar resource availability as well as an array's DC:AC ratio, will impact the inverters capability to provide VAr support functions.

Key findings for the energy storage system include:

- As the campus's load had high variation, predicting the peak hour was a significant challenge. As a result, different peak shaving strategies were utilized for the winter vs. non-winter months. While dispatching at a higher magnitude for a shorter window increased the realized benefits, shortening the time window ran the risk of missing the demand peak all together.

- ESS coupled with PV generation can further impact the time at which peak net demand occurs, making the peak more variable by shifting to earlier or later in the day. Thus accurate forecasting, both real-time and day-ahead, is a critical component in order to implement proper control and dispatch strategies for the use case sought and must be able to differentiate between existing loads and mix of DER types.

- Sizing of the battery in relation to the use case or load is also an important consideration. While the battery was small in relation to campus load, it was proven to be able to provide demand charge savings. Additionally the PV also contributed to energy savings and a significant portion of these savings were attributed to Day Ahead Market pricing savings, along with demand charge savings during summer months. While PV is generally not coincident with Central Hudson's system peak demand, it is important to understand which customers may have peak load profiles that do coincide with PV output.

- Micro-grid operations were successfully tested for critical loads. However, when utilizing an ESS for both micro-grid functionality along with demand savings, a portion of the battery capacity must be reserved specifically for this function. During the duration of this project, about half the battery capacity was reserved for micro-grid mode and thus limited a portion of the overall potential demand savings.

In addition to the research findings for these projects, there were also various challenges that have furthered Central Hudson's knowledge related to interconnections for smart inverters and ESS systems.

The first was associated with retrofitting the ESS to an existing building, rather than being a part of new construction. Space constraints and safety requirements required multiple design revisions for both the physical location of the ESS along with protective requirements as part of interconnection to the grid. Knowledge of this has enabled Central Hudson to provide better support during current and future interconnections. Additionally, the inverters required maintenance throughout the testing. On four occasions, the smart inverters stopped accepting commands to activate or deactivate advanced functions and required multiple attempts over several days. Additionally, on three occasions the PV inverters stopped producing AC power after a snowfall (even after the snow had been cleared from the PV modules) and needed to be reset. Finally, during the late stages of the project, the ESS vendor ceased operations and prevented the ability to access or modify the energy storage management system. Therefore, settings that were programmed prior to loss of the communications could not be changed until a new vendor was procured to restore access. These experiences emphasize the importance of reliable communications, including considerations for requiring additional backup communication and protection. This is especially critical if these DER systems are to be utilized and relied upon as part of grid support functions or mitigations, as well as when requesting restricted operating parameters.

In addition to partnering for this installation, 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 PV systems and customer load. Central Hudson currently has 95 of these installations spread throughout the service territory, three of which are residential stand-alone battery storage systems only. In addition, there are another nineteen 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 four projects going through the NYISO interconnection process with a total capacity and energy of 416 MW/1456 MWhr; an additional nine projects with total capacity and energy of 132 MW/528 MWhr currently are in the Central Hudson interconnection process.

b) Describe the utility's current efforts to plan, implement, and operate beneficial energy storage applications. 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 energy storage plans; see above

(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 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. Central Hudson has completed a BESS use case study, worked with an energy consultant (Quanta Technology LLC) in their development of the documentation for the planning and evaluation of energy storage system (ESS) applications in the electric utility industry, and currently has two projects identified which will incorporate energy storage applications. One of these projects concluded in March 2020 (SUNY New Paltz PV + Battery Storage Research Project) and the other is in the implementation phase (Four Corners Microgrid Project). In addition, Central Hudson recently completed a solicitation for bulk power energy storage scheduling and dispatch rights for 10MWs or greater of energy storage.

Bulk Power Energy Storage Scheduling and Dispatch Rights RFP

(1) A detailed description of this project is included above under Section III.D.2.a) Current Progress. This project fits into Central Hudson's long range energy storage plans for the integration of increased levels of ES 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 projects overall economics/economic viability within the service territory. This project provided Central Hudson with valuable experience in the ES RFP process – this is discussed in more detail in item d) below. Central Hudson issued an Energy Storage (ES) Request For Proposal (RFP) on 9/30/2019, with bids to be received no later than 1/31/2020. Based on the results of this RFP, all bidders' ES project proposals failed the Central Hudson Benefit Cost Analysis (BCA) and there

were no bidders selected to move forward. Based on the results of this RFP process, Central Hudson presently does not have any planned bulk energy storage projects.

(2) As a result of the 12/13/2018 New York State Public Service Commission (NYSPSC) "Order Establishing Energy Storage Goal and Deployment Policy" in Case 18-E-0130, Central Hudson developed and issued on 9/30/2019 an ES RFP to solicit ES project proposals with an ES project Commercial Operations Date of on or before 12/31/2022. Bids were due back by 1/31/2020. Central Hudson received eight bids. Bid evaluations were completed by 4/30/2020, and the results were provided to the developers by 5/15/2020.

(3) As indicated, following bid evaluations/BCA analysis, none of the bids passed the BCA analysis and Central Hudson is not currently moving forward with any of the projects. Central Hudson is working with DPS and may elect to issue another ES RFP to solicit ES project proposals with an ES project Commercial Operations Date of on or before 12/31/2022 from interested bidders to comply with the 12/13/2018 NYSPSC "Order Establishing Energy Storage Goal and Deployment Policy" in Case 18-E-0130.

(4) The following is a list of lessons learned to-date from the ES RFP:

   a. A set of energy storage (ES) RFP documents for future use were developed.

   b. An ES RFP solicitation and evaluation process was developed.

   c. An ES RFP team of Subject Matter Experts (SMEs) for evaluating bidders' ES project proposals was established. These SMEs cover the following areas:

      i. Bidders' Credit Rating and Financials.

      ii. Land and Property.

      iii. Project Construction Schedule.

      iv. Electric Interconnection.

      v. Legal.

      vi. Economic Evaluation.

d. An ES project Economic Evaluation model, with CH vendors' support for this model was created. This Economic Evaluation model can be used to evaluate and forecast the potential revenue which may be obtained from owning the dispatch rights to an in-front of the meter ES project that participates in the NYISO market. This potential revenue is based on the following revenue categories:

   i. Net Electric Energy Arbitrage revenue.

   ii. Ancillary Service revenue.

   iii. Electric Capacity revenue.

   iv. CH Transmission & Distribution (T&D) Deferral value.

   v. NYSERDA funding.

e. From the review of the bidders' ES project proposals, Central Hudson gained a firsthand experience to increase Central Hudson's knowledge and understanding of the ES systems that are currently available in the marketplace and of these ES systems' electrical and physical characteristics and capabilities.

f. Central Hudson has compiled a list of ES RFP bidders that can be used for future RFP solicitations or for Central Hudson to contact to obtain answers to questions in regards to ES systems.

(5) Based on discussions and working with ES bidders that responded to the Central Hudson ES RFP issued on 9/30/2019, Central Hudson may adjust future ES RFP deadlines to provide qualified bidders with a little more time to create and submit their ES project proposals. Central Hudson may also improve the RFP process by setting up a better system for receiving bidders' email ES project proposal submissions that may contain large MB size attachments.

(6) Because Central Hudson has just completed its first ES RFP solicitation (completed on 5/15/2020), Central Hudson is still in the process of considering what would be the appropriate next steps to take.

SUNY New Paltz PV + Battery Storage Research Project

(1) A detailed description of this project is included above under Section III.D.2.a) Current Progress This project fits into Central Hudson's long range energy storage plans by providing technical learnings in the following areas: smart inverter grid support functions (power factor, volt-VAr, PV smoothing), peak demand reduction capabilities, and operation in microgrid mode. Central Hudson believes that the inverter grid support functions will be important in playing a role in integrating PV systems on the system and as potential cost effective methodologies to increase hosting capacity. The project also focused on the utilization of energy storage for peak demand reduction and microgrid operations. Central Hudson believes that energy storage can potentially play a role in peak demand reduction portfolios and may be able to operate either independently or paired with the resources to help address localized reliability needs.

(2) The project was originally planned to be in service 8/2017. The project schedule is outlined below:

- 5/18/2015 EPRI awarded NYSERDA PON
- 8/11/2016 Central Hudson received interconnection application
- 11/23/2016 Central Hudson approved the project for construction
- 6/2017 factory testing of the battery identified issues resulting in redesign
- 2/2018 battery and inverter delivered to the site and installed
- 4/5/2018 Central Hudson witnesses acceptance test and provided approval
- 4/2018 workshop #1 at SUNY New Paltz campus to demonstrate operation of smart inverters
- 8/2018 thru 3/2020 advanced smart inverter functions and energy storage dispatch settings are tested
- Throughout the project, EPRI hosted multiple webinars with Central Hudson and on 3/2020 a summary report was provided by EPRI
- 4/2020 (POSTPONED) workshop #2 at SUNY New Paltz campus to share lesson learned from demonstration project with NY Stakeholders

(3) The project was finalized in March 2020.

(4) Reference the general description provided above for documentation describing the lessons learned for this project.

(5) Reference the general description provided above for documentation describing project adjustments and improvement opportunities identified for this project.

(6) The project outcomes and learnings were documented and a final report from EPRI was provided in March 2020. The remaining step for this project is to share lessons learned with other NY Stakeholders via a workshop to be held at the SUNY New Paltz campus. This was originally scheduled for April 2020; however, the current COVID-19 pandemic has resulted in this workshop being postponed until further notice.

Quanta BESS Study – PV Integration and Reliability Uses Cases

(1) A detailed description of this project is included in Section III.D.2.a). This project fits into Central Hudson's long range energy storage plans by providing technical learnings in the application of storage systems for both PV integration and distribution reliability uses cases. More importantly, the project developed methodologies to be used in determining the economic viability of storage projects in comparison to alternative T&D solutions. The project demonstrated the use of these methodologies in a number of applications on both the transmission and distribution system to help determine the costs, benefits, and overall economic viability of storage projects.

(2) The original project schedule was to complete the analysis by year-end 2017.

(3) The project/analysis is complete. The final report was issued on 4/20/2018.

(4) The final report for this project outlines the conclusions and lessons learned. This report was included as an Appendix to the 2018 DSIP and is available on request.

(5) The project is complete. There were minor adjustments to the schedule based on market learnings and re-work as part of the analysis.

(6) The project is closed (final report dated 4/20/2018). The project outcomes identified that while BESS may have niche applications and will have a role on utility systems in the future, it is currently challenging to identify a use case that passes a benefit-cost analysis on Central

Hudson's system. Neither of the two use cases and none of the five projects evaluated in the study pass a BCA and meet an acceptable threshold for inclusion in Central Hudson's capital program. As battery system costs continue to decline in the future and other project benefits are identified (such as demonstration value), the analysis should be reconsidered. As part of this project, the Company was able to develop tools and methodologies to compare storage solutions versus traditional T&D solutions and evaluate as compared to curtailment options. The methodologies and learnings from the project will be applied to future use cases with adjustments for costs and market revenues applied as applicable.

Four Corners Microgrid

(1) A detailed description of this project is included in Section III.D.2.a). 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 was to have Phase 1 design complete by August 14, 2018. Phase 2 (construction) is scheduled for completion in February, 2022.

(3) The project is currently on schedule to meet the February 2022 in-service date.

(4) The project is in the permitting/pre-construction stage and does not have documented lessons learned to date.

(5) The project is in the permitting/pre-construction stage and does not have project adjustments or improvement opportunities identified to date.

(6) The project is currently in the permitting/pre-construction stage of Phase 2 (construction). The project is scheduled for a February 2022 completion date.

c) Provide a five-year forecast of energy storage locations, types, capacities, configurations, and functions.

Battery storage is a technology capable 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 was prohibitive in the past, generation, transmission, and distribution infrastructure was sized to meet extreme peak demand. However, the costs of battery storage have been declining, which 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 414 MW with a total of 1,456 MWh of capacity currently are 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 all distribution substations and primary feeders, Central Hudson has enough load serving capability to meet peak demands. The most current Avoided T&D Avoided Costs Study (reference Appendix D), identified very limited Locational System Relief Value (LSRV) areas. Based on this data, 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 Energy Storage Roadmap, Central Hudson will look to see if future solicitations for NWAs can better take into consideration the benefits of energy storage systems.

Historical Adoption of Distribution Connected Energy Storage

Battery costs have decreased substantially 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 27 shows the annual historic solar and storage interconnection capacity for the residential and non-residential sectors from 2015 to 2019, calculated from the historic interconnection data. For the residential sector, storage capacity installed in 2019 was nearly 6% of solar capacity installed in the same year, up from 3.6% in 2018 and virtually 0% prior. For the non-residential sector, storage capacity was 8.1% of total capacity in 2018 but 0% in all other years. For the storage forecast, it was assumed that future residential and non-residential storage capacity would continue to be 6% of solar installations, based on the ratio in 2018, the highest annual historic percentage for the residential sector.

Table 27: Historic Residential and Non-Residential Solar and Storage Capacity Interconnections

Year	Residential			Non-Residential		
	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %
2016	0	13,920	0.0%	0	2,573	0.0%
2017	6	8,151	0.1%	0	924	0.0%
2018	217	6,000	3.6%	100	1,235	8.1%
2019	387	6,567	5.9%	0	1,313	0.0%
Total	**610**	**34,638**	**1.8%**	**100**	**6,009**	**1.7%**

In addition, Central Hudson tracks interconnection applications for community solar and remote net metering applications, which often include battery storage. As discussed in Appendix B, because of their scale and build lead time, roughly one fifth of community solar and remote solar 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.

Table 28 shows the historic storage and solar capacity for both community solar and large remote net metering projects since July 2016 (the start of the community solar analysis period). Storage capacity applications have ranged from 2% to 42% of solar capacity since 2016, with the total share of storage capacity from 2016 to 2019 being 24% of solar capacity. Going forward, Central Hudson assumes that storage capacity will be equal to 30% of community solar capacity (no remote net metering projects have storage, and remote net metering new applications are forecasted to be zero).

Table 28: Historic Community Solar and Large Remote Net Metering Solar and Storage Capacity Applications

Year	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %
2016	5,160	24,739	20.9%
2017	2,340	122,831	1.9%

2018	20,160	88,195	22.9%
2019	66,358	153,092	43.3%
Total	**94,018**	**388,857**	**24.2%**

Forecasted Adoption of Distribution Connected Energy Storage

Because it's a relatively new technology, market potential estimates for battery storage are inherently uncertain. Figure 30 shows the forecasted adoption of distributed battery storage. Most of the growth in the next five years is expected to come from community solar projects with battery storage. However, the forecasts have substantial amount uncertainty as shown by the confidence bands.

Figure 30: Distributed Battery Storage Capacity Forecast with 95% Confidence Interval

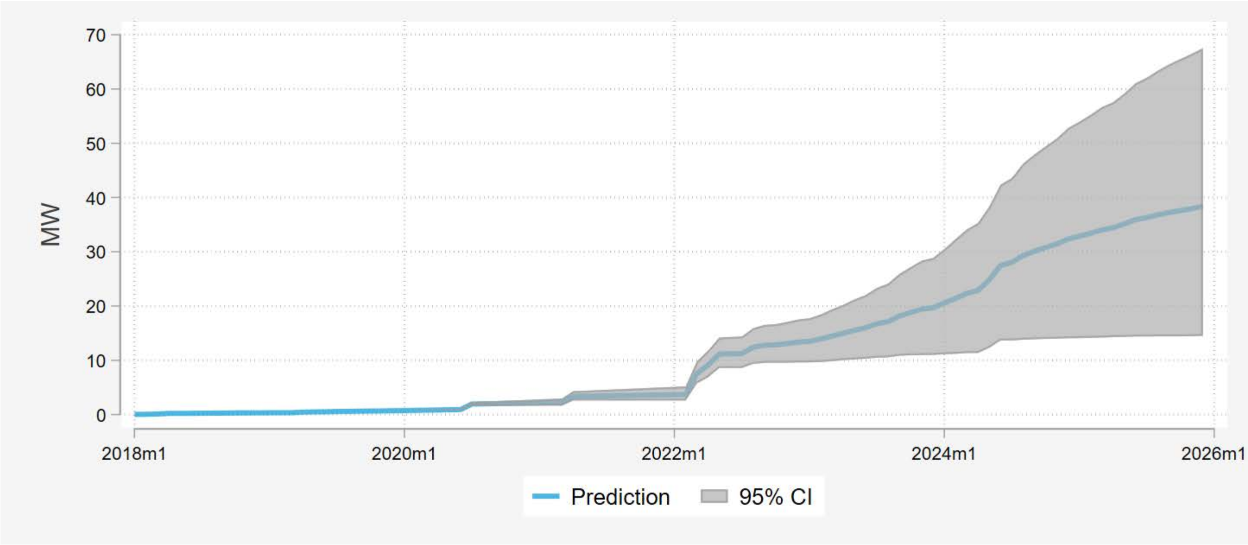


Figure 31 and Figure 32 show the expected locations for battery storage. The granular battery storage projections are tightly woven to expected completion rates of community solar projects. As noted earlier, roughly four fifths of community solar applications are eventually withdrawn and are not completed. Thus, the substation level forecasts are highly uncertain. For any specific substation, the magnitude of battery energy storage resources could be zero or several orders of magnitude larger than the location specific forecast, depending on which projects are eventually completed.

Figure 31: Battery Storage Capacity Forecast by Substation: December 2025

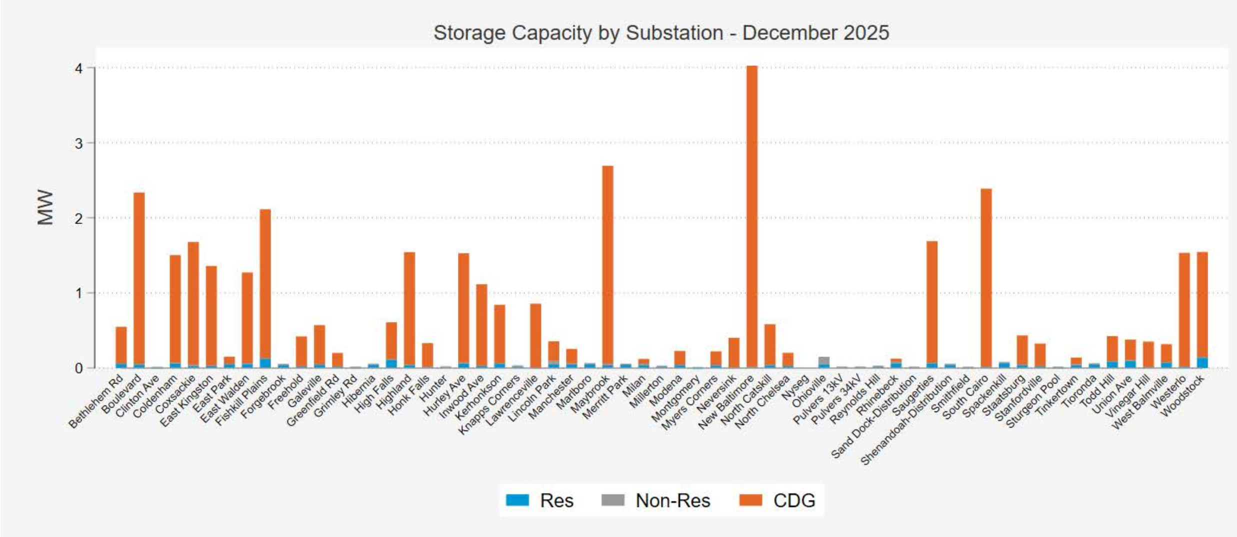
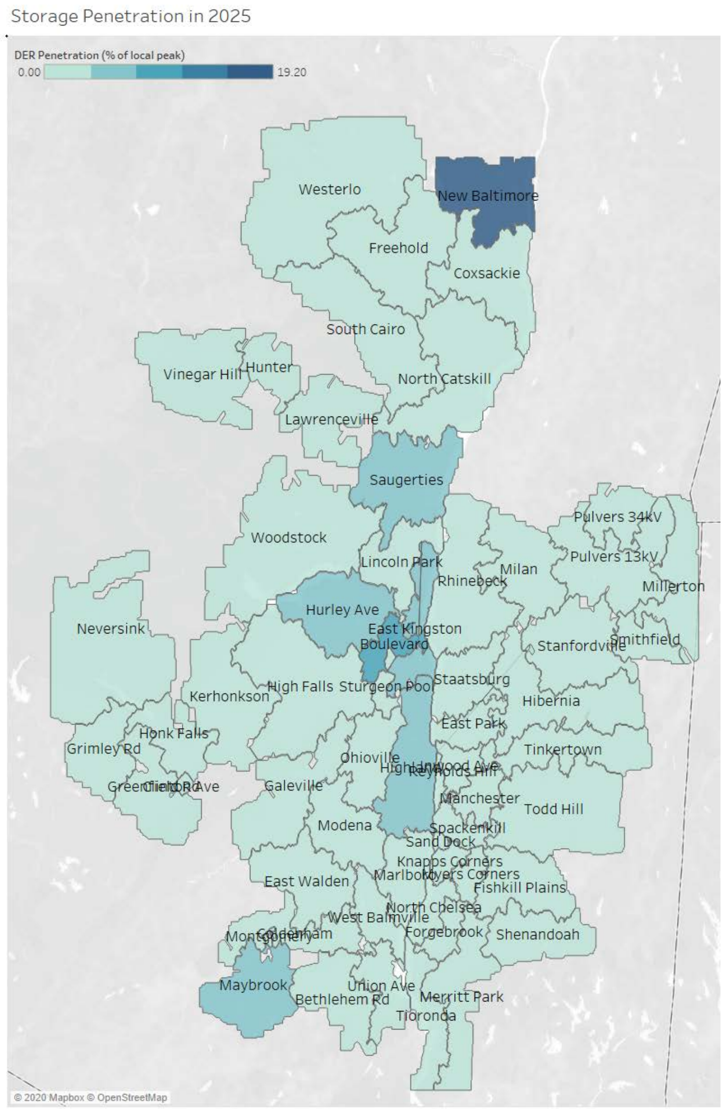


Figure 32 shows the territory served by each individual substation and the projected penetration of battery energy storage. The color varies to reflect the battery storage installed capacity as share of the peak demand at the substation.

Figure 32: 2025 Forecast Battery Energy Storage Penetration (% of Peak) by Substation



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 systems proposed. In addition to these storage projects, there currently are four projects going through the NYISO interconnection process with a total capacity and energy of 416 MW/1,456 MWhr; an additional nine projects with total capacity and energy of 132 MW/528 MWhr currently 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. When the overall installed costs of these systems becomes comparable to alternative technologies or when additional revenue streams materialize to adequately offset system costs, Central Hudson will develop appropriate implementation plans. The evaluation of these installations will include both transmission and distribution sited BESSs in varying capacities and configurations based on the system needs, applications, and revenue streams.

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

(1) its location;

(2) the energy storage capacity (power and energy) provided;

(3) the function(s) performed4;

(4) the period(s) of time when the function(s) would be performed; and,

(5) the nature and economic value of each benefit derived from the energy storage resource.

In alignment with the New York Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations, Central Hudson recognizes the three market segment groupings (customer-sited, distribution system, and bulk system) for storage deployment applications.

Consistent with the roadmap, Central Hudson recognizes retail bill management, demand response, and storage paired with PV as three potential customer-sited use cases. Section III.H (Customer Data) 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, (for over 275 distribution circuits) and 8760 historic and forecast load data for 58 of the 63 load serving substations where available on the system (see Section III. G for additional information).

(1) The location of the energy storage for these uses cases would vary and would be on customer-sited locations.

(2) The energy storage capacity provided would vary by need and application.

(3) The function would be retail demand management, demand response and storage paired with PV.

(4) The period of time when the function would be performed would vary by each particular application/use case.

(5) The nature and economic value of each benefit derived from the energy storage resource would be customer-specific but would predominantly be customer bill reduction.

For the distribution system use cases, Central Hudson identifies both NWA areas and LSRV areas and determines a system-wide demand reduction value (DRV). 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. Furthermore, the current NYISO interpretation of FERC Order 841 (dual participation) creates a barrier for storage developers to achieve additional revenue streams through storage assets that are deployed to meet utility needs. These additional revenue streams could potentially have a positive influence on project economics.

As part of this filing (Appendix D), Central Hudson completed a new Avoided T&D Cost Study. This analysis provides an updated system-wide DRV and identified potential areas where the application of energy storage systems may be beneficial.

(1) The location of the energy storage for these uses cases would be within one of the existing NWA areas (Northwest Area, Shenandoah/Fishkill Plains and Merritt Park).

(2) The energy storage capacity provided would vary by need, location and application. 10MW was solicited for the Northwest Area NWA, 5MW for the Shenandoah/Fishkill Plains Area NWA and 1 MW for the Merritt Park Area NWA.

(3) The function for these applications would be demand reduction for system capital deferral.

(4) The period of time when the function would be performed would vary by each particular application/use case. For the NWA areas, the time period is defined within the solicitation. For the LSRV areas, compensation is based on the resources prior year performance during the top ten highest usage areas within each particular location.

(5) The nature and economic value of each benefit derived from the energy storage resource would be a contract payment based on terms negotiated for the NWA areas. For the potential LSRV areas, the economic value would be the LSRV values as determined by the 2020 Avoided T&D Cost Study (see Appendix D). Note – Central Hudson will continue to utilize the values from the 2016 Avoided T&D Cost Study as the Commission ordered until new MCOS results are adopted by the Commission.[21]

[21] Order Adopting Program Changes with Modifications and Making Other Findings Case 15-E-0190 and 0190

e) Identify and describe all significant resources and functions that the utility and stakeholders5 use for planning, implementing, monitoring, and managing energy storage at multiple levels in the distribution system6.

Central Hudson is utilizing the New York Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations as a guideline for the planning of energy storage systems. Based on this report, and the results of the 2019 solicitation for Bulk Power Energy Storage and Dispatch Rights, the wide scale deployment of storage systems within the service territory (NYISO Zone G) currently does not meet the breakeven installed cost of storage (BICOS) for most applications. As indicated within the document, every individual use case has unique parameters that need to be evaluated, but generally these systems are currently not cost beneficial within Central Hudson's service territory. Central Hudson also utilizes the output of the Avoided T&D Cost Study to determine the system wide DRV and to identify the 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.

In conjunction with the DRV and LSRV areas, as noted previously, Central Hudson maintains a System Data Portal that provides 8760 historic circuit load data, where available, (for over 275 distribution circuits) and 8760 historic and forecast load data for 58 of the 63 load-serving substations where available on the system (see Section G for additional information). This publically 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. Although designed for renewable (PV) generation as the primary driver, the information within this application can provide useful information for energy storage system developers. Additional information regarding the hosting capacity maps can be found in Section III.L 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.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 may become cost effective to invest in 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. The implementation of such a system is not defined in Central Hudson's current investment plans. Central Hudson

(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. 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 suppling a number of key data points for the system, including: the circuit's ID, operating voltage level, number of phases, minimum and maximum 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 backfeed protection status. Additional information regarding the hosting capacity maps can be found in Section III.L Hosting Capacity.

f) 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 should include:

(1) the amount of energy currently stored (state of charge);

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

(3) the time, size, duration, consumer (grid and/or local load), and purpose of each energy storage discharge;

(4) 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,

(5) the capacity of the distribution system to deliver or receive power at a given location and time.

(1) through (4) 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. Central Hudson is unwilling to invest in infrastructure and systems for this until this type of information is necessary based on penetration levels. Central Hudson, therefore, does not currently have systems (i.e., the means and methods) to determine the following: the 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) for energy storage resources.

(5) 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 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 have the ability to operate at full output only limited by customer requirements or distribution system abnormal conditions. Abnormal distribution systems may dictate that the system remain offline until the distribution system returns to normal.

In addition, Central Hudson has a number of 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 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. 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 the DERs on the Central Hudson 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.

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

(1) the amount of energy stored (state of charge);

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

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

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

(5) 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 plans for 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. Based on the current interconnection process under the NYS SIR, 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.

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

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 publically available. In response to stakeholder feedback, the Joint Utilities developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals with available system data and customer data is also being made available through UER. The Joint Utilities' website (https://jointutilitiesofny.org/system-data/) includes utility-specific links to the system data listed above.

i) By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with the objectives established in New York State's recently signed Energy Storage Deployment legislation7 and Governor Cuomo's new initiative to deploy 1,500 megawatts of energy storage in New York State by 2025.

- Central Hudson's plans are aligned with the objectives established in New York State's recently signed Energy Storage Deployment legislation and Governor Cuomo's new initiative to deploy 1,500 megawatts of energy storage in New York State by 2025 as demonstrated by the following:

- In September 2019, to meet the requirements of Case 18-E-0130, In the Matter of Energy Storage Deployment Program ("Storage Order"), Central Hudson issued a Request For Proposal (RFP) to procure a total of at least 10 MWs of scheduling and dispatch rights for bulk connected energy storage within the service territory. Per the Commission, the project(s) must be operational by December 31, 2022. Eight project proposals were submitted for consideration. Based on the overall evaluation of the submittals, none of the proposals passed Central Hudson's benefit cost analysis. However, there were a number of processes and documents developed and lessons learned as a result of the RFP and evaluation processes that will facilitate the deployment of energy storage on the system. Central Hudson may issue additional RFPs for the procurement of bulk connected energy storage scheduling and dispatch rights in the future.

- Central Hudson is an active participant on the DPS Utility T&D Investment Working Group, with representatives on the steering committee and each of the three identified working groups – Transmission Policy Working Group (TPWG), the Technical Analysis Working Group (TAWG) and the Advanced Technologies Working Group (ATWG). Kicked off in January 2020, the group is identifying ways to facilitate the CLCPA targets and the goals outlined in the "accelerated renewable energy growth and community act". The primary goal of the working group is to identify new transmission development and policy changes necessary to facilitate the interconnection of large scale renewables.

- Central Hudson was an active participant in the use case development in the New York Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations, providing input and feedback during the process.

- 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 Interconnection Technical Working Group (ITWG) and the Interconnection Policy Working Group (IPWG), with representatives from Central Hudson chairing both of these committees. 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. Central Hudson was instrumental in making changes to the SIR to accommodate storage systems, including both standalone and hybrid systems. These efforts should help increase the deployment of energy storage within the state.

- Central Hudson has been very 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 continues to actively engage with energy storage providers to identify potential cost effective solutions that may meet the program needs and, as part of the Storage Roadmap, 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 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 storage use cases (capital deferral, PV integration, reliability improvements) as detailed within the Quanta BESS Study – PV

Integration and Reliability Uses Cases analysis. As the storage assets become cost effective, Central Hudson will incorporate these assets into its investment plans.

j) 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.

The Joint Utilities formed an internal working group to coordinate on energy storage implementation efforts. As part of this working group, the Joint Utilities have shared information regarding efforts to deploy storage assets across their footprints. These coordination efforts have focused on aspects such as permitting considerations, the technologies being deployed, and the applications that energy storage will serve in each case. This coordination will inform current and future energy storage efforts and help the utilities design a diverse portfolio of projects targeting a diversity of applications. The Joint Utilities remain committed to continuing this coordination to further support the diversity of energy storage applications and technologies across the state.

In support of the "Storage Order", the Joint Utilities formed a separate working group to review the requirements of the order. The group worked closely with DPS and NYSERDA Staff during the development of Order, providing input to the RFP process and NYSERDA's bridge incentive program. The group continued to meet throughout the RFP development and review process ensuring best practices and lessons learned were shared across utilities. Following the receipt of bids, the group discussed the evaluation criteria and overall review process. The working group continues to convene as needed to discuss emergent issues regarding storage such as land use and auto-DLM participation among other items.

E. Electric Vehicle Integration

1. Context and Background

Electrifying transportation offers numerous benefits for customers and communities, including increased efficiency, improved sustainability, energy security, and the opportunity to relieve rate pressure in an environment of stagnant sales growth. According to the Department of Environmental Conservation, the transportation sector accounts for 40% of NY State's greenhouse gas emissions. Therefore, in order to meet the State's clean energy goals, the transportation sector must be part of the solution. To this end, the NYS PSC Commission commenced a proceeding, Case 18-E-0138, to consider the role of electric utilities in providing electric transportation infrastructure and rate design.

Electric vehicle adoption is expected to grow as more stakeholders support the industry transformation and battery costs decline. Studies have shown that a major barrier to electric vehicle adoption is "range anxiety." A recent study by the Union of Concerned Scientists found that the single biggest concern for those who are considering purchase of an electric vehicle is that there are too few public charging stations where respondents traveled.

The electric vehicle charging equipment market is a classic example that may warrant public investment and the involvement of regulated utilities. Investment in charging infrastructure, including ownership and operation of charging stations, is an appropriate and necessary activity for utilities and is a natural extension of their existing infrastructure.

Utilities Will Play a Key Role in Transportation Electrification

- The Joint Utilities recognize electric vehicles (EVs) as one of many valuable tools to help achieve state clean energy objectives and seek to support and encourage EV adoption across the State of New York.

- The Joint Utilities have an important role to play in jump-starting EV adoption in New York. Utilities have been advancing EV demonstrations, pilot projects, and programs, and continue to work with stakeholders such as customers, regional groups, associations, and governments to promote EV initiatives and charging infrastructure awareness.

Utilities Seek Flexibility in the Development of Infrastructure Investment Strategies

- The EV market remains in its early stages of growth and may develop differently in various parts of the State due to many factors such as demographics, population, building and housing density, the location of major thoroughfares, and propensity for third party infrastructure investment.

- Given the significant differences among communities across the State, it is appropriate for utilities to develop charging infrastructure investment strategies that reflect such differences.

- The Joint Utilities seek to learn more about where, when, and for how long drivers will charge their EVs, and adapt their investment strategies accordingly.

- The Joint Utilities recognize that investment strategies may need to be progressive and proactive and may outpace the immediate market need. Rate treatment and recovery that is consistent with current practices for prudent recovery of approved program costs and incentives for meeting specified goals should be globally applied to Joint Utility programs.

- The Joint Utilities envision many different roles for themselves in supporting EV charging infrastructure deployment, with the utility role likely varying by market segment and by geography.

    - The utilities may serve more of an enabling role, for example, investing in make-ready infrastructure and/or chargers or offering incentives.

    - In some instances, the utility may own and operate the electric vehicle supply equipment (EVSE; the actual hardware that connects an EV to the electrical grid).

- A variety of creative business arrangements can be developed within and around these fundamental roles with the goal of advancing the deployment of EV charging infrastructure.

Utility Investment Strategies and Measuring Success

- Growth of EV adoption is subject to a number of forces outside of the utility's control, such as vehicle costs and performance, gasoline and other fuel prices, consumer preferences, and public policies.

- Utility success in the EV market should be determined by objective measures specific to the type of utility investment. 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 2018 DSIPs, EV integration remains one of the most active segments in the development of the DSP, primarily driven by regulatory activity and program implementation. The JU have continued to meet weekly to discuss technical topics (including utility role/make-ready, rate modification proposals, fleet electrification, education and outreach, and program implementation issues) and to discuss positions on issues to share with staff and stakeholders

On April 24, 2018, the Commission initiated a proceeding regarding EVSE&I. The EVSE&I Order acknowledged that Commission 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."

The Commission directed DPS Staff to collaborate with stakeholders to identify and address immediate and long-term actions to best support ZEV market growth, and to convene a technical conference to consider the following topics: (1) potential utility roles in supporting EVSE deployment; (2) potential utility roles in supporting EV charging services; (3) requirements to enable EVs and EVSE to operate as a source of grid services and system value, including possible data and instrumentation needs; (4) location considerations, including electric system, customer need, and community considerations; (5) how to treat EVs and EVSE as distributed energy resources (DER); (6) if tariffs and demand charges should be adjusted; (7) potential utility roles in encouraging EV adoption; (8) compatibility with ongoing regional initiatives and other state's programs; and, (9) other similar actions proposed by stakeholders. The Commission also directed DPS Staff to issue a whitepaper that addresses these topics and any additional issues identified by stakeholders.

Around the time that the EVSE&I Order was issued, the New York Power Authority (NYPA), the New York State Department of Environmental Conservation (DEC), the New York State Department of Transportation (DOT), and the New York State Thruway Authority (Thruway Authority) (collectively, the Joint Petitioners) filed a petition for Immediate and Long-Term Relief to encourage Statewide Deployment of Direct Current Fast Chargers (Joint Petition).

The Joint Utilities' efforts to respond to the Joint Petition resulted in Central Hudson, Con Edison, NYSEG, NYPA, DEC, DOT, NYSERDA, Thruway Authority, National Grid, O&R, and RG&E filing a Consensus

Proposal. The Consensus Proposal called for each utility to provide an annual per-plug incentive to support the development of public DCFC stations. Each utility proposed slightly different programs and funding levels since each company has different rate structures and underlying costs.

The Commission issued the DCFC Program Order on February 7, 2019, as a response to the Joint Petition, the technical conference, the working groups, and the Consensus Proposal. The DCFC Program Order established a seven-year per-plug incentive program through which up to 1,074 newly-constructed, publicly accessible DCFC plugs may receive an annual payment. This payment is capped at the station's total delivery cost in the twelve-month billing period for which the incentive is calculated.

To complement these initiatives, DPS Staff proposes that the Commission approve a Make-Ready Program in each electric utility service territory and address several other issues critical to EV deployment. Illustrating the challenging economics confronting the EV industry today, there are only nine approved plugs enrolled in the DCFC per-plug incentive program. DPS Staff's proposals recognize that the Joint Utilities are in a unique position to encourage responsible EV charging station deployment, which should increase EV adoption and put New York on a path to meet the CLCPA goals and ZEV MOU.

The Joint Utilities support New York State's clean energy objectives, including its leadership in the transition to clean transportation. As the EVSE&I Whitepaper notes, because statewide emissions from transportation are the largest source of greenhouse gas (GHG) emissions in the State, achieving these objectives will require the broader electric vehicle (EV) market to work together, including auto manufacturers, dealerships, charging station developers, site hosts, New York State Electric Research and Development Authority (NYSERDA), government at all levels, and utilities. The Joint Utilities look forward to implementing programs that seek to build adequate utility and charging infrastructure to support broad-based EV adoption throughout NYS in a cost-effective manner.

Once the EVSE&I whitepaper issues are addressed, the JU EV WG will re-focus on the key areas of interest identified by working group members:

- Fleet Electrification
- Make Ready Program implementation
- Education and Outreach
- Service applications (streamlining/ombudsman) for installations/queue management

- DCFC load serving capability maps
- Demand management/mitigation
- Continue discussions around demand charges
- EV charging profiles, EV Load capture, and load factor

2. Implementation Plan

a) Current Progress

Central Hudson has developed a new strategic focus on EV Initiatives to increase EV adoption through stakeholder participation and advocacy, improve the employee EV experience, and demonstrate leadership in EV policy. The strategic approach will now focus on Utility Infrastructure and make-ready implementation, Vehicle Charging station plans and deployment, and Advocacy and Education. The initial priority actions include:

- Establishing program leadership and a cross-functional team;
- Developing and implementing an employee program focused on education and adoption;
- Expanding existing advocacy efforts with an "EV Summit" or similar annual events;
- Establishing outreach to local counties and municipalities.
- Addressing rate design issues and proposing solutions that advance the program; and
- Proposing a transportation electrification program in accordance with the rate order.

Central Hudson wants to play a lead role in deploying electric vehicle charging infrastructure in the Hudson Valley and encouraging the transition from gasoline-powered vehicles to electric vehicles. Central Hudson supports the State's goals to increase electrification and reduce emissions (see the Powering the Path to a Cleaner Future initiatives) and is working with stakeholders to make public charging stations a reality.

What is Central Hudson doing?

Planning and Investments: Central Hudson is facilitating private electric vehicle charging and infrastructure through planning and investments in the electric distribution system, industry collaboration in innovative rate design, and directly assisting local governments and private parties in planning and installing electric vehicle equipment.

Fleet Assessment: Through a research and development project utilizing independent consultants, Central Hudson developed partnerships with local fleet operators to determine which vehicles are the most suitable in converting to electric vehicles, including its own.

Mapping Project: Central Hudson is working with Electric Power Research Institute on a method to map suitable locations for charging infrastructure in the Hudson Valley.

Incentives, Rate Structure: Central Hudson, the New York Public Service Commission, the New York Power Authority, and other New York utility companies have jointly and successfully developed an incentive for fast charger deployment in the State, effective March 1, 2019. Central Hudson is also supportive of rate designs that encourage recharging during periods that support the electric system, for example, coupling charging with solar production and offering electric vehicle time-of-use rate incentives.

EV Penetration Forecasting Approach and Methodology

The EV market is poised for significant growth over the next several years due to increased consumer offerings, more competitive vehicle pricing, and favorable policies. However, the expected near-term levels of EV adoption do not significantly impact utility system planning scenarios and related distribution system investment plans. The assumptions are consistent with industry-wide experience, which shows the majority of light-duty EV charging will occur at home. Central Hudson's EV forecasting assumptions, methodology, and results are listed in the appendices (Appendix B).

Projected Utility System Impacts and Investment

Distribution-level impacts are possible as a result of EV clustering and charging at discrete locations (e.g., with significant fast charging demands). However, considering the anticipated power and energy demands of EVs in the near- to mid-term future, the impacts can be addressed through normal infrastructure without significant extension of investments.

To study the impacts of incremental DCFC through 2025 and beyond, Central Hudson has estimated for locations and installations first along main travel route exits and travel plazas, then shopping centers, then travel plaza build-outs, and finally at population centers. For the Level 2 public-facing chargers, the locations were spread based on the residential population and for Level 2 Work Place Chargers, the locations were spread based on commercial account population. This distributed additional loading can be used to assess the impact of public and workplace DCFC and Level 2 charging on circuit loading and the need for peak reduction strategies.

Service Connection Requirements and Processes

The Joint Utilities EVSE Working Group is collaborating to reduce the barriers to deploying charging infrastructure and improve their existing individual service connection processes to provide a more positive user experience. To date, Central Hudson has utilized its normal service connection process for DCFC and Level 2 chargers, but will evaluate this going forward to see if there are ways to streamline the process, short of developing a separate process.

Local Ordinances, Building Codes, and Design Guidelines

Local zoning and parking ordinances, building codes, and design guidelines for EVSE may enable easier and less costly installation. Central Hudson will be working both individually and with the Joint Utilities to engage local and regional government stakeholders seeking to adopt "EV ready" policies and plans, and provide support where possible. The Company has also assessed its own service standards to ensure that new services are capable of serving EV charging load.

Rate Design Considerations

With EV deployment in its early stages, utilities can begin to explore effective rate design considerations. Central Hudson does not believe that the elimination of demand charges for low load factor loads is sustainable in the long term, and is committed to finding solutions that address short-term economic challenges that enable the growth of the market.

Central Hudson has adjusted its rate design with the following key considerations in mind:

- Comply with the requirements of Assembly Bill 288;
- Minimize the costs of EV charging, interconnection costs, and potential distribution system impacts;
- Encourage EV drivers to charge at preferred times using price signals;
- Provide EV charging rates that drivers can easily understand; and

- Provide EV drivers with a cost-competitive rate when compared to the standard/flat rate and the potential to realize cost savings relative to gasoline.

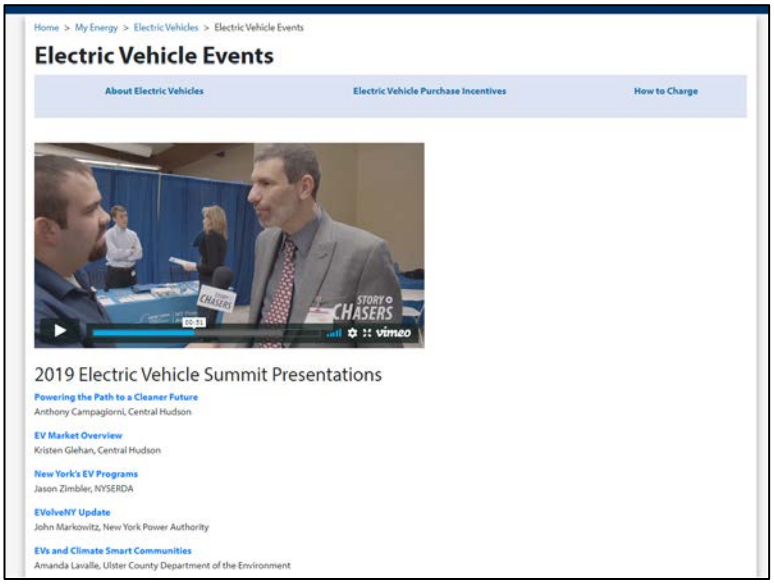
Designed for residents with electric vehicles, the EV Time of Use Rate enables owners to purchase electricity at lower rates during times when home vehicle charging is expected to be most frequent – after 7 p.m. and prior to 2 p.m. This optional billing method converts your residential electric account to a time-based rate, billed at a higher cost during peak demand periods (2 to 7 p.m.) and at a lower one all other times. By charging your vehicle during periods of lower demand, and shifting the majority of your other energy use to this same time structure (when choosing the whole home option), you may benefit from a lower bill. The rate is available on a Whole Home option with Bill Protection for the first year, or with a separate meter exclusive to EV charging.

EV service providers and other stakeholders have expressed explicit concern about the potential negative impacts of demand charges on DC fast charging. Central Hudson recognizes that DC fast charging can help achieve higher rates of EV adoption through the reduction of range anxiety and is actively seeking solutions to improve the business case. However, Central Hudson does not support the waiving of Demand Charges for EV charging stations or the shifting of EV chargers from demand to non-demand rates, especially for equipment that will likely have a negative impact on the circuit and system load factor. However, Central Hudson remains open to discussing this as part of the PSC proceeding and is willing to explore other rate design considerations or equipment supply options, such as EVSE coupled with Battery Storage, as a way to address both the system impact and economics of EVSE.

Education and Outreach

Central Hudson continues to leverage a range of channels to communicate with customers about electric vehicle topics, including e-newsletters, social media, events, press releases, websites, direct mail, vehicle wraps, and advertisements. The Company actively collaborates with manufacturers, local advocacy groups, and other parties to expand awareness of electric vehicle information and develop new opportunities. Central Hudson has sponsored annual Electric Vehicle Summit events bringing stakeholders together to advance. In addition to these efforts, Central Hudson Employees are provided hands-on opportunities to increase their knowledge of electric vehicles and to promote electric vehicle adoption within the communities they serve.

Figure 33: Central Hudson EV Outreach Page



b) Future Implementation and Planning

Central Hudson's primary focus for Electric Vehicle Integration will be to implement the installation of public charging infrastructure through the proposed Make Ready Program. Central Hudson will advance this work either through a future rate case proposal or through the Commission Proceeding and action following the whitepaper.

Central Hudson will also be looking to expand this Make Ready Program in a form that will apply to Fleet and Municipal Transit installations, allowing the Company to both incentivize and finance Fleet and Municipal EVSE.

Finally, Central Hudson will be working with its Fortis Affiliates to more fully understand the impact that EV charging at home and at the workplace may have on service and distribution equipment. This research effort may result in changes to service standards, distribution design, and inform how controlled charging can be valued and implemented to ensure that the electrification of the transportation sector does not negatively impact the grid and Central Hudson's ability to supply reliable service.

3. Risks and Mitigation

Central Hudson recognizes a number of risks with its plans for Electric Vehicle 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 forecast of EV adoption 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 technology improvements.

Central Hudson's approach will be to balance the need for EVSE, match the supply equipment need with the 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 medium and heavy-duty market, and that the impact on Central Hudson's infrastructure would be significant. To avoid this, Central Hudson 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.

4. Stakeholder Interface

Beyond the aforementioned EV Summits, Central Hudson has participated in the July 17-18 2018 Technical Conference (hosted by DPS Staff) and a stakeholder webinar on the DCFC proposal (November 27, 2018) and in the EV Readiness WG Meeting & Make-Ready Technical Conference (March 18, 2020). The Joint Utilities filed joint comments on the January 2020 Staff Whitepaper on April 27, 2020 and reply comments on May 10, 2020.

Through the Joint Utilities, Central Hudson participates in the preparation of joint comments, weekly discussions, and targeted developer outreach to ensure that the programs being considered are well thought out and vetted. In addition, the Joint Utilities continue working with other JU working groups, including the Information Sharing WG and the Integrated Planning WG on data mapping and planning issues related to EV.

5. Additional Detail

a) 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:

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

(2) the number and spatial distribution of existing instances of the scenario;

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

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

(5) the number of vehicles charged at a typical location, by vehicle type;

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

(7) the number(s) of charging ports at a typical location, by type;

(8) the energy storage capacity (if any) supporting EV charging at a typical location;

(9) an hourly profile of a typical location's aggregated charging load over a one-year period;

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

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

The common framework envisioned in this directive is a detailed electric vehicle charging infrastructure siting analysis. Initially, the Joint Utilities had developed the EV Readiness Framework, which identified key strategies to support EV adoption through utility action, engagement, and collaboration. 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 contemplates the number of light duty EV in the service territory and estimates their location, the percentage of at home charging, and the number and location of DCFC and Public/Workplace Level 2 chargers based on the Whitepaper Targets, and then uses industry load curves to estimate the impacts on the distribution system.

b) Describe and explain the utility'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 will support EV adoption in a nascent market, helping to achieve and, where possible, accelerate 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 to 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 – utilities are proactively seeking to encourage behavior that supports and improves prospects for increased EV adoption and addresses the goals of REV 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.

c) 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.

(1) Explain how each of those resources and functions supports the utility's needs.

(2) Explain how each of those resources and functions supports 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. The Joint Utilities in this DSIP filing provide more detail on the resources and functions required for planning, implementing, monitoring, and managing EV charging. The Load and DER Forecast specifically highlights the impacts of both at home charging and station charging on the distribution system under both expected EV penetration levels and also under “pressure test” levels of EV penetration.

d) 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., Level 2 charging vs DC fast charging; 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 or Level 2. Note that it is unlikely that the utility plays a substantive role in deploying Level 1 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.

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.

e) 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 2025 and an estimated 850,000 for New York State by 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 and high market forecasts are currently between 19,615 and 37,681 EVs in the service territory by 2030 (see Table 29), which are in the same magnitude as other projections that will meet the ZEV goals.

Table 29: Electric Vehicle Forecasts

Year	Scenario 1			Scenario 2		
	EVs	PHEVs	BEVs	EVs	PHEVs	BEVs
2020	3,799	1,809	1,990	4,627	2,091	2,536
2021	4,626	2,037	2,589	6,414	2,590	3,824
2022	5,613	2,238	3,375	8,474	3,024	5,451
2023	6,698	2,347	4,352	10,752	3,310	7,442
2024	7,976	2,410	5,566	13,475	3,520	9,955
2025	9,433	2,476	6,957	16,550	3,732	12,818
2026	11,087	2,560	8,527	20,016	3,982	16,034
2027	12,934	2,661	10,274	23,866	4,264	19,602
2028	14,981	2,772	12,209	28,113	4,568	23,545
2029	17,208	2,901	14,306	32,717	4,906	27,811
2030	19,615	3,049	16,567	37,681	5,281	32,401

- 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.

- Central Hudson will be using this information in its planning process to assess the impact of EVSE on the broader distribution system.

- In addition, Central Hudson has run "pressure test" scenarios in its forecasts to assess the impact of EV at even higher levels of penetration.

f) Describe the utility's current efforts to plan, implement, and manage EV-related projects. 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 EV integration plans;

Central Hudson has developed a strategic focus on Electric Vehicle Integration as a way to improve system efficiency, greenhouse gas reduction, and improved revenues. The program's priority initiatives are as follows:

- Establish program leadership and a cross-functional team;

- Develop and implement an employee PEV program focused on education and adoption;

- Expand existing advocacy efforts with a "EV Summit" or similar annual event;

- Establish outreach to local counties and municipalities;

- Address rate design issues and propose solutions that advance the program; and

- Propose a transportation electrification program (external) in accordance with the anticipated rate order.

(2) the original project schedule;

Central Hudson has continued on this path by holding annual EV Summit events, installing DCFC and Level 2 chargers at its headquarters and establishing a workplace charging policy, and preparing a proposal for public and fleet charging for consideration in its next rate proceeding.

(3) the current project status;

Of the priority items, the program leadership and cross functional team has been established and efforts on increasing and improving consumer outreach are underway. The employee workplace chargers and fleet chargers are in progress and will be completed in 2020.

(4) lessons learned to-date;

The lesson learned to date is that the development of charger sites takes a lot more time than anticipated, much of which is not related to utility service or processes.

(5) project adjustments and improvement opportunities identified to-date;

Central Hudson has proposed several adjustments or improvement opportunities in the DCFC Incentive program based on lessons learned and unintended consequences.

(6) next steps with clear timelines and deliverables;

The Company is reviewing the Electric Vehicle Supply Equipment (EVSE) and Infrastructure white paper issued by the Department of Public Service Staff on January 13, 2020 as applicable to the development of future Company plans for electric vehicles. Additionally, the Company intends to continue with the following:

Help Develop the Local Electric Vehicle Market

As published in the Powering the Path to a Cleaner Future white paper, Central Hudson believes there are opportunities to further develop the electric vehicle market by working with elected leaders and local municipalities. The Company also sees opportunities related to Level 2 and Direct Current Fast Charge (DCFC) infrastructure and plans to develop a make-ready program to support expansion in this area.

Electric Vehicle Education and Advocacy

Central Hudson continues to be an advocate for the adoption of electric vehicles and acts as a resource for its customers. The Company runs an active electric vehicle education program through its website, social media, e-newsletters, direct mail, printed handouts, and events, including a Company hosted Electric Vehicle Summit, National Drive Electric Week community events, and public showcase events such as county fairs. Information on electric vehicle technology, benefits, purchasing incentives, and charging options is provided, intended to build awareness and adoption of electric vehicles and help meet New York State carbon reduction objectives. Company representatives also continue to participate in state and local events focused on electric vehicles and charging infrastructure. The Company intends to expand efforts through the development of a fuel cost comparison calculator, establishment of a trade ally network of EVSE installation contractors, and dealer based marketing and educational materials to better support customers in their decision making process.

DCFC EVSE Incentive

During the first quarter of 2019, Central Hudson launched the Direct Current Fast Charger Incentive program in response to the Public Service Commission's Order Establishing Framework for Direct Current Fast Charging Infrastructure Program issued and effective February 7, 2019 in 18-E-0138. Application requirements of this seven-year program are reviewed as needed, to ensure compatibility with current PSC orders and other market influences.

Workplace Charging

In 2019, Central Hudson initiated a workplace charging program to expand the availability of Level 2 chargers to five of its district locations, including Poughkeepsie, Fishkill, Kingston, Newburgh, and Catskill, thus enabling employees and campus visitors the ability to charge their vehicles. Construction is expected to be completed early in 2020 with a projected total of 60 Level 2 plugs and 2 DCFC plugs installed.

EV Suitability Assessment and Integration of Electric Vehicles to Fleet

Early in 2019, the Company initiated a research and development project to determine the suitability of converting light-duty fleet vehicles to electric. The study is ongoing, with anticipated completion in 2020. The Company's transportation department is actively reviewing opportunities to convert varying vehicle types to electric.

Marketplace Availability and Incentives for Level 2 EVSE

Central Hudson has offered Level 2 electric vehicle home chargers for purchase on the CenHub Store marketplace since 2018 and is now engaged with the implementation of a NYSERDA PON that will fund an incentive for a limited number of chargers to promote EV Adoption and Smart Charging Bundles. The new offer is expected to launch and be promoted within the 2020 calendar year. The next steps are listed above in the priority actions; however, no clear timelines or deliverables have yet been established.

g) Explain how the Joint Utilities are coordinating the individual utility EV-related projects to ensure diversity of both the EV integration use cases implemented and the technologies/methods employed in those use cases.

The Joint Utilities recognize that practical demonstration projects will likely form the basis of planning related to transportation electrification moving forward. Further, the Joint Utilities have noted that rapid technological advances and the diversity of EVs in the current market require utilities to begin planning for charging infrastructure today for the EV deployment of tomorrow. To develop a better understanding of the most effective way to engage in transportation electrification, the Joint Utilities continue to be involved in a wide array of demonstration and pilot projects. The diversity of those EV-related projects reflects the diversity of approaches that utilities have developed to address transportation electrification.

The Electric Vehicle Working Group provides a platform for collaboration and coordination on EV-related issues for the Joint Utilities of New York. While each individual utility advances EV-related projects in their own service territory, subject to internal business decisions and resource prioritization, the Joint Utilities will continue to use the EV Working Group as a platform to collaborate and share lessons learned, thereby ensuring the sustained diversity of EV integration use cases and the technologies and methods employed in the use cases.

h) 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 Joint Utilities were proactively engaged with NYSERDA, NYPA, DEC, and DPS staff through the development of the EV Readiness Framework published in March 2018. Multiple staff members from these organizations actively participated in the two stakeholder meetings, held in September 2017 and February 2018. Further, the Joint Utilities have invited staff from these organizations to present to the EV Working Group several times over the past twelve months. The presentations covered a range of issues, including the costs and benefits of EV deployment in New York State and the role of demand charges in DC fast charging use cases.

In addition, Central Hudson and the Joint Utilities are actively participating in the PSC case on EV and in the Tech Conferences being held to advance the Commission's understanding of the nuances of rate design, infrastructure needs, and ownership models, and system impacts.

F. Energy Efficiency Integration and Innovation

1. Context and Background

Central Hudson is proud to implement programs that offer customers opportunities to reduce their energy use, manage their energy bill, and contribute to the achievement of the 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.

Central Hudson has been administering a portfolio of energy efficiency programs continually since 2009. During that time, the portfolio has expanded into new technology areas and customer segments. In 2016, Central Hudson integrated new residential lighting opportunities into the portfolio. These programs have led to a significant increase in energy savings opportunities and will continue in the near term. The expansion of lower cost lighting initiatives continues to drive down the average cost of the electric portfolio and maximize the MWh savings. Lighting initiatives such as the Residential Retail Lighting and Efficient Products, the CenHub Online Store, and the Community Lighting initiative, have provided residential customers with more opportunities and choices to participate. Residential customers now have the option to shop online through the CenHub Store or visit local brick and mortar retail stores to purchase LED lights and efficient products at a reduced cost. Additionally, the Community Lighting initiative is the first Central Hudson initiative targeted toward low-income customers. Since 2016, the Company has distributed over 2 million efficient LEDs to its customers. More details on the Company's Energy Efficiency portfolio can be found within the System Energy Efficiency Plan: 2019 Annual Report, filed on June 1, 2020[22].

New Efficiency: New York

Energy efficiency is one of the cornerstones in New York State's national leadership on clean energy and combatting climate change. Through a new comprehensive strategy, Governor Andrew M. Cuomo has set the State on a path to accelerate energy efficiency and reduce greenhouse gas emissions, decrease consumer energy costs, and create job opportunities.[23]

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[22] Central Hudson Gas & Electric Corporation Energy Efficiency Transition Implementation/ System Energy Efficiency Plan ("ETIP/SEEP") 2019 Annual Report
[23] https://www.nyserda.ny.gov/About/Publications/New-Efficiency

As part of this initiative, New York's utilities are called upon to achieve significantly more in their energy efficiency activities, in both scale and innovation. The New York State Public Service Commission's (PSC) Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025. ("January 2020 Order")[24] adopts significantly accelerated utility energy efficiency targets, which will double utility energy efficiency achievement over 2019 to 2025, including a subsidiary goal for energy savings from the installation of heat pumps.

Central Hudson is substantially increasing the reach of its already robust energy efficiency portfolio. The January 2020 Order directs Central Hudson to achieve an incremental 67,174 MWh and 51,797 MMBtu of natural gas savings above previously approved levels by 2025. The January 2020 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.

Heat Pump Electrification

The January 2020 Order also authorized an incremental $43.2 million to support the achievement of approximately 255,000 MMBtu of energy savings through heat pump electrification. Heat pumps represent approximately 2% of the heating and cooling market in New York State as well as 2% of the heating market within Central Hudson's service territory. Heat pump technologies present a great opportunity in meeting the ambitious statewide greenhouse gas reduction goals due to their ability to provide efficient heating and cooling for residences and businesses alike. 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.

To grow the heat pump market, the PSC initiated the NYS Clean Heat Program, a common statewide heat pump framework among the Joint Utilities, to offer incentive measures to foster the adoption of efficient heat pump technologies. The NYS Clean Heat Program established a statewide budget of over $454 million to achieve an energy savings target of over 3.5 million MMBtu.

The measures within the NYS Clean Heat Program include incentive rebates for partial space heating and full load installations of 90-120% 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. Central Hudson aims to complete

[24] Order Adopting Accelerated Energy Efficiency Targets, Issued and Effective December 13, 2018, Case 18-M-0084

approximately 12,000 heat pump installations by 2025, with a total energy savings of 255,000 MMBtu. For Clean Heat projects in Central Hudson's service territory, customers receive rebates of up to $1,600 per 10,000 BTUh of heating capacity for an air-source heat pump installation, plus an additional $1,000 for the installation of a qualifying heat pump water heater.

Central Hudson's Earnings Adjustment Mechanisms

On June 14, 2018, the PSC issued an "Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan," under Cases 17-E-0459 and 17-G-0460, which establishes new Earnings Adjustment Mechanisms ("EAMs"). Including Energy Efficiency, there are five EAMs for electric comprised of seven different metrics. Central Hudson has the opportunity to earn average annual pre-tax earnings on a prorated basis between $1.3M and $4.9M from 2018 through 2021. The EAMs are intended to provide the Company with incentives to:

- Increase electric system efficiency through peak reduction and distributed energy resource utilization;
- Increase achieved electric and gas energy efficiency;
- Reduce residential and commercial customers' electric energy intensity (total usage on a per-customer basis);
- Increase residential customer participation in voluntary Time of Use rates; and
- Reduce carbon emissions through increased penetration of environmentally beneficial electrification technologies.

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 Energy Efficiency, Energy Intensity, and Environmental Beneficial Electrification directly support the "New Efficiency: New York" targets of reducing carbon emissions by achieving 185 TBtu of building energy savings by 2025 and reducing overall carbon emissions by 40% by 2030.

The Electric Energy Efficiency EAM is composed of three metrics, one is programmatic, and two are outcome-based. The metrics consist of: Electric Energy Efficiency (programmatic), Residential Electric Energy Intensity (outcome-based), and Commercial Electric Energy Intensity (outcome-based).

Additionally, the Rate Plan Order established targets for the Environmentally Beneficial Electrification EAM, which is also discussed below.

The Electric Energy Efficiency EAM metric incentivizes the Company to achieve energy efficiency savings in calendar years 2018 through 2021 that are significantly above its historical first-year annual savings target of 34,240 MWh. This metric will be calculated as the sum of MWh savings from all of Central Hudson's administered electric energy efficiency programs, including behavioral programs, which may be utilized to achieve MWh targets. As a precondition to earning the incentive associated with this metric, the EUL of the Energy Efficiency portfolio must be at least 7.9 years. The Energy Efficiency EAM targets for electric were also converted to gross MWh targets in order to be consistent with the Order issued on March 15, 2018, in Case 15-M-0252.[25]

The Residential Electric Energy Intensity EAM and the Commercial Electric Energy Intensity EAM will incentivize Central Hudson to reduce residential (SCs 1 and 6) and commercial (SC 2 non-demand) customers' total usage on a per-customer basis. This metric will be evaluated as the sum of weather-normalized annual residential MWh sales adjusted for Community Distributed Generation allocations and increased sales due to beneficial electrification technologies, such as heat pumps and electric vehicles, divided by the 12-month average number of residential customers.

The Commercial Electric Energy Intensity EAM metric incentivizes Central Hudson to reduce commercial (SC 2 non-demand) customers' total usage on a per-customer basis. This metric will be measured as the sum of the weather-normalized annual commercial MWh sales adjusted for Community Distributed Generation allocations and increased sales due to beneficial electrification technologies such as heat pumps and electric vehicles, divided by the 12-month average number of commercial customers.

The Environmentally Beneficial Electrification EAM metric incentivizes the Company to reduce carbon emissions by facilitating greater penetration of technologies that utilize electricity and reduce carbon emissions relative to traditional technologies that rely on more carbon intensive fuel sources. Examples of these technologies include geothermal heating and cooling, air source heat pumps for heating and cooling, and electric vehicles. The metric will be measured as the lifetime short tons of avoided carbon dioxide from environmentally beneficial electrification technologies, as identified in the Company's Carbon Reduction Implementation Plan. The Environmentally Beneficial Electrification EAM will be

[25] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018).

measured as the incremental lifetime short tons of avoided carbon dioxide (“CO2”) from incremental electric vehicles and heat pumps. Incremental lifetime tons of CO2 will be calculated as the number of incremental units multiplied by the assumed avoided tons of CO2 multiplied by the average technology life as agreed to below.

- Electric vehicles (“EV”): EV registrations * 3.8 tons CO2 * 10 years
- Air-source heat pumps (“ASHP”): ASHP installations * 6.7 tons CO2 * 15 years
- Ground-source heat pumps (“GSHP”): GSHP installations * 6.7 tons CO2 * 25 years

The EV component of the Environmentally Beneficial Electrification metric is an outcome-based metric and will be calculated as the incremental electric vehicles registered in Central Hudson’s service territory. Electric vehicles are defined as battery electric vehicles (“BEVs”) and Plug-in hybrid vehicles (“PHEVs”). Data will be obtained from the IHS Markit Vehicle Market Analysis: Registrations and Vehicles-in-Operation. Quantification of the ASHP component of the Environmentally Beneficial Electrification metric will be determined through participation in Central Hudson’s Carbon Reduction Program. Quantification of the GSHP component of the Environmentally Beneficial Electrification metric will be determined by the number of Central Hudson customers participating in NYSERDA’s geothermal rebate program, receiving the Central Hudson Rate Impact Credit, or participation in Central Hudson’s Carbon Reduction Program.

The annual electric EAM minimum, midpoint, and maximum targets associated with Energy Efficiency and Environmentally Beneficial Electrification are shown in the following chart.

Table 30: Energy Efficiency and Environmentally Beneficial Electrification EAM Targets

EAM		2018	2019	2020	2021
Energy Efficiency (Gross MWh)	Min	53,262	53,262	53,262	53,262
	Mid	63,658	63,658	63,658	63,658
	Max	79,102	79,102	79,102	79,102
Residential Energy Intensity (MWh/Customer)	Min	7.68	7.60	7.52	7.44
	Mid	7.59	7.51	7.44	7.36
	Max	7.51	7.43	7.35	7.27
Commercial Energy Intensity (MWh/Customer)	Min	48.24	47.90	47.56	47.22
	Mid	48.05	47.71	47.36	47.02
	Max	47.85	47.51	47.17	46.83
Environmentally Beneficial Electrification (Lifetime Tons CO2)	Min	4,257	8,514	8,514	8,514
	Mid	12,123	24,245	24,245	24,245
	Max	19,988	39,976	39,976	39,976

2. Implementation Plan

a) Current Progress

Central Hudson has implemented a portfolio of Energy Efficiency programs since 2009, with specific initiatives targeted at various end uses and customer segments. Over this period, Central Hudson has integrated many innovative approaches and practices in order to optimize the cost and increase the quantity of MWhs achieved. Central Hudson's progress in these efforts is illustrated in the chart below. As Central Hudson Energy Efficiency programs have evolved, the average annual MWh savings have increased by 217%, and the cost per MWh has decreased by 59%.

Table 31: Central Hudson Historical MWh Savings and Costs

Framework	Years	MWh Savings	Expenses	Avg Annual MWh Savings	$/MWh
EEPS[26]-1	2009-2011	75,133	$21,459,934	25,000	$286
EEPS-2	2012-2015	152,804	$32,393,211	38,200	$212
EET[27]	2016-2017	105,005	$13,508,138	52,500	$129
ETIP[28]	2018	81,964	$8,773,420	81,964	$107
SEEP[29]	2019	79,221	$9,209,197	79,221	$116
Total		494,127	$85,343,900		

3. Future Implementation and Planning

Central Hudson is currently developing incremental energy efficiency offerings associated with "New Efficiency: New York," the State's initiative to accelerate energy efficiency and reduce greenhouse gas

[26] Energy Efficiency Portfolio Standard
[27] Energy Efficiency Transition
[28] Energy Efficiency Transition Implementation Plan
[29] System Energy Efficiency Plan

emissions, decrease consumer energy costs, and create job opportunities. The most notable areas of expansion are heat pump electrification and programs designed specifically to serve low-to-moderate income ("LMI") customers.

Low-to-Moderate Income

In response to the January 2020 Order, Central Hudson is collaborating with Joint Utilities (JU) across New York State and NYSERDA to develop coordinated statewide efficiency initiatives targeting low and moderation income (LMI) customers. Statewide, over 40% of households qualify as low-to-moderate-income. This collaboration includes defining the LMI market (e.g., identifying the portion customers that fit into the LMI categorization); determining key performance indicators that will be used to inform the success of individual initiatives as well as the portfolio as a whole when evaluated, and developing initiative descriptions, including measures and incentives offered, target audience (e.g., single-family v. multifamily), fuel type, delivery model, key partners, participation and savings (MWh and MMBtu) (2020-2025), and budgets (electric and gas funding).

Central Hudson has taken an active role in the development of each of the initiatives presented in the LMI implementation plan (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 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, which is to be filed on July 14, 2020, includes the following initiatives:

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

Central Hudson, in conjunction with the JU and NYSERDA, continues to refine these initiatives – the corresponding budgets and targets- as well as possible pilots, address beneficial electrification, plan for an LMI Management Committee, and shared marketing and outreach through a Customer Hub.

Evaluation Activities

The Commission determined in the March 15, 2018 Order (Utility EE Order)[30], that a greater focus on actual realized savings is needed due to the wide variability in energy efficiency program realization rates. The Commission directed Staff, in consultation with the utilities, NYSERDA, and other interested stakeholders, to issue guidance regarding gross savings verification. The Clean Energy Guidance document CE-08: Gross Savings Verification Guidance, Version 1.0, was issued on August 23, 2019. This Clean Energy Guidance document provides details on the implementation of the Verified Gross Savings (VGS) policy and its use for general reporting, and Earnings Adjustment Mechanism (EAM) reporting, as applicable.

Central Hudson has accelerated its impact evaluation activities to further develop its gross savings verification and comply with the CE-08 guidance. Each of Central Hudson's energy efficiency programs is in various stages of evaluation studies, with all scheduled to be complete by 2021. 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 evaluation were filed on June 1, 2020. An overview of these efforts is laid out in the following table.

Table 32: Planned Program Evaluation Activities

EM&V Activity (Electric)	Expected Plan Submission Date	Expected Start Date	Expected Completion Date	Status
Residential Appliance Saturation Study	N/A	2018 Q2	2018 Q4	Completed
Impact Evaluation – *Residential Behavioral Modification*	2020 Q1	2019 Q4	2020 Q1 2021 Q1	In Progress
Impact Evaluation - *Residential HVAC*	2020 Q1	2020 Q2	2021 Q1	Upcoming

[30] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018).

Impact Evaluation – *Residential Retail Lighting & Efficient Products*	2020 Q1	2019 Q4	2021 Q1	In Progress
Impact Evaluation - *C&I Rebates*	2020 Q1	2020 Q2	2021 Q4	Upcoming
Impact Evaluation - *Small Business Direct Install*	2019 Q2	2019 Q2	2020 Q2	In Progress
Impact Evaluation – *CenHub Online Store*	2020 Q1	2020 Q2	2021 Q1	Upcoming
Impact Evaluation – *Appliance Recycling*	2020 Q1	2020 Q2	2020 Q4	Upcoming
Impact Evaluation – *Community Lighting*	2020 Q1	2020 Q2	2020 Q4	Upcoming
Impact Evaluation – *Municipal Streetlights*	2020 Q1	2020 Q2	2020 Q4	Upcoming
Process Evaluation – *Residential Retail Lighting & Efficient Products*	2020 Q1	2020 Q2	2020 Q4	Upcoming
Process Evaluation - *C&I Rebates*	2020 Q1	2020 Q2	2021 Q1	Upcoming
Process Evaluation - *CenHub Online Store*	2020 Q1	2020 Q2	2020 Q3, 2021 Q3	Upcoming
Baseline Study	2019 Q3	2019 Q3	2019 Q4	Completed
Potential Study	2019 Q3	2019 Q3	2020 Q2	In Progress
Free-ridership and Attribution Studies	2020 Q2	2020 Q2	Varies by program	Upcoming
Program Support and Planning	N/A	2019 Q1	Ongoing	In Progress

COVID-19 Impacts

Pursuant to state directives and guidance, various components of energy efficiency initiatives were curtailed or suspended for several months during 2020. With the Mid-Hudson and Capital Regions moving to Phase One of NY Restart, many onsite activities have resumed. The long term impacts of this period to energy efficiency programs are still unknown. Central Hudson has taken proactive steps to boost the energy efficiency programs where possible. For example, all energy efficiency measures on the CenHub store are being offered with free shipping, and several cost-effective measures have increased rebates. For a limited time, Central Hudson is offering small business customers no-cost energy efficiency lighting upgrades for projects up to $10,000, subject to certain exclusions.

4. Risks and Mitigation

A known risk factor to Central Hudson's electric energy efficiency portfolio is the significant forecasted decline in potential over the next few years. Central Hudson commissioned a Potential Study that was filed in Matter 16-002180 on June 1, 2017[31]. The study indicated that the realistic achievable potential ("RAP") was significantly lower than the maximum targets set within the Company's Rate Plan Order. This is primarily due to more stringent EISA lighting standards, which are expected to significantly diminish the ability to achieve incremental savings through utility programs during the latter years of the period covered by the Rate Plan. The Company's mitigation strategy involves diversifying the portfolio amongst different end uses to the extent possible. Additionally, lighting programs are currently being maximized before the adoption of new EISA lighting standards take effect.

5. Stakeholder Interface

Central Hudson frequently interacts with various stakeholders to develop, design, and implement its Energy Efficiency programs. These stakeholders include potential and current vendors, customers, trade allies, and DPS Staff.

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

[31] Matter 16-02180, In the Matter of Clean Energy Program Evaluation, Measurement and Verification, Central Hudson Potential Study (Filed, June 1, 2017).

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 REV and energy efficiency related working groups, which provide an opportunity to interface with stakeholders. One such example is the REV Connect sprints, where utility representatives have in-person meetings with various vendors and solution providers throughout a one-day event.

Furthermore, when Central Hudson determines a service provider is needed, a request for proposal (RFP) will be 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 discusses 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.

Customer Interfaces

Central Hudson is continuously looking for ways to make the customer experience as easy and fluid as possible. From the introduction of the CenHub customer engagement platform to the implementation of each energy efficiency initiative, engagement, quality assurance, and cost to participate are the focus of the customer experience design. Additionally, Central Hudson has recently focused on the customer experience through two studies and ongoing process evaluations.

Process evaluations ensure that a program or individual program offering is operating as intended and provides information that can enable improvements in both the program design and implementation. Process evaluations assess customer understanding, attitudes about, and satisfaction with programs, individual offerings, and other educational activities.

6. Additional Detail

a) The resources and capabilities used for integrating energy efficiency within system and utility business planning, including among other things, infrastructure deferral opportunities as part of NWAs, peak and load reduction and/or load or energy shaping with an explanation of how integration is supported by each of those resources and capabilities, or other shared savings / benefits opportunities.

Central Hudson's NWA solicitations are technology agnostic, so energy efficiency may be utilized as a 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 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.

b) 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 NENY proceedings. The Commission has set new targets within the Joint Proposal. For the majority of energy efficiency projects, the Company tracks the location of each participant and can readily identify the overall impacts 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.

c) How the utility develops and provides its short and long-term forecasts of the locations, times, and amounts of future energy and peak load reductions achievable through energy efficiency.

A five year electric forecast is developed as a system forecast. It does not forecast locations or times.

The impacts of energy efficiency are embedded in the historical demand data utilized to construct the peak demand model. As a result, incremental impacts of future energy efficiency are developed and applied to the base peak forecast. The reductions attributable to EE are developed by utilizing data available from the NYISO's Gold Book, specifically applying the historical trend of the ratio of Central Hudson's peak to the total of peaks for Zones E and G to the NYISO's incremental EE reductions anticipated for Zones E and G

d) How the utility assesses energy efficiency as a potential solution for addressing needs in the electric system and reducing costs.

Central Hudson's NWA solicitations are technology agnostic, so energy efficiency may be utilized as a 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 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.

e) How the utility collects, manages, and disseminates customer and system data (including energy efficiency project and load profile data) that is useful for planning, implementing, and managing energy efficiency solutions and achieving energy efficiency potential.

Central Hudson collects its system load data and customer load data through its circuit metering or customer revenue metering. The system load data is sanitized and provided through the System Data Portal as historic hourly load data at the circuit level, aggregated to the substation level, and to the transmission area level. In addition, Central Hudson provides hourly system load forecasts for a 5 year period. Central Hudson uses the System Peak Load Data for distribution planning and capital forecasting. This data can also be used to refine solutions for NWAs by providing load shapes and load duration curves.

Customer load data is used for sales and revenues forecasting and can be used to manage some of the energy efficiency solutions, but additional metering data and estimating methodologies are needed beyond this data to manage Central Hudson's energy efficiency programs. As for disseminating customer data, Central Hudson has Green Button Download for customers and approved agents. Additional methods for dissemination of customer data for public use are currently in development.

f) 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 a new 2025 energy efficiency target called for in Governor Cuomo's 2018 State of the State Address.

As described in more detail within the preceding sections, Central Hudson's Energy Efficiency, Building Electrification, and Low-to-Moderate Income programs have been specifically to support the New Efficiency: New York directives.

g) A description of lessons learned to date from energy efficiency components of REV Demonstration Projects with specific plans for scaled expansion of successful business model demonstrations. In addition, provide a description of each hypothesis being tested as part of energy efficiency components of ongoing Demonstration Projects and the anticipated schedule for assessment.

The Joint Utilities have pursued a variety of REV Demonstration Projects focused on developing a better understanding of how to deploy innovative energy efficiency programs effectively. While the utilities are developing and implementing these energy efficiency Demonstration Projects independently, they have learned collectively from the different aspects of products and services that the projects have addressed, including online portals to connect customers with energy products and services, building efficiency initiatives, and incentive programs for demand reduction. The Joint Utilities have identified two key mechanisms that can be used to boost customer participation and engagement in energy efficiency initiatives and enable new utility business models. The first is to provide customers with greater visibility into both their own energy use patterns and the wide variety of available products and services tailored to their energy needs. The utilities' smart metering, demand reduction, and home energy report Demonstration Projects are all examples of offerings that advance engagement, motivating customers to take control of their energy use and management and enabling utilities to successfully meet their energy efficiency commitments. The second mechanism is building specific awareness of energy efficiency opportunities through carefully crafted marketing strategies. These may include project-specific incentives for large C&I customers; distribution channel partnerships with ESCOs, retailers, and contractors; new-homeowner and school-based education and awareness initiatives; and targeted marketing to customers through the online marketplace platform, based on customers' usage patterns and specific energy needs.

Engaging Customers with CenHub

Central Hudson’s first demonstration project, CenHub, was proposed on July 1, 2015, in compliance with Ordering Clause 4 of the Commission’s Order Adopting Regulatory Policy Framework and Implementation Plan (issued and effective February 26, 2015). CenHub’s primary purposes were to increase customer engagement with electricity and natural gas use and to provide an economically efficient energy efficiency delivery mechanism. CenHub provides customers with extensive functionality, including but not limited to:

- A customer portal with personalized electric energy usage dashboard;
- Personalized messaging, energy saving tips, and recommended actions;
- The ability to purchase products and services through an online marketplace and automatically apply rebates at checkout; and

Cross-promotion of programs that meet the specific needs of the individual customer; Central Hudson is also aware of the growing expectations of customers based on their interactions with other industries and businesses. Industry trends can be leveraged to design solutions that align with today’s customer expectations, as illustrated in Figure 34.

Figure 34: Customer Experience Industry Trends

On April 3, 2016, the CenHub Platform was made available to Central Hudson’s customers and has seamlessly provided information, decision-making support, and access to incentives and rebates for a host of energy efficient products around services. At this time, 51% of Central Hudson’s customers have engaged with the CenHub Platform. Per Central Hudson's current Rate Plan,[32] CenHub graduated from its status as a demonstration project and is now funded through base rates. During the term of the current rate plan, CenHub is expected to continue evolving and engaging customers through:

- improving the mobile platform;
- increasing the number of self-service options;
- providing a personalized dashboard;
- engaging with DER providers to develop third-party partnership portals;
- providing personal usage disaggregation;
- providing municipalities with additional information regarding the aggregated customer information; and
- providing calculators to support customer decisions regarding energy efficiency, voluntary time-of-use, and environmentally beneficial electrification.

These changes to the CenHub platform will increase customer convenience and control by improving the means by which they can manage their energy use and increasing the transparency of the associated financial and environmental impacts while directly supporting the State's Energy Policy goals.

The demonstration project timeline ended on June 30, 2018. Per Central Hudson's most recent rate order, the CenHub platform will continue to exist and has been built into the ongoing group expense. New feature sets planned for CenHub are included in the capital plan.

The CenHub Store platform has performed as a low cost delivery mechanism for energy efficiency rebates on lighting, advanced power strips, thermostats, and water saving products. The Store has run at approximately 10.5 to 11 cents per kilowatt hour each year, and from 2016 to 2019 it has delivered the following savings:

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[32] Case 17-E-0459, et. al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas and Electric Corporation for Electric Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Current Rate Plan"), (issued June 14, 2018), Appendix Y.

- 2016 – 3,183 MWh
- 2017 – 1,137 MWh
- 2018 – 914 MWh
- 2019 – 999 MWh

Engaging Customers with Ongoing Demonstration Projects

Insights+ is a subscription based offering provided on the CenHub Platform since June 6, 2017. Specifically, the Insights+ offering is a continuing demonstration project that comes with the installation of an advanced meter that captures 15-minute interval customer load data and communicate this information over cellular networks. This subscription is available to residential customers only at the cost of $4.99 per month. Customers can receive a reduced subscription cost of $1.99 per month if they sign up for the Voluntary Time of Use rate along with Insights+. At this time, approximately 150 customers have subscribed to the Insights+ service.

Beyond the Insights+ demonstration project scope, the Company has expanded the use of the Insights+ meters to assist in accomplishing other operational objectives:

- **Measurement and Verification (M&V):** Itron utilizes a statistical sample set of Insights+ meters for M&V as part of the Peak Perks NWA program. Itron pays the monthly meter fee, and the customer receives the Insights+ service as part of their Peak Perks program participation incentives. Currently, approximately 420 customers are provided with Insights+ data through the Peak Perks program.

- **Value Stack**: The Insights+ meter data meets the criteria for value stack, and the hosted Itron Meter Data Management ("MDM") can accommodate the additional meters at no additional system cost.

- **Time of Use**: The Insights+ meters capture data for the original Time of Use intervals as well as the new Voluntary Time of Use intervals. They also provide enhanced visual displays that differentiate time of use periods and peak and off-peak usage analytics

h) Explain how the utilities are coordinating on energy efficiency to ensure diversity of both the models demonstrated and the technologies/methods employed in those applications

The Joint Utilities have actively coordinated their energy efficiency program design and implementation since the May 2007 order instituting an Energy Efficiency Portfolio Standard (EEPS). This coordination continues today with formal and informal teams addressing all aspects of the Reforming the Energy Vision and Clean Energy Fund Proceedings. As described in the "New York Program Administrator Coordination Report" filed by the Joint Utilities and others in January 2017 as part of the Clean Energy Advisory Council (CEAC) process, this coordination has occurred through many different processes and groups and has had a wide range of foci and goals.[33] Today, this effort includes the evolution of the utility energy efficiency programs from the Energy Efficiency Transition Implementation Plan (ETIP) framework to the recently instituted System Energy Efficiency Plan (SEEP) framework, according to which, over the most recent planning period, each utility its energy efficiency planning into their forecasted system plans and evolved their ETIP into a SEEP that describes the entirety of the utility's expanded reliance on and use of cost effective energy efficiency to support their distribution system and customer needs.[34] As part of their continuing coordination efforts, the Joint Utilities participate in various working groups in which they share information regarding the development and testing of new energy efficiency programs and strategies with other utilities, NYSERDA, and DPS Staff. These coordination efforts address topics such as electrification, Low-to-Moderate Income programs, and Energy Efficiency. This coordination informs the current and future energy efficiency efforts, and help the utilities design a diverse portfolio of projects targeting a broad range of customers. These efforts include a focus on the development of and outcomes from demonstration projects, to avoid duplicative efforts and ensure the sharing of lessons learned from each utility demonstration project to all the Joint Utilities. The Joint Utilities remain committed to continuing this coordination to further support the diversity of energy efficiency programs across the State, and to achieve the energy efficiency targets prescribed by New Efficiency: New York.

[33] 16-01005, In the Matter of the CEAC's Clean Energy Implementation & Coordination Working Group January 31, 2017), pp. 2-6.

[34] CASE 15-M-0252 - In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets And Targets For 2019 – 2020, (March 18, 2018), p. 29.

i) Describe how the utility is coordinating and partnering with NYSERDA's related ongoing statewide efforts to facilitate energy efficiency market development and growth.

The Company maintains consistent coordination with NYSERDA to ensure complementary and non-duplicative efforts and programs. This coordination is achieved through regular communication and meetings between specific energy efficiency and demand management program managers and other subject matter experts. NYSERDA continues to be central to the statewide efforts related to New Efficiency: New York related initiatives.

NYSERDA joins Central Hudson and other utilities on weekly calls to develop and implement the NYS Clean Heat Program. NYSERDA's market transformation efforts supplement program operations and general implementation efforts by the utility program administrators. NYSERDA will participate with the utilities on the NYS Clean Heat joint management committee to ensure consistent statewide implementation.

For the LMI Portfolio, the Company and NYSERDA will coordinate and align across the customer-funded LMI Portfolio and jointly offer programs and resources. There will be a focus on coordinated outreach and education strategies between NYSERDA and the Company. The intent of a statewide joint administration of the LMI Portfolio is to improve customer experience, reduce administrative costs, and offer increased operational efficiencies, while simultaneously offering an appropriate level of commonality across the LMI portfolio.

G. Distribution System Data

1. Context and Background

Significant emphasis has been placed on the role of system data in facilitating market development and greater DER adoption. 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 four years has included extensive discussion and development of the datasets identified by the Commission as essential for improving the transparency of utility planning and operations and aiding market growth.

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 in the development of System Data Portals for DER developers to gather valuable system data. In addition, during the past two years, the Joint Utilities have been working together to develop a greater understanding of system data needs and studying use cases, however; these discussions have not resulted in significant changes in the amount of available data or in the way this data is accessed.

The REV Track One Order acknowledged the importance of data availability for the future adoption of DERs and customer management of energy usage. Acting on this, the REV Track One Order established a policy framework to develop DER markets and advance State clean energy goals. In doing so, the Commission called for a single, uniform platform for retail market access throughout New York that would also serve as a statewide market for REV-enabled products and services. The Commission intended for REV to establish markets so that customers and third parties can be active participants in the new, dynamic energy grid, resulting in a more efficient and secure electric system with better utilization of distribution, bulk generation, and transmission resources. Through this market animation, DERs will become integral tools in the planning, management, and operation of the electric system. Developers will be able to monetize the value of DERs in this market, allowing DERs to compete with more centralized options. Furthermore, customers will be able to create new value opportunities while improving system efficiency by exercising choices within an improved electricity pricing structure.

To enable these markets, the Commission described New York's investor-owned electric utilities as transitioning from the historical model of a unidirectional electric system, serving an inelastic demand, to a more dynamic, bidirectional system including a modernized infrastructure, price-reactive loads, and greatly enhanced capabilities for acquiring, communicating, and managing data. The REV Track One Order deliberated on many issues and options, including, but not limited to, stakeholders' needs for different types of data (e.g., system and customer data) to enable markets, data accessibility, cybersecurity, and the creation of an independent data exchange. At the time of the REV Track One Order, many parties suggested, and the Commission agreed, that the idea of a separate data exchange was premature; however, the concept of an independent data exchange was a longer-term goal to be explored as the grid and markets evolved to fulfill REVs goals.

To guide this transformation of the utility model, the Commission defined a set of functions that a modern utility, which the Commission termed a Distributed System Platform (DSP), should perform. The REV Track One Order required each utility, as a future DSP, to periodically file a comprehensive Distribution System Implementation Plan (DSIP) that includes detailed information about the utility's existing and planned capabilities for providing useful, market-enabling data to customers and third parties.

On April 20, 2016, the Commission issued an order adopted guidance for the organization and contents of the Joint Utilities' DSIPs. The DSIP Guidance Order made clear that certain data is needed to encourage market animation and drive DER penetration. The Commission stated that:

> …barriers to DER entry need to be removed. Addressing the information imbalance that currently exists will help remove such barriers. Today, there is very little information available to DER providers regarding the value of, or cost to, site resources in any particular area of the distribution system, or what type of resources or operational characteristics would have the most value. The system data supplied should bring together the information that DER providers will need to locate resources in areas of the system that will produce the most value. Utilities should work with stakeholders to address the types and levels of data to be provided, the methodology and rules for providing system data (including addressing security concerns), and frequency of updates.

Staff provided the Joint Utilities with more detailed DSIP guidance in a May 2018 whitepaper, further emphasizing the importance of customer and distribution system data. The DSIP Guidance Whitepaper stated that:

> [m]aintaining a full and timely exchange of DSIP information between the utilities and stakeholders is critical to achieving the most beneficial deployment and use of DERs. Key areas of emphasis should include: the purposeful development of stakeholder tools and information sources useful to DER providers in fostering productive DER development; collecting, managing,

and sharing system and customer data; and, advances toward an integrated planning environment.

Since launching REV, the Commission has continued to work on numerous data-related initiatives encompassing both customer and system data access. Nonetheless, DER providers and customers are still unable to efficiently access most of the data that would be useful to them. Without such access, the State will not be able to implement the dynamic, reactive, and efficient distribution system envisioned in the REV.

To propose the next steps to enable access to useful energy data, on May 29, 2020, the Department of Public Service Staff released a Whitepaper - Recommendation to Implement an Integrated Energy Data Resource. Central Hudson looks forward to working collaboratively with DPS Staff and NYSERDA to help achieve a useful and valuable resource.

2. Implementation Plan

a) Current Progress

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:

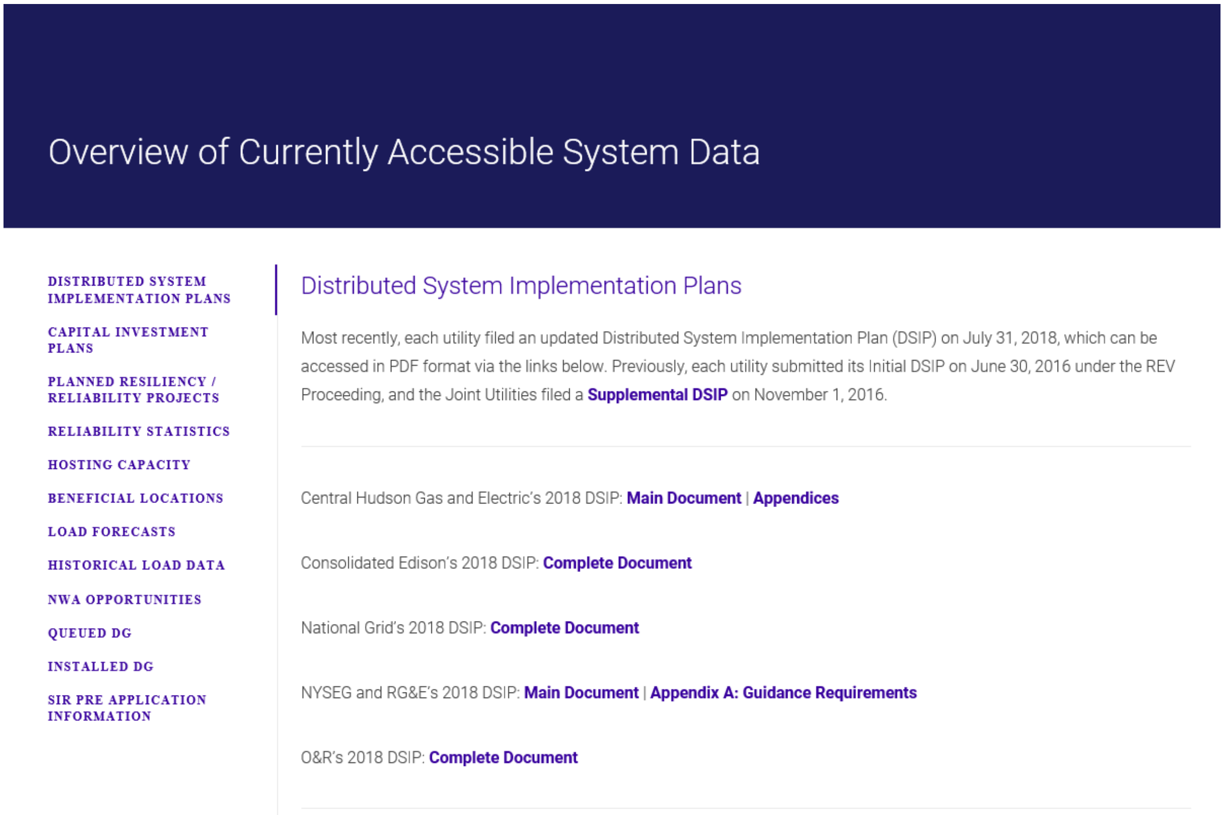
- DSIP Filing Documents;
- Annually updated five year Capital Investment Plans as filed with the PSC;
- Planned Resiliency / Reliability Projects as filed with the PSC;
- Reliability Statistics at the circuit level as filed with the PSC;
- Hosting Capacity Maps for all circuits above 12 kV;
- Beneficial Locations Maps;

- 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 (directs to separate JU-specific webpage) and Maps;
- Queued and installed DG; and
- SIR Pre Application Information.

The historical and forecasted load and DER data contained in this DSIP is an enhancement of the extensive system data available through the 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.

The Joint Utilities' stakeholder engagement sessions identified (1) the desire for and the broad value of information and (2) how the utilities could work to enhance what information is provided. In 2017, the Joint Utilities enhanced their individual data portals and the Joint Utilities' central data portal to improve the accessibility and usefulness of this high-value information. Links to the utility-specific websites with available system data can be found on the Joint Utilities of New York website shown in Figure 35 (http://jointutilitiesofny.org/system-data/).

Figure 35: Overview of Currently Accessible System Data



To better understand how data is utilized and what data is necessary to meet their needs, the Joint Utilities and stakeholders co-developed multiple business use cases and identified the "need to have" and "nice to have" data that enables each use case. In addition to increasing the amount of data available, the Joint Utilities also worked with stakeholders to make it easier to access system data both across the utilities and within individual utility data portals. The Joint Utilities System Data Working Group continues to engage stakeholders on the business use cases for system data, identify additional datasets to share, and respond to stakeholder requests to improve ease of access to system data.

b) Future Implementation and Planning

Central Hudson will continue to work with the Joint Utilities System Data Working Group on updates to and the consistency of individual utility data portals, as well as refining and/or expanding system data use cases to better meet stakeholder needs. Central Hudson and the JU will also continue engaging stakeholders on business use case discussions, which will continue to provide a forum for further dialogue around improving access to more refined "information sets" developed through analysis/analytic applications. These discussion forums may offer more value to stakeholders than simply directing business developers to the basic data resources they need to derive the required information on their own. As identified in some use case discussions, some of this information may already exist or could be easily created without requiring additional effort and cost to the utilities and their customers. The Joint Utilities System Data Working Group will continue to coordinate with stakeholders and the Joint Utilities Customer Data Working Group to advance the definitions and implications of basic and value-added system data and customer data.

Despite these efforts, it remains the opinion of many stakeholders that DER providers and customers are still unable to efficiently access most of the data that would be useful to them. Without such access, the State will not be able to implement the dynamic, reactive, and efficient distribution system envisioned in REV. As such, the DPS Staff have developed a whitepaper proposing the next steps to enable access to useful energy data.

Central Hudson agrees with the need to provide access to useful energy data to enable achievement of the State's energy policy goals. The timing to provide such access has become urgent with the recent adoption of the CLCPA. Utilities will not be able to efficiently and effectively meet the needs of NY State’s energy industry stakeholders by simply evolving the existing fragmented framework.

While Central Hudson agrees with the premise and will work collaboratively with the DPS Staff and NYSERDA, the Company may not agree with all aspects of Staff's proposal for an IEDR, and associated development, build, and implementation process. Central Hudson applauds the Staff for recognizing the complexities involved in IEDR development and encourages them to remain flexible in order to take advantage of new information during the development process, including knowledge gained or legitimate concerns expressed in comments.

3. 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 system data. There are a number of 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 data refresh and accuracy, 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 refinements to Central Hudson's planning processes to ensure accuracy.

Lastly, Central Hudson will continue to work with DPS, NYSERDA, and the DER Industry Group through the newly established Case 20-M-0082 Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data on the Implementation of an Integrated Energy Data Resources to ensure that the effort made to develop this information and make it publically available is justified. Additionally, future data elements should be thoroughly vetted to ensure that they are needed, used, and are worth the effort to develop, share, and update.

To ensure that this is done effectively and adds value to stakeholders, Central Hudson joined with the other utilities in offering some guiding principles.

- Enhancing customer value should be the guiding principle for designing a statewide data platform.
- The JU recognize 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.

4. Stakeholder Interface

Through the Joint Utility System Data Working Group, extensive stakeholder engagement has been used to progress the understanding of and access to DSP System Data. Since before the 2018 DSIP, the JU has been reaching out to selected stakeholders to invite participation in focused one-on-one discussions to better understand stakeholders' business use for utility system data. There were 15 targeted stakeholder calls and 9 business uses cases developed.

In general, most stakeholders were not fully aware of available system data, nor had they used the utility data portals to explore available system data. In many cases, the data that stakeholders said they needed/wanted was already available. Across the use cases discussed, there were five data types consistently mentioned:

1. Historical load data (feeder/circuit)
2. Forecasted load data (feeder/circuit)
3. Customer demographics (type, load data, tariff)
4. Interconnection costs estimates
5. Reliability Statistics: SAIDI, SAIFI, CAIDI, Outage Cause (feeder/circuit)

Through the JU Stakeholder Interface process, Central Hudson has formed a better understanding of the data elements essential for the development of DERs and the potential additional features that developers might find useful if made available.

5. Additional Detail

a) Identify and characterize each system data requirement derived from stakeholder input.

Table 33 identifies the data requirements derived from stakeholder input during the Joint Utility Use Case discussions. Many of these data elements are already provided by Central Hudson, but others are not currently provided or will not be made publically available. Other elements described in Table 33 are considered Customer Data, but they were identified through stakeholder discussions as necessary for various forms of DER or market development or evaluation.

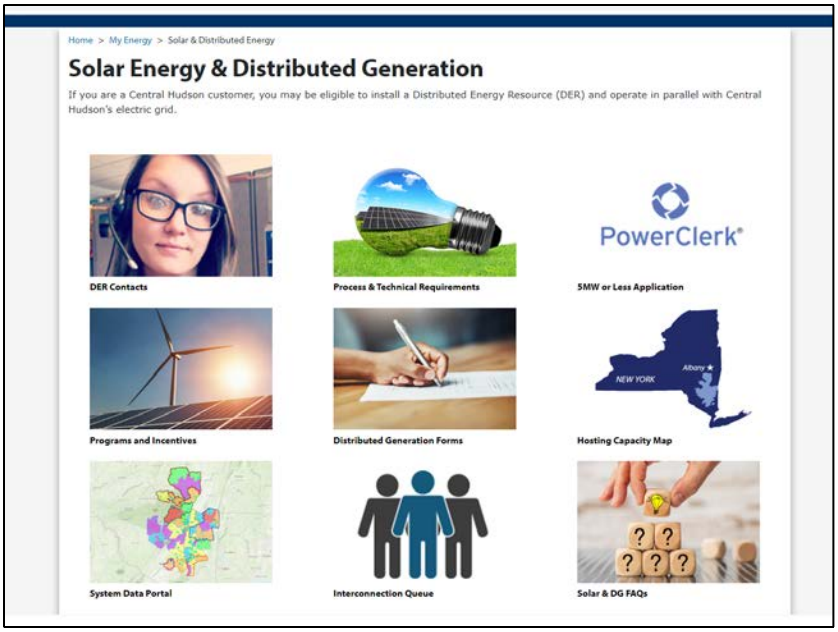
Table 33: Data Requirements Derived from Stakeholder Input

HISTORICAL DATA	FORECASTED DATA	NWA
•Peak (Time + Load) •Load Substation/Feeder/Circuit (Typical load shape, 5-year, 8760 from 1-5 years) •DER Interconnected (number of systems and size) •Reliability statistics: SAIDI, SAIFI, CAIDI, outage cause (5-years by feeder/circuit) •SCADA data	•Peak (Time + Load) •Load (8760 + 5-year) •DER (Solar, EV) •Break out and display EV forecast as in HC maps	• Feeder Location in GIS Map •Load Relief Need (MW and MWh) •Customer Demographics by Feeder (type % and load) •CapEx Plan •Load •Tag Circuit with NWA RFP •Circuit mapping with feeders in need (Microgrid) •Available utility-owned sites
AGGREGATED CUSTOMER DATA	**NETWORK**	**FEEDER / CIRCUIT**
•Customer Count by Rate Class •Historical Load by customer type (feeder, circuit) – NDA to override privacy standard •Load Shape by Customer Type •Tariffs components (intervals, costs by kW, costs by kWh) •Interconnection capacity •Power Quality •Number of residential customer that achieve summer peak > X •Resiliency capabilities and cost estimates to serve customers •Reliability statistics: SAIDI, SAIFI, CAIDI, outage cause	•Distribution Load Flow Models (with NDA and contract) •Network Model for applicable circuits •One-line diagram (Sub-transmission, short circuit) •LMP Node pricing	•Circuit ID # in Map •Conductor size + type •Utility Fault Current Contribution and Impedance @ PCC •Interconnection Costs •Interconnection Queue on Map •Voltage •Circuit Type (i.e. 3-Phase) •Protection requirements, settings •Upgrades / CapEx plans •Pre-Application Report data & Information as a means of estimating interconnection costs before making the formal application •SIR Inventory Information

b) Describe in detail the resources and methods used for sharing each type of distribution system data with DER developers/operators and other third parties.

Central Hudson provides System data primarily through its public website at www.cenhud.com. On the My Energy page in the menu of the home page, 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 36 below). Other data, such as the DSIP regulatory filings, reliability data, Capital Expansion Plans, and DER interconnection data, is included on the Joint Utilities System Data portal at (http://jointutilitiesofny.org/system-data/).

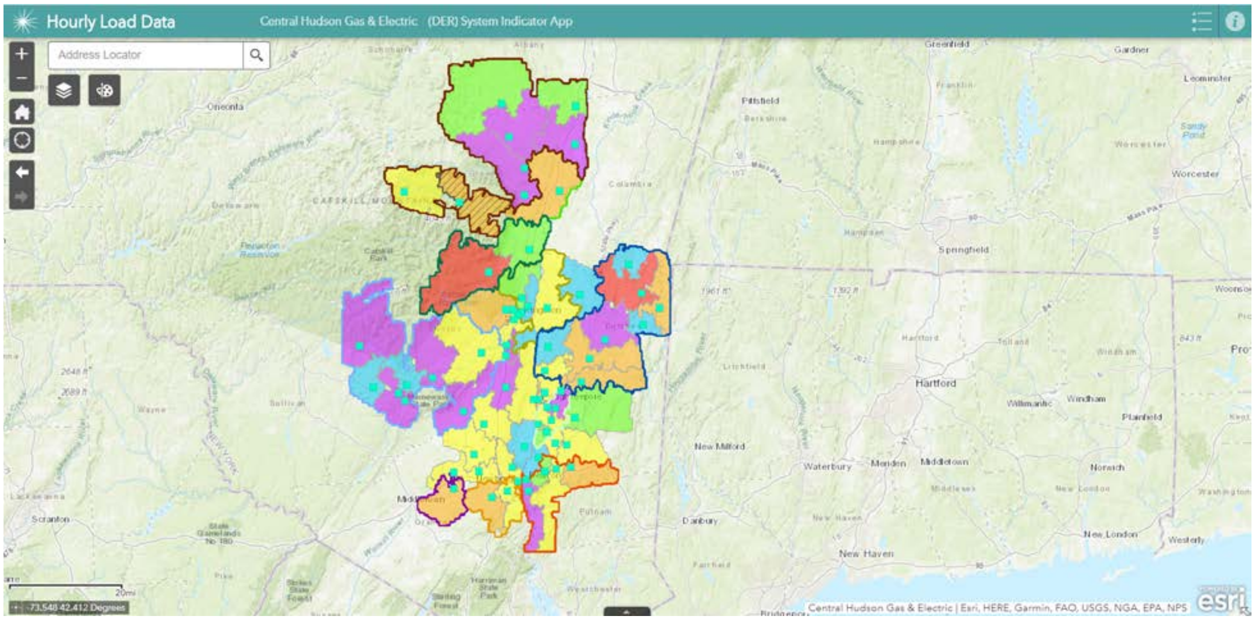
Figure 36: Central Hudson Website – Solder & Distributed Energy Page



c) Describe where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download each type of shared distribution system data.

The System Data portal is a GIS map-based data portal providing historical and forecasted load data by location. See Figure 37 for an example.

Figure 37: System Data GIS Map



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 38 for an example.

Figure 38: Historic and Forecasted Load Example

A1 | *fx* date

	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	tempf_1in	mva_1in2	mva_p01	mva_p05	mva_p10	mva_p25	mva_p50	mva_p75	mva_p90	mva_p95
2	1/1/2013	1	4.816827	0	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	5.624557	0	STAATSBU	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	STAATSBU	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	STAATSBU	2013	1	37.04	5.098444	4.993628	5.024333	5.040702	5.068054	5.098444	5.128833	5.156185	5.172554
14	1/1/2013	13	5.796375	0	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	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	STAATSBU	2013	1	30.02	6.289248	6.159951	6.197828	6.21802	6.25176	6.289248	6.326735	6.360476	6.380667

Data map | **2013** | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | ...

READY

d) Describe how and when each type of data provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

The majority of the system data elements have been in place since the 2016 DSIP filings and the 2017 establishment of the Joint Utilities System Data portal. These data elements have been refreshed through this DSIP Update, and Central Hudson has continued to work with the Joint Utilities, through focused stakeholder sessions, to research new potential data elements as well as best practices in how this data is shared. One such data sharing conversation is with Scenic Hudson, with whom Central Hudson is working to share its system and hosting capacity data through its URL, allowing Scenic Hudson to incorporate this information with its mapping platform. Although there have been follow-up stakeholder sessions to advance the Joint Utility's understanding of the use cases being advanced by various parties, these have not resulted in dramatic changes to the System Data Maps presented with the 2018 DSIPs.

e) Identify and characterize the use cases which involve third party access to sensitive distribution system data and describe how the third party's needs are addressed in each case.

As previously mentioned, the Joint Utilities and stakeholders have co-developed multiple business use cases and identified the "need to have" and "nice to have" data that enables each use case to better understand how data is being used and what data is necessary to meet their needs. Table 34 shows several use cases developed through this process.

Table 34: Use Case Data

#	Use Case	Status
1	Interconnection Cost Estimating – Pre CESIR	Completed
2	Evaluate Development Risks for Potential Projects	Completed
3	Microgrid Development	Completed
4	Integrated Distribution Planning (LMP+D & LNBA)	Completed
5	Prospecting for Development Opportunities (Storage Focus)	Completed
6	Prospecting for Development Opportunities (Non-Storage)	Completed
7/8	Reliability and Resiliency	Completed
9	Estimating Future Market Cost Behaviors	On-hold
10	EVSE Development	Completed
11	Economic Development	Completed
12	EVSE Development – DCFC	In Progress

Within these use cases, there were a few data elements described that were considered sensitive distribution system data, such as distribution load flow models (including conductor size and type, utility fault current contribution and impedance, and protection requirements and settings), network models for applicable circuits, one-line diagrams (sub-transmission, short circuit), LMP node pricing, SCADA data, and various elements of customer-specific data. Most of these data elements were identified as "Nice to Have" data elements. In these cases, the System Data elements would not be made publically available but could be made available to developers through executed CEII-NDAs.

f) Identify each type of distribution system data which is/will be provided to third parties and whether the utility plans to propose a fee.

Table 35 provides a listing of the data currently provided by Central Hudson through its data portals or through links.

Table 35: System Data Currently Provided Without a Fee or Restriction

Data Type	Data Available
Historic Data	Hourly Circuit Load – 7 Years (2013 to 2019) Hourly Substation Load – 7 Years (2013-2019) Hourly Transmission Area Load – 7 Years (2013-2019) Circuit Reliability – 5 years – (2015 to 2019)
Forecasted Data	Hourly Substation Load and DER – 5 Years (2020-2024) Hourly Transmission Area Load and DER – 5 Years Peak System Load and DER – 10 Years (2020-2029) Annual System Energy – 10 Years (2020-2029)
Circuit Data	Circuit ID and GIS location Associated Substation Voltage Number of phases Type (Overhead or Underground) Hosting Capacity (Max and Min)
Substation Data	Substation Name/ID and GIS location Associated Transmission Area Hosting Capacity
DER Data	Interconnected DER – size, type, location DER in Queue – size, type, location
Capacity Data	Circuit Peak Capacity/Design Rating Substation Peak Capacity/Design Rating Transmission Area Peak Capacity/Design Rating Circuit Hosting Capacity Substation Hosting Capacity
Market Data	Beneficial Locations Non-Wire Alternative Areas
NWA Data	Feeder Location Load Relief Needed (MW and year) Customer Demographics Capital Project Avoided
Regulatory	DSIP Filings Capital Expansion Plan

Table 36 provides a listing of data elements request by stakeholders that Central Hudson currently does not provide due to Critical Energy Infrastructure Information (CEII) concerns, customer data privacy concerns, or commercial sensitivity. This data could be provided under confidentiality provisions through an NDA.

Table 36: System Data Requested Not Currently Provided

Data Type	Unavailable Data
Historic Data	SCADA Data Sub Circuit/Nodal Reliability Data Customer Reliability Data
Forecasted Data	Hourly Circuit Load and DER – 5 Years Mapped DER Forecast Hosting Capacity Forecast
Circuit Data/System Elements	Conductor Size/Type Circuit Source Impedance Protection Devices/settings Circuit Models Power Quality Data
Substation Data	Load Flow Models One Line Diagrams
NWA Data	Capital Project Avoided cost Estimate

As for the discussion regarding value added data, the following takeaways were derived from the Joint Utility System Data Working Group stakeholder discussions:

- There did not seem to be much interest in paying for more detailed data;
- There was potential to improve the user experience and provide more analytics both as "basic" and potentially more advanced as "value-added "; and
- The concept of value-added data should be focused on more "processed" information rather than including additional raw, granular data (e.g., downloadable data by feeder/substation).

g) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are highly consistent with the means and methods at the other utilities

As previously mentioned, the Joint Utilities' stakeholder engagement sessions in 2016 identified (1) the desire for and broad value of information and (2) how the utilities could work to enhance what information is provided. In response to stakeholder feedback, the Joint Utilities developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals with available system data. The Joint Utilities' website[35] includes utility-specific links to an expanded range of useful information.

In addition to hosting the links to the enhanced utility-specific web portals, the new Joint Utilities web portal has increased access to and improved the usability of useful stakeholder-requested information. The Joint Utilities have advanced their efforts to release data in more accessible formats, and stakeholders now have a better understanding of the data currently available through utility-specific web portals. 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. Combined, these factors foster market development.

Through the business use case work and stakeholder input, the Joint Utilities are evolving the system data effort to focus more on user experience, data presentation, and potentially more analytic information presentation. The discussions around business use cases have identified that the majority of requested information that is already publicly available but may not be easily accessible and, as a result, the Joint Utilities have enhanced the accessibility and similarity of the information provided, with the understanding that granularity may vary across utilities. In parallel, the Joint Utilities have been able to delve further into the specificity of the information requested by developers and the business reasons behind the requests. Subsequently, the Joint Utilities have made progress in providing additional information that is of greater value to developers. The use case discussions also provide a way to share with stakeholders why certain information may have a low probability of being shared. For example, a piece of information requested may be embedded in utility planning models and is perhaps not readily available for public presentment, requiring further discussion around the need for the data and the

[35] https://jointutilitiesofny.org/system-data/

potential to provide as a value-added service. Central Hudson has not yet established a fixed definition for the fee structures for data requests, but it would likely be related to whether the data is readily available and the level of effort needed to package and deliver the data. Information that is not readily available and requires additional utility effort to prepare would be considered data provided at a fee.

The Joint Utilities System Data Working Group will continue focusing on updates to and consistency of individual utility data portals, as well as refining and/or expanding system data use cases to meet stakeholder needs better. The Joint Utilities will now begin engaging stakeholders in discussions aimed at the development of the Integrated Energy Data Resource, which will provide a forum for further dialogue around potential value-added information and improved access to more extensive and refined information sets. Much of this information already exists or could be easily created without requiring additional effort and cost to the utilities and their customers.

h) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

Central Hudson continues to work with the Joint Utilities to develop consistency in the System Data online portals and the data being shared. As advances and enhancements are made by the individual utilities on the distribution system data that they share and the mechanisms to share this data, these enhancements are being reviewed in the System Data Working Group so that each of the utilities can benefit from them. There are currently some aspects of the distribution system data that are inconsistent among the Joint Utilities in the way they are portrayed or shared, but these inconsistencies are minimal. For example, Central Hudson, unlike many of the other utilities, has not required registration or approval for access to and use of the information provided on its hosting capacity or system data portals. In addition, Central Hudson is willing to share its data through URL to third parties for use and portrayal of this data on their mapping systems without the use of a formal agreement or other restrictions.

H. Customer Data

1. Context and Background

Central Hudson and the Joint Utilities have been actively exploring different ways to improve access to aggregated and customer-specific data to support the development of new energy products and services, while also protecting customers' privacy. The Joint Utilities have continued to evolve customer data sharing procedures, standards, and protocols, and the utilities have taken steps individually to expand data access.

Central Hudson understands the importance of customer data sharing to support the goal of market development. Access to customer data is relevant to many stakeholders, such as customers, DER providers/developers, and institutions. Providing customers with more granular and timely usage and cost data empowers them to make better energy choices. For DER developers, access to customer-specific or aggregated data can help them tailor their products and services and better inform their business prospecting. Finally, customer data can be relevant to local governments (i.e., cities, municipalities), state agencies, and academic institutions to analyze the impacts of policies and create action plans.

As the Joint Utilities continue to advance customer data sharing mechanisms, they share the Commission's interest in strengthening privacy and cybersecurity to protect customers.[36] The protection of utility IT systems and customer information, including energy usage data and personal information provided by the customer, is one of the utilities' responsibilities and commitments to their customers.

The Joint Utilities have worked together to achieve consensus on proposed statewide standards for aggregated[37] and whole-building[38] customer data sharing privacy standards to enhance stakeholder access to data and facilitate business opportunities for third parties, while still protecting customers' privacy rights. As the companies improve their access to customer data through the implementation of

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[36] Case 14-M-0101 *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Staff Proposal Distributed System Implementation Plan Guidance, Issued and Effective October 15, 2015, p. 21.
[37] Cases 16-M-0411 *et al., In the Matter of Distributed System Implementation Plans* ("DSIP Proceeding"), Order on Distributed Implementation Plan Filings, Issued and Effective March 9, 2017 ("DSIP Order"), p. 26.
[38] Cases 16-M-0411 *et al., In the Matter of Distributed System Implementation Plans* ("DSIP Proceeding"),
Joint Utilities' Benchmarking Of Aggregated Customer Data Privacy And Proposed Privacy Standard For Building Energy Management, Issued and Effective June 7, 2017.

new technologies (i.e., AMI), they will continue to evolve data sharing mechanisms and standards that apply to customers and other stakeholders.

2. Implementation Plan

In both its initial DSIP and 2018 DSIP, Central Hudson recognized the importance of the exchange of customer data between entities participating in competitive energy markets and the critical aspect of this exchange in the development of those markets. At the time, Central Hudson identified two broad uses of customer data which are still relevant today:

- **Provision of regulated utility service** – Central Hudson maintains a significant amount of customer data in its customer information system (CIS), which is available to employees and vendors who work in areas such as customer service and energy efficiency, to help them provide high quality, reliable, regulated utility service.

- **Third party availability, including Energy Service Companies (ESCOs)** – Central Hudson provides both individual customer data, with documented customer authorization, and aggregated customer data to ESCOs, either individually or through a Community Choice Aggregation (CCA).

Individual customer data access methods were, and still are, largely dependent on the type of requestor:

- **Individual customer** – Customers can access their data by telephone or through Central Hudson's website. Hourly Pricing Provision ("HPP") customers with demand equal to or greater than 300 kW can access their electric hourly interval meter data by logging onto the large commercial and industrial (C&I) customer portal, which is based on the Itron Energy Manager system.

- **Third party** – Individual customer data is available by telephone, through Central Hudson's website utilizing a custom web transaction (Specific Account Usage Inquiry), or through electronic data interchange (EDI).

It should be noted that method-specific security measures are in place, such as the use of an account number, or user name and password convention, before a customer or third party may gain access to customer data. Additionally, a third party requesting customer-specific data is required to obtain customer authorization and must maintain records of this authorization in compliance with the Uniform Business Practices.

The customer data available to individual customers and third parties is consistent with the data the UBP and DER UBP require Central Hudson to provide to a customer and/or third party, and includes, for gas and electric service as applicable (DER UBP addresses items 1 through 13 only):

1. The customer's service address;
2. An electric or gas account indicator;
3. The sales tax district used by the utility and whether the utility identifies the customer as tax exempt;
4. The rate service class and subclass or rider by account and by meter, where applicable;
5. The electric load profile reference category or code, if not based on service class, Whether the customer's account is settled with the ISO utilizing an actual 'hourly' or a 'class shape' methodology, or Installed Capacity tag, which indicates the customer's peak electricity demand;
6. The number of meters and meter numbers;
7. Whether the customer receives any special delivery or commodity "first through the meter" incentives, or incentives from the New York Power Authority;
8. The Standard Industrial Classification (SIC) code;
9. The usage type (e.g., kWh or therm), reporting period, and type of consumption (actual, estimated, or billed);
10. Whether the customer's commodity service is currently provided by the utility;
11. Twelve months (or the life of the account for accounts less than one year old) of customer data via EDI if an ESCO, and, upon separate request, an additional twelve months (or the life of the account) of customer data, and, where applicable, demand information. If the customer has more than one meter associated with an account, the distribution utility shall provide the applicable information, if available, for each meter;
12. Electronic interval data in summary form (billing determinants aggregated in the rating periods under a distribution utility's tariffs);

13. A weather normalized forecast of the customer's gas consumption (for gas customers) for the most recent twelve months (or life of the account), and the factors used to develop the forecast;

14. The meter reading date or cycle and reporting period;

15. The billing date or cycle and billing period;

16. The life support equipment indicator;

17. A gas pool indicator (for gas customers);

18. The gas capacity/assignment obligation code (for gas customers);

19. The customer's location based marginal pricing zone (for electric customers);

20. A budget billing indicator;

21. Credit information for the most recent 24 months (or life of the account) including the number of times a late payment charge was assessed and incidents of service disconnection; and

22. Usage data and estimated consumption for a period and, upon request, a class load profile for the customer's service class.

Central Hudson provides 24 months of data at no charge upon the request of customers, ESCOs, and other applicable third parties. A customer or third party may request the same data twice within a 12-month period. There is a minimal charge of $15 per request for each additional request during the current 12-month period or for requests for information older than 24 months if it is available. Additionally, a customer, ESCO, or authorized third party can utilize the Specific Account Usage Inquiry web transaction to view 24 months of individual customer usage data. This web transaction is free of charge and can be used multiple times.

A CCA program implementation requires the connecting utility to provide up to three types of datasets: aggregated customer and usage, customer contact, and customer account number. The provision of aggregated customer and usage data is made in accordance with the "15/15"[39] privacy standard for

[39] "15/15"– 15 customer accounts and no one customer can represent more the 15% of the total usage.

aggregated datasets adopted in the Commission's March 9, 2017 DSIP Order. Once a CCA decides to move forward, the utility is required to provide the CCA with customer contact information to support the mailing of opt-out notices, which serve as indirect customer consent for the release of information contained in the third data set. Following the Commission's Order Establishing Community Choice Data Access Fees,[40] uniform fees across utilities of $0.16 per account and $0.64 per account were established for the provision of aggregated data and customer lists, respectively.

On April 20, 2018, the Commission issued its Order in Cases 17-M-0315, 16-M-0411, and 14-M-0224, adopting the Utility Energy Registry (UER) "to promote and facilitate community-based energy planning and energy use awareness and engagement."[41] The UER is an online public platform developed and maintained by the New York State Energy Research and Development Authority to provide access to aggregated community-scale utility energy data. In addition to the initial population of data, the utilities are required to upload data every six months in three layers, including zip code (New York City only), incorporated municipality, and county within three sector groupings. Reported data includes total customer count and CCA ineligible customer count (including count of customers served by an ESCO or with a block on their account and count of TOU customers, but not assistance program participant count due to the sensitivity of that information). Anonymity of data is maintained with a 15/15 privacy standard for residential customer data and a 6/40 privacy standard for small commercial customer data. If a dataset fails the privacy screen the data is rolled into other datasets to protect privacy. The UER now contains four years (2016-2019) of monthly electric and natural gas data.

a) Current Progress

Since the 2018 DSIP, the Joint Utilities have continued to "support making energy consumption and related information available for public use to assist with community-based energy planning, raise energy usage awareness, facilitate effective adoption of DER, and support state and national energy and environmental goals"[42], including:

[40] Cases 17-M-0315, 16-M-0411, and 14-M-0224, In the Matter of the Utility Energy Registry, In the Matter of Distributed System Implementation Plans, Proceeding on Motion of the Commission to Enable Community Choice Programs (UER Proceeding), Order Establishing Community Choice Data Access Fees, Issued and Effective December 14, 2017.

[41] Id., Order Adopting Utility Energy Registry, Issued and Effective April 20, 2018, p. 2.

[42] Id., Joint Utilities' Comments on Utility Energy Registry Status Report, Filed March 23, 2020.

- Collaboration with NYSERDA to develop and file a Memorandum of Understanding (MOU) for the request and transfer of customer data sets for specifically approved purposes;
- Preparation and filing of a report describing the current process for providing aggregated whole building electric and/or gas meter data, upon customer request, for any given building or tax lot, for use in benchmarking;
- Participation in a Staff convened collaborative with a follow up report providing the current status of GBC implementation and detailing the terms and conditions for third-party use of GBC;
- Continued provision of the data necessary to populate the UER;
- Evaluating potential opportunities for aggregated data automation;
- Engaging with stakeholders to solicit feedback and inform future customer data needs and means of accessing that information; and
- Continued collaboration with stakeholders to enhance customer data security controls.

On January 17, 2019 the Commission issued an order generally granting "NYSERDA's request for access to non-participant customer utility data for the specified purposes related to the evaluation and measurement of clean energy programs and analysis related to NYSERDA's responsibilities as established in PAL [Public Authorities Law] and the State Energy Plan."[43] To facilitate access to both participant and non-participant usage data, the Joint Utilities were directed to work with NYSERDA to develop and execute a MOU to govern the transfer of data to and maintenance of data by NYSERDA and its contractors.[44] In fact, customer data has been transferred to NYSERDA under the provisions of this MOU for use by NYSERDA in structuring offerings for low-income participation.

The Commission's Order Adopting Accelerated Energy Efficiency Targets[45] included a requirement for the utilities to file a report addressing their state of readiness regarding three capabilities related to

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[43] Cases 14-M-0094 et al., *Proceeding on Motion of the Commission to Consider a Clean Energy Fund*, Order Regarding New York State Energy Research and Development Authority Data Access and Legacy Reporting, Issued and Effective January 17, 2019, p. 2.
[44] Matter 19-00087, *In the Matter of NYSERDA Data Requests*, Final MOU filed October 3, 2019.
[45] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, Order Adopting Accelerated Energy Efficiency Targets, Issued and Effective December 13, 2018.

benchmarking for building energy performance. These capabilities include provision of aggregated whole building electric and/or gas meter data for any given building or tax lot to an owner, subject to the Commission's anonymity rules, the capability for automated upload of the aggregated energy data, and development, in collaboration with NYSERDA, of a benchmarking offering. In response, the Company, along with a number of utilities, filed a joint report on September 30, 2019 addressing each utility's current provision of such data and their state of readiness for automation. In general, customers currently submit a request for usage information through either a general inquiry received within a utility's contact center or directly through a key account manager within their geographic district.

Central Hudson HPP customers can access their electric hourly interval meter data by logging onto Energy Manager, the large customer portal. All other requests are fulfilled manually, utilizing a standard report format recently developed by the Company, incorporating Commission-established anonymity rules, to streamline the aggregation of usage data from multiple electric and/or gas meters within a template that is compatible with Energy Star Portfolio Manager.[46] Responses are generally provided within one week depending on the complexity of the request and the volume of data requested. Central Hudson's municipal aggregation portal was rolled out in the 2nd quarter of 2020. This portal will give towns and cities throughout the service territory access to their average residential usage and total usage for both electricity and natural gas. This information will be used to create energy challenges (such as a 10% energy reduction challenge) and drive competition with other municipalities to improve their carbon footprint. The portal will also include actionable information to facilitate the adoption of energy efficiency, beneficial electrification, customer-sited renewables, and community distributed generation.

The Energy Efficiency Order also required the Joint Utilities to participant in a collaborative with stakeholders to develop Green Button Connect My Data (GBC) terms and conditions for third-party use. On October 15, 2019, the Joint Utilities submitted a report describing the identified terms and conditions, which started with a description of the status of GBC implementation at each utility. Central Hudson does not offer GBC but offers Green Button Download My Data. The features of GBC are generally preferred in instances where more granular data from AMI meters is available to the majority or all of a utility's customers. At this time, Central Hudson does not have plans to deploy AMI meters on a system-wide basis, nor has there been any material customer interest in voluntary AMI as discussed in Section III.K (Advanced Metering Infrastructure). Additionally, as discussed below, Central Hudson is replacing its

[46] Energy Star Portfolio Manager is a no-cost, online tool developed by the Environmental Protection Agency that can be used to measure and track energy and water consumption, as well as greenhouse gas emissions.

foundational customer information system ("CIS"). Because of the CIS system replacement, any effort to build a GBC interface at this time would require a future rebuild to connect to the new CIS system and would result in unnecessary costs to customers. Until there is greater demand for GBC, which Central Hudson has not experienced, or a system-wide deployment of AMI meters, or complete implementation of the new CIS, Central Hudson does not see GBC as a prudent investment. Once any of these three factors occur Central Hudson will re-evaluate the benefits and costs necessary to enable GBC functionality.

The Joint Utilities have supported the UER since its inception and continue to provide the data necessary for its population. More recently, on March 23, 2020, the Joint Utilities provided comments responsive to the Commission's Notice Soliciting Comments on the Utility Energy Registry Status Report.[47] In these comments, the Joint Utilities support NYSERDA convening a UER working group to provide overall governance for UER and serve as a forum to evaluate protocols, methodologies, and other technical and policy decisions, with participation of various stakeholders. Additionally, the Joint Utilities recommend that this UER working group complement other Commission efforts to evaluate data access needs across the State, in particular the newly instituted Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data[48] (Data Proceeding).

Since the filing of the 2018 DSIP, the Joint Utilities have continued to dedicate considerable effort to the collaborative process for developing a Data Security Agreement (DSA), establishing the minimum cybersecurity and data protection requirements applicable to entities accessing customer data through utility IT systems. This effort has also included a proposed DSA process to maintain such protections to address changing customer data requirements and cybersecurity standards. In compliance with the Commission's Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings,[49] the Joint Utilities filed a revised DS and Self Attestation on December 16, 2019.[50]

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[47] UER Proceeding, Notice Soliciting Comments on the Utility Energy Registry Status Report, Issued January 10, 2020, and NYSERDA's Utility Energy Registry Status Report prepared by Climate Action Associates, LLC, Issued December 30, 2019.
[48] Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data*, Order Instituting Proceeding (Issued and Effective March 19, 2020).
[49] Cases 18-M-0376 et al., *Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place*, Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings, Issued and Effective October 17, 2019.
[50] The Joint Utilities subsequently issued an errata notice on January 8, 2020 correcting inadvertent errors contained in the DSA filed on December 16, 2019.

Finally, the Joint Utilities, in coordination with Staff, NYSERDA, stakeholders and a third-party web-based data platform and analytics developer, completed design of "a pilot resource for compiling and analyzing integrated energy data while protecting utility customer's privacy…that will help DER developers identify, evaluate, and initiate DER development opportunities in New York State."[51] While this database resource currently contains data for only select customers of Orange and Rockland Utilities, Inc., if it proves successful, the Commission may authorize its expansion to include customer, system, and other data for all of the State's investor-owned utilities.

b) Future Implementation and Planning

Central Hudson has launched a major, multi-year system modernization project to replace the current legacy CIS with an enterprise resource planning software package. While this software will still provide the necessary day-to-day process functionality of customer data maintenance and billing, it will move the Company away from a transactional system that merely records data toward a system that will enable the Company to provide customers with more personalized experiences, enhance digital self-service options, increase energy choices, seamlessly integrate distributed generation onto the electric grid, and allow for more robust and efficient data processing functionality. While this project will ultimately improve various business processes, enhance flexibility, and redefine functionality using a customer-centric approach, the enhancement of customer data capabilities within the current CIS system will be significantly limited. Currently, the Company anticipates that the new CIS platform will be operational in the third quarter of 2021, with enhanced customer data functionality following in 2022.

The Joint Utilities will continue to engage stakeholders to identify and evaluate additional customer data datasets and process improvements that can support greater customer choice, DER market development, and the broader REV and clean energy objectives. While it is anticipated that activity will continue in the numerous aforementioned proceedings, the newly initiated Data Proceeding will provide a comprehensive and unified forum for addressing the strategic use of energy related data. In particular, the Joint Utilities will need to address the recommendations included in the two Staff whitepapers[52] issued May 29, 2020 in the Data Proceeding: (1) the Data Access Framework Whitepaper which proposes a framework that "would serve as a single source for data access policies and provides uniform and

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[51] Cases 18-E-0130 et al., *In the Matter of Energy Storage Deployment Program*, Notice Announcing the Pilot Integrated Energy Data Resource, Issued January 14, 2020, pp. 1-2.

[52] Data Proceeding, Department of Public Service Staff Whitepaper Regarding a Data Access Framework (Data Access Framework Whitepaper), Issued May 29, 2020 and Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource (IEDR Whitepaper), Issued May 29, 2020.

consistent guidance on what is needed for access to, and the availability of, energy-related data,"[53] and (2) the IEDR Whitepaper which generally recommends the implementation of an IEDR "to collect and integrate a large and diverse set of energy-related information on one statewide data platform."[54] Central Hudson will also continue to evaluate the potential for additional customer data beyond Green Button Download My Data. In addition, the Customer Data Working Group will continue to monitor other relevant proceedings such as the privacy standards proceeding, the UER, and the Value Stack proceeding and coordinate with other groups, such as the DER Sourcing Working Group and System Data Working Group.

3. Risks and Mitigation

The Joint Utilities continue to discuss cybersecurity standards with stakeholders, including customers, ESCOs, EDI Providers, Direct Customers, and DER Suppliers. The continued development of competitive markets increases the electronic communications between utilities and competitive providers, and therefore, cybersecurity risks. With the support of the Commission as enunciated in Case 18-M-0376, business to business discussions are underway to refine and implement current standards through DSAs under the authority of the UBP and DER UBP.

Risk mitigation will take the form of information technology security standards required of all parties, confidential data protection standards, contractual liability protection, and cyber insurance. For a more comprehensive discussion of cybersecurity, see the cybersecurity section of this report.

4. Stakeholder Interface

Central Hudson has continued to work with the Joint Utility Customer Data working group to reach out to additional interested stakeholders to co-develop business use cases for customer data, in order to develop a deeper understanding of the need and use for various types of customer data, including public availability, private availability, and possible value-added data elements.

Additionally, Central Hudson will continue to work with stakeholders through the Customer Data Working Group or the ongoing customer data related proceedings such as the privacy standards, the Utility Energy Registry (UER), the Value Stack, and the Data Proceeding.

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[53] Data Access Framework Whitepaper, p. 2.
[54] IEDR Whitepaper, p. 2.

5. Additional Detail

a) Date Types, Description and Management Processes

(1) Describe the type(s) of customer load and supply data acquired by the utility.

Central Hudson acquires customer load (use) and supply injection data by capturing information that is measured and recorded by the customer meter(s). These can be interval, AMI, and/or register-read meters. There are differences in the type and granularity of the customer load and supply data acquired based on customer type, existing metering, and the extent to which AMI has been adopted by the customers. Generally, larger C&I customers will have additional data such as demand (kW) and reactive power (VAR) data for billing under the applicable tariff, with the largest C&I customers having hourly interval usage data available. As Central Hudson implements new technologies such as AMI, more granular (interval) data will be available, and data sharing mechanisms and standards will evolve as appropriate.

(2) Describe the accuracy, granularity, latency, content, and format for each type of data acquired.

See response to a) above.

(3) Describe in detail the utility's means and methods for creating, collecting, managing, and securing each type of data.

See response to a) above.

b) Data Uses, Access and Security

(1) Describe the means and methods that customers and their properly designated agents can use to acquire their load and supply data directly from their utility meters without going through the utility, should they want to.

While direct access to meters is not provided, customers can access their data by telephone or through Central Hudson's website. Hourly Pricing Provision ("HPP") customers with demand equal to or greater than 300 kW can access their electric hourly interval meter data by logging onto the large commercial and industrial (C&I) customer portal, which is based on the Itron Energy Manager system. Customers subscribing to Central Hudson's Insights+ program can view daily and hourly energy consumption using the Insights+ dashboard.

(2) Identify and characterize the categories of legitimate users beyond customers and their properly designated agents who will be provided access to each type of data.

Central Hudson, through the Joint Utilities, has been proactively engaging with stakeholders to review proposals for providing aggregated customer data consistent with customer privacy standards and improve the type of data and the process for accessing customer-specific data with proper customer authorization. In addition, the Joint Utilities are actively conducting one-on-one conversations with DER developers to better understand their specific customer usage data needs, share current practices, and inform their future data-sharing plans. Through the targeted conversations, Central Hudson understands the underlying basis for the requests and stakeholders gain better insight into the information currently available and how to access it.

The UER online public platform developed and maintained by the New York State Energy Research and Development Authority provides access to aggregated community-scale utility energy data. Central Hudson's municipal aggregation portal provides towns and cities throughout the service territory access to their average residential usage and total usage for both electricity and natural gas.

(3) For each type of data, describe how its respective users will productively apply the data and explain why the data provided will be sufficient to fully support each type of application.

Through collaboration with Staff and stakeholders, the Joint Utilities are finalizing development of a process for sharing aggregated data for whole buildings and refining the municipal level data available through the UER. These offerings will allow building owners to better manage and benchmark their building energy usage and communities to make informed decisions on community-based Distributed Generation Projects, Energy Choice Aggregation programs, and Energy Efficiency initiatives. The information available through the municipal aggregation portal can be used to create energy challenges (such as a 10% energy reduction challenge) and drive competition with other municipalities to improve a municipality's carbon footprint. The portal will also include actionable information to facilitate the adoption of energy efficiency, beneficial electrification, customer-sited renewables, and community distributed generation.

(4) For each type of data, describe in detail the utility's policies, means, and methods for securely providing legitimate users with efficient, timely, and useful access to the data. Include information which thoroughly describes and explains the utility's approach to providing customer data to third parties who would use the data to identify and design service opportunities which benefit the utility and/or its customers.

Method-specific security measures are in place, such as the use of an account number, or user name and password convention, before a customer or third party may gain access to customer data. Additionally, a third party requesting customer-specific data is required to obtain customer authorization and must maintain records of the authorization in compliance with the UBP and DER UBP.

(5) Describe how the utilities are jointly developing and implementing uniform policies, protocols, and resources for controlling third party access to customer data.

The Joint Utilities continue to actively work through numerous processes to develop and implement uniform policies and approaches in response to Commission and stakeholder requests through the use case conversations with DER developers. Since the 2018 DSIP, the Joint Utilities have actively collaborated with stakeholders to advance several customer data efforts, including:

- The filing of an MOU for the request and transfer of customer data sets to NYSERDA for specifically approved purposes;
- Documenting and filing a report describing the current process for providing aggregated whole building electric and/or gas meter data, upon customer request, for any given building or tax lot, for use in benchmarking;
- Participation in a Staff convened collaborative with a follow up report providing the current status of GBC implementation and detailing the terms and conditions for third-party use of GBC; and
- Continued collaboration with stakeholders to enhance customer data security controls.

Currently, there are several channels that share customer data with customers and authorized third parties. These include utility bills, GBD, EDI, UER, SFTP, File Transfer Protocol with PGP Encryption, online third-party data platforms, and the data identified in DER UBP.

(6) Describe in detail the utility's policies, means, and methods for rigorously anticipating data risks and preventing loss, theft, or corruption of customer data.

Central Hudson maintains a comprehensive cybersecurity program, as described in Section III.I (Cyber Security).

(7) Identify each type of customer data which is/will be provided to third parties at no cost to the recipient, and the extent to which the practice comports with DPS policies in place at the time, as appropriate.

The Commission-approved UBP and DER UBP provide detailed lists of the customer-specific data that is available to third parties at no cost (see Section III.H X.B).

(8) Identify each type of customer data which the utility proposes to provide to third parties for a fee, and the extent to which the practice comports with DPS policies in place at the time, as appropriate. For each data type identified, describe the proposed fee structure and explain the utility's rationale for charging a fee to the recipient.

Central Hudson provides 24 months of data at no charge upon the request of customers, ESCOs, and other applicable third parties. A customer or third party may request the same data twice within a 12-month period. Pursuant to the Company's Commission-approved tariffs, P.S.C. No. 15 – Electricity and P.S.C. No. 12 – Gas, respectively, there is a minimal charge of $15 per request for each additional request during the current 12-month period and requests for information older than 24 months, if it is available. Additionally, a customer, ESCO, or authorized third party can utilize the Specific Account Usage Inquiry web transaction to view 24 months of individual customer usage data. This web transaction is free of charge and can be used multiple times.

A CCA program implementation requires the connecting utility to provide up to three types of datasets: aggregated customer and usage, customer contact, and customer account number. Once a CCA decides to move forward, the utility is required to provide the CCA with customer contact information to support the mailing of opt-out notices, which serve as indirect customer consent for the release of information contained in the third data set. Per the Commission's December 14, 2017 Order Establishing Community Choice Data Access Fees in Cases 17-M-0315, 16-M-0411, and 14-M-0224, uniform fees across utilities of $0.16 per account and $0.64 per account were established for the provision of aggregated data and customer lists, respectively.

(9) Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are highly consistent with the means and methods at the other utilities, and the extent to which these practices comport with DPS policies in place at the time, as appropriate.

The Joint Utilities are working together to develop a statewide standard in phases, with the understanding that utilities will have different starting points. Utilities implementing full AMI solutions plan to provide basic customer usage data to customers via online platforms and to customer-authorized third parties using the GBC standard or a comparable specification. Utilities not implementing full AMI solutions expect to provide basic customer usage data to end-users via GBD or an alternative specification. The Joint Utilities will continue to leverage existing platforms, including GBC, EDI, SFTP, and online customer engagement platforms.

(10) Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

Central Hudson's access to customer data is primarily consistent with other utilities, except that Central Hudson does not yet offer Green Button Connect but does offer Green Button Download My Data. This functionality is available through CenHub. The features of Green Button Connect are generally preferred in instances where data from AMI meters is available to the majority or all of a Utility's residential customers. At this time, Central Hudson does not have plans to deploy AMI meters on a system-wide basis. Until there is greater demand for Green Button Connect or a system-wide deployment of AMI meters is implemented, the Company does not see Green Button Connect as a prudent investment.

c) Green Button Connect Capabilities

(1) Describe where and how DER developers, customers, and other stakeholders can readily access up-to-date information about the areas where customer consumption data provided via Green Button Connect (GBC) is available or planned.

Central Hudson does not yet offer Green Button Connect but does offer Green Button Download My Data. This functionality is available through CenHub.

(2) Describe how the utility is making customers and third parties aware of its GBC resources and capabilities.

Central Hudson actively markets its customer data functionality and other features through its one-stop customer interface CenHub.

(3) Describe the utility's policies, means, and methods for measuring and evaluating customer and third-party utilization of its GBC capabilities.

There are currently a very limited number of Green Button applications available via the Google Play Store and Apple's App Store. The applications offered provide some of the functionality already available through CenHub. Central Hudson does not yet offer Green Button Connect. Significant investment is required by Central Hudson and website host partners to enable Green Button Connect functionality, and no Central Hudson customers have requested to enable Green Button Connect. Central Hudson has been monitoring the use of the Green Button Download My Data feature over the life of CenHub and it is minimal. Additionally, the features of Green Button Connect are generally preferred in instances where data from AMI meters is available to the majority or all of a Utility's residential customers. At this time, Central Hudson does not have plans to deploy AMI meters on a system-wide basis. Until there is greater demand for Green Button Connect or a system-wide deployment of AMI meters is implemented, the Company does not see Green Button Connect as a prudent investment.

I. Cyber Security

1. Context and Background

Cybersecurity and the prevention of security breaches and cyber events is an essential responsibility and priority of the Joint Utilities. The Supplemental DSIP outlined a common and comprehensive approach to managing cybersecurity risks in the evolving REV environment. The Joint Utilities' Cyber and Privacy Framework focuses on the people, processes, and technology needed to maintain data security. The Framework requires the implementation of an industry-approved risk management methodology and alignment of control implementations with the control families in the National Institute of Standards and Technology ("NIST") Special Publication (SP) 800-53 Revision 4. The Joint Utilities periodically assess the need for updates to the Framework. The current version, as filed in the Supplemental DSIP, remains relevant with no updates required.

In the Supplemental DSIP, the Joint Utilities committed to maintain individual cyber and privacy management programs and participate in industry working groups, including the New York State Security Working Group (NYS SWG). The Joint Utilities also agreed to share lessons learned and advancements in security technology among themselves. The Joint Utilities continue to meet to discuss multiple security topics, lessons learned, current threats, and future regional exercises.

Central Hudson's Cyber Security Executive Committee ("CSEC") serves as a governance committee that oversees the enterprise-wide cybersecurity program. The program consists of a strategic plan, policies and procedures, security controls, a risk management program, a security awareness program, incident response, third-party security and privacy reviews, security assessments, administering and monitoring security tools, and methods to address and resolve security alerts. There are four groups that work closely together to protect Central Hudson's information assets, which consist of customer information, utility information, critical infrastructure information, and information technology systems. These groups are Cyber Security, Corporate Security, IT Technical Support, and Operational Technology.

2. Implementation Plan

a) Current Progress

Central Hudson continues to assess its cybersecurity program for further enhancements. In addition to regularly scheduled security assessments, Central Hudson developed a formal cybersecurity risk assessment methodology in 2018 based off of the NIST Cybersecurity Framework, International Organization for Standardization's Security Standard 27001. In 2019, Central Hudson performed an assessment based on this risk methodology and utilized the results to develop a plan to continue to enhance its cybersecurity program.

In 2019, Central Hudson was successfully audited by the Northeast Power Coordination Council (NPCC) on Version 5 of the NERC CIP Standards. Additionally, since the original DSIP filing in 2016, Central Hudson continues to develop and deploy internal standards for the Cyber Security of Operational Technology (CSOT) to protect Operational Technology assets enterprise-wide that are not within the scope of NERC CIP Standards.

b) Future Implementation and Planning

Central Hudson continues to implement identified cybersecurity initiatives and review its privacy initiatives for opportunities to enhance the cybersecurity initiatives identified in the 2016 DSIP filing. Central Hudson is in the process of implementing a System Information and Event Management (SIEM) solution and a Network Access Control (NAC) solution, which will be utilized to enhance its vulnerability management program and increase network segmentation.

As DSIP initiatives are planned and designed, and DER providers look to connect to Central Hudson's grid, cybersecurity requirements will be incorporated into the contractual language and riders before connection to CH resources.

3. Risks and Mitigation

The main risks pertaining to DSIP cybersecurity initiatives are:

- Unauthorized access to confidential customer or utility data;
- Unauthorized disclosure of confidential customer or utility data;
- Unavailability of critical or significant systems; and
- Unavailability to perform a business service.

Central Hudson has assessed these risks in its environment and has controls in place to mitigate them properly. As part of the planning and design phase of a DSIP initiative, additional risks may be identified. The Central Hudson cybersecurity team will assess these risks and implement appropriate controls to properly mitigate those risks, regardless of who is responsible for the controls – Central Hudson or a third party.

4. Stakeholder Interface

As stakeholders propose new or existing DERs that will interface with Central Hudson's internal communication network and monitoring and control assets, cost-sharing proposals will be provided for communication needs, and stakeholders will be provided with preliminary cybersecurity requirements subject to alteration and finalization as additional details of planning and design are completed, based on the risk to data and grid operations. Cybersecurity requirements will be revised as required by legal, regulatory, and technical advancements.

5. Additional Detail

a) Describe in detail the utility policies, procedures, and assets that address the security, resilience, and recoverability of data stored and processes running in interacting systems and devices which are owned and operated by third-parties (NYISO, DER operators, customers, and neighboring utilities). Details provided should include:

The Joint Utilities (JU) have created a framework (JU Framework) to guide New York Utilities as they develop their own governance and risk management process to address cybersecurity and privacy risks that may arise from any REV related initiative. Central Hudson continues to leverage that framework to enhance its current cybersecurity and privacy programs. Minimum requirement guidelines are outlined below; additional requirements will be addressed during planning and design to effectively address Central Hudson's specific cybersecurity concerns based on the plan submitted by the third party.

(1) the required third-party implementation of applicable technology standards;

Third parties will be required to have appropriate controls in place, based on industry-recognized best practices, to protect customer and utility information, grid operations, and operational and information technology systems. Some examples of industry-recognized best practices are the Energy Sector's Cybersecurity Capability Maturity Model (C2M2), NIST Special Publications or Cyber Security Framework, International Organization for Standardization (ISO) 27001, Control Objectives for Information and Related Technologies (COBIT), NERC Critical Infrastructure Protection (CIP), Central Hudson's Cyber Security of Operational Technology, and the JU's own Cyber Security Framework.

(2) the required third-party implementation of applicable procedural controls;

Third parties will be required to have appropriate controls in place, based on industry-recognized best practices, to protect customer and utility information, and grid operations and information technology systems. Some examples are the Energy Sector's C2M2, NIST Special Publications or Cyber Security Framework, ISO 27001, COBIT, or the JU's own Cyber Security Framework.

(3) the means and methods for verifying, documenting, and reporting third-party compliance with utility policies and procedures;

The third party must provide formal attestations, evidence, and allow for annual compliance audits. Central Hudson will review compliance for representative third parties.

(4) the means and methods for identifying, characterizing, monitoring, reporting, and mitigating applicable risks;

The third party must have a documented risk identification and mitigation program that is assessed at least once a year.

(5) the means and methods for testing, documenting, and reporting the effectiveness of implemented security measures;

The third party must complete scheduled assessments of implemented security measures or provide Central Hudson with an independent third-party audit report, such as SOC II or its equivalent, assessing the security measures.

(6) the means and methods for detecting, isolating, eliminating, documenting, and reporting security incidents; and,

The third party must have a documented Cyber Security Incident Response Plan. Central Hudson requires notification within a reasonable timeframe after a third party discovers a potential cybersecurity incident to prevent any harmful impact to Confidential Customer or Utility Information, grid operations, OT or IT systems.

(7) the means and methods for managing utility and third-party changes affecting security measures for third-party interactions.

The third party must have a documented change management process that includes notifying Central Hudson of any changes that occur within a reasonable timeframe. For changes that will have a critical or significant impact on the operation of systems, the third party must notify Central Hudson before making the change so that Central Hudson may assess the risk associated with the change.

b) Describe in detail the security, resilience, and recoverability measures applied to each utility cyber resource which:

(1) contains customer data;

(2) contains utility system data; and/or,

Central Hudson has a Cybersecurity Policy, Cybersecurity Incident Response Plan, and a Disaster Recovery Plan. The Incident Response and Disaster Recovery plans are tested annually. These plans are consistent with good utility practice and industry standards to minimize the risk of cyber events and confirm the ability to recover from an event. Central Hudson has primary and backup EMS and DMS, redundancy in the communication network, and primary and backup power supplies.

(3) performs one or more functions supporting safe and reliable grid operations.

Central Hudson has security, resiliency, and recoverability measures as required by the North American Electric Reliability Corporation Critical Infrastructure Protection plan (NERC CIP). Additionally, for non-NERC CIP assets that may contain functions supporting safe and reliable grid operations below the threshold of applicability to the Bulk Electric System (BES), Central Hudson has established Cyber Security of Operational Technology (CSOT) Standards. The processes and procedures for these standards are in progress by designated Subject Matter Experts.

c) For each significant utility cyber process supporting safe and reliable grid operations:

(1) Provide and explain the resilience policy which establishes the utility's criteria for the extent of resource loss, damage, or destruction that can be absorbed before the process is disrupted;

Central Hudson has procedures in place that serve to mitigate the impact of a resource loss or the damage or destruction of a critical asset. Central Hudson has security controls and tools in place to monitor and alert on the systems utilized in grid operations. The alerts will be reviewed by Central Hudson analysts and addressed as needed. Depending on the severity of the alert, Central Hudson may activate its Incident Response Plan to minimize the potential impact on grid operations. If a situation warrants the shutdown of a critical asset at the primary location, Central Hudson has a Disaster Recovery Plan to restore the system at a secondary location.

(2) Provide and explain the recovery time objective which establishes the utility's criteria for the maximum acceptable amount of time needed to restore the process to its normal state;

Central Hudson has recovery time objectives for critical assets defined in its Disaster Recovery Plans. The recovery time objectives are determined based on the impact downtime will have on Central Hudson's operations.

(3) Provide and explain the plan for timely recovery of the process following a disruption; and,

Central Hudson's Disaster Recovery Plans were developed to provide for the timely recovery of critical assets. While an asset is down, Central Hudson has Business Continuity Plans to allow for continuity of business operations.

(4) Describe each process, resource, and standard used to develop, implement, test, document, and maintain the plan for timely process data recovery.

Central Hudson's Incident Response, Disaster Recovery, and Business Continuity Plans are reviewed on an annual basis and updated as needed. These plans are tested annually, and any lessons learned are incorporated into the plans.

d) Identify and characterize the types of cyber protection needed for strongly securing the utility's advanced metering resources and capabilities. Describe in detail the means and methods employed to provide the required protection.

Central Hudson is conducting a demo project for advanced metering. This project's resources were assessed for security compliance. These resources are not planned to directly interface with any Central Hudson assets and will continue as a data-sharing project only.

e) Identify and characterize the requirements for timely restoring advanced metering resources and capabilities following a cyber disruption. Describe in detail the means and methods employed to provide the required recovery capabilities.

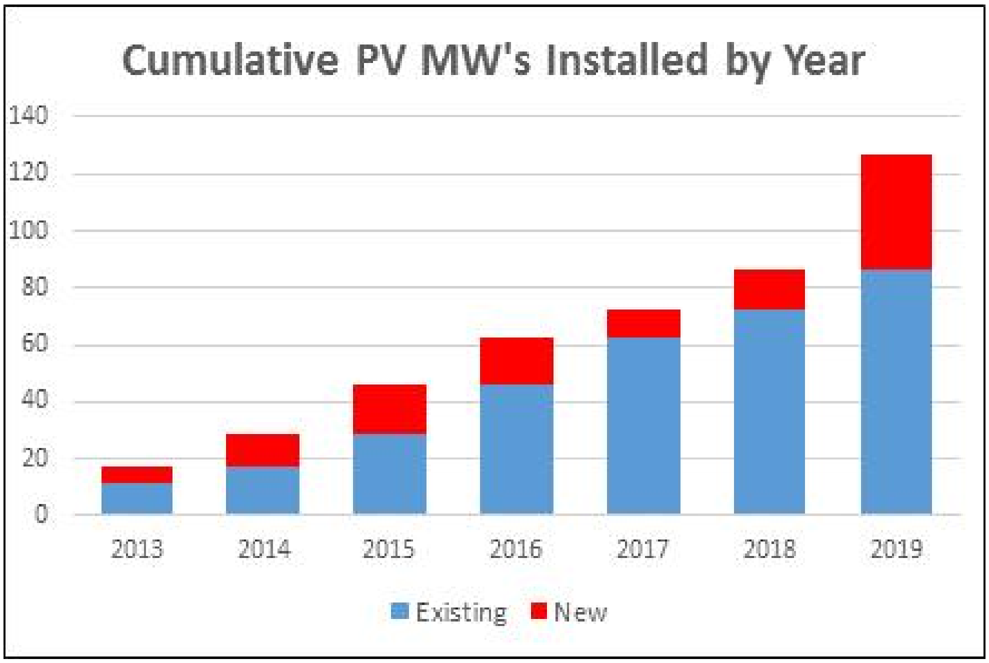
Central Hudson has incorporated contractual terms with the third party, which address cyber disruptions and ensure the availability of resources.

J. DER Interconnections

1. Context and Background

Since the 2018 DSIP filing, Central Hudson has continued to process interconnection applications within the required timelines specified in the New York State Standardized Interconnection Requirements (NYSSIR). Figure 39 below shows the cumulative growth in MWs for solar photovoltaic (PV) installed from 2013-2019. The majority of Distributed Energy Resources (DER) applications within the service territory are solar photovoltaic (PV); however, Central Hudson is also experiencing an increase of Energy Storage System (ESS) applications. In 2019, of the total MWs installed, approximately 99% were PV or a hybrid of PV + ESS.

Figure 39: PV MW's Installed 2013-2019



As described in the 2018 DSIP, there was a substantial increase of large applications (nameplate ratings > 300kW) submitted in 2015 and 2016 due to the launch of the Community Distributed Generation program in NY State. While the PSC's Order Adopting Interconnection Management Plan[55] (Queue Management Order) and updates to the NYSSIR have enabled a more timely progression of the queue, Central Hudson began seeing an increase in large applications again towards the end of 2017. This was a result of the March 2016 NYSSIR[56] update and subsequent March 2017 VDER[57] Orders to update the threshold from 2MW to 5MW. Since this change, the number of larger DER applications submitted has continued to increase substantially. 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 2015-2019.

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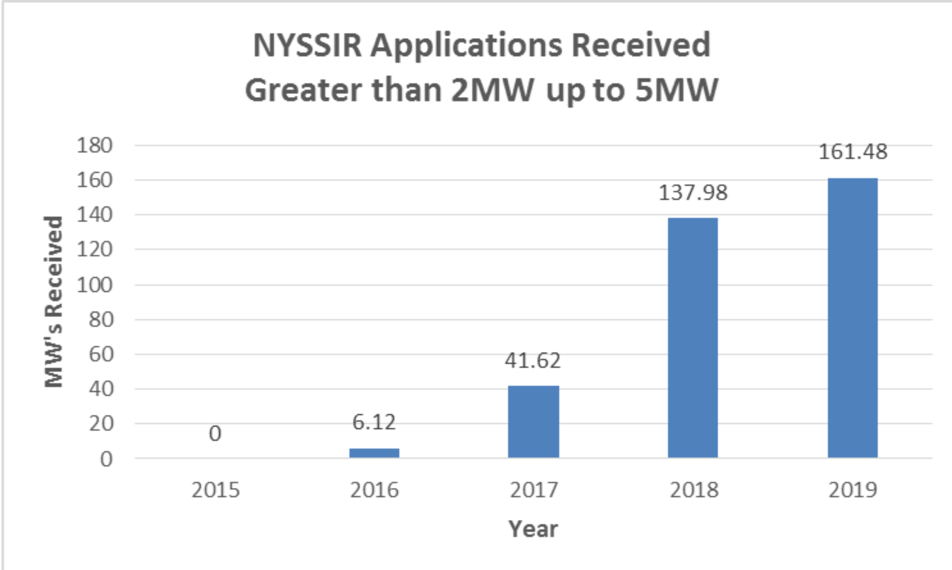
[55] "Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, And Making Other Findings", State of New York Public Service Commission, January 25, 2017, Case 16-E-0560, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={22BEAB22-7F9F-45B8-89FD-0E8AD84692B4}, pp.4-9, 22-28.

[56] "Order Modifying Standardized Interconnection Requirements", State of New York Public Service Commission, March 18, 2016, Case 15-E-0557, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6A1ABD8B-5D69-4745-9A64-03B36C38736D}, pp. 2, 13, 25, 27, 28, 33

[57] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", State of New York Public Service Commission, March 9, 2017, Case 15-E-0751, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FD2886CF-87D6-4F02-A252-95F9094A2CED}, p. 194

Figure 40: NYSSIR Applications Received Greater than 2MW up to 5MW



Additionally, Central Hudson has seen an increase in NYISO interconnection requests starting in 2018. Table 37 below illustrates the number of interconnection and pre-application requests received over the last ten years. Prior to 2018, the Company processed approximately 295MWs of proposals; from 2018 to present, the Company has experienced approximately 1,235MWs of proposals.

Table 37: NYISO Interconnection and Pre-Application Requests

Year	Interconnection Requests	Pre-Application Requests
2009	1	0
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	2	0
2015	0	0
2016	3	0
2017	6	8
2018	9	5
2019	10	9

While the NYISO projects follow a separate process and have primarily proposed to interconnect to the transmission system, some of these DER systems have requested service on medium voltage substation 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 is experiencing increased penetration levels in localized areas of the service territory. This complicates the review process and presents queue coordination issues (i.e., coordination among the NYSSIR, New York Independent System Operator ("NYISO"), and Central Hudson queues). To resolve the queue coordination issues, Central Hudson worked with the NYISO, other New York Transmission Owners (TOs), and DPS Staff to establish a guideline on base case inclusion rules that help facilitate coordination among the various interconnection queues. A straw proposal, Coordination of Inclusion Rules for Interconnection Queues[58] ("Inclusion Rules"), was completed in December 2018. Stakeholder input was received from members within the ITWG and IPWG. As Central Hudson has seen a high penetration of DER projects within localized areas, the Company has been applying the Inclusion Rules to each of the three queues.

Since the 2018 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 PSC's March 9, 2017 DSIP Order[59] (DSIP Order). The IOAP continues to successfully run and allows DER developers to submit interconnection applications electronically. Along with the inclusion of ESS into the April 2018 updated NYSSIR[60] and Material Modifications in the December 2019 updated NYSSIR[61] to address

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[58] "Straw Proposal Coordination of Inclusion Rules for Interconnection Queues", December 31, 2018, http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/Straw%20Proposal-Coordination%20of%20Inclusion%20Rules%20for%20Interconnection%20Queus%20-%20Draft.pdf

[59] "Order On Distributed System Implementation Plan Filings", State of New York Public Service Commission, March 9, 2017, Case 16-M-0411, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F67F8860-0BD8-4D0F-80E7-A8F10563BBA2}, pp. 15-18.

[60] "Order Modifying Standardized Interconnection Requirements", State of New York Public Service Commission, April 19, 2018, Case 15-E-0557, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={83E4738F-38C2-4995-9EC8-D5ABEF5B20CD}

[61] "Order Modifying Standardized Interconnection Requirements", State of New York Public Service Commission, December 13, 2019, Case 19-E-0566, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={58CA1F06-72C4-488D-A69B-EDCA9CB1F2D6}

changes to existing projects in queue, various IOAP updates have been completed since the 2018 DSIP update. As a result of the continued enhancements and required updates, a full-time Program Designer is employed to manage and maintain updates in the IOAP.

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 Interconnection Technical Working Group (ITWG) and Interconnection Policy Working Group (IPWG). Since the 2018 DSIP, these groups have continued to meet on a bi-monthly and monthly basis respectively, focused on modifying interconnections requirements and processes based on industry concerns and benchmarking with other utilities outside of NY. These groups have also worked together to develop various joint guidelines and regulatory filings and have allowed for modifications to existing interconnection requirements including:

- Evaluating appropriate screens for updating the NYSSIR, including flicker impacts
- Standardized preliminary screening and CESIR templates
- Submitting a joint proposal between NY Utilities and DER Developers for an updated NYSSIR
- Established requirements for Material Modifications and developed a guidance document for developers
- Reformatted Appendix K to better suit the information needs surrounding ESS projects
- Established different metering options and configurations for hybrid systems
- Developed standard pricing matrix for CESIR studies, including cost drivers, as well as standard upgrades
- Developed secondary network screens to NYSSIR
- Established Joint Utility Inclusion rules for SIR and NYISO project queue coordination

Lastly, since the 2018 DSIP filing, Central Hudson has continued to maintain and improve hosting capacity maps for 12kV feeders. Details regarding Hosting Capacity efforts and results can be found in Section III.L. However, the hosting capacity at the substation and transmission level is not yet available due to its significant complexities and prioritization in the roadmap.

2. Implementation Plan

a) Current Progress

Central Hudson continues to refine and improve the IOAP as more experience is gained, using the software and new updates provided by Clean Power Research. Since the 2018 DSIP, Central Hudson has implemented the following improvements to the portal; updated statuses and deadlines to differentiate between utility and applicant for added responsibility clarification, updated fields and timelines in accordance with each NYSSIR update, added energy storage data collection fields, and configured various additional automations to further reduce manual interactions.

As the April 19, 2018 PSC Order[62] directed the NY Joint Utilities to begin efforts for Phase 2 implementation of the IOAP, Central Hudson began working with Clean Power Research on the scope of work for integrating PowerClerk with DEW in April 2018. One of the prerequisites to meeting Phase 2 requirements was to establish a link between the Distribution Engineering Workstation (DEW) load flow software and Central Hudson's ESRI GIS system. This link was implemented in April 2019. The goal of Phase 2 of the IOAP is to automate the technical screening analysis, such that when a customer submits an application using the PowerClerk software online, the IOAP will link to DEW, pull the correct circuit model from Central Hudson's server, and run a load flow analysis to compute the results for Preliminary Screens A to F in the NYSSIR. These results will then be transferred back to PowerClerk. This work requires construction of additional fields and statuses within the IOAP as well as the development of various use cases to be tested in order to ensure the automation is working as intended. The mechanisms used to automate the applicable NYSSIR screens are currently in place. Central Hudson is upgrading to a new ESRI GIS version which requires the link to DEW to undergo additional quality assurance testing. Final acceptance testing and a move into production is expected to take place by the end of July 2020. Full automation however, will be in service once ESRI GIS model quality assurance is complete.

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

[62] "Order Modifying Standardized Interconnection Requirements", State of New York Public Service Commission, April 19, 2018, Case 18-E-0018, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={83E4738F-38C2-4995-9EC8-D5ABEF5B20CD}, pp. 21.

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:

- Smart Inverters
- Effectiveness of Updated NYSSIR Screens
- Primary CT accuracy/range issues for Hybrid projects
- CESIR analysis methods
- Reviewing timelines for required documentation during the application process
- Reevaluating cost sharing techniques
- Prioritizing remaining efforts on energy storage roadmap

Working jointly with other NY utilities, Central Hudson implemented Stage 3 and 3.1 Hosting Capacity to provide more granular hosting capacity values, as well as including existing interconnected DER. Details on current hosting capacity efforts can be found in Section III.L.

Due to the significant increase in applications for large solar PV system, as well as a focus on inverter-based applications, Central Hudson recognized the need to update the Company's Interconnection Guidelines. Central Hudson completed the update of the interconnection guidelines in December 2019. The document has also been publicly posted on the Company's Distributed Generation website for reference by developers. This document has also been filed with FERC as part of the 2020 Form 715 filing. Developers now have a more accurate technical guidance document for connecting to the Central Hudson system. Central Hudson plans to update these guidelines on an annual basis, as needed.

Since the 2018 DSIP update, the Joint Utilities have established a JU Smart Inverter working group to discuss and formalize an implementation plan regarding the use of smart inverters within NY State. The group initially focused on surveying and benchmarking practices of utilities outside NY State related to the integration of smart inverters and their respective experiences. The working group is in the process of developing a road map to lay the groundwork for future smart inverter discussions. Additionally the ITWG has also began discussing the use of smart inverters. The first step included consolidating a list of JU and Industry stakeholder questions related to the implementation of smart inverters. To-date, the ITWG has held two smart inverter webinars in 2020. These efforts and discussions will continue, in order to provide the JU with a better understanding on the application of these advanced functions. Central Hudson has also supported and participated in various research and development projects related to smart inverters, to further the Company's knowledge on this technology.

b) Future Implementation and Planning

As described within EPRI's Functional Requirements for Implementation of an IOAP, Phase 3 of the IOAP includes full automation of all utility processes. Future work regarding interconnections will require integration with distribution planning functions as well as further integration with utility systems. This level of integration however, including establishing a timeline first requires the completion of other on-going initiatives as well as feedback from stakeholders. Hosting capacity as indicated in Section III.L, as well as stakeholder prioritization of DER concerns, will drive future requirements in regards to interconnections.

The JU will continue efforts and discussions related to the use of smart inverters on the distribution system. Based on Central Hudson's continued discussions and findings as part of both the internal JU Smart Inverter Group and ITWG, additional pilot project will likely be needed. The first application of smart inverters may employ advanced settings for interconnection as a low cost mitigation strategy in place of traditional T&D solutions. Future considerations may include use for grid support functions. However, additional research and considerations are still required, regarding the ability to model and simulate inverter settings, communication strategies, integration into DMS and DERMs, and cybersecurity concerns.

3. Risks and Mitigation

Application volume for interconnections continues to vary significantly depending on regulatory changes or new initiatives. Drivers for volume fluctuations include NYSERDA 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 an increase in larger applications >2MW. These larger applications typically require greater levels of resources to process, study, and review. 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.

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, as the rise in the larger applications as well as NYISO projects has required greater participation with additional engineering groups within the Company, this has become more challenging to manage. 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 level.

In addition to the incremental work associated with the actual interconnections, the Company continues to invest resources in associated process 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.

4. Stakeholder Interface

Stakeholder interface and feedback has continued to be a significant focus for interconnections since the 2018 DSIP was filed. The ITWG continues to meet on a bi-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 providers the ability to voice administrative or policy related issues. 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 such as flicker screening, as previously discussed in Section III.A above. 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 Section III.L. Central Hudson will remain active within the ITWG and IPWG. Topics of interest which will be discussed on upcoming working group agendas are included earlier in Section III.J.2 above.

5. Additional Detail

a) A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.

In early 2017, Central Hudson began soliciting Request for Proposals from third party software vendors in order to obtain new interconnection software that would meet the requirements listed in EPRI's IOAP

Functional Requirements[63]. This software was pursued to replace Central Hudson's previous web portal that was developed in-house. Central Hudson's new Interconnection Online Application Portal (IOAP) went live on September 26, 2017. It 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.

While Central Hudson previously worked to improve the interconnection process internally, the Company ultimately decided to pursue the PowerClerk software created by Clean Power Research (CPR) to meet the requirements in the PSC Order and provide a more streamlined, user friendly experience. Based on the interconnection portal gaps identified in the Initial DSIP, the new IOAP using PowerClerk provides better features for the application process and enables the applicant to have more visibility into the process. Gaps identified as a result of the new software that have since been addressed, as well as new updates since the 2018 DSIP, include but are not limited to:

- Online payment during application submittal, as well as study and upgrade payments;
- Automated e-mails to the applicant each time the application moves to the next stage, in addition to deadline reminders;
- Real-time application status to enable transparency throughout the application process;
- Submission of all application components via the web portal, including pre-application and final application documentation;
- Built-in electronic signature capabilities;
- Updates to existing application information as required;
- Convenience of interconnection application data housed in one location which can be used for real-time data reporting for internal and external use;

[63] "New York Interconnection Online Application Portal Functional Requirements", Electric Power Research Institute, September 2016, http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf.

- Auto-fill application capabilities as well as auto-calculations including system size and transformer loading;
- Election of VDER Compensation by applicant, which is utilized in the generation of the Compensation Eligibility Letter upon receipt of payment;
- Integration of existing utility systems to enable auto population of customer information to eliminate inaccuracies and duplicative efforts;
- Ability to request a modification to an existing application after the application has been reviewed and approved, including Material Modification requests;
- Ability to submit Moratorium notification, DER Registration Compliance Affirmation, Remote Net Metering Form, and Community Distributed Generation (CDG) Allocation Request Form

b) 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) the connected substation, circuit, phase, and tap;

(6) the DER's remote monitoring, measurement, and control capabilities;

(7) the DER's primary and secondary (where applicable) purpose(s); and,

(8) the 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 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 logon with appropriate encryption to ensure the privacy of customer data. Employees within the Electric Distribution Planning 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. The following information is available within the IOAP:

- DER type, size, and location;
- Net Energy 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 NY State Department of Public Service website under Matter Number 13-00205. This information 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. Additionally, Central Hudson is in the process of developing and posting its internal queue on the Company's Distributed Generation 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 being installed for backup, as well as the type of net-metering system including Community DG or remote net-metering.

Central Hudson's Solar PV Hosting Capacity Map is a public resource 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 phase currently exists at each feeder location. The following information is also available within the pop-up: queue information for the feeder and substation, substation transformer peak 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 500kW 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 (OATT) Attachments X, S, and Z.

c) 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 the introduction of the new 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 Engineering Technicians and Contractors to easily track the approaching deadlines for each of these projects in a separate document. The IOAP is also setup to provide e-mail reminders for upcoming due dates, based on the timelines listed in the NYSSIR. Employees within the Distribution Planning 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, have 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.

d) 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 login and view the status of their application in real-time. Automated e-mails 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 such. The IOAP status also clarifies if the next steps are the responsibility of the developer or the utility.

In additional to the IOAP, Central Hudson also maintains a centralized e-mail 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.

e) The utility's processes, resources, and standards for constructing approved DER interconnections.

Central Hudson follows the procedures and requirements as 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 one employee 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 primary point of contact. Central Hudson also has one employee designated to manage and maintain the IOAP.

For systems greater than 50kW, which are subject to technical screening, Central Hudson currently has three employees available that are able to perform these technical screens. For applications which require a CESIR, the Company currently contracts these studies out to two consultant resources, however, assistance and additional review is provided by employees within Central Hudson's Distribution Planning Group and System Protection Group and input on cost estimates are provided by the Company's Estimating Group.

In addition to the requirements within the NYSSIR, Central Hudson utilizes two additional requirements documents for interconnection: the Interconnection Guidelines, which were updated in December 2019, and Central Hudson's Requirements for Electric Installations. Both of these documents are publically 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 CESIR cost drivers. These documents can be found on 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 X, S, & Z are also helpful in understanding the NYISO processes. These documents contain NYISO-specific requirements that are in addition to Central Hudson requirements.

f) 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 50kW where the typical upgrade is only a transformer upgrade, the applicant can pay for the transformer upgrade and obtain information on its 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 only need to contact the utility through the IOAP again to request a meter change and submit final approval documentation.

For applications greater than 50kW that require new service or utility upgrades, these customers are provided with the contact information for a 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. For projects under 500kW, Central Hudson's District Directors in the New Business Department act as designated Project Managers in each of the following districts: Catskill/Kingston, Poughkeepsie, Newburgh, and Fishkill. For systems above 500kW, there is a single Project Manager designated to provide guidance on interconnection projects for all five of Central Hudson's districts.

Once a project provides 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 initiative appropriate next step 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 Distribution Planning Group provides a status report for systems greater than 50kW. As DER system construction nears completion, the Project Manager will inform the appropriate groups within Central Hudson in order to coordinate a timely completion on any upgrades needed on Central Hudson's end.

For projects interconnecting through the NYISO, the NYISO maintains an Interconnection Queue on their website that provides information on each proposed project.

g) Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information concerning construction status and workflows for approved interconnections.

Applications requiring construction upgrades or new service are provided with contact information for a Project Manager once the applicant opts to move forward with their project by providing upgrade payment(s). This is typically done after the completion of engineering studies which identify upgrades and the associated estimated costs. The Project Manager becomes the primary resource for providing DER developers with construction status, including any new service work that may be required. In addition, the IOAP continuously provides visibility into the current status of a project, including differentiation between when a project is approved for construction and when the utility is awaiting payment.

K. *Advanced Metering Infrastructure*

1. Context and Background

Central Hudson's Initial DSIP filing (dated June 30, 2016) contained a comprehensive analysis of the benefits and costs of implementing an advanced metering infrastructure (AMI), which was performed pursuant to the *Order Adopting Distributed System Implementation Plan Guidance* and in accordance with the *Order Establishing the Benefit Cost Analysis Framework*.[64] AMI deployment was assessed from three perspectives (societal, utility, and ratepayer), across two scenarios (full and partial deployment), and between benefit categories (operational only versus incremental AMI enabled benefits contingent on regulatory changes).

Central Hudson's analysis recognized the potential for AMI to offer customers, market participants, and utilities increased visibility and resolution with regard to energy usage and flow. However, the results across all scenarios of this analysis consistently indicated that the cost to integrate AMI systems with new and existing applications and devices to improve analytical capabilities and customer tools significantly exceeded the identified benefits. As a result, the analysis did not support universal implementation across the service territory. Further, the analysis pointed to several characteristics that explain the significant gap between AMI benefits and costs of full deployment:

- Distribution Automation – The continued deployment of approved distribution automation will capture a substantial portion of benefits, thus limiting the incremental benefits from AMI.
- Existing Advanced Meter Reading (AMR) – The existing and anticipated penetration of AMR will capture the benefits of more efficient meter reading and meter accuracy improvements.
- Meter Reading Frequency – Central Hudson's bi-monthly reading schedule for the majority of meters results in lower reading costs than a monthly frequency.

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

- **Gas Meter Co-Location** – The presence of gas meters at approximately 25% of electric customer sites results in the imposition of AMI installation costs with little incremental benefit.
- **Remote Geography** – The larger distances between meter sites leads to reduced operational savings and increased costs due to the need for additional network infrastructure and cellular meters.

The analysis also found that a partial AMI deployment is not cost-effective by an even greater margin as the results are not only impacted by the above characteristics, but by two other primary reasons:

- **Foundational Investments** – Significant IT investments are required independent of the number of meters deployed.
- **Smaller Meter Base** – A smaller meter base translates to reduced savings for operational benefits that are proportional to meter deployment, such as meter reading and outage management.

As there have been no changes to these characteristics or significant changes in deployment costs, widespread AMI deployment continues to fail to provide a cost-effective opportunity for Central Hudson customers to incorporate these resources into the REV market.

Although the Company has decided not to pursue widespread AMI deployment, it continues to pursue and support individual initiatives that present cost-effective opportunities for customers to access and assess their energy usage data and allow the Company to support demand side management options and DER deployment through rates and programs, including:

- **Hourly Pricing Program (HPP)** – Customers with demand exceeding 300 kW are subject to the provisions of the HPP if electing to purchase energy from Central Hudson. As a result, all customers exceeding the 300 kW threshold are required to have an interval meter with cellular communications capability. This does not result in a large number of active meters, as only 0.1% of customers meet this threshold. However, it does result in a significant portion of the throughput on Central Hudson's system, approximately 31.6% of deliveries, metered on an interval basis, with this hourly data accessible to these customers on a daily basis through a web-based platform.
- **Commercial System Relief Program (CSRP)** – The CSRP is a tariffed program that allows non-residential customers and third-party aggregators to contract to provide load relief during

Company designated load relief periods. All customers enrolled in the CSRP, either directly or through an aggregator, are subject to interval metering and telecommunications requirements.

- **Targeted Demand Response Program (TDRP)** – The TDRP is a Commission-approved[65], localized non-wires alternative project which utilizes a combination of non-residential interval metering and a sample of residential interval metering, as discussed further below, for measurement and verification purposes.

- **Value of Distributed Energy Resources Phase One Value Stack (Value Stack)** – Pursuant to Commission *Order on Net Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters* and *Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters*[66], Central Hudson implemented Value Stack compensation for certain DERs on November 1, 2017. The granularity of compensation embodied in the Value Stack, which will enable a more "distributed, transactive, and integrated electric system,"[67] is based on the requirement of interval metering and concomitant telecommunications, which to more accurately record and value net hourly customer consumption and electric system injections.

- **Residential Time-of-Use (TOU) Rate** – On December 1, 2017, Central Hudson implemented an alternative voluntary residential TOU rate.[68] Although this rate offering relies only on a general TOU register meter, Central Hudson's outreach for this new rate offering includes the potential for TOU customers to access advanced metering through a subscription service, as discussed

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[65] Case 14-E-0318 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Approving Rate Plan, Issued and Effective June 17, 2015.
[66] Cases 15-E-0751 and 15-E-0082 – In the Matter of the Value of Distributed Energy Resources and Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order on Net Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters, Issued and Effective March 9, 2017; Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, Issued and Effective September 14, 2017 (Value Stack Order).
[67] Value Stack Order, p. 2.
[68] Cases 17-E-0369, et al. – *Petition of Central Hudson Gas & Electric Corporation for Time of Use Rate Review and Recommendations*, Order Approving Voluntary Time of Use Rates, Issued and Effective November 17, 2017.

more fully below. This service would permit customers to view more granular usage data beyond the on-peak/off-peak billed totals provided by a register meter.

- Optional Standby Rates – On July 1, 2019, Central Hudson expanded eligibility for standby rates to all demand-metered customers according to the Commission's Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates.[69] Demand-metered customers are required to have an interval meter and concomitant telecommunications capability in order to take service under standby rates. Additionally, on September 23, 2019, the Company filed draft tariff amendments, in response to the same order, to extend eligibility for standby rates to mass market customers, including the requirement for interval metering and telecommunications capability.

- Mass Market Net Energy Metering (NEM) Successor Rate Design – Work has continued on a rate design that could serve as the basis for a mass market NEM successor tariff, most recently with a stakeholder comment process in response to the December 9, 2019 issuance of the Staff Whitepaper on Rate Design for Mass Market Net Metering Successor Tariff.[70] Department of Public Service Staff recommended that work continue during 2020 on the development of additional rate design alternatives for further study or implementation on a voluntary basis, and that such work be informed by various sources including, but not limited to, outcomes from electric vehicle charging tariffs, standby and buyback service rate design, and AMI implementation.

- Optional Residential Advanced Metering and Data Services (Insights+) – Central Hudson offers 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 provides 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. Currently, this subscription service is available for $4.99 per month. Customers can receive a reduced

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[69] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates, Issued and Effective May 16, 2019.
[70] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Notice Soliciting Comments on Staff Mass Market Net Metering Rate Design Whitepaper, Issued December 17, 2019.

subscription cost of $1.99 per month if they sign up for the Residential TOU rate along with Insights+.

2. Implementation Plan

a) Current Progress

As previously described, Central Hudson currently offers a subscription-based service called Insights+, which includes installation of an advanced meter that captures 15-minute interval data with the communication of data over a cellular network. This subscription is available to residential customers only at the cost of $4.99 per month. Customers can receive a reduced subscription cost of $1.99 per month if they sign up for the Residential TOU rate along with Insights+.

Beyond the Insights+ demonstration project scope, Central Hudson has expanded the use of the Insights+ meters to assist in accomplishing other operational objectives:

- **Measurement and Verification (M&V):** Itron utilizes a statistical sample set of Insights+ meters for M&V as part of the Peak Perks NWA program. Itron pays the monthly meter fee, and the customer receives the Insights+ service as part of their Peak Perks program participation incentives.

- **Value Stack:** The Insights+ meter data meets the criteria for the application of value stack compensation, and the hosted Itron MDM can accommodate the additional meters at no additional system cost.

- **Residential TOU:** The Insights+ meters capture data for the original TOU intervals as well as the Company's newer alternative TOU intervals. They also provide enhanced visual displays that differentiate TOU time periods and peak and off-peak usage analytics.

- **Load Research:** In June 2020, the Company began replacing approximately 400 electric interval meters included in the load research program with Insights+ meters. This replacement will provide expedited access to data in contrast to the current staggered, two–month lag consistent with Central Hudson's bi-monthly metering reading process. While load research data has been primarily used to construct load profiles for retail access and cost of service purposes, 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.

b) Future Implementation and Planning

Central Hudson continues to look for ways to cost-effectively expand the use of AMI to lower operational costs associated with the startup of new programs and technologies.

Although Central Hudson's initial comprehensive analysis of the benefits and costs of implementing AMI contained in the Company's Initial DSIP filing (dated June 30, 2016) did not support universal implementation across the service territory, the Company is constructing an AMI pilot program (AMI Pilot) to identify and gauge benefits more accurately. The AMI Pilot is designed to primarily focus on narrow geographic regions, targeting specific circuits in the Spackenkill area of the Company's service territory and the City of Poughkeepsie. Approximately 7,500 residential meters will be included, encompassing 4,766 electric, 1,644 gas, and 936 Life Support Equipment (LSE) customers.

The majority of the AMI Pilot will make use of the Company's internal communications network, referred to as the Network Strategy Network (NSN). The NSN consists of a Tier 1 high capacity backbone of fiber optic cables and microwave, which serves as the backhaul for the Tier 2 medium capacity radio mesh network. Central Hudson plans to use this Tier 2 network as the backhaul for the AMI system, which will be referred to as the Tier 3 network. Since the LSE meters are distributed throughout the service territory, they will be served by a cellular network.

The Company has identified a number of potential benefits for measurement, including:

- the availability of more granular energy consumption data which could be integrated into customer-facing applications to provide opportunities for energy usage and bill management;
- the availability of more granular energy consumption data that could be shared, with customer permission, with third parties including DER developers;
- integration within the outage management process;
- utilization of inside gas meters to measure and test methane detection;
- data availability for innovative rate and clean energy program designs;
- a reduction in the number of estimated bills, particularly with respect to the Company's current bi-monthly meter reading process;
- a reduction in customer inquiries regarding outages and bill inquiries; and,
- an increase in overall customer satisfaction.

3. Risks and Mitigation

The most significant risks related to the Company's decision not to pursue widespread AMI deployment would be the Commission's desire for a broader program, consistent with other utility programs across the state, and the implementation of additional rate and programmatic design structures that require more granular consumption data. The risk of AMI deployment for statewide consistency is the resulting additional cost recovery obligations imposed on customers without concomitant benefits, as previously discussed. Under this approach, Central Hudson would tailor customer education and outreach to address customer concerns. While the analysis of alternative rate design structures should include the costs incurred, including metering, implementation of such structures over time could lead to a fragmented meter inventory based on changing technology and design structures. It will be critical for Central Hudson to continuously monitor and evaluate meter and support technology to maintain an efficient, integrated system.

In contrast, additional AMI deployment increases both safety and security risks. 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 continue to address customer opposition to AMI, which utilizes digital and wireless technologies, as customers cite health, privacy, and security concerns. While Central Hudson maintains a comprehensive cybersecurity program as described in Section III.I (Cyber Security), it will be critical to adequately address any cybersecurity concerns, in order to minimize the risk associated with increased communications and access to data that accompanies AMI deployment.

4. Stakeholder Interface

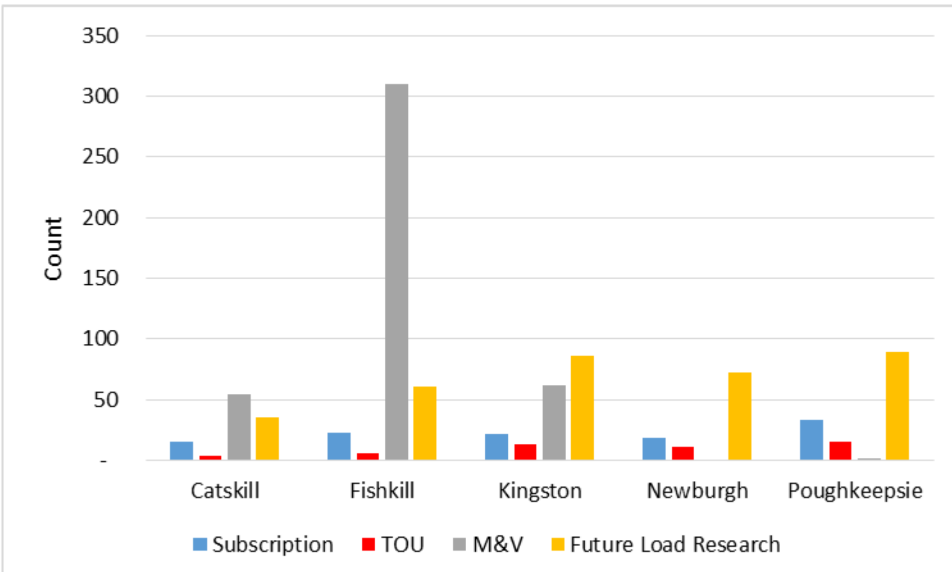
Additional AMI deployment will require the Company to effectively engage customers to ensure that they understand how to take advantage of AMI-provided capabilities. Central Hudson will also need to expand its customer data initiatives to further collaborate with interested stakeholders to co-develop business use cases for more granular metering data, in order to develop a deeper understanding of the need and use for various types of consumption data, including public availability, private availability, and possible value-added data elements. A foundational goal of any stakeholder interface will be to ensure that the AMI resources are effectively utilized.

5. Additional Detail

a) Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.

Insights+ meters for M&V purposes have been deployed within Central Hudson's Targeted Demand Response zones of Merritt Park, Fishkill, and the Northwest Corridor. Figure 41 shows the current distribution within the service territory of Insights+ meters resulting from subscriptions, TOU participation and M&V activity, as well as future installations resulting from replacement of load research meters.

Figure 41: Distribution of Insights+ Meters



b) Describe in detail where and how the utility's AMI provides capabilities which:

(1) help the utility integrate DERs into its system and operations;

Insights+ meters provide multiple channel configuration, including the measurement of power inflows and outflows, which are utilized in the determination of net exports eligible for Value Stack compensation. Additionally, Insights+ meters capture voltage as one of the configured channels. These measurement capabilities provide enhanced data that may be used in load planning, distribution planning and management, hosting capacity determination, and identification of locational value.

(2) help DER developers plan and implement DERs;

AMI can provide distribution planners with an additional source of data that may be incorporated into the review of distribution circuit loads to assist in the determination of resulting hosting capacity.

(3) help DER operators plan and manage operation of their DERs;

The granular data provided by AMI can support the development of innovative rate and compensation programs, providing more accurate signals regarding the value of the flow of power. AMI data can also be used to measure and support DER and demand response performance.

(4) enable or enhance the utility's ability to implement and manage automated Volt-VAR Optimization (VVO);

Insights+ meters capture voltage as one of the configured channels.

(5) improve the utility's ability to prevent, detect, and resolve electric service interruptions;

Real-time data supplied by AMI meters may be incorporated into the Company's outage management system to support earlier outage identification and potentially more accurate outage assessment.

(6) improve the utility's ability to implement rate programs which facilitate and promote customer engagement, DER development, and EV adoption;

Insights+ meters capture 15-minute interval data for power inflows and outflows and can be configured to capture this data across Company-defined peak and off-peak periods. This flexibility enables the use of the meters across dynamic rate offerings, including compensation of net exports eligible under the Value Stack. The integration of the meter data into the online engagement platform creates visualization tools to assist customers in better managing their energy usage and understanding the effects of usage and dynamic rate offerings on their monthly bill.

c) Describe in detail how the AMI enables secure communication with and among devices at customers' premises to support customer engagement, energy efficiency, and innovative rates

The Insights+ meters communicate only to the Itron head end and are not connected to any customer-level home area network architecture. Data exchange from the head end system to Central Hudson and associated partners that facilitate the delivery of the online engagement platform is executed using secure file transfer protocols.

d) 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.

Customers can learn about and enroll in Insights+ on CenHubStore.com.

L. Hosting Capacity

1. Context and Background

In order to encourage further DER integration, Central Hudson provides estimates of their 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 each circuit's hosting capacity by evaluating potential power system criteria violations that could result from interconnecting large solar PV systems[72] to three-phase distribution lines. This approach was deliberately chosen to deliver value in a timely manner to DER developers that are most active in New York State. The analysis increases visibility into hosting capacity for larger-scale solar PV 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 costs of interconnection are likely to be the lowest.

Since the 2018 DSIP, the following is an updated roadmap of the Hosting Capacity milestones for the Joint Utilities:

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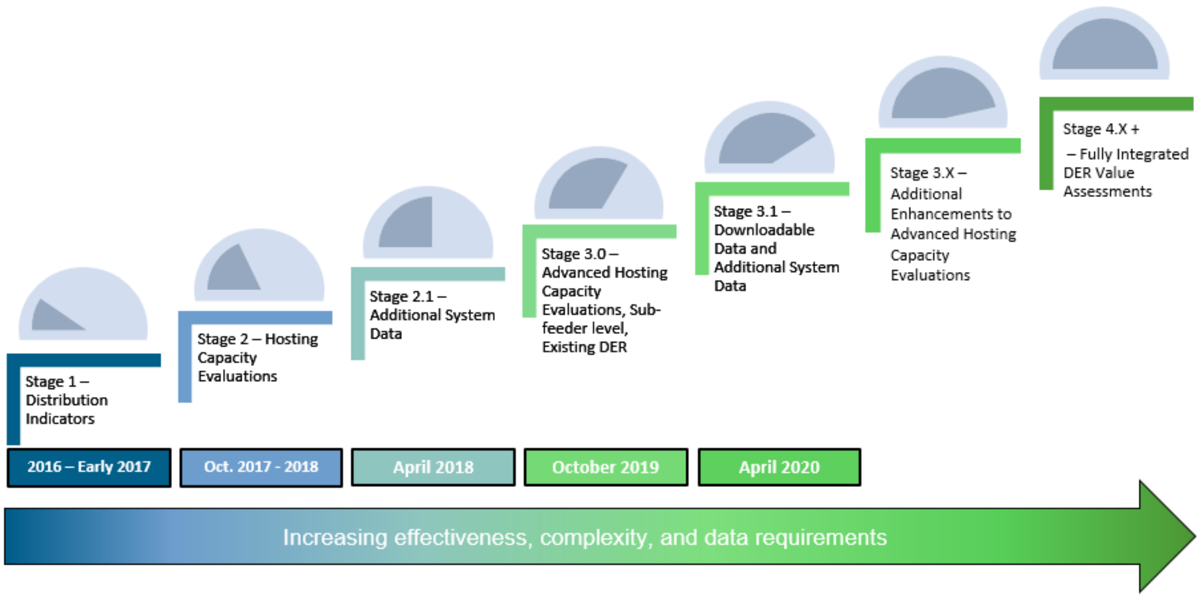
[71] Electric Power Research Institute ("EPRI"), Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, Report Number 3002008848 ("EPRI Roadmap"), June 2016, p. 2. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848.

[72] Solar with an AC nameplate rating starting at and gradually decreasing from 6000 kW.

Figure 42: Joint Utilities Hosting Capacity Roadmap



EPRI's DRIVE tool continues to be utilized to conduct hosting capacity, in order to support alignment and a common approach across the Joint Utilities, while enabling utilities to leverage existing circuit models in a utility's native distribution planning software.

Following the Stage 2 release on October 1, 2017, which included feeder level hosting capacity analysis for radial distribution circuits at and above 12kV, the Joint Utilities hosted two stakeholder engagement sessions in 2017 to solicit input on future enhancements to Stage 2 and on the development of Stage 3.[73]

The hosting capacity displays use pop-up boxes to provide system data, including minimum and maximum total three-phase feeder hosting capacity, voltage, and installed and queued DG values. The Joint Utilities worked collaboratively with stakeholders to identify additional data elements that could further enhance the value of the displays to developers. The Joint Utilities agreed to provide these additional data

[73] A full list of the stakeholder recommendations for Stage 3 is available on the Joint Utilities website. See Joint Utilities of New York Stakeholder Engagement Group information here http://jointutilitiesofny.org/joint-utilities-of-new-york-engagement-groups/

elements as part of a "Stage 2.1" release by April 16, 2018. The additional data elements provided at the substation level[74] included:

- Installed and queued DG;
- Total DG (sum of installed and queued DG);
- Peak load
- 3V0 upgrade status (where applicable)

Central Hudson updates pop-up data fields for installed, queued, and total DG monthly and updates peak load information annually. Where appropriate, 3V0 upgrade information is updated annually or upon major changes for relevant circuits.

Following the 2018 DSIP, Joint Utilities completed their annual refresh of the Stage 2.1 hosting capacity displays, which was released October 1, 2018. In addition, the Hosting Capacity working group finalized specific details regarding the Stage 3 Hosting Capacity analysis. The final enhancements that were determined for Stage 3.0 increased the geospatial granularity of the analysis to include sub-feeder level hosting capacity and relevant hosting capacity data at the substation level and introduced explicit modeling of existing solar PV. The evolution to this more granular analysis allows better visibility into hosting capacity for sub-feeder segments. Developers can identify specific locations with higher levels of hosting capacity and potentially lower interconnection costs. By October 1, 2019, the JU produced results for Stage 3.0 hosting capacity across their distribution systems.

In 2019, the Hosting Capacity Working Group held three stakeholder engagement sessions, which were structured corresponding to the release of the Stage 3.0 displays and look-ahead to future releases. The Joint Utilities also developed a stakeholder survey to solicit further input from a broader stakeholder audience on the proposed enhancements to prioritize future time and resource development. In May 2020, the JU held an additional stakeholder meeting to discuss the survey results and Stage 3.2-4.0 and 4.X+ prioritization. The Joint Utilities are incorporating feedback from stakeholders on other requested

[74] Substation-level information may be provided at the individual substation transformer bank level when appropriate. A unique identifier is included noting the specific substation transformer bank in those instances.

system data elements and functionality to include more iterative Stage 3.2-4.0 updates as part of the Hosting Capacity Roadmap.

The three stakeholder meetings held in 2019 provided the JU with well-developed suggestions to many of the potential enhancements; this allowed for interim progress concurrent with the stakeholder survey. Stage 3.1 was released on April 1, 2020, where some new data elements were added to the hosting capacity map which included:

- Estimated 3V0 protection threshold (where applicable)
- Substation/Bank Thermal Capacity
- Annotated notes for additional circuit-specific info

In addition to these data elements, the Stage 3.1 updates focused on greater transparency of the analysis, better communication of supporting materials, and greater access to the data – this includes:

- Substation Locations symbolized on the Hosting Capacity Map
- Common attribute tables and downloadable feeder-level summary data (.csv) that includes the data elements currently available in the pop-ups
- Supporting material on the DRIVE tool inputs by utility, and additional user reference material on the Stage 3.0 displays

From this point, Central Hudson will continue to update pop-up data fields monthly as preparations are made to release the Stage 3.1 Refresh by October 1, 2020. The Hosting Capacity Working Group will continue to meet and focus on the development of the future stages and releases of Stage 3.2-4.0 and Stage 4.X+. The JU anticipates hosting an additional Stakeholder meeting in November of 2020 to continue these discussions.

2. Implementation Plan

a) Current Progress

As indicated in the 2018 DSIP, Central Hudson hired an additional Junior Distribution Planning Engineer in June 2018, which has helped facilitate keeping the hosting capacity analysis in-house. Central Hudson has continued working with Electric Distribution Design to maintain the automation of the file extraction from the Distribution Engineering Workstation (DEW) load flow software to the EPRI DRIVE tool for analysis. The mechanisms to automate this process are in place and are currently being utilized. Full automation will be in service once the ESRI GIS model QA is complete.

Utilizing internal resources, Central Hudson will publish an annual refresh to the 3.1 sub-feeder level hosting capacity by October 1, 2020. The Company is also prepared to provide hosting capacity refreshes at an increasing rate based on Stakeholder requests. This includes providing a semi-annual refresh starting April 2021. This updated analysis, however, will only occur for circuits that have seen an increase in interconnected DER >500kW since prior analysis. The Joint Utilities are continuing to evaluate additional enhancements to the hosting capacity portal following the publication of the Stage 3.1 analysis. The future Stage 3.2-4.0 releases will include enhancements, such as further increasing analysis refresh frequency and providing additional map functionality, as well as load capacity maps. Prioritization of these future releases will be informed by use cases and stakeholder engagement, as described in the following sections of this document.

In addition to supporting developer priorities as part of stakeholder sessions, the JU began working with Scenic Hudson towards the end of 2019 and early 2020. Scenic Hudson is a non-profit environmental and land conservation advocacy group. Scenic Hudson's goal is to support renewable energy goals for the Mid-Hudson valley, while ensuring the preservation of land and farms. To support both of these goals, Scenic Hudson is in the process of establishing a public solar siting map that will enable municipal leaders and developers to make better informed decisions related to siting solar. In addition to including features within the map that point out specific aspects of an area, such as wetlands or protected lands, Scenic Hudson requested that each of the NY utilities feed their hosting capacity data into Scenic Hudson's ESRI GIS based platform as well. As a result, the JU have had on-going discussions related to providing Scenic Hudson with a live link URL, which will enable each of the JU hosting capacity displays to be overlaid with Scenic Hudson's public maps. Central Hudson commends Scenic Hudson's efforts to better guide and inform siting decisions for solar and is happy to support and aid their efforts for creating a consolidated NY map. Central Hudson anticipates providing Scenic Hudson with a live link URL in June 2020.

b) Future Implementation and Planning

The subsequent Stage 3.1 release further enhanced the information provided on the hosting capacity portal. The Joint Utilities are evaluating options to improve the analysis further, and will continue to solicit the input from stakeholders on the development of the JU hosting capacity roadmap. Based on feedback received during stakeholder sessions and survey results, near-to-medium term enhancements the JU plan to focus efforts include:

- Increased Analysis Refresh Rate
- Additional Map Functionality
- Load Capacity Maps

The frequency of analyses refresh rate will be increased from an annual to bi-annual basis, starting April 2021. This bi-annual refresh will only occur for circuits that experienced an increase of connected DG above 500kW within the past six months. The second near-term enhancement is to provide developers and stakeholders with additional map functionality. The JU believe they can leverage the use of the live URL that is provided to Scenic Hudson as an option for third parties as well. The last medium-term effort is to create load capacity maps. The JU have discussed a separate display/layer focused on a load-based hosting capacity analysis, which could serve as the basis for future analyses, or displays specific to other technologies such as energy storage or EVs. As storage may be implemented with an infinite number of use cases, and the EV market is relatively immature, the specific needs of developers of these DERs will evolve, and also must be related to the System Planning roadmap for Central Hudson.

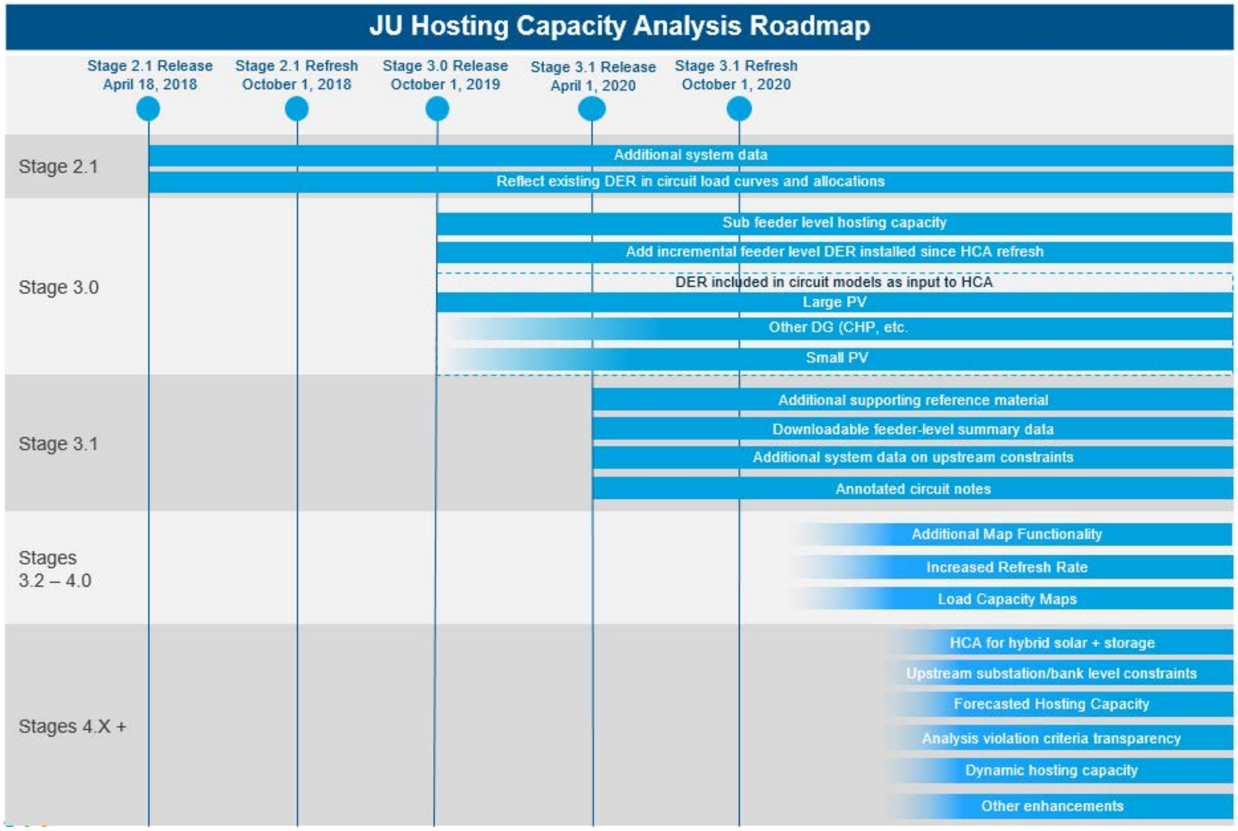
Additional longer-term enhancements in Stage 4.X+ releases identified thus far include the following:

- Hosting Capacity for Hybrid Solar + Storage
- Forecasted hosting capacity
- Upstream substation/bank-level constraints
- Analysis violation criteria transparency
- Dynamic hosting capacity

As forecasted hosting capacity continues to remain a priority for stakeholders, the JU will evaluate options for forecasting hosting capacity. These options must take into account the accuracy of such an analysis given the uncertainty in the location, the timing and configuration of DER adoption forecasts, projected changes to individual customer loads, and any upgrades or changes to the utility system. The roadmap for forecasting hosting capacity must incorporate models of future utility system configurations, gross load forecasts, and DER forecasts. Each of these items has its own roadmap and consideration of scenario-based planning, probabilistic, and deterministic approaches covered in Sections III and IV of this DSIP. These concepts must be integrated to produce a forecast, and to decide what level of granularity is appropriate before the level of uncertainty rises significantly. The JU plan to address the potential timing of the longer-term enhancements by the November 2020 stakeholder engagement meeting.

The Joint Utilities have and will continue to actively coordinate with EPRI and other Utilities in North America on the DRIVE tool roadmap in order to evaluate options for future Stage 4.X+ releases. Figure 43 below illustrates the JU Roadmap for HCA Stages completed thus far as well as future 3.2-4.0 and 4.X+ releases.

Figure 43: JU Roadmap for HCA Stages 3.2-4.0 and 4.X+



3. Risks and Mitigation

The risks to Hosting Capacity Analysis are primarily driven by software and analytical capabilities, availability of data, and the accuracy and speed of model updates. To mitigate this risk, Central Hudson participates in the EPRI DRIVE users group to help influence the development and prioritization of software capabilities to align with the needs of stakeholders in New York. Since the 2018 DSIP update, Central Hudson has continued to refine the load flow models of its entire distribution system to facilitate hosting capacity analysis, as well as distribution automation and the availability of hourly load data, including minimum load data required for hosting capacity analysis, which continues to improve along with the execution of the capital plan. 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 new DER technologies into hosting capacity analysis. Initial hosting capacity analysis has been focused on solar photovoltaics; as other technologies with distinct operating characteristics are introduced, the process may become more manual, slowing the speed and accuracy. The balance between complexity, speed, and accuracy must be considered to provide the most timely and effective information to stakeholders. Additionally, depending upon the extent to which Stage 3.X or Stage 4 is implemented, supplementary GIS resources may be required to close out work orders at an accelerated pace and update system models. Supplementary Distribution Planning 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.

4. Stakeholder Interface

The Joint Utilities continue to view stakeholder feedback as a critical input to further improvements to the hosting capacity analysis and displays. The Joint Utilities will continue to engage stakeholders for their input on these approaches to further inform expansion of the hosting capacity roadmap, although the group may need to grow to include emerging developers and those representing other types of DERs. In the case of hosting capacity analysis for energy storage, input on developer use cases will help inform the appropriate work product that will be most beneficial to stakeholders. This input will be especially important, given the broad range of energy storage technologies, applications, and operating characteristics that such analyses could reflect. Forecasted hosting capacity will likewise benefit from stakeholder input, given the level of complexity of the analysis that impacts the accuracy and precision of its results.

Keeping with the approach in 2018 and 2019, the Joint Utilities continue to hold stakeholder engagement sessions corresponding with the release of each stage to provide an update to stakeholders on progress to date and solicit input on future stages. The Joint Utilities plan to continue facilitating open discussions with stakeholders via the engagement group sessions beyond the Stage 3.1 release. As described in the

Supplemental DSIP, completion of Stages 3 and 4 of the hosting capacity roadmap will be a long-term focus for utilities based on lessons learned from previous stages and the availability of enhanced analytical tools to conduct this degree of analysis.[75] The longer-term focus on Stages 3 and 4 complements the Joint Utilities' interest in engaging stakeholders to provide the highest value results for users.

5. Additional Detail

a) The utility's current efforts to plan, implement, and manage 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. Section III.D of this document describes the Energy Storage projects that have been completed or are currently being evaluated at Central Hudson. While there are several benefits of energy storage being explored as a part of these projects, PV smoothing will be specifically evaluated as a part of the SUNY New Paltz PV + battery storage projects. The ability to smooth PV may increase hosting capacity in an area, although the costs and benefits will need to be weighed against more traditional transmission and distribution upgrades. Central Hudson has also been participating with consultants and other vendors in smart inverter research and projects, which has high potential to increase hosting capacity across the service territory without requiring extensive upgrades to the electric system infrastructure. Please refer to Section III.J for more detail.

[75] REV Proceeding, Supplemental DSIP, p. 56.

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 2021-2025 Electric Capital Plan filed July 2020, 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. All of these projects have the added benefit of increasing hosting capacity. The Company will continue to convert 4800V circuitry to 13.2kV operation over the upcoming years and will retire and convert two substations that operate at 4kV over the next three years. Also, a significant amount of circuitry will be reconductored as a part of the copper wire replacement program, operating/infrastructure programs, and distribution automation program. Finally, the Distribution Automation/Distribution Management System projects described in further detail in Sections III and V 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.

b) 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: www.cenhud.com/dg.

c) 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.

Please see Section III.L.2. for more information.

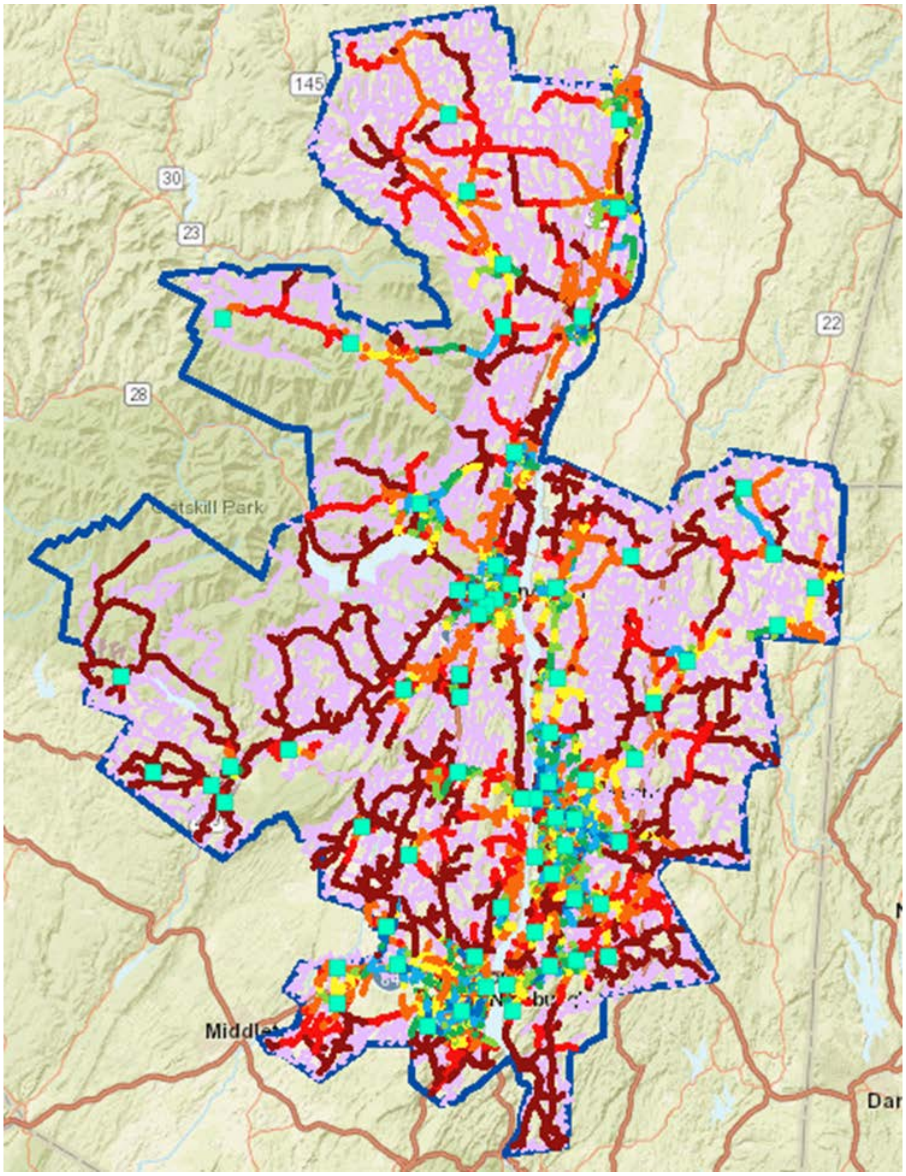
d) The means and methods used for determining the hosting capacity currently available at each location in the distribution system.

Central Hudson developed an interactive map that illustrates hosting capacity for its distribution circuits. The analyses presented in these displays provide the sub-feeder level hosting capacity for distribution circuits emanating from a substation at 12kV and above. The analyses were conducted under current configurations, without installed DER, 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. However, 3V0 upgrade information is included in a separate pop-up display on the map.

For the Stage 3.0 displays, 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 sub-feeder level hosting capacity and relevant hosting capacity data at the substation level, and introduced the explicit modeling of existing solar PV.

Issues related to circuit protection require further analysis to make a definitive determination of hosting capacity. This 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 range at any given location. As a rule of thumb, the local minimum hosting capacity value and local maximum hosting capacity value is indicative of the range of available hosting capacity across any selected segment within the map. The installed 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 will be updated monthly.

Figure 44: Hosting Capacity Map for Central Hudson’s Service Territory



Once in the map, as shown in Figure 44 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, local minimum and local maximum hosting capacity values of the segment, 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 operating voltage may denote voltages below 12kV such as: $2.4kV_{Line\text{-}Gnd}$, $4.16kV_{Line\text{-}Gnd}$, $4.8kV_{delta}$, or $7.62kV_{Line\text{-}Gnd}$. 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).

Additional information regarding means and methods for hosting capacity analysis can be found in the Supplemental DSIP.

e) 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 as forecasting of hosting capacity is further defined and prioritized within the Hosting Capacity Stakeholder Sessions. Section III.L.2.a) describes the required components of a hosting capacity forecast.

f) 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 www.cenhud.com/dg website with additional hosting capacity information and maps as they are available. Additionally, along with the Joint Utilities, Central Hudson, will host stakeholder webinars as needed to roll out new features of the analysis.

g) 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; and,

(2) timely increase hosting capacity to enable productive DER development at those locations.

Central Hudson is improving the System Planning Process through a transition in forecasting methodologies and the application of a more 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 (CPCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act, the Company is modifying its planning process to better align with these goals. As noted, the electric capital plan is predominately comprised of condition-based infrastructure type projects. A number of these existing projects provide incremental hosting capacity benefits. 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, study work has started to help identify other potential projects that would facilitate the attainment of these goals based on system constraints and forecasted renewable penetration levels.

M. Beneficial Locations for DERs and Non-Wires Alternatives

1. Context and Background

NWA 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. As the volume of opportunities increases, developing uniform NWA suitability criteria and establishing more consistent solicitation processes may facilitate more NWA opportunities and make it faster, easier, and cheaper for developers to respond. 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 rating in 1/3 the time as a location with a 1% growth rate. It also does not factor in uncertainty and, in particular, the reality that many growth trajectories are possible, and the growth pattern is less certain further into the future.

To identify beneficial locations, Central Hudson relied on the probabilistic analysis developed as part of the study. Locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering and infrastructure investment by 2030 (10 years). In total, this included one transmission area (the Northwest 115-69kV)) and four substations (Woodstock, Maybrook, Pulvers 13.8kV and Shenandoah). While the locations can benefit from DERs, in some instances, Central Hudson could provide temporary relief through load transfer or other low-cost steps. For example, load transfers to neighboring areas, if needed, can be completed at a relatively low cost for three of the substations identified. This may postpone the timing of the upgrades and their inclusion as NWA projects.

As part of the 2018 DSIP filing 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 2020 study are included in Appendix D of this filing.

2. Implementation Plan

a) Current Progress

Identification of Beneficial Locations for DERs and NWAs

As noted, Central Hudson's 2020 Avoided T&D cost study (see Appendix D) helps Central Hudson determine beneficial locations for DERs and NWAs on its system. This study focuses on substation and transmission costs (it does not include circuit feeders) and was designed to meet the following objectives:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level;
- Develop location-specific forecasts of growth with uncertainty;
- Quantify the probability of any need for infrastructure upgrades at specific locations;
- Calculate local avoided T&D costs by year and location using probabilistic methods; and
- Identify beneficial locations for DERs.

Within this study, the T&D avoided costs estimates are produced are at a local level. The study uses a bottom-up approach to quantify historical year-to-year growth patterns and the amount of variability in growth. In addition, load growth forecasts and avoided cost estimates are developed using probabilistic methods rather than straight-line forecasts. The approach takes into account the reality that there is much greater uncertainty ten years out than one year out, and it accounts for the risk mitigation value of resources that manage local peak loads.

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. If a customer helps reduce coincident demand, either by injecting power within the distribution grid or by reducing demand, 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 aging 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 fairly 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.

The key findings from the T&D study are:

- Most substations and transmission areas are experiencing declining loads or have ample room for growth over the next ten years.

- The expected avoided costs vary by location, year, season, and hour, and they are highly concentrated. Avoided costs are realized if additional resources are placed in the right locations and can deliver load relief at the right times. Without targeting, the value of distributed resources is diluted.

- For many distribution substations and transmission areas that have expected growth, the potential for avoided infrastructure upgrades through DERs is minimal because there is already sufficient capacity built in the area to meet load growth.

- The avoided cost estimates reflect the uncertainty in the forecasts and the risk mitigation value of demand management. Despite a low likelihood of exceeding design rating in the next ten years, DER resources can provide risk mitigation value at targeted transmission areas and substations if they are at the right locations, target the right hours, and are available at the right times.

- In practice, all avoided T&D costs are location specific. For system-wide untargeted values, the estimates take into account the likelihood reductions would be in locations with value due to random chance. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low.

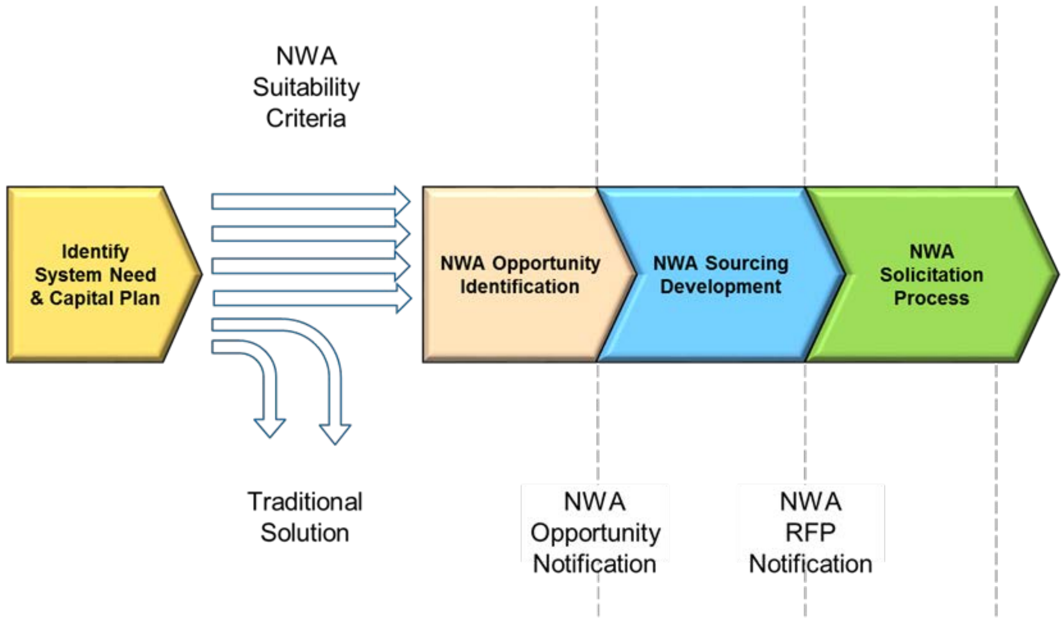
Within the study, locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering an infrastructure investment by 2030 (ten years). In total, one transmission area and four substations were identified. While the locations can benefit from DERs, in some instances, Central Hudson can provide temporary relief through distribution load transfers. This is specifically the case for three of the substations: Woodstock, Maybrook, and Pulvers 13.8kV. For areas that lack load transfer options for deferring upgrades further, the right type of DERs with the right availability may allow for deferral of infrastructure investment. This is the case for the other substation, Shenandoah.

The 2018 Avoided T&D Cost Study identified two locations (Hunter and Lawrenceville Substations) as having locational value. Due to load declines in the past two years and forecasted negative load growth, neither area had a greater than 5% probability of triggering an upgrade in ten years in the current study. The two locations with value in the 2020 study (Northwest 115-69kV transmission area and Shenandoah Distribution substation) are both relatively highly loaded, have positive growth rates, and have ratings decrease expected in the study (due to NWA and generation load serving capability expirations), resulting in a high investment trigger likelihood in the absence of further NWAs. One key reason the 2018 study did not show risk for the Northwest 115-69kV area was that it did not incorporate the 13.1 MW decrease to the rating at the end of 2025 attributable to generation retirement. The 2024 planned generation retirement was a result of the New York State Department of Environmental Conservation recently (March 2020) promulgated 6 NYCRR Subpart 227-3 "Ozone Season Oxides of Nitrogen (NOx) Emission Limit for Simple Cycle and Regenerative Combustion Turbines" which imposes more stringent emission standards for these units which makes the CTs in the Northwest 115-69kV area uneconomic. Overall, avoided costs in the 2020 study are higher than in the 2018 study because different locations have avoided cost value and because the risk of investment is higher at these locations than the 2018 study.

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 45.

Figure 45: Joint Utilities Planning Process and Sourcing Overview



Each utility continues to coordinate with the Joint Utilities as part of the DER Sourcing / NWA Suitability Criteria Working Group to develop RFPs that have a similar structure and supporting information when possible. RFPs provide the detail 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 38 summarizes the Central Hudson RFPs released to date. The demand within these existing NWA areas represents approximately 17% of Central Hudson's system peak demand.

Table 38: NWA Solicitations

2017-18 NWA Projects	Load Relief Needed (MW)	Need Date	Date Solicitation Issued	Status
Coldenham / C-4027 Distribution Feeder Upgrade	0.5MW	May 2020	March 2017	NWA withdrawn
Shenandoah / Fishkill Plains	5MW	May 2018	Nov 2014	NWA Currently Underway
Northwest Corridor / Transmission Upgrade	10MW	May 2019	Nov 2014	NWA Currently Underway

2017-18 NWA Projects	Load Relief Needed (MW)	Need Date	Date Solicitation Issued	Status
Merritt Park / (2) Distribution Feeder Upgrades	1MW	May 2019	Nov 2014	NWA Currently Underway

b) Future Implementation and Planning

Identification of Beneficial Locations for DERs and NWAs

Central Hudson believes the methodologies and processes outlined and followed in the Avoided T&D cost (see Appendix D) study 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. Although this is Central Hudson's third study utilizing this methodology, it is still relatively new and may require future refinements and improvements. Future studies can be further bolstered by conducting sensitivity analyses and through the refinement of engineering rules which trigger T&D infrastructure upgrades. 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 declining loads, it is expected that this methodology will result in lower and lower T&D avoided cost values.

NWA Implementation

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. Since the 2018 DSIP filings, the JU have continued to meet on a bi-weekly basis to share updates on NW solicitations, evaluation, and contracting topics. 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 2020); commercial and performance requirements, and non-performance issues of NWA contracts. The team also spent a significant amount of time working with the Energy Storage Working Group and DPS Staff reviewing the December 2018 Energy Storage Order requirement for the unused, undedicated, and suitable land inventory.

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.

3. Risks and Mitigation

Any forecasting technique includes inherent risks in terms of overall accuracy. The longer the time 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 5,000 simulations of potential load growth patterns for each substation and transmission area, respectively. For each simulation, Central Hudson is able to 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.

4. Stakeholder Interface

The Joint Utilities continue to engage stakeholders to produce useful information about stakeholder needs and utility plans that have resulted in greater alignment. As noted in the 2018 DSIP filing, the Joint Utilities met with stakeholders twice in 2017 to provide insight into the NWA solicitation processes and request feedback on future solicitations. The Joint Utilities met with stakeholders again during 2019 (May 29, 2019), hosting the Joint Utilities of New York DER Sourcing Stakeholder Session.

The first stakeholder engagement meeting in 2017 reviewed outcomes of the 2016 stakeholder engagement process on NWA suitability criteria and DER sourcing and presented the Joint Utilities' implementation efforts planned for 2017 based on the commitments made in the Supplemental DSIP. The meeting included the Joint Utilities' presentation and discussion of the NWA sourcing process, which provided stakeholders an opportunity to ask questions and provide input. The second Joint Utility stakeholder engagement in 2017 discussed challenges in past solicitations, and identified potential improvements to the RFP process. During this session, the Joint Utilities shared some of the challenges that surfaced during the solicitations and how they are addressing these challenges to improve the NWA RFP process. A key objective for the webinar was to learn more about the experiences of stakeholders who have participated in the NWA RFP processes.

The 2019 webinar focused on updates to the evolving non-wires procurement process. During the webinar, the Joint Utilities updated where each utility stands in terms of the overall NWA process, including identification of open RFPs, the status of awarded projects, and lessons learned from past RFPs.

The webinar also included a review of BCA approaches and suitability criteria and provided time for additional questions.

The Joint Utilities continue to maintain updated information in the following sites that include utility-specific portals that contain notifications of NWA opportunities and NWA RFPS:

- Central Hudson webpage (https://www.cenhud.com/contractors/non-wires-alternative-opportunities/)
- Joint Utilities of New York central data portal (http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/)
- REV Connect (https://nyrevconnect.com/non-wires-alternatives/)

As the NWA solicitation process evolves, the Joint Utilities will continue to hold focused conversations with stakeholders regarding the information available, requested, and useful for both utilities and developers to allow for efficient and repeatable market transactions.

Due to the unique circumstances of Central Hudson's service territory, which is characterized by flat to declining load and areas with ample capacity for growth, only four NWA opportunities have been identified since the initiation of REV. As indicated previously, the demand in these four NWA areas represents 17% of the Central Hudson peak system demand. The fourth NWA area, Coldenham 4027, was identified as a potential NWA area as part of the normal planning process. The NWA process began with the Company conducting a solicitation during the 1st and 2nd quarters of 2017 to assess the viability of NWA solution(s). This solicitation resulted in several cost effective options to meet the need through a variety of distributed energy resources ("DER") types. Loading within the area was continually reviewed as part of the NWA process, and during the 1st quarter of 2018, a new "4055" feeder from the Union Avenue Substation was put into service. This new feeder has the capacity to serve the excess load on the 4027 and to absorb expected near-term load growth on both circuits. This additional capacity alleviated the short term design constraint, and the Company decided not to implement the NWA at this time. The 4055 circuit was constructed to meet an emergent new lumped load (single industrial customer). Due to the timing of the facility, this project did not meet the NWA suitability criteria in terms of time frame. No additional solicitations have occurred within the past year which would have allowed Central Hudson to integrate the process improvements that resulted from the stakeholder engagement process. However, the Company strives to integrate such improvements in future solicitations.

5. Additional Detail

a) The resources provided to developers and other stakeholders for:

(1) accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and,

As indicated, Central Hudson utilizes the results of the avoided T&D cost study to identify and evaluate beneficial locations and other locations in the distribution system where an NWA compromising one or more DERs or energy efficiency measures could reduce, delay, or eliminate the need for upgrading distribution infrastructure or materially benefit distribution system operations. Appendix D provides the details of the methodologies utilized and the results of the current study. Central Hudson completes these studies every two years.

(2) efficiently sorting and filtering locations by the type(s) of capability needed, the timing and amount of each needed capability, the type(s) and value of desired benefit, the serving substation, the circuit, and the geographic area.

Due to the unique circumstances of Central Hudson's service territory, which is characterized by flat to declining load and areas with ample capacity for growth, only four NWA opportunities have been identified since the initiation of REV, with one of these NWAs being withdrawn prior to implementation. As indicated previously, the demand in the three NWA areas represents 17% of the Central Hudson peak system demand. With this limited number of projects, there has not yet been a need to develop a process in which stakeholders are provided with advanced searching capabilities.

b) The means and methods for identifying and evaluating locations in the distribution system where:

(1) a NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations; and/or,

Central Hudson utilizes the results of the avoided T&D cost study to identify and evaluate both beneficial locations and locations in the distribution system where a NWA comprised one or more DERs or energy efficiency measures could reduce, delay, or eliminate the need for upgrading distribution infrastructure or materially benefit distribution system operations. Appendix D provides the details of the methodologies utilized and the results of the current study. Central Hudson completes these studies every two years. Based on the results of the current study, one transmission area and four substations were identified as potential beneficial locations. Temporary relief through distribution load transfers can be performed for three of the substation locations. For the other substation, Shenandoah, the right type of DERs with the right availability may allow for deferral of infrastructure investment. The one transmission area (Northwest 115kV area) and one substation area (Shenandoah) have existing NWAs in place. These areas will be evaluated in future studies to determine if the NWAs will be extended or if these areas will become eligible for LSRV compensation. A third possible option, to leverage these areas to develop an overall system-wide relief value (DRV), most likely will not be pursued because the more targeted approaches (NWA/LSRV) provide value in the areas of need and are more effective and cost effective at addressing these needs.

(2) one or more DERs and/or energy efficiency measures could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk electric system reliability, efficiency, and/or operations.

The NYISO completes a Reliability Needs Assessment (RNA) to determine both the resource adequacy and the transmission security needs of the New York Control Area (NYCA) Bulk Power Transmission Facilities (BPTF). Along with Central Hudson's own analyses, the results of the RNA are utilized to determine the adequacy and security of Central Hudson's portion of the NYCA transmission system. The RNA is completed every two years and looks out across a ten year horizon. As part of the NYISO process, the NYISO solicits market-based and alternative regulated proposals from interested parties to address any identified BPTF reliability needs. The NYISO will also designate one or more Responsible Transmission Owners to develop a regulated backstop solution to address each identified BPTF reliability need. The most current RNA in progress, identified a local reliability need within the Central Hudson System. The need is driven by the planned retirement of two Combustion Turbines (CTs) in the Westerlo 69kV transmission loop. The planned CT retirements are in response to the New York State Department of Environmental Conservation recently promulgated (March 2020) 6 NYCRR Subpart 227-3 "Ozone Season Oxides of Nitrogen (NOx) Emission Limit for Simple Cycle and Regenerative Combustion Turbines" which imposes more stringent emission standards for these units which makes the CTs at these locations uneconomic. As these units are currently required for local transmission and distribution reliability needs, capital projects are necessary to address these needs prior to the retirement of the CTs. Central Hudson has included the required upgrades within its five-year capital plan.

c) Locations where energy exported to the system, or load reduction, would be eligible for:

(1) compensation under the utility VDER Value Stack tariff;

(2) utility dynamic load management programs, including the Commercial System Relief Program, Distribution Load Relief Program, and Direct Load Control Program;

(3) and/or, increased value-based customer incentives for energy efficiency measures with load profiles that align with the system needs through utility energy efficiency programs or New York State Energy Research and Development Authority's (NYSERDA) Clean Energy Fund (CEF) programs, while ensuring utility-NYSERDA coordination.

Central Hudson's avoided T&D cost study (Appendix D) identifies beneficial locations where energy exported to the system, or load reduction, would potentially be eligible for compensation under the utility VDER Value Stack tariff. Based on the results of the current study, one transmission area and four substations were identified as potential beneficial locations. Temporary relief through distribution load transfers can be performed for three of the substation locations. For the other substation, Shenandoah, the right type of DERs with the right availability may allow for deferral of infrastructure investment. Since both of the two remaining areas (Shenandoah substation area and the Northwest 69-115kV transmission area) have existing NWAs in place, the Company is developing plans to potentially extend them beyond current project timeline and/or procure incremental resources to achieve additional deferral value.

Central Hudson's Dynamic Load Management portfolio is comprised exclusively of the Commercial System Relief Program (CSRP). Customers are eligible to enroll a minimum of 50kW of load reduction anywhere in Central Hudson's service territory in accordance with the program tariff.[76] Load reductions are calculated using a Customer Baseline Load or "CBL" methodology[77], similar to the NYISO SCR program. This methodology compares event day load to the customer's predicted load based on an analysis of their load during comparable days and other factors. There is currently no restriction on energy export contributing to performance. Energy export is simply treated as negative load within the performance calculation. Because a CBL methodology is used, however, energy export would need to be

[76] https://www.cenhud.com/globalassets/pdf/my-energy/csrp-tariffs-2019.pdf
[77] https://www.cenhud.com/globalassets/pdf/my-energy/cbl-methodology-2016.pdf

incremental to that which occurs outside of CSRP event hours to make a positive contribution to performance. The CSRP program is offered consistently throughout the service territory.

Central Hudson's Energy Efficiency programs have traditionally been system-wide programs that are implemented consistently throughout the geography of the Company's service territory. It is possible, however, to leverage additional value streams within NWA areas in order to enhance incentives or other operational aspects of the program in the interest of increase or accelerate Energy Efficiency penetration. Central Hudson is currently utilizing energy efficiency kickers, or enhanced incentives designed to promote higher adoption rates, within multiple NWA areas. In accordance with the December 13, 2018 Order Establishing Energy Storage Goal and Deployment Policy, Central Hudson filed an implementation plan to procure longer term "Term-DLM" resources for the 2021 season. Term-DLM procurements will be incremental to existing Demand Response programs. Resources will be procured for a minimum of three years with locked-in incentive payment rates. The procurement will also include penalties for non-performance, unlike existing DLM resources. Within the procurement, Central Hudson will also provide for a premium "Auto-DLM" category which requires higher performance factors, has more stringent availability and participation commitments. The new categories will impose limitations on fossil fuel generators. The compensation structures will be designed to avoid double compensation for the same benefit stream for customers participating in both the Procurement and Net Energy Metering or Value Stack tariffs.

N. Procuring Non-Wires Alternatives

1. Context and Background

Non-wires alternatives (NWAs) are important vehicles for deploying DER via market mechanisms, which is a core policy goal of REV and a critical aspect of DSP 1.0. NWA offer opportunities to defer or avoid a subset of traditional "wires" investments, potentially resulting in cost savings for customers and/or environmental benefits, while maintaining system reliability and resiliency. NWA are defined as any action or strategy that addresses the defined system need while deferring, reducing, or eliminating the need to construct or upgrade distribution infrastructure. They are identified as part of the annual capital planning process and can be sourced through RFPs, auctions, sole source contracts, and other procurement vehicles.

2. Implementation Plan

a) Current Progress

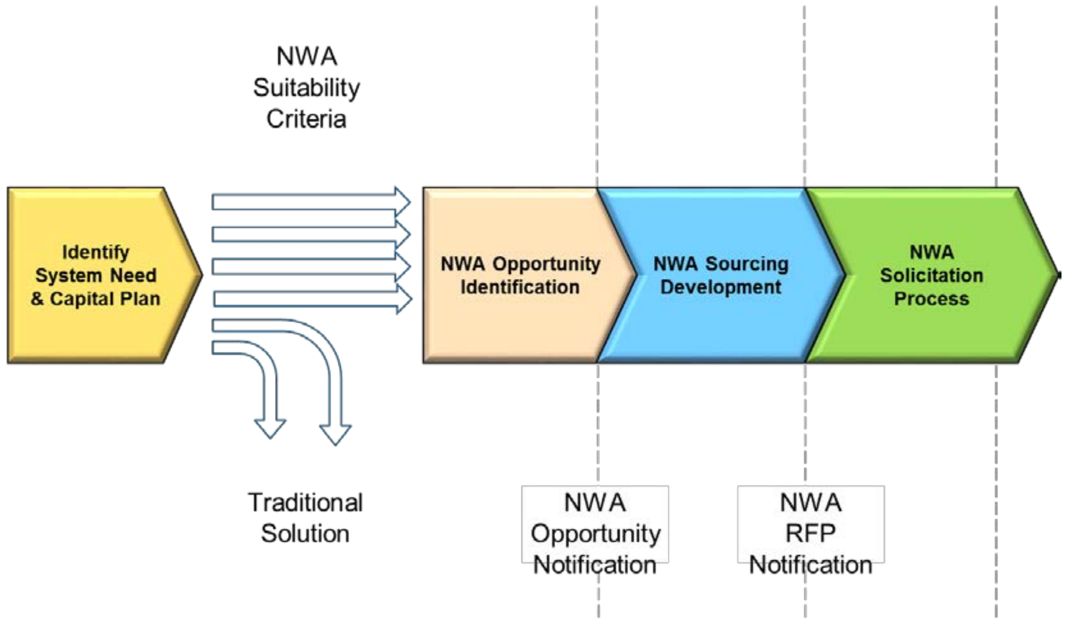
The Company has made significant progress in increasing NWA opportunities and improving the solicitation process. All projects in the capital plan that met the suitability criteria and were deemed feasible as NWA candidates were posted on the Company's website and advanced for consideration for the solicitation process, which is discussed further in the DER Sourcing section.

In 2017, the Joint Utilities shared additional information with stakeholders on the NWA identification and evaluation process in order to improve transparency and support developers' business planning. For example, the Joint Utilities submitted two filings in 2017 related to NWA suitability criteria and NWA sourcing processes. The first, submitted March 1, 2017, provided utility-specific guidance for the three criteria included in the common Supplemental DSIP NWA suitability criteria framework: project type, timeline, and cost.[78] To provide greater developer insight into the planning and sourcing processes, the Joint Utilities submitted another filing on May 8, 2017, which addressed the Commission's directive to describe "how the Suitability Criteria will be incorporated into utility planning procedures, and how and

[78] DSIP Proceeding, Joint Utilities Utility-Specific Implementation Matrices For Non-Wires Alternatives Suitability Criteria (filed March 1, 2017) ("March 1 Filing").

when the Suitability Criteria will be applied to projects in their current capital plans."[79] This filing describes the end-to-end process for identifying and sourcing NWA, including the capital planning process, opportunity identification, and sourcing and solicitation processes, as represented in Figure 46 below.[80]

Figure 46: Joint Utilities Planning Process and Sourcing Overview



The filing includes the timing of the development of the Company's capital plan, identification of NWA opportunities, a description of project needs, and the expected timing of solicitations tied to those opportunities. It also includes a description of how each utility applies the NWA suitability criteria to its five-year capital plan and presents the resulting 70 NWA opportunities.

Suitability criteria differ across the Joint Utilities, but through stakeholder engagement efforts, the Joint Utilities now have an enhanced, predictable, and more consistent market mechanism for incorporating NWA into their planning processes.

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[79] DSIP Proceeding, DSIP Order, p. 32.

[80] DSIP Proceeding, Joint Utilities Supplemental Information On The Non-Wires Alternatives Identification And Sourcing Process And Notification Practices (filed May 8, 2017) ("May 8 Filing").

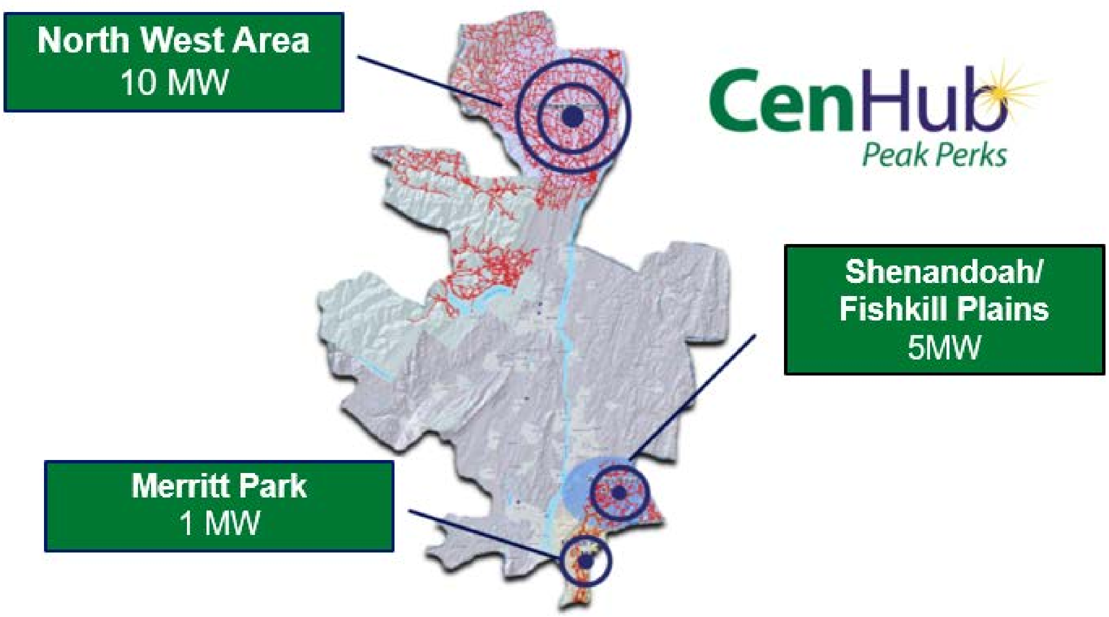
b) Future Implementation and Planning

The Company continues to integrate DER 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.

Targeted Demand Response

The Company is in the process of implementing three Non-Wires Alternatives (NWA), as described in Section III.M of this document. These NWAs are being implemented jointly as the Company's "Targeted Demand Response" Program or "CenHub Peak Perks." Combined, the Company aims to achieve a localized peak load reduction of 16MW across the three areas.

Figure 47: Current NWA Project Locations and Targets



The table below illustrates the load reductions available as of May 31, 2020. The Company anticipates achieving the full 16MW target by the end of 2021.

Table 39: Potential Load Reductions for Current NWA Projects

Program Locations	Residential & Small Commercial	Targeted Energy Efficiency	Large Commercial & Industrial	Avoided Distribution Line Losses[81]	Total kW available	Total kW Towards Target
Fishkill	2,899	480	80	169	3,627	3,627
Merritt Park	331	6	800	54	1,191	1,000
Northwest Area	1,385	1,084	3,731	217	6,417	6,417
Total	**4,615**	**1,570**	**4,611**	**440**	**11,235**	**11,044**

More detail on this project can be found in Central Hudson Gas & Electric Corporation's 2019 Annual Report for the Targeted Demand Response Program, a Central Hudson Non-Wires Solution. [82]

3. Risks and Mitigation

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.

4. Stakeholder Interface

The Company is an active participant in the "DER Sourcing" Joint Utilities working group. This group facilitates the sharing of best practices in DER procurement between New York utilities. The utilities have

[81] Avoided distribution line losses have been calculated by Central Hudson per the Operation Procedure
[82] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F9BEBACE-E1EF-43DB-B750-29B44A0E449D}

held various workshops to promote the sharing of ideas and feedback on existing processes directly from DER developers and other stakeholders. This feedback is utilized to optimize procurement procedures and optimize the participation experience of developers. The Company makes every effort to provide the most detailed information available directly to prospective DER providers through RFPs. For each solicitation, the Company will respond to specific questions and discuss topics requested by stakeholders during a pre-bid conference.

Detailed information on past and current solicitations can currently be found on the REV Connect website, Joint Utility webpage, as well as Central Hudson's web page.

https://nyrevconnect.com/non-wires-alternatives/[nyrevconnect.com]

http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/

https://www.cenhud.com/contractors/non-wires-alternative-opportunities/

5. Additional Detail

a) How the NWA procurement process works within utility time constraints to support DER developers' planning and solution implementation in time to serve the system need.

The timing of system needs factors into the suitability of an NWA solution being considered for that need. The Company continually monitors the T&D system to identify potential areas that could benefit from an NWA solution, as described in Section III.M of this document. When a need is identified, the Company strives to begin the solicitation process for an NWA to meet that need as early as practicable.

b) The NWA procurement means and methods; including: How the utility and DER developers time and expense associated with each procurement transaction are minimized;

(1) How the utility and DER developers time and expense associated with each procurement transaction are minimized;

(2) The use of standardized contracts and procurement methods across the utilities.

To enhance the DER integration process, the Joint Utilities continue to share lessons learned from developing and implementing specific NWA Requests for Proposals (including supporting data) and resultant contract terms and conditions to work towards a more similar approach for procurement within the Company and across the utilities. For example, a successful NWA contract will clearly state assumptions, pricing, applicable incentives, and expectations for the intended use of the resource by the utility, opportunities that may allow a resource to generate additional revenue streams through participating in other markets (e.g. wholesale), and operational and commercial requirements, including expected performance and corresponding payment terms. In terms of payment guidelines, the utility must clearly outline payment duration and schedule and include language that holds DER vendors accountable for commercial payment and ensures bids include the cost of any security instruments required. Through the information sharing across the utilities, the Joint Utilities have agreed that contracts should also include clear and consistent use of key terms and descriptions regarding the NWA DER vendor's market participation, regardless of payment cadence.

The Joint Utilities have made efforts to add consistency to NWA solicitations and contract negotiations. While there are unique needs for each utility, the Joint Utilities continue to share best practices for issuing contracts and implementing procurement methods.

c) Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities. For each opportunity, the resource should describe the location, type, size, and timing of the system need to be addressed by the project.

Detailed information on past and current solicitations can currently be found on the REV Connect website, Joint Utility webpage, as well as Central Hudson's web page.

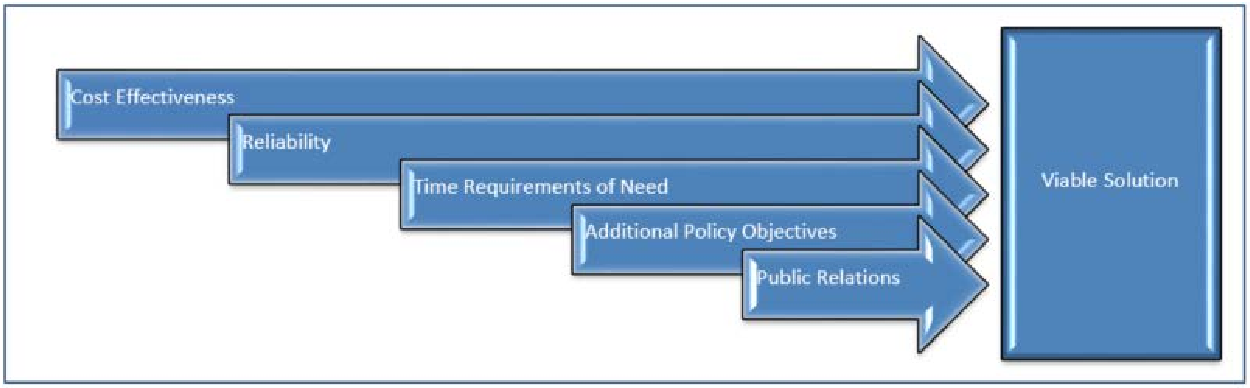
https://nyrevconnect.com/non-wires-alternatives/[nyrevconnect.com] http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/

https://www.cenhud.com/workingwithus/non-wires-alternative-opportunities

d) How the utility considers all aspects of operational criteria and public policy goals when selecting which DERs to procure as part of a NWA solution.

Below are considerations for selecting a solution for an NWA:

Figure 48: Considerations for Selecting an NWA Solution



1. **Cost effectiveness**: What benefits/costs are associated with each solution? Cost effectiveness is determined in accordance with the BCA Handbook.

2. **Reliability**: How reliably will the solution(s) meet the operational needs? The main factors considered (but are not limited to) include:

   - Coincidence: Does the solution perform when needed? If so, to what extent?
   - Dispatch: Is the resource dispatchable? If so, what limits to the frequency and duration of dispatch exist?
   - Intermittency: Is the solution available only intermittently? If so, how is that intermittency characterized? Does the resource need to be "de-rated" to account for intermittency?
   - Limitations: What general and technical limitations exist for this DER?

- Timing: Can the solution be operational in time to meet a forecasted need?

3. **Time Requirements**: How timely is the need? What is the risk to the T&D system associated with failure to meet the identified need, or with any delay associated with finding a replacement technology if the initial solution were to be unsuccessful?

4. **Policy Objectives**: Will any solution(s) help this NWA meet any policy objectives in addition to fulfilling the primary grid need? What are the economic and environmental impacts of the project?

5. **Public Relations**: How does this NWA impact the Company's public relations? Does it engage customers? If so, how many and to what degree? Will the NWA improve customers' opinions of Central Hudson?

e) Where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:

(1) Describe the location, type, size, and timing of the system need addressed by the project;

Detailed information on past and current solicitations can currently be found on the REV Connect website, Joint Utility webpage, and Central Hudson's web page.

https://nyrevconnect.com/non-wires-alternatives/[nyrevconnect.com]

http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/

https://www.cenhud.com/workingwithus/non-wires-alternative-opportunities

(2) Describe the location, type, size, and provider of the selected alternative solution;

Detailed information on past and current solicitations can currently be found on the REV Connect website, Joint Utility webpage, and Central Hudson's web page.

https://nyrevconnect.com/non-wires-alternatives/[nyrevconnect.com]

http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/

https://www.cenhud.com/workingwithus/non-wires-alternative-opportunities

(3) provide the amount of traditional solution cost which was/will be avoided;

Central Hudson does not provide this information, because the Company believes doing so would have a negative impact on the solicitation and procurement process. The traditional solution competes with DER solutions just as solution providers compete with each other by providing confidential bids through a solicitation.

Costs may only be provided after the NWA need is sufficiently met to account for the possibility that all/or part of the need may still need to be procured after the original solicitation in the event the primary solution is unsuccessful.

(4) explain how the selected alternative solution enables the savings; and,

Detailed benefit cost analyses are developed in collaboration with DPS Staff and ultimately filed with the Department of Public Service as part of a Non-Wires Alternative project. Due to the sensitive nature of these analyses, these filings are confidential.

(5) describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s).

The nature of the desired pricing arrangement between Central Hudson and its providers is described in some detail within each RFP. Each contract, however, is vendor-specific and reflects the unique needs of the particular project.

IV. DSIP Governance

1. Describe the DSP's scope, objectives, and participant roles and responsibilities. A participant could be a utility employee, a third party supporting the utility's implementation, or a party representing one or more stakeholder entities.

As has been previously described in Central Hudson's DSIP filings, the DSP is segregated into three main functional areas: Distribution Planning, Distribution Grid Operations and Distribution Markets.

Central Hudson's 2020 DSIP filing provides an opportunity for the Company to share its progress to date and the roadmap going forward of key initiatives within these three main functional areas. Organizationally, Central Hudson has aligned functional responsibility under two group heads: the Assistant Vice President of Electric Engineering and Operations and the Vice President of Customer Services and Gas Operations. The responsibilities under the Assistant VP of Electric Engineering and Operations include all responsibilities associated with Distribution Planning, Distribution Grid Operations and Distribution Market policy including integration and coordination with wholesale markets. The responsibilities under the VP of Customer Services and Gas Operations include more of the market function and customer engagement initiatives including NWA solicitations and implementations, demonstration projects, and development of service and rate offerings to enhance the customer experience. While these organizations work collaboratively, the Company 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 operate today with transmission planning and operations and the wholesale markets.

In order to best coordinate with the Joint Utilities and receive valuable input from stakeholders, Central Hudson has been an active participant and has played a leadership role in the Joint Utilities and the DSP Steering Committee. Central Hudson has also been active under the functional implementation working groups that fall under the Steering Committee, which include the Interconnection Technical Working Group, Interconnection Policy Working Group, and Market Design & Integration Working Group. These coordinated efforts have been invaluable in providing a streamlined forum for stakeholder participation, utility collaboration, sharing experiences, and receiving valuable input from the group's consultants, who has the benefit of pulling in experiences from other jurisdictions.

2. Describe the nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSP work. Also describe and explain how the work processes are expected to evolve over the next five years. Workflow diagrams that show significant internal and external dependencies will be especially useful.

As described above, Central Hudson has implemented an organizational structure that segregates the distribution planning and operations functions from market operations functions. As detailed in the System Planning and Grid Operations sections of the report, 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. The completion of these initiatives is currently projected to occur in 2024; detailed timelines are included in the Grid Operations Section.

Aligned with the completion of these investments is the buildout and staffing of the 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, the Company has recognized the need to put in place a new Control Center as well as develop the resources and the procedures necessary to operate this much more dynamic and complex grid. Highlighted in the Grid Operations Section (Section III.C) is a project timeline for the Operation Center, which lays the groundwork for the Company's current vision of the major operational policy and resource changes needed to make this transition.

With regard to Distribution Markets, the Company continues to work through the many established proceedings. The JU have shared their DSP roadmap of how they anticipate these markets will evolve over time. DPS Staff's issued Guidance for 2018 DSIP Updates included an additional joint filing at a later date on the DSP Market Design and Integration Working Group. This group will develop detailed recommendations for Staff, to inform a whitepaper regarding the design and implementation of the DSP market functions needed to enable and optimize operation of DERs in the utilities' electric distribution systems. The scope of the effort is to create:

- Marketable DER functions and attributes which serve the needs of the electric distribution system and/or the bulk electric system.

- Roles, responsibilities, and rules which govern the actions and interactions of all entities involved in the transaction of marketable DER functions and attributes.
- Ways and means for coordinating and performing the planning, operating, and settlement activities involving marketable DER functions and attributes.

Generic Working Group activities will include:

- identifying and evaluating information, principles, concepts, practices, policies, and laws that are relevant to designing and developing DSP market functions;
- identifying and characterizing means and methods (technical, economic, legal, or regulatory) that could enhance and/or accelerate development of DSP market functions;
- identifying and characterizing gaps, obstacles, and risks (technical, economic, legal, or regulatory) that will or might impede development of DSP market functions; and
- recommending means and methods to address identified gaps, obstacles, and risks. Central Hudson will continue work collaboratively with Staff, stakeholders, and the rest of the JU group to develop the transition and a roadmap for how the distribution level markets will evolve.

3. Identify and describe in detail the tools (i.e. project management, collaboration, and content management software) and information resources currently employed internally by the utility and/or presented for stakeholder use. Also describe and explain how the tools and information resources are managed and how they are expected to evolve over the next five years.

Throughout the report, numerous tools are identified that the Company has implemented or is in the process of implementing for both internal and stakeholder use. Internal tools include the utilization of probabilistic planning tools and the ongoing implementation of the Distribution Management System. With regard to external facing tools, the Company has deployed the Interconnection Online Application Portal meeting the requirements established by the Commission. The Company has also established a comprehensive web based system data portal. This data portal provides detailed 8760 historical data and forecasts, including probability-banded load data at both the transmission area and substation area as well as facility ratings. Information is also provided on probabilistic forecasts of DERs at the same level.

Our My Energy page and CenHub platform provide locations for customers to get information on program offerings including energy efficiency projects and ideas and various rate offerings that are available. Through the JU stakeholder process, Central Hudson has recognized and provided additional information that stakeholders identified as being valuable and is also consistent with Customer and System data security requirements. A comprehensive listing of the tools is provided in Appendix A.

4. Describe the Joint Utilities of New York Website contents and functions which support aspects of the utility's implementation program. Provide specific examples to explain how those contents and functions help both the utility and its stakeholders.

As indicated above, the Joint Utilities collectively maintain and regularly update their website (www.jointutilitiesofny.org) with valuable resources for interested parties. To further assist with the dissemination of DSP activities, the Joint Utilities have developed a quarterly newsletter, providing meaningful and timely updates to the Joint Utility Activities. The Joint Utilities central portals with utility-specific links for hosting capacity, system data, and NWA opportunities provides one-stop access to each of the utilities' information. These efforts have helped to increase transparency, usability, and availability of information. The website also serves as a valuable repository for stakeholder information, providing key policy and regulatory documents, detailing past stakeholder meetings, summarizing inputs that stakeholders have previously provided and next steps for addressing them, and providing links to other resources such as REV Connect. The Joint Utilities welcome suggestions to enrich the website through their email address at info@jointutilitiesofny.org.

5. Describe and explain the planned sequence and timing of key DSP management activities and milestones. Using calendars, Gantt charts, and narrative text, provide information addressing management functions, collaborative processes (stakeholder engagement and Joint Utilities coordination, for example), and development and maintenance of program tools and information resources.

As described in Section IV.1), the DSP implementation efforts at Central Hudson have been segregated under the Assistant VP of Electric Engineering and Operations and VP of Customer Services and Gas Operations with the goal to segregate the planning and operations functions from the market functions.

The activities are well coordinated between these two organizations as well as with the JU work efforts. The specific timing of the efforts underway at Central Hudson have been outlined in detail in the report and highlighted again in Section IV.1).

In the 2016 DSIP Order, the Commission directed that the DSIP process should include active collaboration among utilities, stakeholders, and the Department of Public Service Staff to promote the transition of the utilities to DSPs. Building on the structure established in 2016 and in the course of the preparation of the Initial DSIPs and the Supplemental DSIP, the Joint Utilities have continued to collaborate effectively to enhance communication channels with stakeholders to develop the 2018 DSIP filings.

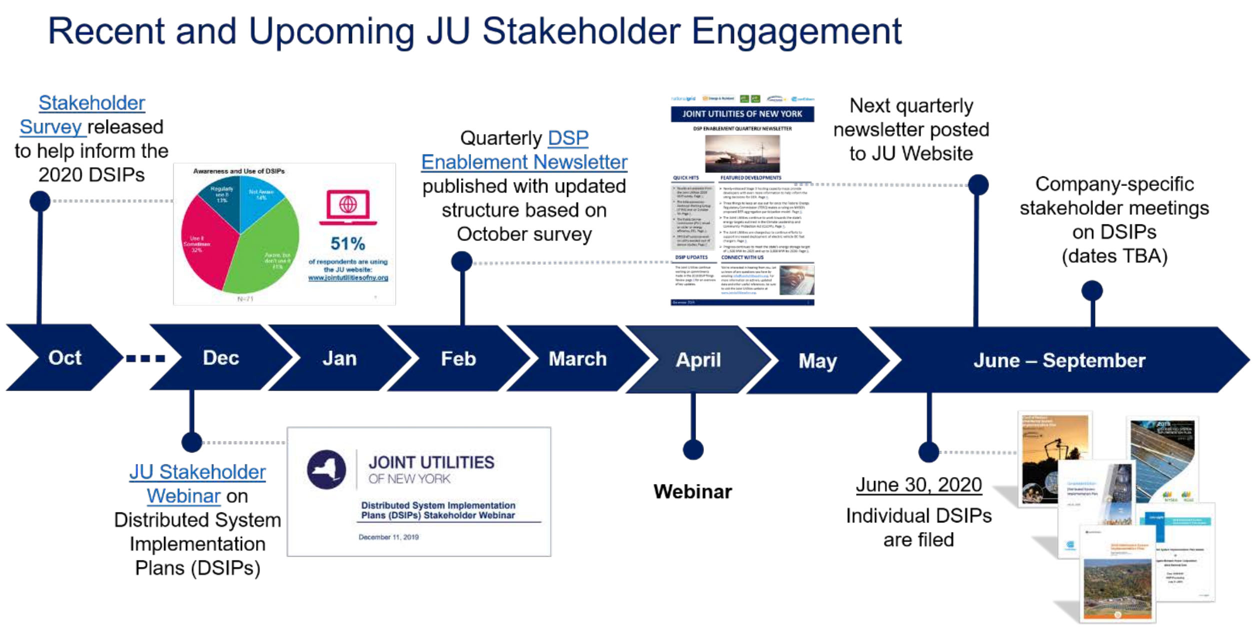
To support consistency across the companies, the Joint Utilities aligned around a common definition of the platform, which includes the three core DSP services of DER integration, information sharing, and market services. The Joint Utilities then developed a common outline for the 2018 DSIP filings in order to align with the requests for information provided in the May 2018 DSIP Guidance to make it easier for stakeholders to access the same information across company filings. The companies also shared timelines and key milestones for filing development in order to support continued comparison and consistency.

The Joint Utilities continued with the implementation efforts based on commitments made in the Supplemental DSIP and 2018 DSIP filings. The Joint Utilities maintained a number of topical implementation working groups. These groups allowed the companies to share information, jointly develop consistent methodologies and Joint Utilities filings, and work with stakeholders to solicit feedback on those methodologies and filings. As a result, the approaches described in the DSIP filings have greater uniformity and stakeholders experience DSPs and market functions that are more consistent across the companies. For example, hosting capacity displays will include the same information and visual elements across companies. To support these collaborative processes across the six companies, the Joint Utilities retained ICF to provide project management office functions and technical expertise, as well as coordination of the implementation working groups and related stakeholder engagement efforts.

The Joint Utilities also continued to collaborate on stakeholder engagement through meetings organized around specific topics across the various working groups.

The Joint Utilities continue to engage stakeholders, as needed, parallel to the working group efforts. Each company is holding utility-specific meetings with stakeholders in the third quarter of 2020, and the Joint Utilities anticipate holding a larger stakeholder conference in the fourth quarter of 2020 to discuss implementation efforts since the DSIP filings and preview future plans. The anticipated stakeholder engagement efforts for 2020 are summarized in Figure 49.

Figure 49: Recent and Upcoming Stakeholder Engagements



6. Describe and explain the planned sequence and timing of the notable activities, dependencies, milestones, and outcomes affecting implementation. Using calendars, Gantt charts, and narrative text, provide information addressing all significant utility processes, resources, and capabilities. Explain how each notable outcome enables one or more significant DSP applications.

The Company's 2020 DSIP filing provides significant details on the timing and key milestones of a number of initiatives that are currently under way. On a summary basis, the key initiatives within the Planning and Operations functional areas include:

- Enhanced capabilities related to probabilistic forecasting including the granular forecasting of DERs;

- Improvements in Hosting Capacity analysis including the Stage 2 refresh and Stage 3 implementation;
- Continued improvements to the Interconnection Online Application Portal with enhanced automation;
- Completion of the implementation of the foundational investments of Distribution Automation, Distribution Management System and Network Strategy enterprise communication infrastructure;
- Development of the new Transmission and Distribution Primary Control Center; and
- Development and Implementation of the policies and procedures and resource needs identified in the Distribution System Operations Whitepaper.

With regard to Markets and Customer engagement, there are a significant number of activities that are being coordinated through the JU efforts. These include:

- Continued implementation of aggressive energy efficiency programs that are economically justified;
- Continued solicitation and implementation of NWA opportunities;
- Improving the process of accurately compensating DERs through participation in the VDER phase 2 proceeding;
- Actively participating in the Electric Vehicle proceeding and help to develop rate structures that foster adoption but are consistent with the goals of REV of improving system load factor;
- Defining reasonable standards for customer data and cyber security that allow for enhanced participation without the threat of security and data breaches; and
- Continued efforts with the NYISO either through the Joint Utility efforts or other stakeholder forums to develop rules and reduce barriers to allow DER to participate in the wholesale market.

V. Appendices

Central Hudson Distributed System Implementation Plan

Appendices

Revised June 30, 2020

People. Power. Possibilities.

Central Hudson

A FORTIS COMPANY

Central Hudson Distributed System Implementation Plan Appendices

Revised June 30, 2020

www.CentralHudson.com

V. Appendices

A. Tools and Information Sources

The following is a listing of the various tool and information resources, and links to the various web pages for DER developers and customers to access the information:

Central Hudson Gas & Electric Corporation	-	www.cenhud.com
Distributed Generation Links	-	www.cenhud.com/dg
Interconnection Application Documents	-	www.cenhud.com/dg
Application Portal	-	www.cenhud.com/dg
Interconnection Technical Requirements	-	www.cenhud.com/dg
Interconnection Queue	-	www.cenhud.com/dg
Interconnection FAQs	-	www.cenhud.com/dg
System Data Links		
Hosting Capacity Map	-	www.cenhud.com/dg
System Data Portal	-	www.cenhud.com/dg
Joint Utilities System Data Page	-	http://jointutilitiesofny.org/system-data/
Electric Vehicles Information	-	www.cenhud.com/electricvehicles
Programs and Incentives	-	www.cenhud.com/electricvehicles
Consumer Information	-	www.cenhud.com/electricvehicles
Charging	-	www.cenhud.com/electricvehicles
FAQs	-	www.cenhud.com/electricvehicles
Energy Efficiency	-	www.cenhud.com/my-energy
Programs	-	www.cenhud.com/my-energy
Savings Central	-	www.cenhud.com/my-energy
Consumer information	-	www.cenhud.com/my-energy
CenHub Store	-	https://www.cenhubstore.com/
Capital Plan Link	-	http://jointutilitiesofny.org/system-data/
Reliability Data Link	-	http://jointutilitiesofny.org/system-data/

Related REV Proceedings

The following is a listing of the related NYS PSC proceedings and efforts underway:

- Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (Case 14-M-0101)
- In the Matter of Distributed System Implementation Plans (Case 16-M-0411)
- In the Matter of the Value of Distributed Energy Resources (Case 15-E-0751)
- VDER Working Group Regarding Value Stack (Matter 17-01276)
- VDER Working Group Regarding Rate Design (Matter 17-01277)
- VDER Low Income Working Group Regarding Low and Moderate Income Customers (Matter 17-01278)
- Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (Case 18-E-0138)
- In the Matter of Offshore Wind Energy (Case 18-E-0071)
- In the Matter of Energy Storage Deployment Program (Case 18-E-0130)
- In the Matter of Utility Energy Efficiency Programs (Case 15-M-0252 and 18-M-0084)
- In the Matter of the Utility Energy Registry (Case 17-M-0315)
- Whole Building Energy Data Aggregation Standard (Cases 16-M-0411)
- Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and Clean Energy Standard (Case 15-E-0302)
- In the Matter of the Regulation and Oversight of Distributed Energy Resource Providers and Products (Case 15-M-0180)
- In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements for Small Distributed Generators (Case 18-E-0018)
- Dynamic Load Management Programs (Cases 14-E-0423 and 15-E-0189)
- Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place (18-M-0376)
- Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs (14-M-0224)
- Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies (19-E-0283)
- In the Matter of Consolidated Billing for Distributed Energy Resources (19-M-0463)
- Proceeding on Motion of the Commission to Consider Resource Adequacy Matters (19-E-0530)
- In the Matter of Strategic Use of Energy Related Data (20-M-0082)

B. Load and DER Forecast

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

2020 Central Hudson
Granular Load and Distributed Energy Resources Forecasts

Prepared for Central Hudson
By
Demand Side Analytics
June 2020

ACKNOWLEDGEMENTS

Demand Side Analytics Team

- Josh Bode
- Alana Lemarchand
- Adriana Ciccone
- Steve Morris
- Mark Noll

Central Hudson Team

- John Borchert
- Hal Turner
- Rich Wright
- Stephanie Palmer

ABSTRACT

The focus of the study is to present the methodology and results for granular forecasting for four distributed energy resources (DERs) – energy efficiency, solar, battery storage, and electric vehicle charging – at the Central Hudson system level and for each individual substation. In particular, we developed 8760 production profiles for each DER and calculated the coincidence factors for each DER and local load area. The expected 8760 production profiles and 90th percentile forecasts will be posted on the Central Hudson website as part of the 2020 DSIP.

TABLE OF CONTENTS

1 INTRODUCTION

A vital role of Central Hudson is to ensure that electricity supply remains reliable by projecting future electricity demand and reinforcing the transmission and distribution systems so the capacity is available to meet local needs as they grow over time. Load forecasts done on a system wide basis and for individual components of the system, including substations and transmission areas, are one key input required to achieve system reliability. Another key input is a set of forecasts of the granular load impacts of different types of distributed energy resources (DERs). The growth of DERs affects both (1) how, when, and where customers use electricity and (2) how, when, and where electricity is produced. This report describes the methodology used to forecast the future impacts on electricity usage and production, and the key results, for four DERs: energy efficiency, solar, battery storage, and electric vehicle charging.

The report is structure as follows:

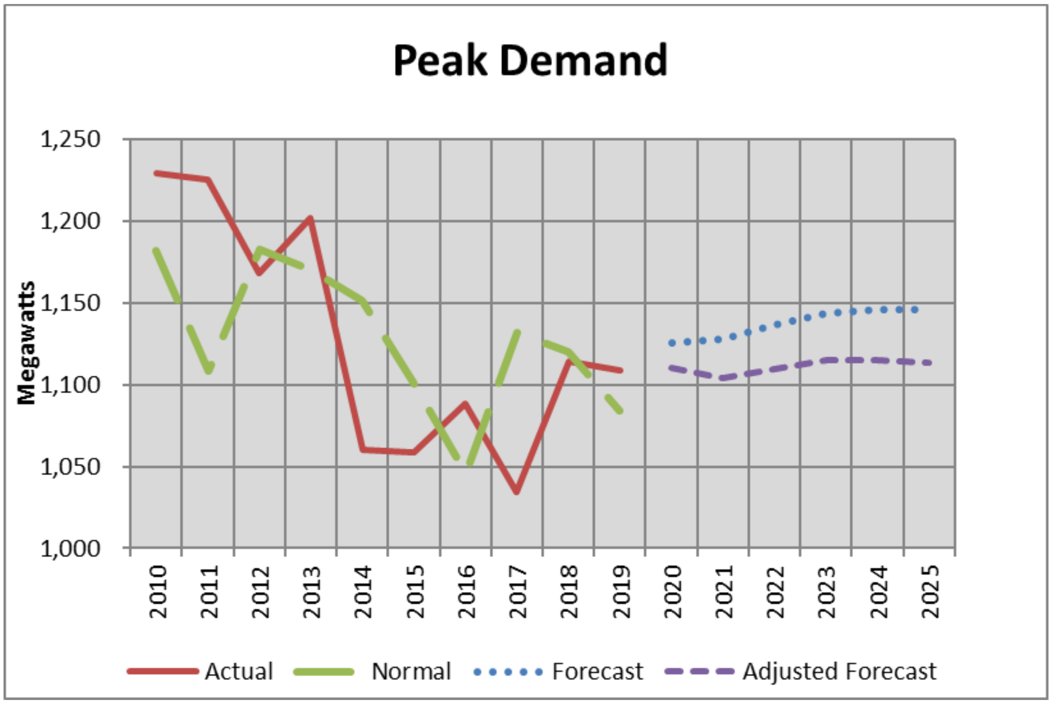
- Section 2 provides an overview of the load forecast for the Central Hudson system as well as for different sub-components including transmission areas and substations.
- Section 3 presents the forecasting methodology and the load impacts for each of the four DERs. The key outputs are the 8760 load impacts for each DER and the coincidence factors associated with each sub-component of Central Hudson's system.
- The Appendices provide additional detail regarding the forecasting methodology and locational results for energy efficiency, solar, and electric vehicles.

2 LOAD FORECASTS

2.1 SYSTEM LEVEL FORECAST

Figure 1 provides the current 5 Year System Wide Forecast. Central Hudson peak loads have declined in recent years due in part to more efficient appliances and building, program based energy efficiency, and increased solar adoption. Going forward, additional adoption of energy efficiency and solar are expected to result in relatively flat peak load patterns.

Figure 1: System Historical and Forecasted Peaks



Central Hudson has evolved its planning process to produce granular, location-specific, probabilistic forecasts. The granular forecasts were produced as part of the T&D marginal cost study and the methodology for producing them is discussed in more detail in that study. In this section, we provide forecasting results as context for the DER granular forecasting and coincidence factor results.

2.2 TRANSMISSION AREAS

Table 1 shows the historical peaks and growth rates for each of Central Hudson's 10 transmission areas, along with the rating (including NWA capacity), while Table 2 shows weather normalized historical and forecasted peaks as well as each location's loading factor.[1] Locations with loading factors closer to 100% have less room for growth. Most transmission areas are experiencing declining or flat load growth and/or have low loading factors. However, two transmission areas – Northwest 115-69kV and Northwest 69kV (which is a subset of Northwest 115-69kV) – are both loaded above 80% and are experiencing positive growth of 1-2% per year. Of these two areas, only the Northwest 115-69kV area is at risk of triggering an infrastructure investment by the end of 2029 (the ten-year study period) in the absence of further load relief. The overload risk at Northwest 115-69kV is driven by three factors: a) expected moderate load growth; b) a ratings decrease of approximately 13 MVA resulting from generation retirement in 2025, and; c) the expiration of an approximately 10 MVA NWA at the end of 2029 that currently serves the Northwest 115-69kV and Northwest 69kV area. By contrast, the rating for the Northwest 69kV area will more than double starting in 2025 as a result of non-deferrable infrastructure upgrades, reducing overload risk to essentially zero. For more detail, see the T&D marginal cost study.

Table 1: Transmission Area Historical Load Growth Estimates (2014-2019)

Transmission Area	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Ellenville	251.0	58.0	61.1	64.1	60.7	62.3	61.4	24.5%	1.3%	1.5%
Hurley-Milan	193.0	81.8	80.7	80.4	79.0	83.4	80.5	42.1%	0.4%	1.1%
Mid-Dutchess	230.0	118.8	117.0	113.5	113.0	110.6	108.1	51.1%	-1.3%	0.9%
NW 115-69 Area	149.6	126.7	119.4	125.7	127.4	132.2	128.6	82.5%	1.2%	1.3%
NW 69 Area	116.1	102.3	99.5	98.3	104.2	105.5	106.9	82.5%	1.8%	1.3%
Pleasant Valley 69	107.0	72.4	67.8	73.6	71.2	69.8	59.4	60.7%	0.2%	2.0%
RD-RJ Lines	144.0	87.2	88.5	89.0	89.7	89.5	92.8	60.3%	1.1%	1.4%
Southern Dutchess	211.0	146.8	145.3	141.2	137.6	139.3	139.2	70.3%	-1.6%	0.7%
WM Line	68.0	41.8	43.5	45.2	43.4	48.8	40.2	63.7%	1.7%	1.9%
Westerlo Loop	83.6	67.7	66.6	66.2	64.1	57.4	62.6	71.5%	-0.9%	1.3%

[1] The loading factor is defined as the 2019 weather-normalized peak load divided by the 2019 rating, including NWA capacity.

Table 2: Transmission Area 1-in-2 Normalized Peak Load Estimates, Historical (2015-2019) and Forecast (2020-2025)

Transmission Area	Historical 1 in 2 Annual Peak (MVA)					Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Ellenville	58.4	59.1	59.9	60.7	61.5	61.7	62.5	63.4	64.2	65.1	65.9	251.0
Hurley-Milan	80.1	80.4	80.7	80.9	81.2	81.3	81.6	81.9	82.2	82.5	82.8	193.0
Mid-Dutchess	123.8	122.2	120.7	119.1	117.5	117.1	115.6	114.1	112.6	111.2	109.7	230.0
NW 115-69 Area	117.7	119.1	120.5	122.0	123.4	123.9	125.3	126.9	128.4	129.9	131.5	149.6
NW 69 Area	89.2	90.8	92.5	94.1	95.8	96.3	98.1	99.8	101.7	103.5	105.4	116.1
Pleasant Valley 69	64.7	64.8	64.8	64.9	65.0	65.0	65.1	65.2	65.3	65.5	65.6	107.0
RD-RJ Lines	83.2	84.1	85.0	86.0	86.9	87.2	88.1	89.1	90.1	91.1	92.1	144.0
Southern Dutchess	158.3	155.7	153.2	150.8	148.3	147.6	145.2	142.9	140.6	138.3	136.1	211.0
WM Line	40.6	41.3	41.9	42.6	43.3	43.5	44.2	45.0	45.7	46.5	47.2	68.0
Westerlo Loop	62.0	61.5	60.9	60.4	59.8	59.7	59.1	58.6	58.1	57.6	57.1	83.6
System	**995.5**	**1006.9**	**1019.8**	**1033.3**	**1046.4**	**1050.5**	**1064.9**	**1080.2**	**1094.1**	**1107.1**	**1121.4**	**N/A**

2.3 SUBSTATIONS

Table 3 shows the weather normalized historical loads and the forecast loads for each substation as well as the rating, grouped by load area (load areas are groups of neighboring substations). The peak loads are location specific and are not necessarily coincident with the load area or system peak. Most substations are experiencing declining loads or are not highly loaded. In addition, most locations that are highly loaded and are experiencing load growth can address potential overloads via low-cost load transfers to neighboring substations. The only location at risk of overload without the option of relying on load transfers for load relief is the Shenandoah-Distribution substation, which is driven by positive expected load growth and the expiration of an existing NWA at the end of 2026. For more detail, see the T&D marginal cost study.

Table 3: Substation 1-in-2 Normalized Peak Load, Historical (2015-2019) and Forecast (2020-2025)

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)					Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Ellenville	Clinton Ave	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.6	1.6	7.7
	Greenfield Rd*	6.2	6.3	6.5	6.7	6.8	6.9	7.0	7.2	7.4	7.6	7.8	15.4
	Grimley Rd	4.1	4.2	4.2	4.3	4.4	4.4	4.5	4.6	4.7	4.7	4.8	7.2
	High Falls	16.9	17.1	17.3	17.5	17.6	17.7	17.9	18.1	18.3	18.4	18.6	34.5
	Honk Falls	6.5	6.4	6.3	6.2	6.1	6.0	5.9	5.8	5.7	5.6	5.5	18.2
	Kerhonkson	8.4	8.6	8.8	9.0	9.3	9.3	9.6	9.8	10.1	10.4	10.7	44.6
	Neversink*	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	4.9
	Sturgeon Pool	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	29.7
	Total	**46.5**	**47.3**	**48.0**	**48.7**	**49.5**	**49.7**	**50.5**	**51.2**	**52.0**	**52.9**	**53.7**	**N/A**
Fishkill-D	Fishkill Plains	35.1	35.6	36.0	36.4	36.8	36.9	37.4	37.8	38.3	38.7	39.2	49.9
	Forgebrook	26.8	26.7	26.7	26.6	26.6	26.5	26.5	26.4	26.4	26.3	26.3	47.8
	Knapps Corners	21.0	20.7	20.4	20.0	19.7	19.6	19.3	19.0	18.7	18.4	18.1	47.8
	Merritt Park	33.1	32.9	32.7	32.5	32.4	32.3	32.1	32.0	31.8	31.6	31.5	52.2
	Myers Corners	22.3	21.9	21.6	21.3	20.9	20.8	20.5	20.2	19.9	19.6	19.3	35.1

	North Chelsea	19.5	19.5	19.5	19.5	19.5	19.6	19.6	19.6	19.6	19.6	19.6	48.3
	Sand Dock-D	3.9	4.0	4.1	4.3	4.4	4.4	4.5	4.7	4.8	4.9	5.1	8.0
	Shenandoah-D	11.5	11.6	11.8	11.9	12.1	12.1	12.3	12.5	12.6	12.8	13.0	12.7
	Tioronda	13.1	13.3	13.4	13.6	13.8	13.9	14.1	14.3	14.5	14.7	14.9	25.7
	Total	**186.3**	**186.1**	**185.8**	**185.7**	**185.4**	**185.4**	**185.2**	**185.0**	**184.8**	**184.6**	**184.4**	**N/A**
Kingston-Saugerties	Boulevard	24.2	23.3	22.4	21.6	20.7	20.5	19.7	19.0	18.3	17.6	17.0	35.0
	East Kingston	12.3	12.2	12.2	12.1	12.1	12.0	12.0	12.0	11.9	11.9	11.8	48.0
	Hurley Ave	16.7	17.0	17.2	17.4	17.6	17.7	17.9	18.1	18.4	18.6	18.9	23.1
	Lincoln Park	43.7	43.1	42.5	42.0	41.4	41.2	40.7	40.2	39.6	39.1	38.6	84.0
	Saugerties	20.6	20.6	20.6	20.6	20.6	20.6	20.5	20.5	20.5	20.5	20.5	54.1
	Woodstock	17.2	17.5	17.8	18.1	18.4	18.5	18.8	19.1	19.4	19.8	20.1	19.1
	Total	**133.1**	**131.9**	**130.9**	**129.8**	**128.7**	**128.4**	**127.4**	**126.3**	**125.3**	**124.3**	**123.2**	**N/A**
Modena	Galeville	9.9	10.1	10.2	10.4	10.6	10.7	10.8	11.0	11.2	11.4	11.6	28.7
	Highland	17.4	17.6	17.7	17.9	18.0	18.1	18.2	18.4	18.6	18.8	18.9	32.9
	Modena	12.2	12.4	12.7	12.9	13.2	13.3	13.6	13.9	14.2	14.5	14.8	25.9
	Ohioville	21.7	21.7	21.6	21.6	21.5	21.5	21.5	21.4	21.4	21.3	21.3	29.7
	Total	**59.2**	**59.9**	**60.6**	**61.3**	**62.0**	**62.2**	**62.9**	**63.6**	**64.3**	**65.1**	**65.8**	**N/A**
Newburgh	Bethlehem Rd	35.1	35.0	34.8	34.7	34.6	34.5	34.4	34.3	34.2	34.1	34.0	47.8
	Coldenham	32.9	32.3	31.7	31.1	30.5	30.3	29.8	29.2	28.7	28.1	27.6	47.8
	East Walden	13.8	13.9	14.0	14.2	14.3	14.3	14.5	14.6	14.8	14.9	15.1	26.2
	Marlboro	16.8	17.2	17.6	18.0	18.4	18.6	19.0	19.5	19.9	20.4	20.9	30.9
	Maybrook	13.9	14.5	15.1	15.7	16.4	16.6	17.3	18.0	18.8	19.5	20.3	24.0
	Montgomery*	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	2.8
	Union Ave	47.4	48.4	49.5	50.5	51.6	51.9	53.1	54.2	55.4	56.6	57.8	94.5
	West Balmville	33.5	33.7	33.9	34.1	34.3	34.3	34.5	34.7	34.9	35.1	35.3	47.8
	Total	**193.8**	**195.2**	**196.7**	**198.2**	**199.7**	**200.2**	**201.7**	**203.3**	**204.9**	**206.5**	**208.2**	**N/A**
Northeastern Dutchess	East Park	12.2	12.3	12.5	12.6	12.8	12.8	12.9	13.1	13.2	13.4	13.6	24.2
	Hibernia	8.9	9.2	9.4	9.7	9.9	10.0	10.3	10.6	10.9	11.2	11.5	17.8
	Milan	6.1	6.2	6.4	6.5	6.7	6.7	6.8	7.0	7.1	7.3	7.4	25.9
	Millerton	4.8	4.8	4.9	4.9	5.0	5.0	5.0	5.1	5.1	5.2	5.3	8.3
	Pulvers 13	4.2	4.3	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.8
	Pulvers 34	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	17.2
	Rhinebeck	28.6	28.6	28.6	28.7	28.7	28.7	28.8	28.8	28.9	28.9	29.0	47.8
	Smithfield	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	5.8
	Staatsburg	8.2	8.3	8.4	8.6	8.7	8.8	8.9	9.1	9.2	9.4	9.5	26.5
	Stanfordville	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.6	6.3
	Tinkertown	13.1	13.2	13.3	13.5	13.6	13.7	13.8	14.0	14.2	14.3	14.5	19.1
	Total	**92.2**	**93.2**	**94.2**	**95.2**	**96.2**	**96.5**	**97.5**	**98.6**	**99.6**	**100.7**	**101.8**	**N/A**
Northwest	Coxsackie*	9.9	10.2	10.5	10.8	11.1	11.2	11.5	11.9	12.2	12.6	13.0	16.4
	Freehold	6.0	6.1	6.2	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.9	15.7
	Hunter	10.0	9.5	9.0	8.5	8.1	7.9	7.5	7.1	6.8	6.4	6.1	19.5
	Lawrenceville	10.8	10.3	9.9	9.4	9.0	8.8	8.5	8.1	7.7	7.4	7.0	22.1
	New Baltimore	7.2	7.7	8.1	8.5	9.0	9.2	9.7	10.2	10.8	11.4	12.0	25.8
	North Catskill	23.2	23.3	23.4	23.5	23.6	23.6	23.7	23.8	23.9	23.9	24.0	35.1
	South Cairo*	9.8	10.1	10.4	10.6	10.9	11.0	11.3	11.6	11.9	12.2	12.5	19.9
	Vinegar Hill	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	20.7
	Westerlo	7.8	7.8	7.9	8.0	8.1	8.1	8.2	8.3	8.4	8.4	8.5	27.0
	Total	**85.9**	**86.3**	**86.7**	**87.1**	**87.4**	**87.5**	**87.9**	**88.3**	**88.7**	**89.1**	**89.5**	**N/A**
Poughkeepsie-D	Inwood Ave	23.5	23.6	23.7	23.8	23.9	23.9	24.0	24.1	24.2	24.3	24.4	47.8
	Manchester	29.7	30.0	30.3	30.6	30.9	31.0	31.3	31.6	31.9	32.2	32.5	47.8
	Reynolds Hill	30.9	31.4	31.9	32.5	33.0	33.1	33.7	34.2	34.8	35.3	35.9	47.8
	Spackenkill	31.5	31.2	31.0	30.8	30.5	30.5	30.3	30.1	29.8	29.6	29.4	47.8
	Todd Hill	21.3	21.4	21.5	21.6	21.6	21.7	21.8	21.8	21.9	22.0	22.1	47.8
	Total	**133.3**	**134.0**	**134.6**	**135.3**	**135.9**	**136.1**	**136.8**	**137.5**	**138.2**	**138.9**	**139.5**	**N/A**

3 ENERGY EFFICIENCY

Energy efficiency programs are the most well-established DER at Central Hudson. However, planning and program administration are still typically at the territory-wide level. As planning becomes more granular, it is becoming increasingly useful to understand the locational dispersion of energy efficiency and increasingly possible to incorporate more granular predictions of DER growth into load forecasts. The goal of this analysis is to describe the process of producing 8760 forecasts for energy efficiency for each substation, which account for the temporal and locational variation in energy efficiency savings.

3.1 METHODOLOGY OVERVIEW

Figure 2 provides a high-level overview of the forecasting process for energy efficiency. Bottom-up forecasts were developed by analyzing savings from efficiency measures deployed historically within each transmission area and substation and calibrating this locational dispersion of energy efficiency savings to match total historical and forecasted "top-down" savings, then combining annual savings with an 8760 production profile to produce system peak day and location-specific load reductions. Figure 3 provides more detail on each step in the analysis.

Figure 2: Energy Efficiency Forecast Process Overview

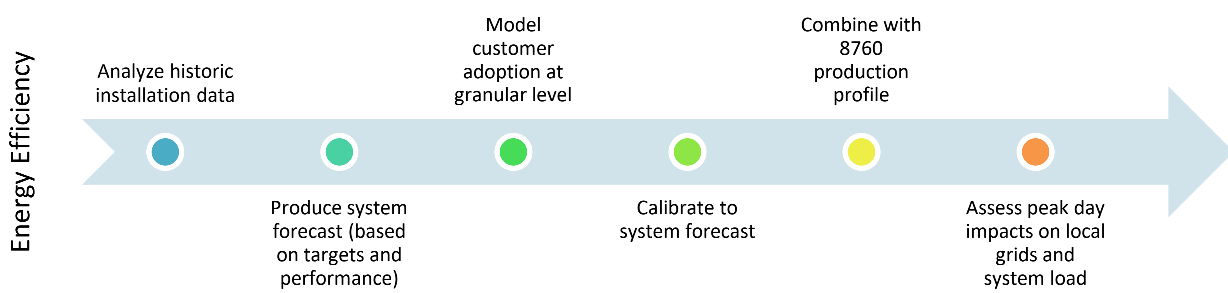


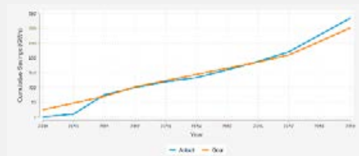
Figure 3: Energy Efficiency Forecast Process Detail

1. Key Drivers & Data

- Central Hudson billing data and historical records of energy efficiency installations and savings
- Energy efficiency programs are more established than other DERS, but adoption varies by location and end use

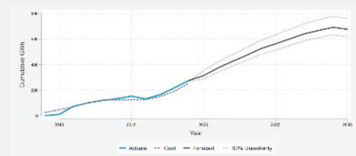
2. Analyze Historical Data

- Assess energy efficiency savings over time
- Assess geographic concentration



3. Produce System Forecast

- Actual cumulative savings have tracked closely to goals over the past 10 years
- Use historical performance variability to forecast system

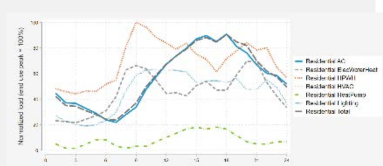


4. Granular Adoption

- Savings allocated based on historical dispersion for measures where customer-level data was available
- Remaining measures allocated proportionally by customer usage
- Scaled to match system-level savings

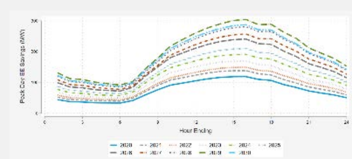
5. 8760 Load Shapes

- Derived from Central Hudson 1 in 2 weather year for 2013
- Individual hourly load shapes developed by sector, end use, and industry (same as 2016 DSIP)



6. Peak Day Impacts

- Apply load shapes to savings forecasts by program/ measure end use
- Output is location-specific forecasts and local peak coincidence factors



3.2 RESULTS

Central Hudson's annual net energy efficiency savings goal range ranges from 39.9 GWh to 69.8 GWh per year through 2030 based on the 2020 Cadmus Energy Efficiency Market Potential Study. To develop our system-wide forecast, we took these forecasted savings, added them to the historical cumulative savings, and then applied the average historical performance. Figure 4 shows the historical actual energy efficiency savings and forecast energy efficiency savings in GWh, along with historical goals and the forecast uncertainty bands. All energy savings represent first-year savings.

Figure 4: Energy Efficiency Savings: Historical and Forecast with Uncertainty

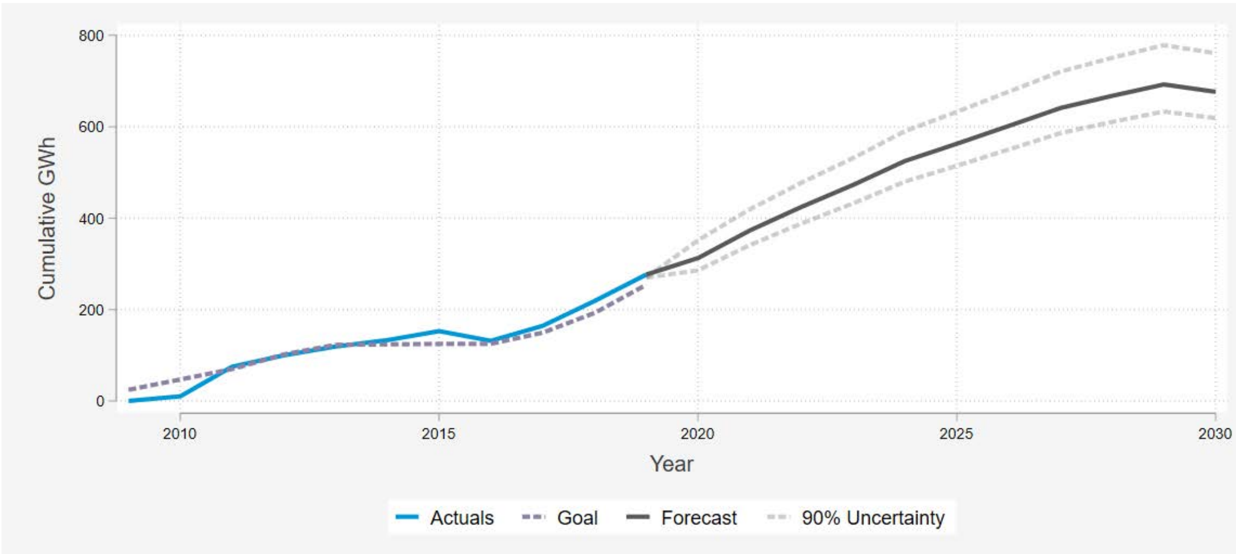


Figure 5 shows the system peak day reduction due to cumulative energy efficiency activity for 2015 to 2025. Figure 6 shows the forecasted peak day savings by sector and program category for 2025. shows the monthly peak contribution of the p50 forecast for energy efficiency relative to system load forecast, also for 2025.

Figure 5: Forecasted Energy Efficiency Savings Peak Day: 2015-2025

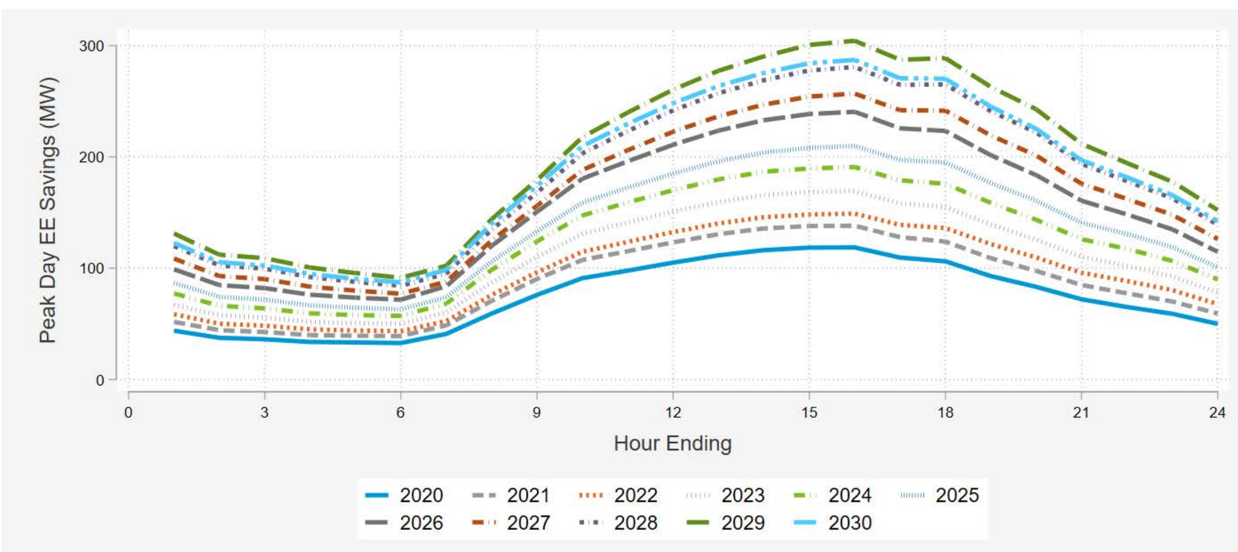


Figure 6: Forecasted Energy Efficiency Savings Peak Day by Category: July 2025

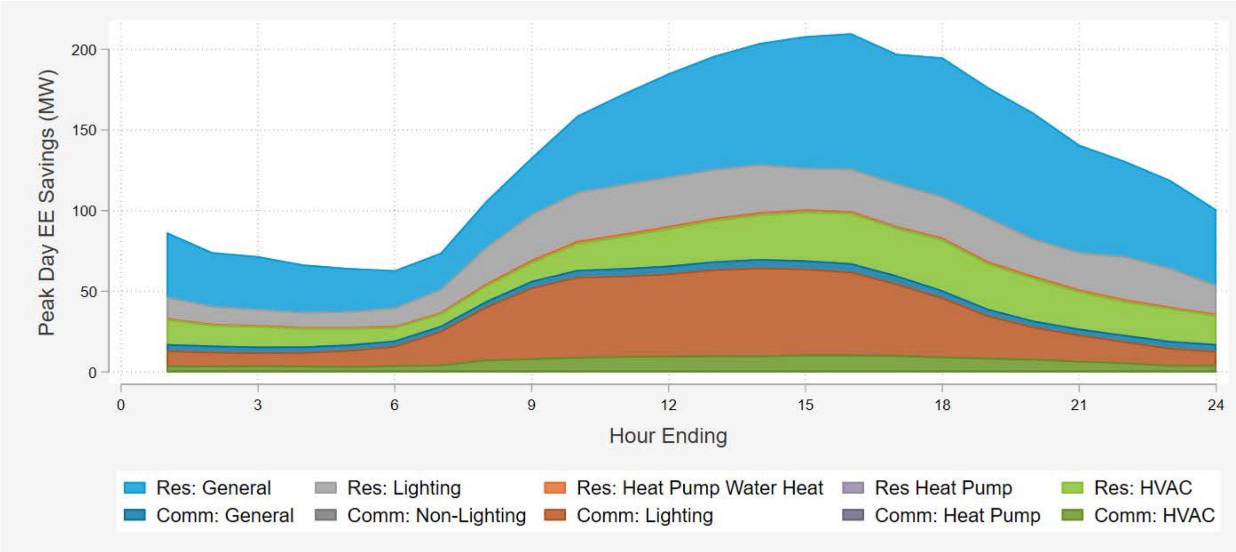


Table 4: Energy Efficiency Forecast Loads (p50) During Monthly Peaks, 2025

Month	Peak Hour	Forecast System Load (MW)	Forecast EE Load (MW)
1	19	901.0	87.0
2	19	828.3	90.3
3	21	806.1	80.7
4	20	716.2	72.5
5	17	1026.3	154.9
6	15	1069.7	175.0
7	17	1214.1	197.3
8	16	950.5	134.8
9	15	1106.1	190.1
10	20	714.1	70.9
11	2	888.9	39.2
12	18	909.1	87.8

In addition to system-wide savings, we calculated the coincident peak day contribution of energy efficiency by substation for each year. Figure 7 shows the local peak contribution in 2019 and 2025 by substation, expressed as a percentage of each substation's peak load, to normalize for substation size. Note that the scale doubles between 2019 and 2025, going from a maximum penetration of 12% in 2019 to 24% in the 2025 forecast.

Figure 7: Energy Efficiency Peak Day Contribution by Substation – 2019 and 2025

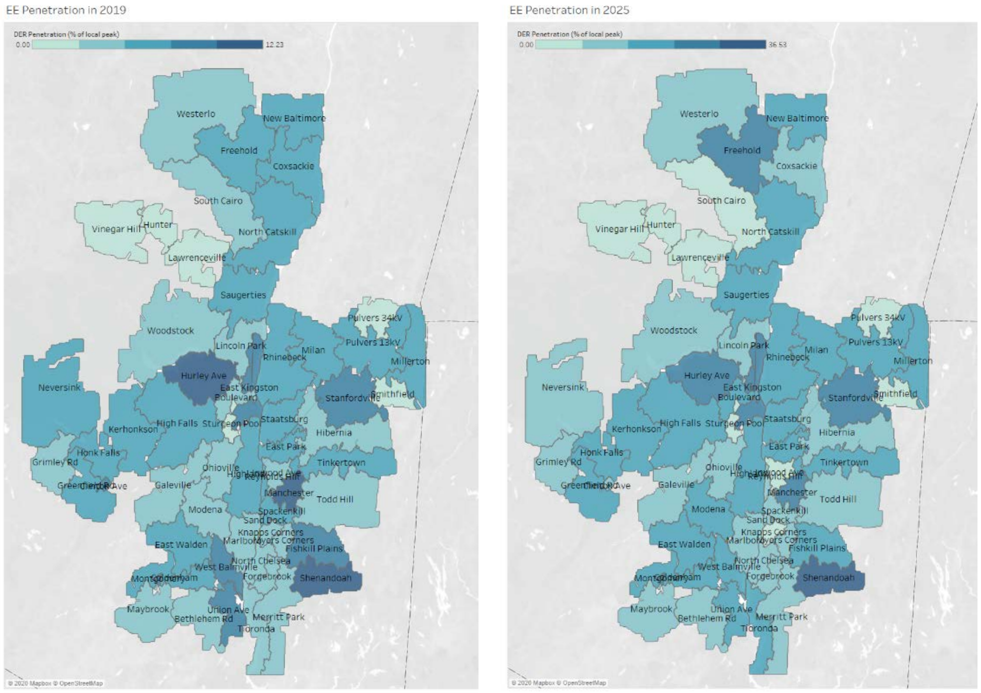


Table 5 shows the weather-normalized peak savings in MW coincident with the local peak of each load area. The estimates show the aggregate effect of multiple years of energy efficiency activity. By 2025, system peak savings from energy efficiency are projected to total approximately 165 MW. Because of differences on when local peaks occur, the sum of individual loads areas does not equal the system coincident peak savings.

Table 5: Peak Coincident Demand Savings by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	1.2	1.8	1.9	2.2	2.8	4.6	5.4	6.2	7.0	8.0	8.9
Fishkill-D	7	19	10.0	7.1	7.6	8.4	9.6	14.1	16.7	19.5	22.5	25.9	29.1
Kingston-Saugerties	7	17	3.3	4.7	5.5	6.6	8.4	12.7	14.9	17.2	19.6	22.1	24.7
Modena	7	18	3.2	2.7	3.8	4.0	4.5	6.5	7.5	8.5	9.6	11.0	12.0
Newburgh	7	17	7.3	8.7	10.5	11.5	14.3	19.8	23.2	25.9	29.0	32.7	36.0
Northeastern Dutchess	7	19	2.9	3.4	4.2	4.5	5.1	8.1	9.5	10.9	12.3	14.2	16.0
Northwest	1	18	1.2	1.0	1.7	2.7	3.5	4.1	5.0	5.8	6.6	7.3	7.9
Poughkeepsie-D	9	17	1.7	2.3	2.8	3.7	4.3	5.2	6.2	7.2	7.9	8.9	9.6
System	**7**	**17[2]**	**40.5**	**40.1**	**46.8**	**52.8**	**62.6**	**90.5**	**105.9**	**120.8**	**130.2**	**148.1**	**164.9**

[2] System peak hour shifts to HE 18 starting in 2023.

4 DISTRIBUTED SOLAR

Distributed solar comprises the largest portion of distributed energy resources (DERs). As of January 2020, there were 9,500 total distributed solar installations in Central Hudson territory with 127 MW of installed capacity. Because solar generation is concentrated during the day and is higher in summer than in winter, the contribution to local peak relief can vary greatly by location, depending on the time and season of the peak.

4.1 METHODOLOGY OVERVIEW

For forecasting purposes, we divided distributed solar in Central Hudson territory into five different sectors: residential solar; smaller non-residential solar, including <300 kW remote net metered ("RNM") solar; large non-residential >300kW remote RNM solar; community distributed generation solar ("CDG"); and projects in the NYISO interconnection queue that will interconnect to the distribution network. The residential sector comprised the majority of capacity as of January 2020.

Figure 8 provides a high level overview of the forecasting process for each solar sector. Bottom-up forecasts were developed by forecasting solar capacity for each sector for each transmission area and substation and then summing each sector and combining with an 8760 production profile to produce system peak day and location-specific load reductions. Figure 9 provides more detail on each step, including distinctions in forecasting methods for different sectors.

Figure 8: Solar Forecast Process Overview

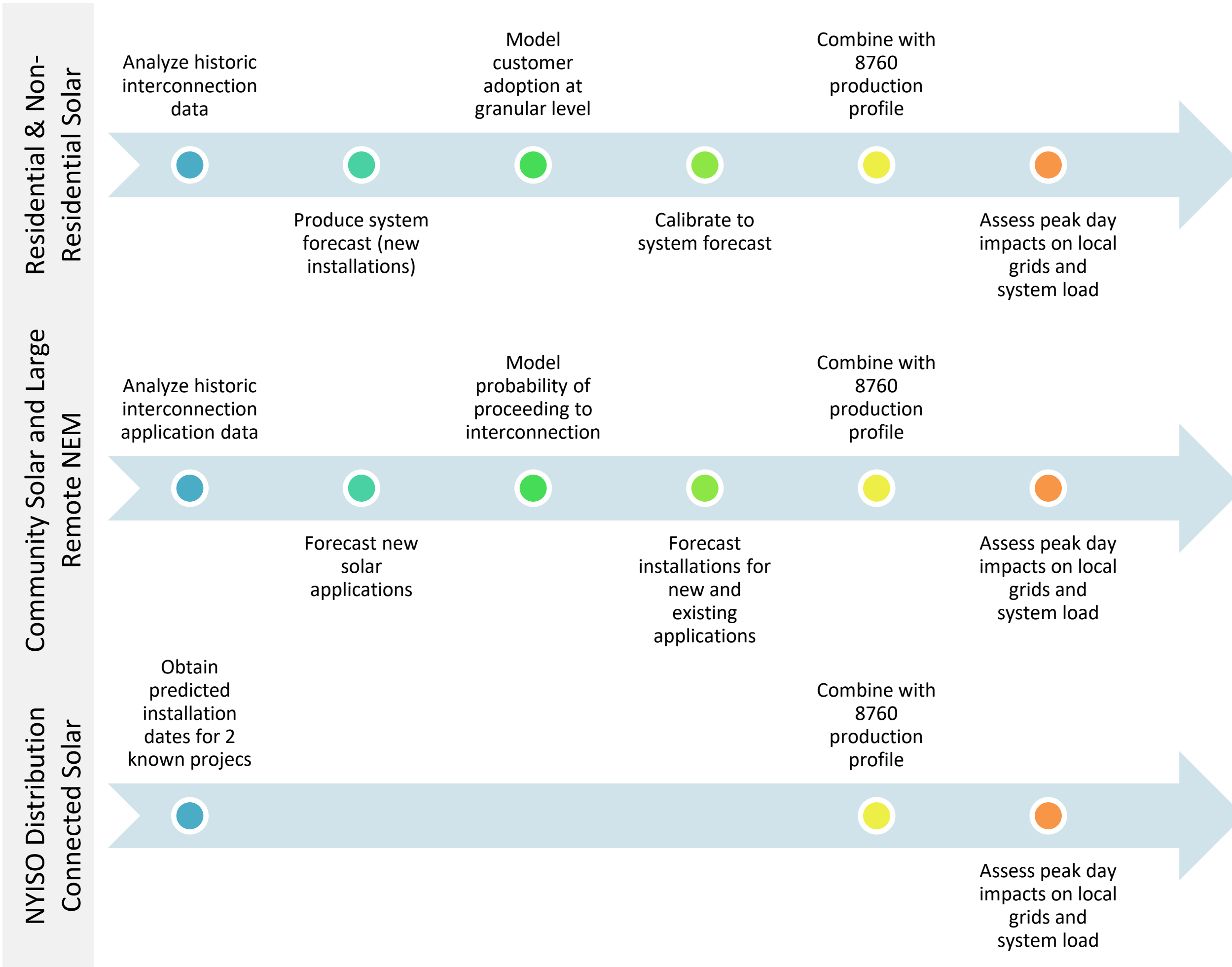


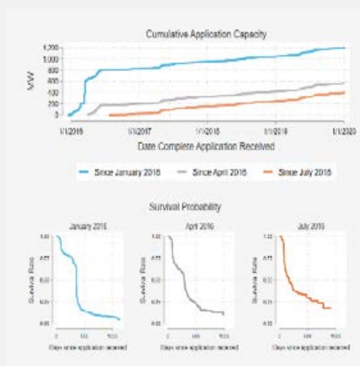
Figure 9: Solar Forecast Process Detail

1. Data and Key Drivers

- Central Hudson historic interconnection queue data (including existing projects in queue)
- NYISO interconnection queue
- NY SUN solar cost database
- Key forecast drivers include the historic installation trend, introduction of the lease/PPA models, cost per watt, and policy incentives

2. Analyze Historical Data

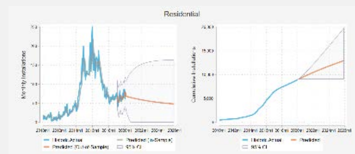
- Assess historical interconnection application and installation patterns
- **RES/NON-RES** - Identify key predictors of solar adoption
- **CDG/RNM** - Use Markov Chain transition matrix to calculate probability of interconnection for applications in queue



3. Produce System Capacity Forecast

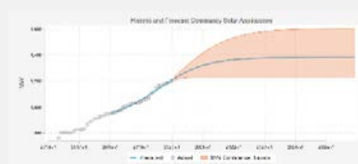
RES/NON-RES

- Use time series forecasting with uncertainty
- Selected best model out of options tested on historic data



CDG/RNM

- Predict new applications based on Bass Diffusion curve
- Predict interconnection capacity based on Markov Chain transition matrix (not all projects in queue proceed to interconnection)



4. Granular Adoption

RES/NON-RES

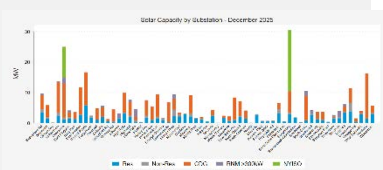
- Model the probability of adoption for each customer
- Calibrate so sum of substations equals aggregate forecast

CDG/RNM

- Existing applications already tied to substation
- New application capacity based on historic distribution of applications

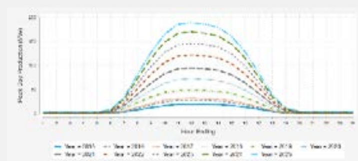
NYISO PROJECTS

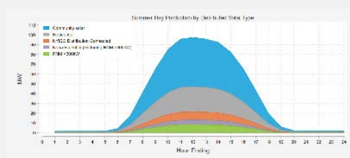
- Predict interconnection date and location for 2 projects (30 MW total)



5. 8760 Load Shapes

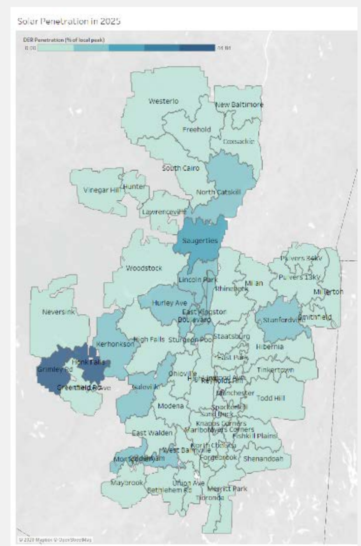
- Calculated average monthly profile based on ISO-NE actual historical solar generation data
- Performance adjustment factor (70% Res / 75% Non-Res / 80% CDG/RNM)
- Hourly MW output is capacity multiplied by production profile





6. Peak Day Impacts

- Aggregate all solar category types for each substation
- Output is location-specific forecasts and local peak coincidence factors



4.2 RESULTS

The final system-wide forecast was created by combining all individual solar components. Figure 10 shows the forecast by solar type, while shows the forecast with the 95% confidence interval. Our estimates predict that by the end of 2025 there will be approximately 340 MW of installed solar capacity online compared to the 127 MW as of January 2020, with the majority of the growth expected from community solar installations.

Figure 10: Solar Capacity Forecast by Solar Type

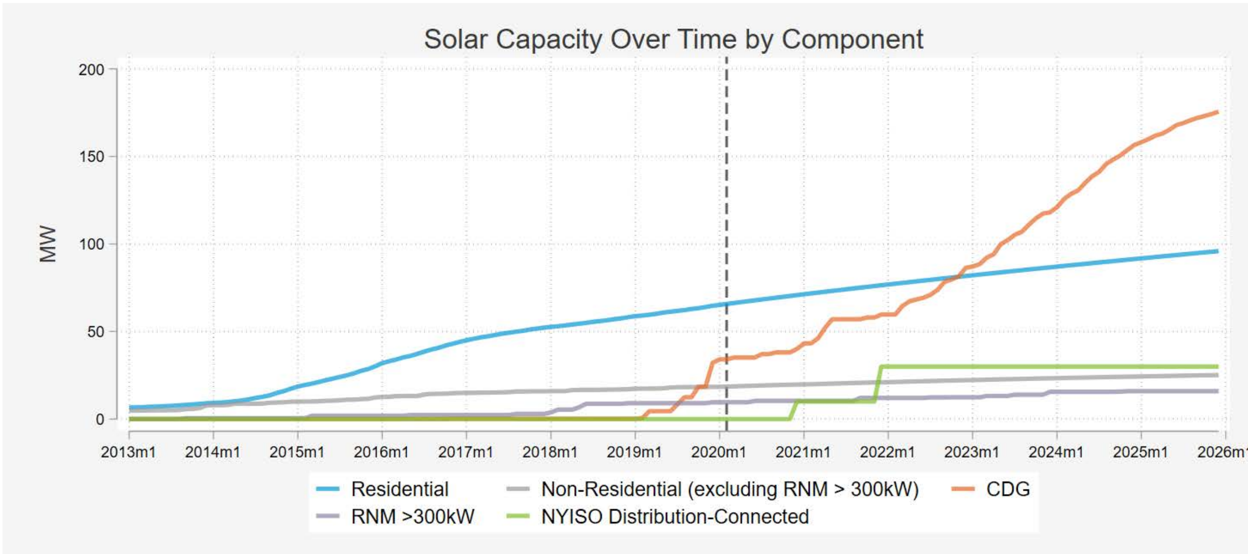


Figure 11: Solar Capacity Forecast with 95% Confidence Interval

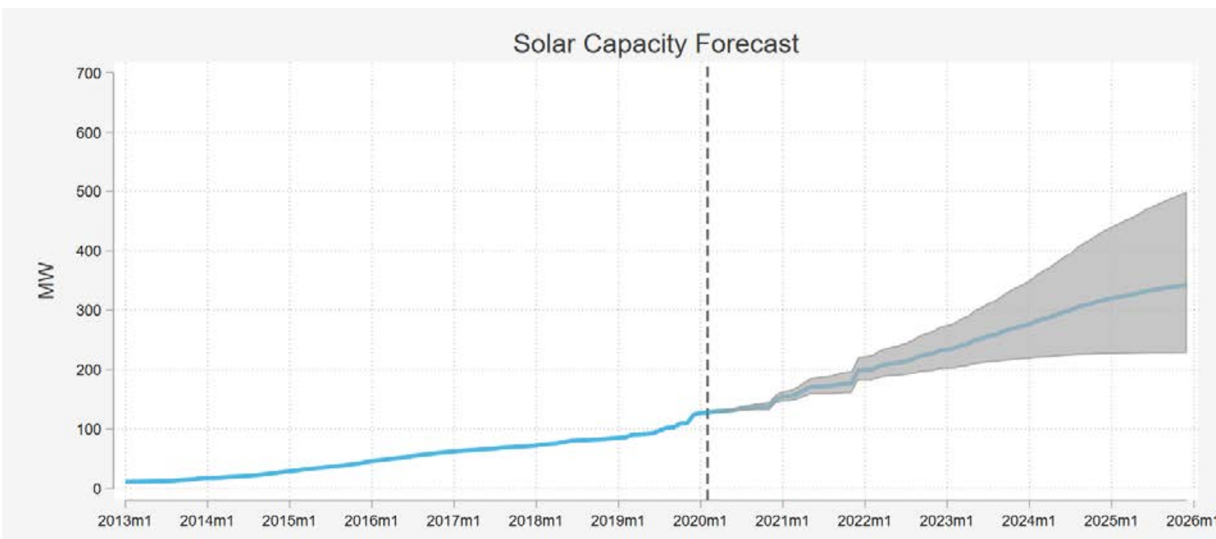


Figure 12 shows the cumulative forecast of distributed solar production on the Central Hudson peak day from 2015 to 2025. Figure 13 shows the 2025 peak production by type of solar. The majority of forecasted production in the solar sector is expected to come from community solar and remote solar projects.

Figure 12: Forecasted Distributed Solar Production Peak Day: 2015-2025

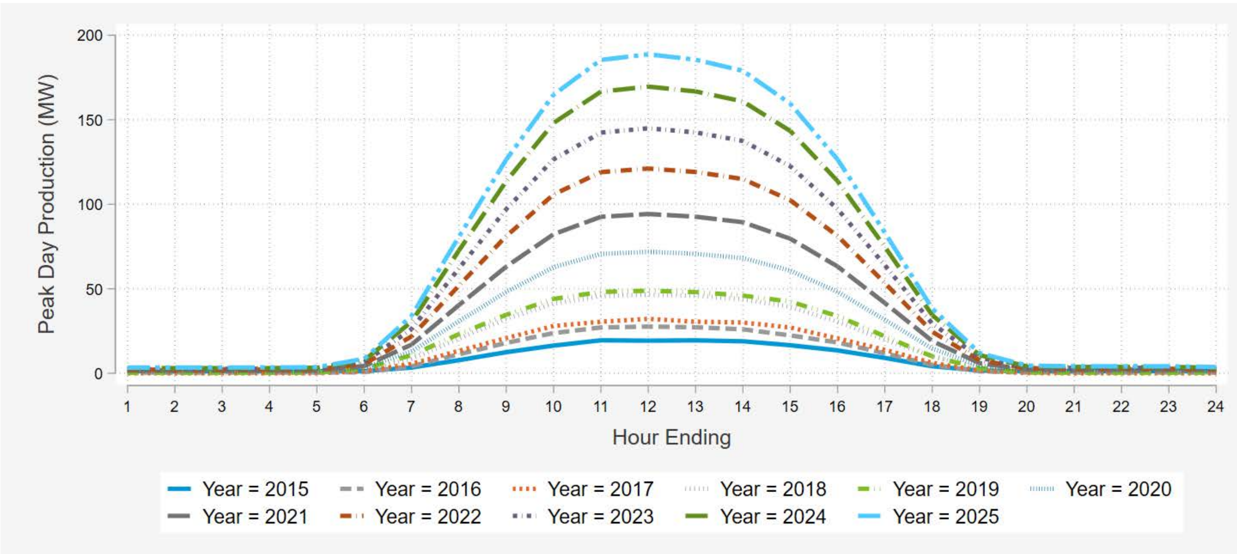
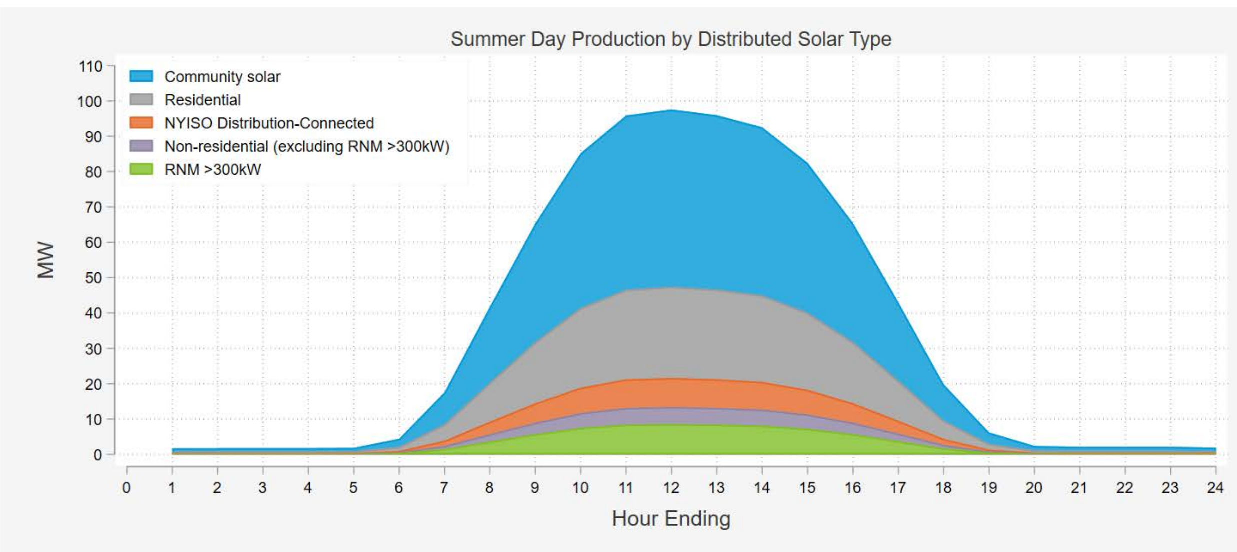


Figure 13: Forecasted Distributed Solar Production Peak Day by Category: December 2025



In addition to system-wide savings, we calculated the coincident peak day contribution of energy efficiency by substation for each year. Figure 14 shows the local peak contribution in 2019 and 2025 by substation, expressed as a percentage of each substation's peak load to normalize for substation size. Note that the scale differs between 2019 and 2025.

Figure 14: Solar Peak Day Contribution by Substation: 2019 and 2025

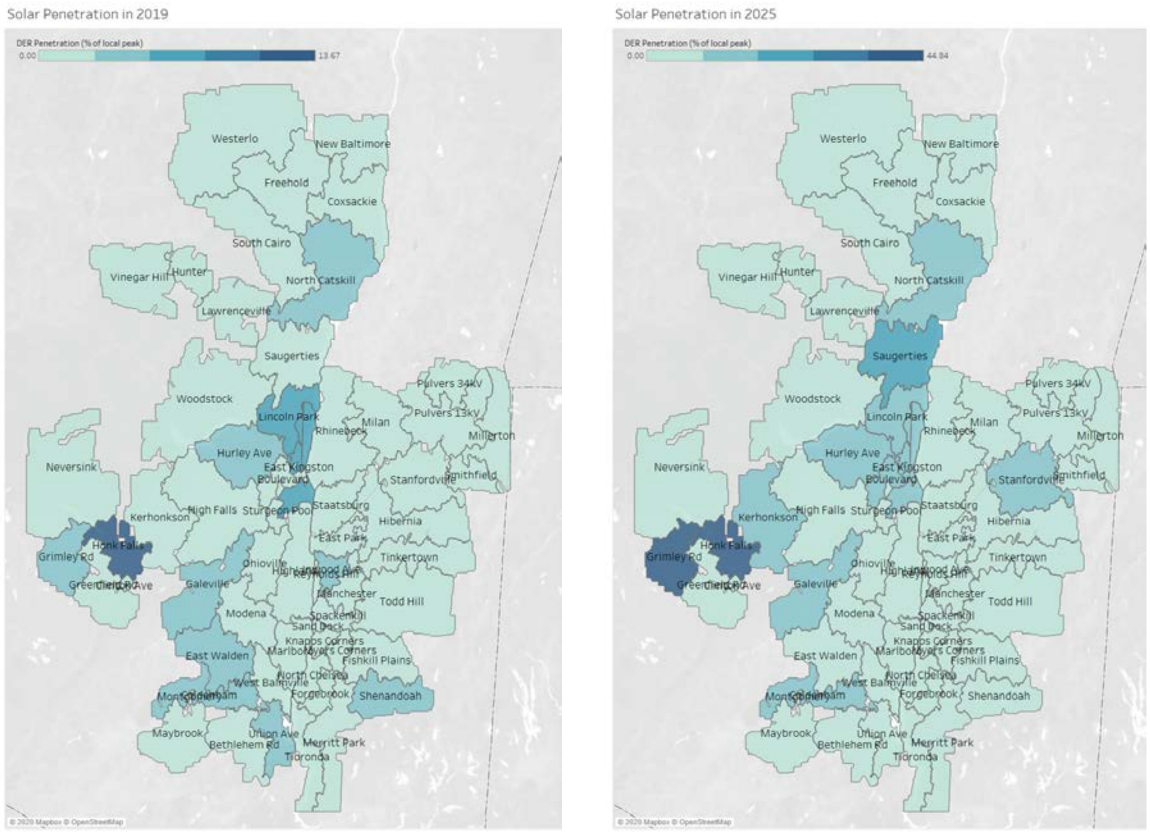


Figure 15 and Figure 16 show the solar capacity by substation as of January 2020 and at the end of the 2025 forecast period. There is substantial heterogeneity across substations; the NYISO solar projects dominate solar capacity at Coxsackie and Saugerties, but for most substations community solar capacity is the largest component. Substations where solar capacity is forecast to exceed 10 MW include Coldenham, Fishkill Plains, South Cairo, Union Avenue, and Westerlo, in addition to Coxsackie and Saugerties.

Figure 15: All Solar Forecast by Substation: January 2020

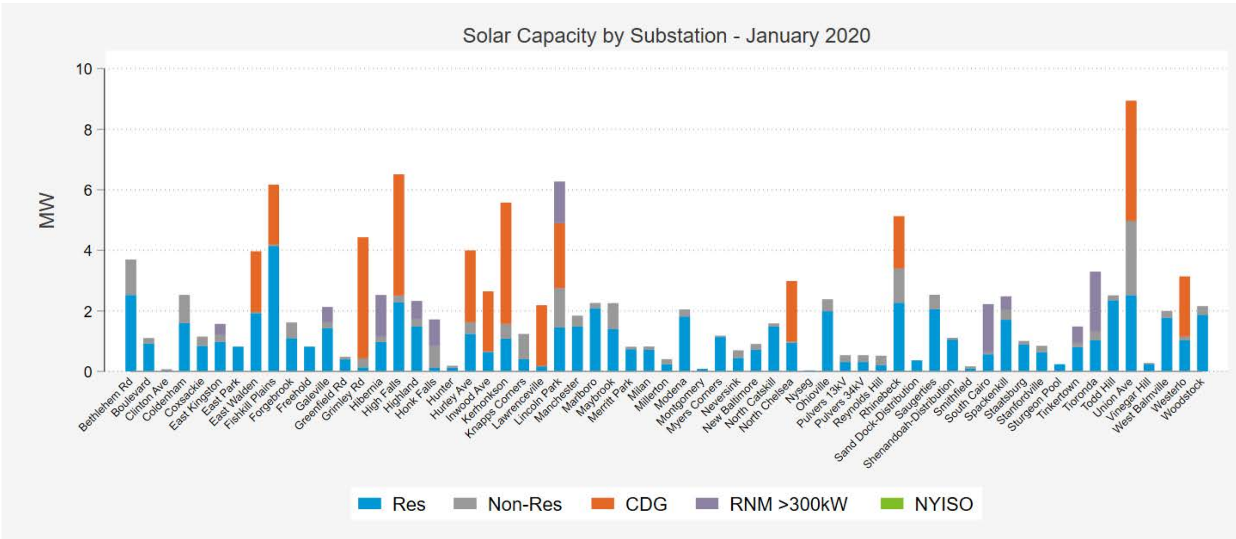
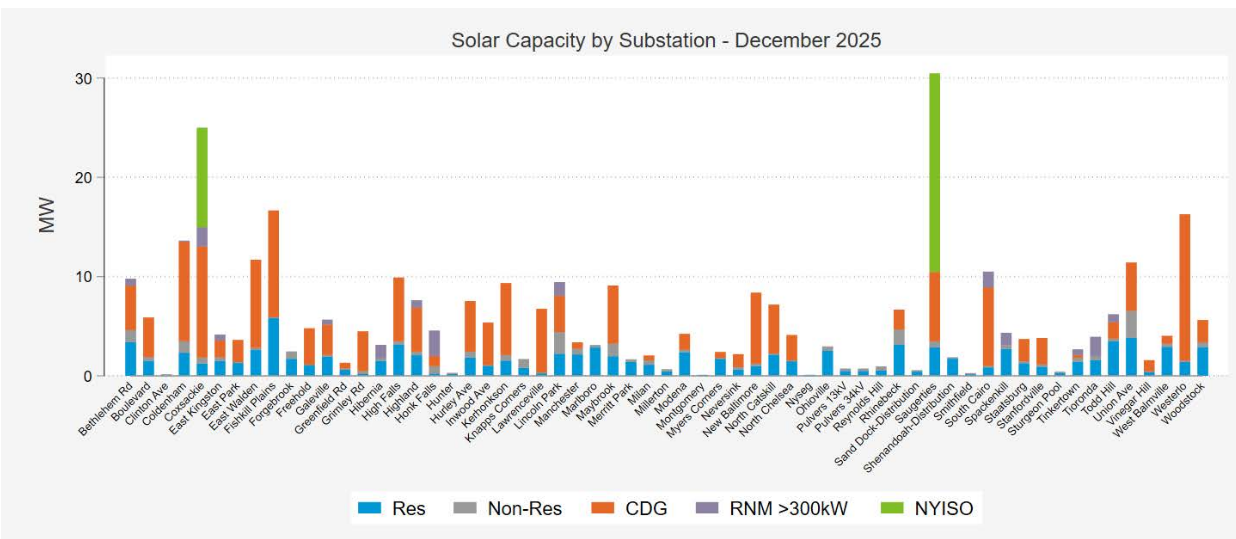


Figure 16: All Solar Forecast by Substation: December 2025



One of the most important factors is how distributed solar adoption impacts substation and transmission area peak loads. Different locations peak at different times, which do not coincide with peak solar generation. The final step was to use solar production shapes to convert forecasted projects and installed capacity into daily peak load impacts.

To do so, we utilized actual solar production data from ISO- NE utility-scale solar projects from October 2014 to January 2020. For each month, we used the average hourly solar production for all days within that month. The utility-scale production data were multiplied by 70%, 75%, and 80% for residential, non-residential, and community solar projects to account for suboptimal installation patterns and maintenance. The forecasted capacity for each substation and time period was multiplied by the expected hourly production profile, expressed as a percent of maximum possible solar output.

The solar production does not necessarily coincide with the local peaks, which are more diverse. Because solar production is substantially higher in the early afternoon, a difference of only several hours can yield significant differences in production. Table 6 shows the solar output coincident with the local peak of each load area. Several of the load areas peak later in the day than the Central Hudson system and one area peaks in the winter.

Table 6: Peak Solar Production by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.3	0.5	0.3	0.9	0.8	2.2	2.3	2.3	2.7	3.2	3.5
Fishkill-D	7	19	0.6	0.8	0.6	1.7	1.7	2.1	2.2	2.5	2.8	3.4	3.7
Kingston-Saugerties	7	17	1.9	2.7	2.5	5.1	5.4	7.3	8.5	19.7	21.3	23.2	25.2
Modena	7	18	1.3	1.4	1.3	2.5	1.8	2.3	2.7	3.0	3.5	4.3	4.8
Newburgh	7	17	3.5	5.4	4.6	8.1	7.4	9.4	10.3	11.1	15.5	19.7	22.4
Northeastern Dutchess	7	19	0.9	0.9	0.7	1.3	1.2	1.6	2.0	2.2	2.5	2.8	3.0
Northwest	1	18	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3
Poughkeepsie-D	9	17	1.2	1.2	2.0	0.8	3.7	2.8	3.0	3.7	4.3	4.7	5.0
System	**7**	**17**[3]	**13.9**	**21.9**	**18.8**	**37.1**	**34.2**	**48.2**	**63.2**	**81.2**	**63.9**	**74.8**	**83.2**

[3] System peak hour shifts to HE 18 starting in 2023.

5 DISTRIBUTED BATTERY STORAGE

Battery storage is a small but rapidly growing resource in the Central Hudson system. As of January 2020, there was approximately 0.8 MW of distributed storage installed on the Central Hudson territory, split between residential and non-residential capacity. However, battery costs have decreased substantially over the past decade, and deployment is expected to grow in the future, especially in the community solar sector.

5.1 METHODOLOGY

Virtually all storage installations have been paired with solar installations thus far, and it was assumed this would continue going forward. Therefore, our approach was to directly tie the storage capacity forecast to the solar capacity forecast, then combine with an 8760 production profile to produce system peak day and location-specific load reductions. Figure 17 summarizes the key steps in the analysis, while Figure 18 describes each step in more detail. For this analysis, we assume that all future distributed storage installations are 4-hour duration lithium ion batteries.

Figure 17: Storage Forecast Process Overview

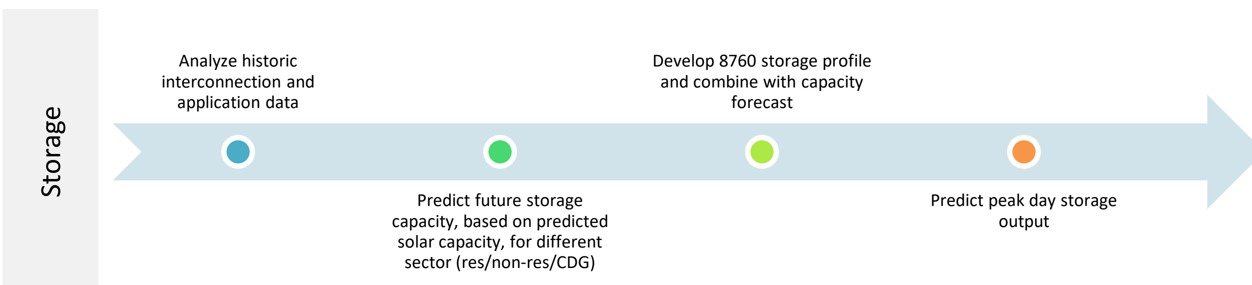


Figure 18: Storage Forecast Process Detail

1. Data and Key Drivers

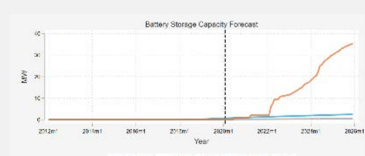
- Central Hudson historic interconnection queue data (including existing projects in queue)
- Key forecast driver is solar capacity installations, described in previous section

2. Analyze Historical Data

- Assess historical ratio of storage capacity to solar capacity in application and installation patterns

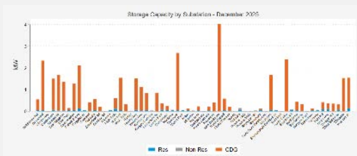
3. Produce System Capacity Forecast

- Tie storage capacity forecast to solar capacity forecast developed in previous section for each sector



4. Granular Adoption

- Assumed to follow same distribution as solar capacity additions for relevant segments



5. 8760 Load Shapes

- Calculated average weekday/weekend monthly profile based on storage dispatch for separate Central Hudson project
- Hourly MW output is capacity multiplied by production profile

6. Peak Day Impacts

- Aggregate all storage category types for each substation
- Output is location-specific forecasts and local peak coincidence factors

5.1.1 Capacity Forecast

The first key step was to analyze historic solar and storage interconnection application data to develop an assumption about the ratio of installed storage to solar capacity going forward. Table 7 shows the annual historic solar and storage interconnection capacity for the residential and non-residential sectors from 2016 to 2020. For the residential sector, storage capacity installed in 2019 was nearly 6% of solar capacity installed in the same year, up from 3.6% in 2018 and essentially 0% in 2016 and 2017. For the non-residential sector, storage capacity was 8.1% of total capacity in 2018 but 0% in all other years. For purposes of this forecast, we assumed that future residential and non-residential storage capacity would be equal to 6% of solar installations over the study period based on the ratio in 2018, the highest annual historic percentage for the residential sector.

Table 7: Historic Residential and Non-Residential Solar and Storage Capacity Interconnections

	Residential			Non-Residential		
Year	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %
2016	0	13,920	0.0%	0	2,573	0.0%
2017	6	8,151	0.1%	0	924	0.0%
2018	217	6,000	3.6%	100	1,235	8.1%
2019	387	6,567	5.9%	0	1,313	0.0%
2020[4]	20	504	4.0%	0	0	N/A

For existing community solar and remote net metering applications that are already in the queue, there is already information on whether the application includes a storage component and the size of the storage. To predict new storage applications – a portion of which will result in interconnection – we again analyzed the historic application data to develop our assumption about the ratio of storage to solar capacity. Table 8 shows the historic storage and solar capacity for both community solar and large remote net metering projects since July 2016 (the start of the community solar analysis period). Storage capacity applications have ranged from 2% to 42% of solar capacity since 2016, with the total share of storage capacity from 2016 to 2019 being 24% of solar capacity. Based on this analysis, we assumed that new storage application capacity would be equal to 30% of community solar application capacity.[5]

Table 8: Historic Community/Remote Solar and Storage Capacity Applications

Year	Storage Capacity (kW)	Solar Capacity (kW)	Storage Capacity %
2016 (July-Dec)	5,160	24,739	20.9%
2017	2,340	122,831	1.9%
2018	20,160	88,195	22.9%
2019	66,358	153,092	43.3%
Total	**94,018**	**388,857**	**24.2%**

5.1.2 8760 Dispatch Profile

To convert battery capacity into a dispatch profile, we relied on a storage dispatch model developed for a recent Central Hudson project, in which a 4-hour battery is dispatched against the day-ahead price in the NYISO Zone J wholesale market using historic volatility in energy and ancillary service markets.[6]

[4] Only shows data through January 2020.

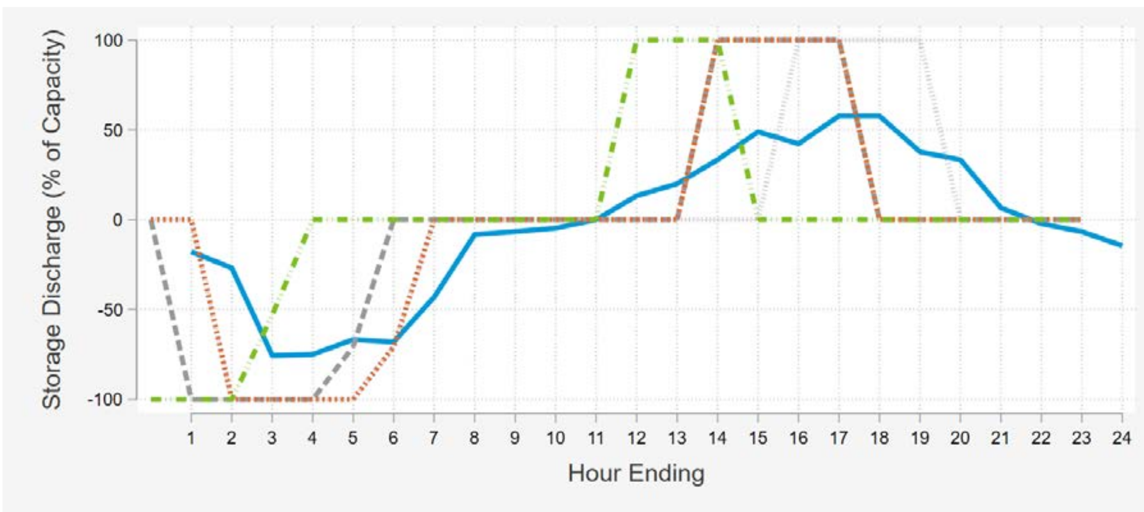
[5] No large remote net metering projects have a storage component, and large remote net metering new applications are forecasted to be zero, resulting in a capacity forecast of zero for large remote net metering projects.

[6] The models were reviewed and approved by DPS Staff.

We calculated an 8760 dispatch profile by using the weekday and weekend mean dispatch across each month. Figure 19 depicts the resulting dispatch profile for the July peak day in solid blue, with the dashed lines corresponding to the dispatch profiles for individual days used to calculate the average. Positive values correspond to battery discharging, while negative values correspond to battery charging.

Because Central Hudson does not have operational control over distributed storage systems, actual battery storage charging and discharging behavior may be different than the blue line depending on the owner's operational decisions, but from a system planning perspective, the "averaging" approach results in a conservative assumption that storage dispatches at 50% of its maximum capacity during the highest system load hours.

Figure 19: July Weekday Battery Storage Dispatch Profile



5.2 RESULTS

Figure 20 shows the battery storage installation forecast by component. Even more so than solar, we predict that community storage capacity will dominate future installations – many of which are already in the application queue – though there is uncertainty about the pace of prediction. In total, the forecast distributed storage capacity is 38 MW by the end of 2025, compared to less than 1 MW at the end of January 2020. However, there remains substantial uncertainty around these projects' success rates and their timelines, as well as the future policy support for these projects, and Central Hudson will continue to monitor distributed storage adoption and adjust forecasts accordingly.

Figure 20: Battery Storage Capacity Forecast

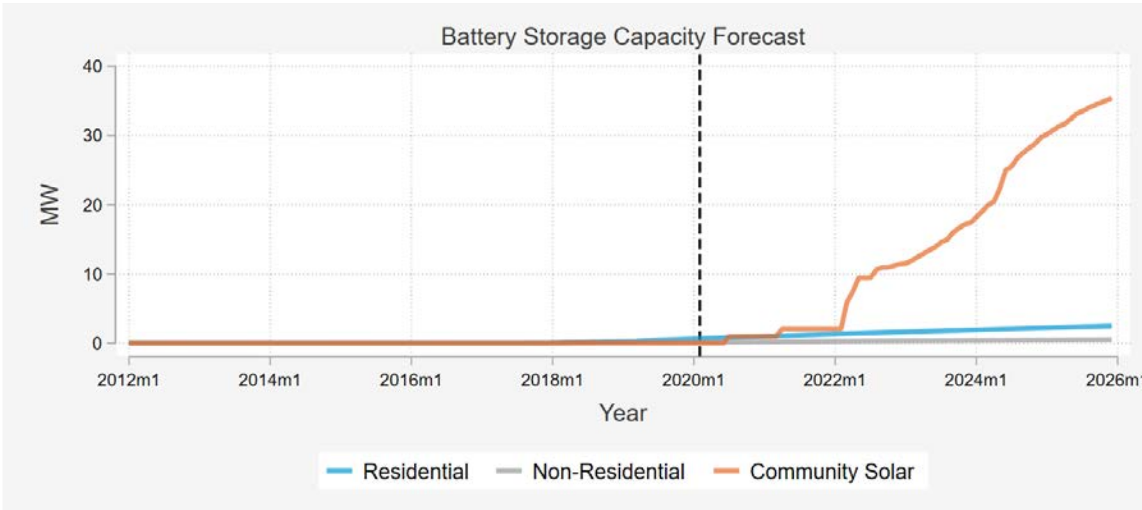


Figure 21 shows the forecast storage capacity by substation by the end of 2025. The New Baltimore substation is expected to have the highest storage capacity, at 4 MW, driven by the presence of two large community solar and storage projects in the existing interconnection queue.

Figure 21: Battery Storage Capacity Forecast by Substation: December 2025

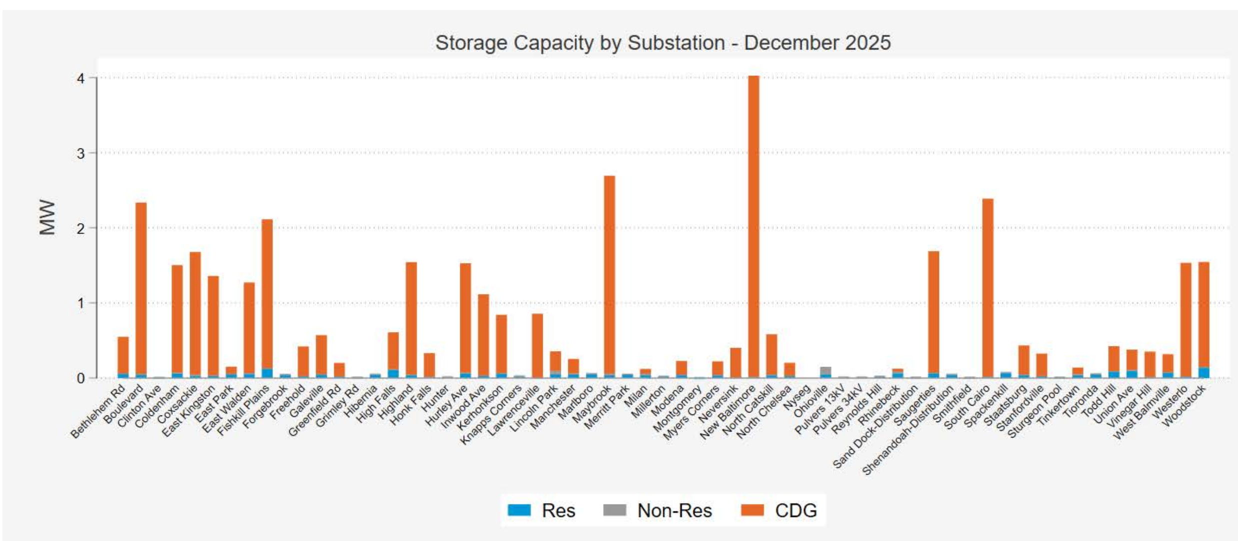


Figure 22 shows the cumulative forecast of distributed solar production on the Central Hudson peak day from 2015 to 2025. On the peak day in 2025, storage is expected to provide up to 20 MW of capacity, compared to well under 1 MW in 2020, though the impacts on system operation will depend on how storage resources are dispatched.

Figure 22: Forecasted Distributed Storage Production on Peak Day, 2020-2025

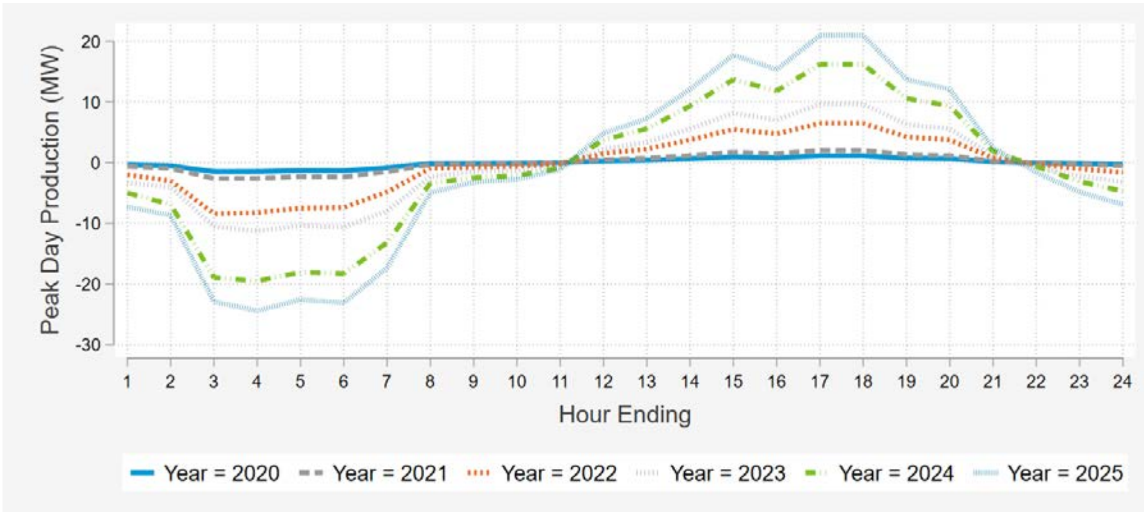


Table 9 shows the storage output coincident with the local peak of each load area. Several of the load areas peak later in the day than the Central Hudson system and one area peaks in the winter. The sum of substations is not equal to the system forecast due to differences in the timing of local peaks.

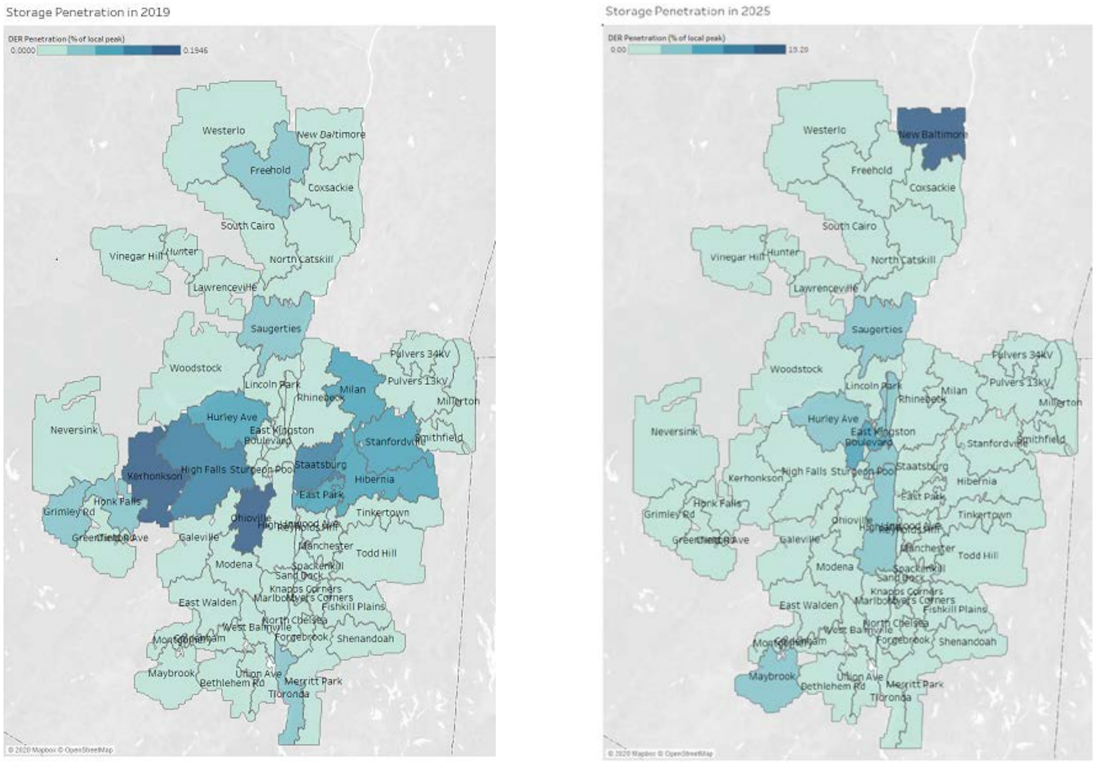
Table 9: Peak Storage Discharge by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.5	1.3
Fishkill-D	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.4	0.7	1.5
Kingston-Saugerties	7	17	0.0	0.0	0.0	0.0	0.1	0.1	0.8	2.6	2.9	4.2	5.1
Modena	7	18	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.9	1.1	1.4
Newburgh	7	17	0.0	0.0	0.0	0.0	0.0	0.1	0.1	1.1	1.6	2.7	3.7
Northeastern Dutchess	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.7
Northwest	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.6	1.8
Poughkeepsie-D	9	17	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.5	0.6	0.8	0.8
System	**7**	**17**[7]	**0.0**	**0.0**	**0.0**	**0.1**	**0.3**	**1.1**	**2.0**	**6.5**	**9.7**	**16.2**	**21.4**

Finally, Figure 23 shows the 2019 and 2025 forecast coincident storage output for all substations. Note the difference in scales between the two panels. The highest relative storage coincident peak output is the New Baltimore, which we forecast will have the highest amount of storage capacity by 2025.

[7] System peak hour shifts to HE 18 starting in 2023.

Figure 23: Storage Peak Day Contribution by Substation: 2019 and 2025



6 ELECTRIC VEHICLES

The goal of this section is to describe the process of producing 8760 electric vehicle (EV) load forecasts at the substation level which account for the temporal and locational variation in the adoption of electric vehicles.

6.1 METHODOLOGY OVERVIEW

Figure 24 provides a high-level overview of the process used to develop the forecast. Bottom-up forecasts were developed by forecasting electric vehicles sales within each transmission area and substation (for both plug-in hybrids and full battery-electric vehicles) and combining 8760 production profiles developed for home and public charging, assuming an 80%/20% split, to produce system peak day and location-specific load reductions. Figure 25 provides more detail on the methodology.

Figure 24: Electric Vehicles Forecast Process Overview

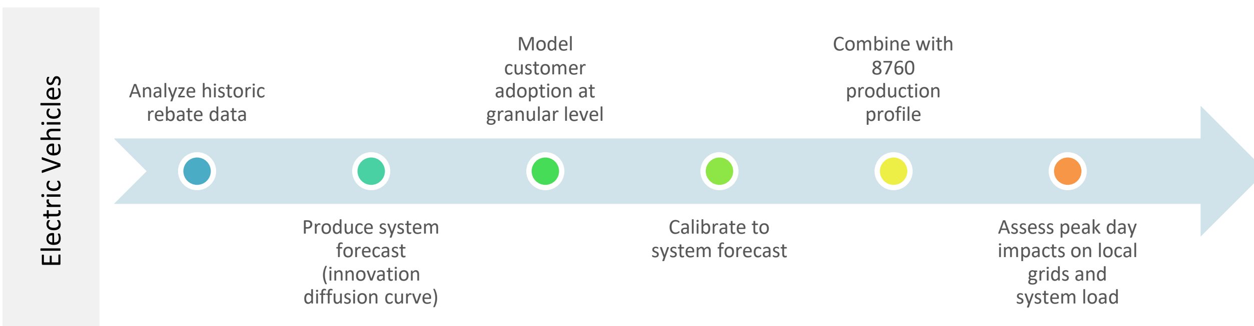
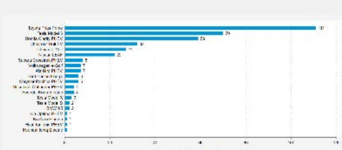


Figure 25: Electric Vehicles Forecast Process Detail

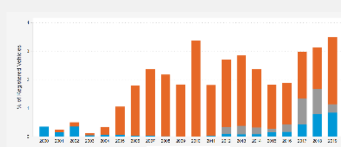
1. Key Drivers & Data

- 11M vehicle registration records in NY
- Vehicle stock and churn in Central Hudson territory
- Charging station locations and types
- Costs and incentives



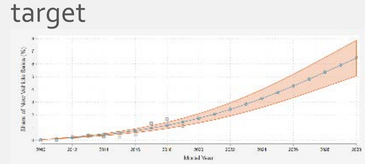
2. Analyze Historical Data

- Use NHTSA VIN decoder API to extract details about vehicle
- Assess adoption patterns over time
- Assess geographic concentration
- Assess relationship between hybrid and EV adoption



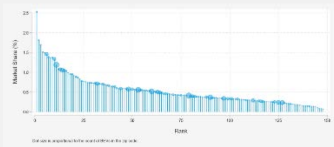
3. Produce System Forecast

- Use innovation diffusion curves with uncertainty (bass curves)
- Apply to EVs over time
- Scenario 1: actual adoption
- Scenario 2: 2x growth
- Scenario 3 (pressure test): 5% Share of 2M EV state target



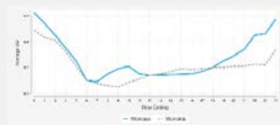
4. Granular Adoption

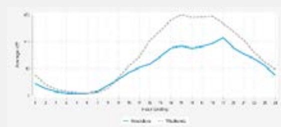
- Map home charging forecasts and charging station forecasts to substations



5. 8760 Load Shapes

- Weekday & weekend shapes
- Home charging load shape from EPRI data
- Charging station load shape from actual charging stations in Central Hudson territory





6. Peak Day Impacts

- Output is location-specific forecasts and local peak coincidence factors

6.2 RESULTS

Figure 26 shows the cumulative forecast of electric vehicle loads on the Central Hudson peak day under the base case scenario. The graph shows the year-by-year change in electric vehicle loads. Figure 27 shows the same information for the pressure test scenario. Figure 28 shows the division of impacts between EVs and PHEVs for the 2025 peak day.

Figure 26: Forecasted Electric Vehicle Load Peak Days – Base Case

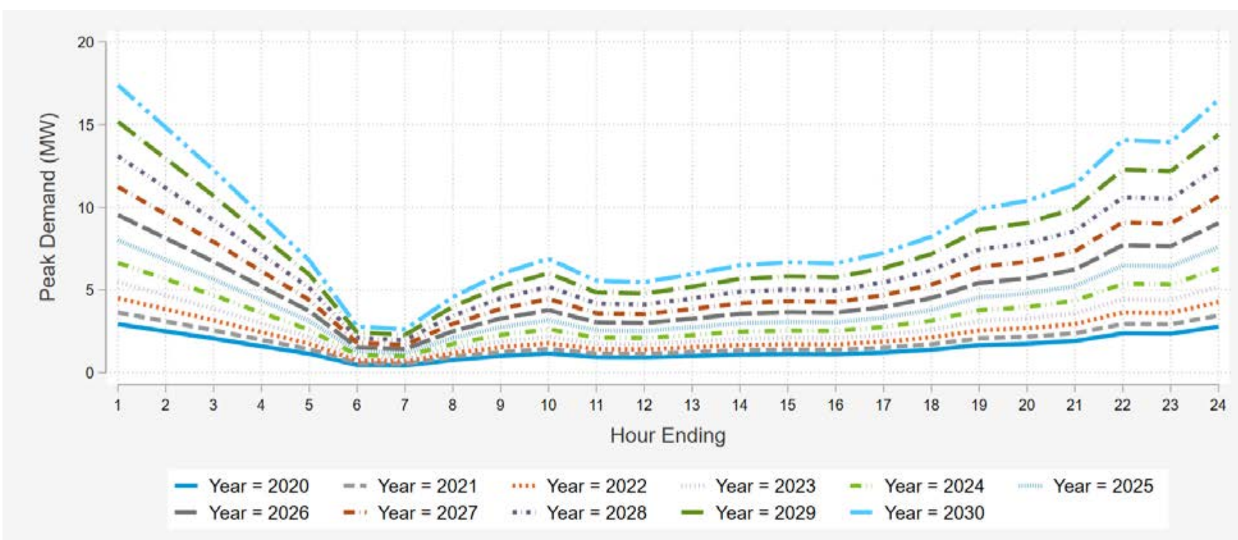


Figure 27: Forecasted Electric Vehicle Load Peak Days – Pressure Test

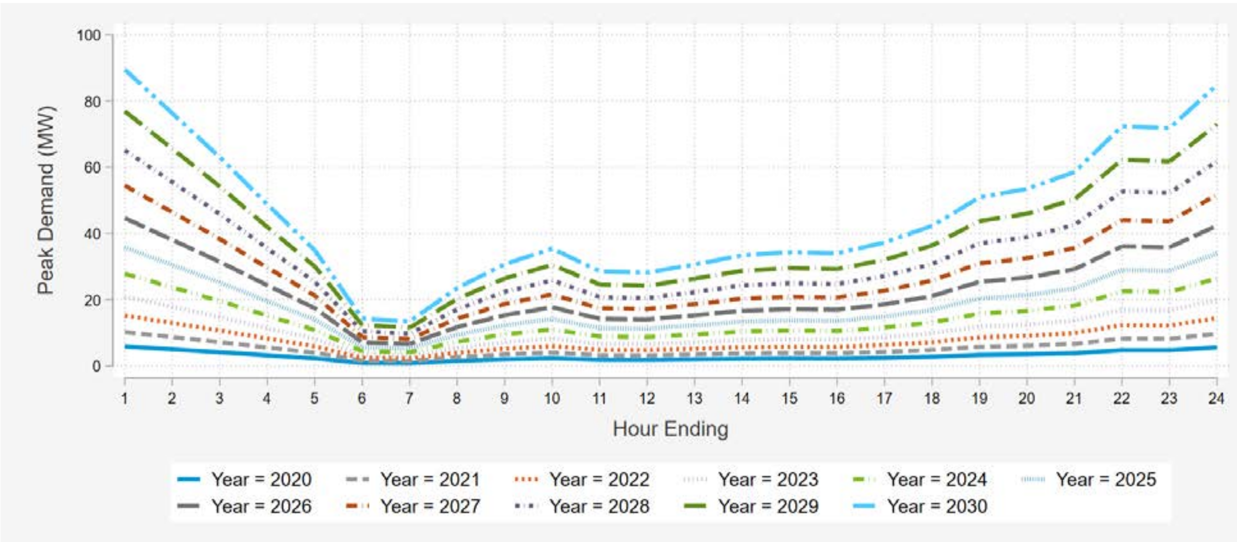
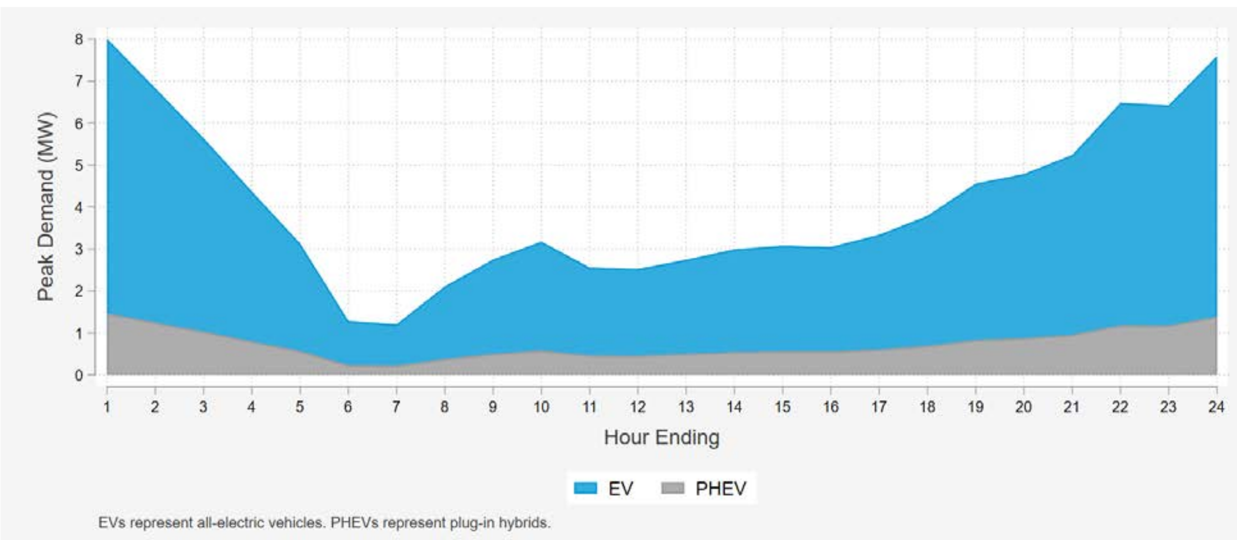
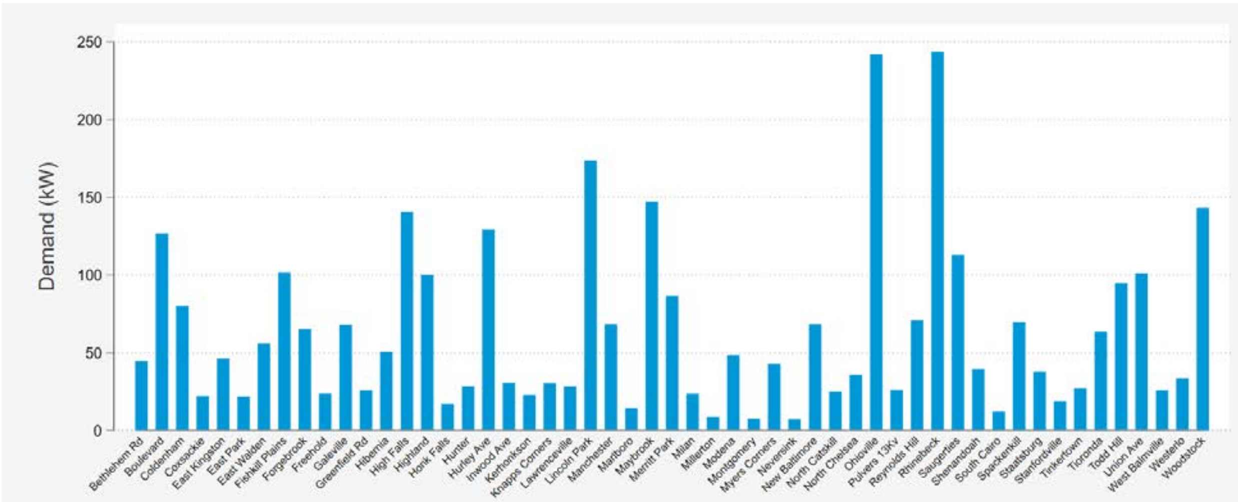


Figure 28: Forecasted Electric Vehicle Charging Impact 2025 Peak Day – Base Scenario with Expected Growth



By substation, Figure 29 shows demand associated with EVs during hour ending 18 (5:00 PM – 6:00 PM) during the typical July weekday. The figure represents forecast year 2025.

Figure 29: Forecast by Substation – 2025



The figure reflects hour ending 16 (3-4 PM). Substations with less than 10 kW of EV load are not shown.

Table 10 shows the electric vehicle loads coincident with the local peak of each load area. Because electric vehicle loads peak late at night or in early morning hours (due to automated timers), they improve utilization of existing T&D resources and their contribution to peak is expected to be minimal.

Table 10: Electric Vehicle Peak Coincident Loads by Load Area and Year

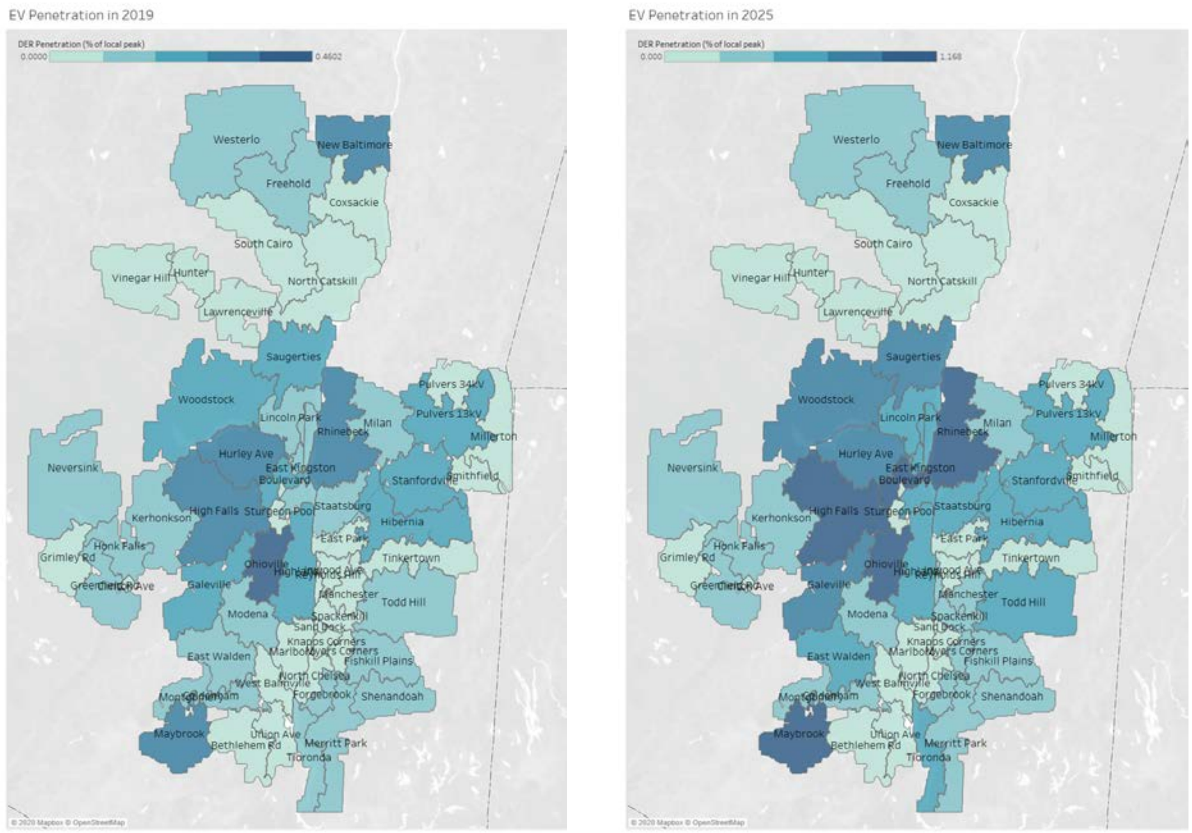
Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3
Fishkill-D	7	19	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.6
Kingston-Saugerties	7	17	0.1	0.1	0.1	0.2	0.3	0.4	0.3	0.4	0.5	0.6	1.0
Modena	7	18	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.6
Newburgh	7	17	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.6
Northeastern Dutchess	7	19	0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.6
Northwest	1	18	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3
Poughkeepsie-D	9	17	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
System	**7**	**17**[8]	**0.2**	**0.3**	**0.5**	**0.8**	**1.3**	**1.6**	**1.5**	**1.9**	**2.6**	**3.1**	**4.5**

Figure 30 shows the electric vehicle coincident peak contribution forecasts by substation for 2019 and 2025. Since electric vehicle coincidence with local area peaks is generally very low, these figures are more reflective of the expected distribution of electric vehicle penetration at the local level. Currently, EV penetration is highest in the Ohioville substation area, with other high concentrations in connecting, central areas such as High Falls, Rhinebeck, and Hurly Ave. By 2025, penetration is expected to grow in

[8] System peak hour shifts to HE 18 starting in 2023.

and around these substation areas, with particular growth in the Woodstock substation and the Maybrook substation on the southern end of the service territory.

Figure 30: Electric Vehicle Peak Day Contribution by Substation – 2019 and 2025



APPENDIX – TRANSMISSION & SUBSTATION TABLES

ENERGY EFFICIENCY

EE Peak Coincident Demand Savings by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	1.2	1.8	1.9	2.2	2.8	4.6	5.4	6.2	7.0	8.0	8.9
Fishkill-D	7	19	10.0	7.1	7.6	8.4	9.6	14.1	16.7	19.5	22.5	25.9	29.1
Kingston-Saugerties	7	17	3.3	4.7	5.5	6.6	8.4	12.7	14.9	17.2	19.6	22.1	24.7
Modena	7	18	3.2	2.7	3.8	4.0	4.5	6.5	7.5	8.5	9.6	11.0	12.0
Newburgh	7	17	7.3	8.7	10.5	11.5	14.3	19.8	23.2	25.9	29.0	32.7	36.0
Northeastern Dutchess	7	19	2.9	3.4	4.2	4.5	5.1	8.1	9.5	10.9	12.3	14.2	16.0
Northwest	1	18	1.2	1.0	1.7	2.7	3.5	4.1	5.0	5.8	6.6	7.3	7.9
Poughkeepsie-D	9	17	1.7	2.3	2.8	3.7	4.3	5.2	6.2	7.2	7.9	8.9	9.6
System	**7**	**17[9]**	**40.5**	**40.1**	**46.8**	**52.8**	**62.6**	**90.5**	**105.9**	**120.8**	**130.2**	**148.1**	**164.9**

EE Normalized Historical and Forecasted Peak Contribution Estimates (2015-2025)

Load Area	Substation	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
				2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	Clinton Ave	2	10	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1
	Greenfield Rd*	7	18	0.2	0.3	0.3	0.3	0.5	0.7	0.9	1.0	1.1	1.3	1.4
	Grimley Rd	7	16	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.3	0.4	0.4
	High Falls	7	19	0.5	0.8	0.8	0.8	1.1	1.8	2.2	2.5	2.9	3.3	3.7
	Honk Falls	7	15	0.2	0.1	0.1	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
	Kerhonkson	7	19	0.2	0.4	0.4	0.6	0.7	1.1	1.2	1.4	1.4	1.6	1.8
	Neversink*	2	19	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4
	Sturgeon Pool	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**7**	**19**	**1.2**	**1.8**	**1.9**	**2.2**	**2.8**	**4.6**	**5.4**	**6.2**	**7.0**	**8.0**	**8.9**
Fishkill-D	Fishkill Plains	7	19	2.9	2.8	3.0	3.0	3.0	4.0	4.5	5.1	5.7	6.5	7.1
	Forgebrook	7	18	0.5	0.9	0.9	1.0	1.3	2.0	2.3	2.6	2.9	3.2	3.7
	Knapps Corners	9	18	0.1	0.3	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.3
	Merritt Park	7	17	0.4	0.8	0.9	1.1	1.5	2.1	2.4	2.9	3.2	3.8	4.2
	Myers Corners	7	19	0.4	0.7	0.7	0.7	0.9	1.3	1.6	1.9	2.2	2.5	2.8
	North Chelsea	7	19	0.3	0.5	0.5	0.6	0.7	1.3	1.5	1.8	2.1	2.4	2.7
	Sand Dock-D	7	19	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.5	0.5
	Shenandoah-D	7	17	7.8	0.4	0.6	0.9	1.2	1.5	2.1	2.7	3.4	4.1	4.7
	Tioronda	7	19	0.4	0.5	0.5	0.6	0.6	1.1	1.3	1.5	1.8	2.0	2.3
	Load Area Total	**7**	**19**	**10.0**	**7.1**	**7.6**	**8.4**	**9.6**	**14.1**	**16.7**	**19.5**	**22.5**	**25.9**	**29.1**

[9] System peak hour shifts to HE 18 starting in 2023.

Kingston-Saugerties	Boulevard	7	17	0.4	0.7	0.7	0.7	1.0	1.6	2.0	2.3	2.7	3.0	3.4
	East Kingston	7	16	0.4	0.6	0.6	0.7	0.9	1.5	1.7	1.9	2.2	2.5	2.8
	Hurley Ave	7	17	0.5	0.8	0.9	1.8	1.9	2.5	2.9	3.2	3.5	3.9	4.2
	Lincoln Park	7	16	0.7	0.9	1.2	1.3	2.0	2.9	3.4	4.0	4.4	4.9	5.5
	Saugerties	7	19	0.7	0.8	0.9	0.9	1.1	1.8	2.2	2.5	2.9	3.4	3.8
	Woodstock	2	18	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.1	1.3	1.5	1.5
	Load Area Total	**7**	**17**	**3.3**	**4.7**	**5.5**	**6.6**	**8.4**	**12.7**	**14.9**	**17.2**	**19.6**	**22.1**	**24.7**
Modena	Galeville	7	18	1.7	0.4	0.4	0.4	0.5	0.8	0.9	1.1	1.3	1.4	1.6
	Highland	7	19	0.4	0.6	0.7	0.8	0.9	1.6	1.8	2.1	2.5	2.8	3.2
	Modena	7	19	0.4	0.4	0.5	0.6	0.6	1.1	1.3	1.6	1.8	2.1	2.4
	Ohioville	9	18	0.2	0.4	0.7	0.8	0.9	1.2	1.3	1.5	1.7	2.0	2.0
	Load Area Total	**7**	**18**	**3.2**	**2.7**	**3.8**	**4.0**	**4.5**	**6.5**	**7.5**	**8.5**	**9.6**	**11.0**	**12.0**
Newburgh	Bethlehem Rd	7	19	0.7	1.1	1.2	1.3	1.5	2.2	2.5	2.9	3.3	3.8	4.2
	Coldenham	7	17	0.8	0.9	1.0	1.0	2.0	2.5	3.3	3.7	4.0	4.6	5.0
	East Walden	7	19	0.4	0.5	0.6	0.6	0.8	1.2	1.5	1.7	1.9	2.2	2.5
	Marlboro	9	19	0.2	0.2	0.4	0.5	0.6	0.8	1.0	1.1	1.3	1.5	1.7
	Maybrook	7	20	0.3	0.4	0.5	0.5	0.6	0.9	1.1	1.2	1.4	1.6	1.8
	Montgomery*	7	17	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4
	Union Ave	7	16	2.2	2.7	3.1	3.7	4.2	6.0	6.7	7.5	8.3	9.2	10.2
	West Balmville	7	17	1.9	2.1	2.8	2.9	3.3	4.3	4.9	5.5	6.0	6.6	7.2
	Load Area Total	**7**	**17**	**7.3**	**8.7**	**10.5**	**11.5**	**14.3**	**19.8**	**23.2**	**25.9**	**29.0**	**32.7**	**36.0**
Northeastern Dutchess	East Park	7	19	0.4	0.5	0.6	0.7	0.8	1.2	1.4	1.5	1.7	1.9	2.2
	Hibernia	7	19	0.3	0.4	0.4	0.4	0.4	0.6	0.8	0.9	1.0	1.2	1.3
	Milan	7	19	0.2	0.2	0.3	0.3	0.4	0.6	0.7	0.9	1.0	1.2	1.3
	Millerton	7	18	0.1	0.1	0.2	0.2	0.2	0.4	0.5	0.6	0.7	0.8	0.9
	Pulvers 13	7	18	0.2	0.2	0.2	0.3	0.3	0.5	0.6	0.7	0.8	1.0	1.1
	Pulvers 34	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
	Rhinebeck	7	18	1.0	1.1	1.2	1.2	1.6	2.4	2.8	3.0	3.5	3.9	4.4
	Smithfield	2	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	Staatsburg	7	19	0.3	0.3	0.4	0.5	0.5	0.9	1.0	1.1	1.2	1.4	1.6
	Stanfordville	7	19	0.2	0.2	0.3	0.2	0.3	0.4	0.5	0.5	0.6	0.8	0.8
	Tinkertown	7	19	0.3	0.5	0.7	0.7	0.7	1.1	1.2	1.4	1.6	1.9	2.1
	Load Area Total	**7**	**19**	**2.9**	**3.4**	**4.2**	**4.5**	**5.1**	**8.1**	**9.5**	**10.9**	**12.3**	**14.2**	**16.0**
Northwest	Coxsackie*	2	18	0.1	0.1	0.3	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.5
	Freehold	7	19	0.3	0.3	0.4	0.4	0.4	0.7	0.9	1.0	1.2	1.3	1.5
	Hunter	1	7	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
	Lawrenceville	1	7	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
	New Baltimore	7	19	0.3	0.3	0.4	0.4	0.5	0.8	1.0	1.2	1.3	1.6	1.8
	North Catskill	7	15	0.6	0.7	0.9	1.1	1.3	2.2	2.7	3.1	3.6	4.1	4.6
	South Cairo*	2	18	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9
	Vinegar Hill	2	8	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
	Westerlo	1	18	0.4	0.1	0.2	0.2	0.4	0.4	0.5	0.6	0.7	0.7	0.9
	Load Area Total	**1**	**18**	**1.2**	**1.0**	**1.7**	**2.7**	**3.5**	**4.1**	**5.0**	**5.8**	**6.6**	**7.3**	**7.9**
Poughkeepsie-D	Inwood Ave	9	17	0.2	0.3	0.4	0.5	0.6	0.8	1.0	1.1	1.2	1.4	1.5
	Manchester	7	17	2.8	3.2	3.3	3.6	3.8	4.7	5.1	5.4	6.0	6.4	7.1
	Reynolds Hill	7	16	1.1	1.3	1.3	1.5	1.8	2.5	2.7	3.0	3.1	3.4	3.7
	Spackenkill	7	19	0.6	1.1	1.2	1.5	1.5	2.1	2.5	3.0	3.1	3.6	4.0
	Todd Hill	7	19	0.9	0.9	1.1	1.1	1.0	1.2	1.4	1.7	1.9	2.3	2.5
	Load Area Total	**9**	**17**	**1.7**	**2.3**	**2.8**	**3.7**	**4.3**	**5.2**	**6.2**	**7.2**	**7.9**	**8.9**	**9.6**

SOLAR

Peak Solar Production by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.3	0.5	0.3	0.9	0.8	2.2	2.3	2.3	2.7	3.2	3.5
Fishkill-D	7	19	0.6	0.8	0.6	1.7	1.7	2.1	2.2	2.5	2.8	3.4	3.7
Kingston-Saugerties	7	17	1.9	2.7	2.5	5.1	5.4	7.3	8.5	19.7	21.3	23.2	25.2
Modena	7	18	1.3	1.4	1.3	2.5	1.8	2.3	2.7	3.0	3.5	4.3	4.8
Newburgh	7	17	3.5	5.4	4.6	8.1	7.4	9.4	10.3	11.1	15.5	19.7	22.4
Northeastern Dutchess	7	19	0.9	0.9	0.7	1.3	1.2	1.6	2.0	2.2	2.5	2.8	3.0
Northwest	1	18	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3
Poughkeepsie-D	9	17	1.2	1.2	2.0	0.8	3.7	2.8	3.0	3.7	4.3	4.7	5.0
System	**7**	**17**[10]	**13.9**	**21.9**	**18.8**	**37.1**	**34.2**	**48.2**	**63.2**	**81.2**	**63.9**	**74.8**	**83.2**

Solar Normalized Historical and Forecasted Peak Contribution Estimates (2015-2025)

Load Area	Substation	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
				2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	Clinton Ave	2	10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Greenfield Rd*	7	18	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3
	Grimley Rd	7	16	0.0	0.0	0.1	0.3	0.2	2.1	2.1	2.2	2.2	2.2	2.2
	High Falls	7	19	0.1	0.2	0.1	0.3	0.2	0.7	0.8	0.8	0.9	1.0	1.1
	Honk Falls	7	15	0.0	0.5	0.4	1.2	0.8	0.9	0.9	0.9	1.0	2.1	2.3
	Kerhonkson	7	19	0.0	0.1	0.2	0.2	0.2	0.6	0.7	0.7	0.8	0.9	1.0
	Neversink*	2	19	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Sturgeon Pool	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**7**	**19**	**0.3**	**0.5**	**0.3**	**0.9**	**0.8**	**2.2**	**2.3**	**2.3**	**2.7**	**3.2**	**3.5**
Fishkill-D	Fishkill Plains	7	19	0.2	0.3	0.2	0.5	0.4	0.7	0.7	0.9	1.1	1.6	1.8
	Forgebrook	7	18	0.2	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.5	0.5	0.5
	Knapps Corners	9	18	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Merritt Park	7	17	0.1	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.5
	Myers Corners	7	19	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
	North Chelsea	7	19	0.0	0.1	0.0	0.1	0.3	0.3	0.4	0.4	0.4	0.4	0.4
	Sand Dock-D	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Shenandoah-D	7	17	0.1	0.2	0.2	0.4	0.3	0.4	0.5	0.5	0.5	0.6	0.6
	Tioronda	7	19	0.0	0.1	0.1	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4
	Load Area Total	**7**	**19**	**0.6**	**0.8**	**0.6**	**1.7**	**1.7**	**2.1**	**2.2**	**2.5**	**2.8**	**3.4**	**3.7**

[10] System peak hour shifts to HE 18 starting in 2023.

Kingston-Saugerties	Boulevard	7	17	0.2	0.3	0.2	0.4	0.4	1.2	1.6	1.6	1.8	1.9	2.1
	East Kingston	7	16	0.2	0.3	0.3	0.6	0.7	0.7	0.8	1.4	1.5	1.7	1.9
	Hurley Ave	7	17	0.3	0.3	0.3	0.6	0.7	1.5	1.6	2.1	2.3	2.5	2.8
	Lincoln Park	7	16	0.8	0.9	0.9	2.6	2.9	3.0	3.1	3.2	3.7	4.1	4.3
	Saugerties	7	19	0.1	0.2	0.1	0.3	0.3	0.3	0.3	3.3	3.5	3.8	4.1
	Woodstock	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
	Load Area Total	**7**	**17**	**1.9**	**2.7**	**2.5**	**5.1**	**5.4**	**7.3**	**8.5**	**19.7**	**21.3**	**23.2**	**25.2**
Modena	Galeville	7	18	0.4	0.4	0.4	0.6	0.4	0.5	0.5	0.5	0.7	1.2	1.3
	Highland	7	19	0.1	0.1	0.1	0.3	0.2	0.4	0.4	0.5	0.7	0.7	0.8
	Modena	7	19	0.1	0.2	0.1	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.4
	Ohioville	9	18	0.3	0.1	0.3	0.1	0.4	0.3	0.3	0.3	0.3	0.3	0.4
	Load Area Total	**7**	**18**	**1.3**	**1.4**	**1.3**	**2.5**	**1.8**	**2.3**	**2.7**	**3.0**	**3.5**	**4.3**	**4.8**
Newburgh	Bethlehem Rd	7	19	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.4	0.9	1.0	1.1
	Coldenham	7	17	0.6	0.7	0.6	1.0	0.8	0.9	1.0	1.0	3.1	4.1	4.9
	East Walden	7	19	0.1	0.2	0.1	0.2	0.4	0.4	0.6	0.7	0.8	1.1	1.3
	Marlboro	9	19	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Maybrook	7	20	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3
	Montgomery*	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Union Ave	7	16	1.1	1.6	1.5	2.9	2.2	4.2	4.3	4.4	4.7	4.9	5.2
	West Balmville	7	17	0.3	0.5	0.4	0.8	0.7	0.7	0.8	0.9	1.0	1.2	1.4
	Load Area Total	**7**	**17**	**3.5**	**5.4**	**4.6**	**8.1**	**7.4**	**9.4**	**10.3**	**11.1**	**15.5**	**19.7**	**22.4**
Northeastern Dutchess	East Park	7	19	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.4	0.4	0.4
	Hibernia	7	19	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Milan	7	19	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
	Millerton	7	18	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Pulvers 13	7	18	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
	Pulvers 34	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Rhinebeck	7	18	0.6	0.6	0.6	0.9	0.7	1.3	1.3	1.4	1.4	1.5	1.6
	Smithfield	2	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Staatsburg	7	19	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4
	Stanfordville	7	19	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.3	0.4	0.4
	Tinkertown	7	19	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3
	Load Area Total	**7**	**19**	**0.9**	**0.9**	**0.7**	**1.3**	**1.2**	**1.6**	**2.0**	**2.2**	**2.5**	**2.8**	**3.0**
Northwest	Coxsackie*	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.4	0.4	0.4
	Freehold	7	19	0.0	0.1	0.0	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.5
	Hunter	1	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Lawrenceville	1	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	New Baltimore	7	19	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.7	0.8	0.9
	North Catskill	7	15	0.3	0.7	0.6	0.9	0.7	0.8	2.2	2.3	2.9	3.3	3.7
	South Cairo*	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	Vinegar Hill	2	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Westerlo	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Load Area Total	**1**	**18**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**
Poughkeepsie-D	Inwood Ave	9	17	0.1	0.1	0.2	0.1	1.1	0.7	0.7	1.3	1.3	1.4	1.4
	Manchester	7	17	0.3	0.4	0.3	0.7	0.6	0.7	0.7	0.8	0.9	1.0	1.1
	Reynolds Hill	7	16	0.1	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.4	0.4	0.4
	Spackenkill	7	19	0.1	0.1	0.1	0.3	0.2	0.4	0.4	0.4	0.4	0.4	0.4
	Todd Hill	7	19	0.1	0.2	0.1	0.3	0.3	0.3	0.3	0.3	0.5	0.6	0.6
	Load Area Total	**9**	**17**	**1.2**	**1.2**	**2.0**	**0.8**	**3.7**	**2.8**	**3.0**	**3.7**	**4.3**	**4.7**	**5.0**

ENERGY STORAGE

BESS Peak Storage Discharge by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.5	1.3
Fishkill-D	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.4	0.7	1.5
Kingston-Saugerties	7	17	0.0	0.0	0.0	0.0	0.1	0.1	0.8	2.6	2.9	4.2	5.1
Modena	7	18	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.9	1.1	1.4
Newburgh	7	17	0.0	0.0	0.0	0.0	0.0	0.1	0.1	1.1	1.6	2.7	3.7
Northeastern Dutchess	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.7
Northwest	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.6	1.8
Poughkeepsie-D	9	17	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.5	0.6	0.8	0.8
System	**7**	**17[11]**	**0.0**	**0.0**	**0.0**	**0.1**	**0.3**	**1.1**	**2.0**	**6.5**	**9.7**	**16.2**	**21.4**

BESS Normalized Historical and Forecasted Peak Contribution Estimates (2015-2025)

Load Area	Substation	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
				2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	Clinton Ave	2	10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	0.0
	Greenfield Rd*	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Grimley Rd	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	High Falls	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3
	Honk Falls	7	15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Kerhonkson	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4
	Neversink*	2	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Sturgeon Pool	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**7**	**19**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**	**0.5**	**1.3**
Fishkill-D	Fishkill Plains	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	1.1
	Forgebrook	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Knapps Corners	9	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Merritt Park	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Myers Corners	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	North Chelsea	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Sand Dock-D	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Shenandoah-D	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Tioronda	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**7**	**19**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.4**	**0.7**	**1.5**
Kingston-Saugerties	Boulevard	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2	1.2	1.3
	East Kingston	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.4
	Hurley Ave	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.8	0.9

[11] System peak hour shifts to HE 18 starting in 2023.

	Lincoln Park	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Saugerties	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	1.0
	Woodstock	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4
	Load Area Total	**7**	**17**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.8**	**2.6**	**2.9**	**4.2**	**5.1**
Modena	Galeville	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3
	Highland	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.5	0.9
	Modena	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Ohioville	9	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	Load Area Total	**7**	**18**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.9**	**1.1**	**1.4**
Newburgh	Bethlehem Rd	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3
	Coldenham	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.8
	East Walden	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.6
	Marlboro	9	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Maybrook	7	20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.8	1.4
	Montgomery*	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Union Ave	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	West Balmville	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2
	Load Area Total	**7**	**17**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**1.1**	**1.6**	**2.7**	**3.7**
Northeastern Dutchess	East Park	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Hibernia	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Milan	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Millerton	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pulvers 13	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pulvers 34	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Rhinebeck	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Smithfield	2	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Staatsburg	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2
	Stanfordville	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2
	Tinkertown	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Load Area Total	**7**	**19**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**	**0.3**	**0.7**
Northwest	Coxsackie*	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4
	Freehold	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2
	Hunter	1	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	-0.0	0.0	0.0
	Lawrenceville	1	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	-0.0	0.1	0.1
	New Baltimore	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	1.4	2.3
	North Catskill	7	15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2
	South Cairo*	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4
	Vinegar Hill	2	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Westerlo	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
	Load Area Total	**1**	**18**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.4**	**0.6**	**1.8**
Poughkeepsie-D	Inwood Ave	9	17	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.5	0.5	0.5
	Manchester	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Reynolds Hill	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Spackenkill	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Todd Hill	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2
	Load Area Total	**9**	**17**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.4**	**0.4**	**0.5**	**0.6**	**0.8**	**0.8**

ELECTRIC VEHICLES

Electric Vehicle Peak Coincident Loads by Load Area and Year

Load Area	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	7	19	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3
Fishkill-D	7	19	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.6
Kingston-Saugerties	7	17	0.1	0.1	0.1	0.2	0.3	0.4	0.3	0.4	0.5	0.6	1.0
Modena	7	18	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.6
Newburgh	7	17	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.6
Northeastern Dutchess	7	19	0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.6
Northwest	1	18	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3
Poughkeepsie-D	9	17	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
System	**7**	**17[12]**	**0.2**	**0.3**	**0.5**	**0.8**	**1.3**	**1.6**	**1.5**	**1.9**	**2.6**	**3.1**	**4.5**

EV Normalized Historical and Forecasted Peak Contribution Estimates (2015-2025)

Load Area	Substation	Peak Month	Peak Hour	Historical 1 in 2 Annual Peak (MW)					Forecasted 1 in 2 Annual Peak (MW)					
				2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ellenville	Clinton Ave	2	10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Greenfield Rd*	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Grimley Rd	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	High Falls	7	19	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2
	Honk Falls	7	15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kerhonkson	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Neversink*	2	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Sturgeon Pool	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**7**	**19**	**0.0**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**
Fishkill-D	Fishkill Plains	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
	Forgebrook	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	Knapps Corners	9	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Merritt Park	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
	Myers Corners	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	North Chelsea	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Sand Dock-D	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Shenandoah-D	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Tioronda	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
	Load Area Total	**7**	**19**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.6**

[12] System peak hour shifts to HE 18 starting in 2023.

Kingston-Saugerties	Boulevard	7	17	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2
	East Kingston	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Hurley Ave	7	17	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2
	Lincoln Park	7	16	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2
	Saugerties	7	19	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
	Woodstock	2	18	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2
	Load Area Total	**7**	**17**	**0.1**	**0.1**	**0.1**	**0.2**	**0.3**	**0.4**	**0.3**	**0.4**	**0.5**	**0.6**	**1.0**
Modena	Galeville	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	Highland	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
	Modena	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Ohioville	9	18	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.2
	Load Area Total	**7**	**18**	**0.0**	**0.0**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**	**0.6**
Newburgh	Bethlehem Rd	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Coldenham	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	East Walden	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
	Marlboro	9	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Maybrook	7	20	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
	Montgomery*	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Union Ave	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
	West Balmville	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**7**	**17**	**0.0**	**0.0**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**	**0.6**
Northeastern Dutchess	East Park	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hibernia	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Milan	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Millerton	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pulvers 13	7	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pulvers 34	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Rhinebeck	7	18	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3
	Smithfield	2	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Staatsburg	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Stanfordville	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Tinkertown	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**7**	**19**	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**	**0.5**	**0.6**
Northwest	Coxsackie*	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Freehold	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hunter	1	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Lawrenceville	1	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	New Baltimore	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
	North Catskill	7	15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	South Cairo*	2	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Vinegar Hill	2	8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Westerlo	1	18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Load Area Total	**1**	**18**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**
Poughkeepsie-D	Inwood Ave	9	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Manchester	7	17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Reynolds Hill	7	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
	Spackenkill	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
	Todd Hill	7	19	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
	Load Area Total	**9**	**17**	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**

APPENDIX – ENERGY EFFICIENCY METHODOLOGY

DATA SOURCES

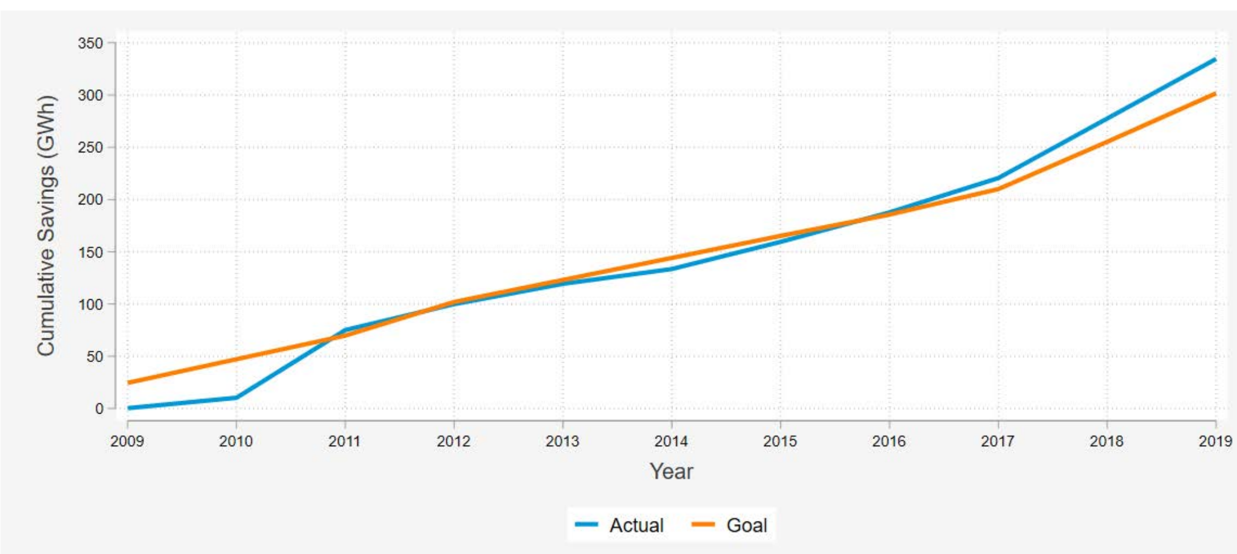
The primary data sources used in this analysis were provided by Central Hudson through billing data and records of historical energy efficiency installations and territory-wide savings. These data sources were used both to calculate cumulative historical energy efficiency by program and the dispersion by granular locations (transmission area and substation). Historical energy savings goals and savings realization (based on past Central Hudson E-TIP filings) as well as future system-wide goals were used to develop a future forecast of energy efficiency with an uncertainty range. This forecast was further applied to the locational database to develop a future location energy efficiency forecast. Finally, end use and segment-specific load shapes derived for the 2020 DSIP were used to develop peak day energy efficiency and coincidence factors by location.

HISTORICAL DATA ANALYSIS

In order to accurately forecast growth in energy efficiency, it is important to understand the historical trends. Central Hudson develops a detailed plan for future energy efficiency in its annual Energy Efficiency Transition Implementation Plan (ETIP). Rather than reproduce the effort involved developing the ETIP, this historical information was leveraged to understand savings goal performance in the past.

Figure 31 shows cumulative energy efficiency savings since 2009. Cumulative savings were calculated by summing annual savings since 2009, taking into account effective useful life (EUL) of energy efficiency measures, ranging from 1 year for behavioral programs to 20 years for LED lighting. Since 2011, cumulative savings have tracked closely to goals: actuals have been 101.9% of goals on average, with a standard deviation of 6.4%. Actual annual savings have been above goal each year since 2016.

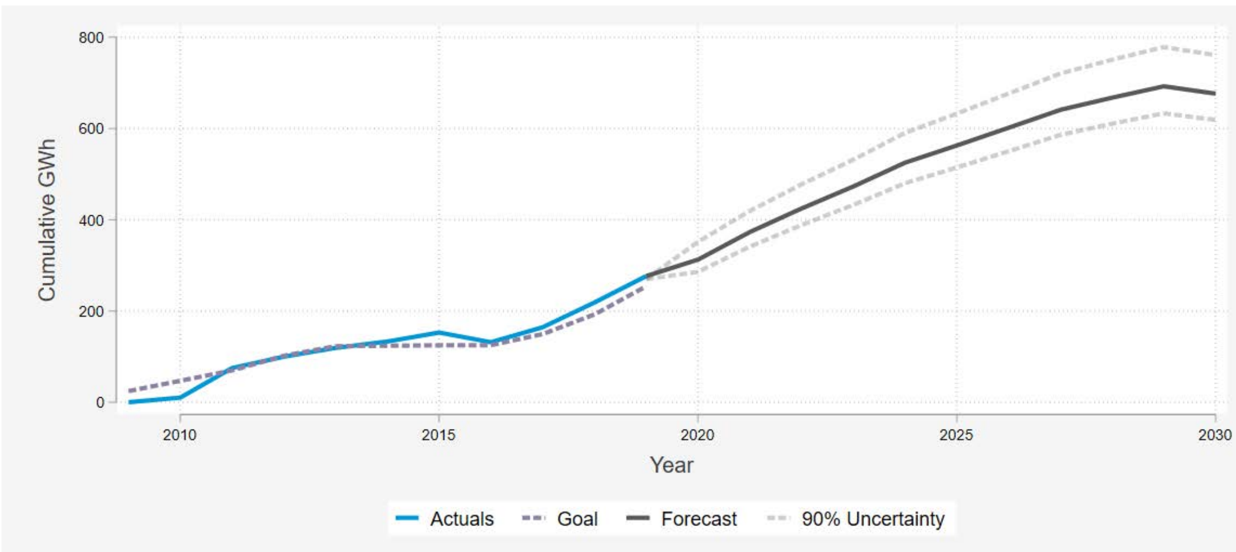
Figure 31: Energy Efficiency Savings – Goal and Actual (Central Hudson E-TIP)



FORECAST SYSTEM ADOPTION

Central Hudson's annual net energy efficiency savings goal range ranges from 39.9 GWh to 69.8 GWh first-year savings per year through 2030, based on the 2020 Cadmus Energy Efficiency Market Potential Study. To develop an energy efficiency forecast, we took these forecasted savings, added them to the historical cumulative savings, then applied the average historical performance. We then derived confidence bands around this estimate by applying the observed historical performance variability (6.4% standard deviation), assuming normally distributed performance variability. The percentile range shown in Figure 32 assumes a 90% confidence range[13]. Note that for all reporting, 2019 is assumed to be the base year for any future savings.

Figure 32: Energy Efficiency Savings: Historical and Forecast with Uncertainty



MODELING DISPERSION AT A GRANULAR LEVEL

After forecasting system-level energy efficiency, we allocated savings by transmission area and by substation. This was a key step for understanding how energy efficiency is distributed across the territory as well as understanding how specific types of energy efficiency coincides with local loads. The dispersion analysis combined a bottom up approach with a top down approach. For programs for which measure and customer level information was available, the savings were allocated by location based on historical dispersion. For measures and programs for which such data was not available, the annual system-level savings were allocated by location proportionally to customer usage in each location. This was done separately for residential and commercial programs using only the usage for the relevant segment.

[13] E.g., the mean performance plus or minus 1.645 times the standard deviation.

CALIBRATE TO SYSTEM FORECAST

The dispersion analysis was further scaled to ensure that program totals from the bottom up approach matched the system-level historical savings.

PRODUCE HOURLY LOAD SHAPES

Segment and end use specific load shapes were developed for Central Hudson for the 2016 DSIP filing and these same load shapes were used here. Detailed descriptions of the load shapes can be found in the 2016 DSIP Appendices, but at a high level they were derived for Central Hudson's 1 in 2 weather year, 2013. Figure 33, Figure 34, and Figure 35 show these load shapes on the 2013 system peak day (July 18). The 8760 loads shapes were normalized so that maximum load for a given end use equals 1.

Some load shapes, as shown Figure 33 and Figure 35, directly pertain to a specific end use (lighting, HVAC, etc.) and show characteristic patterns, such as an evening peak for residential AC. A general load shape was needed for more general programs such as residential behavioral programs or full building commercial measures. For these, the general segment load shape was used and an industry-specific load shape was used where an industry classification for a commercial site was available.

Figure 33: Residential End Use Load Shapes – System Peak Day

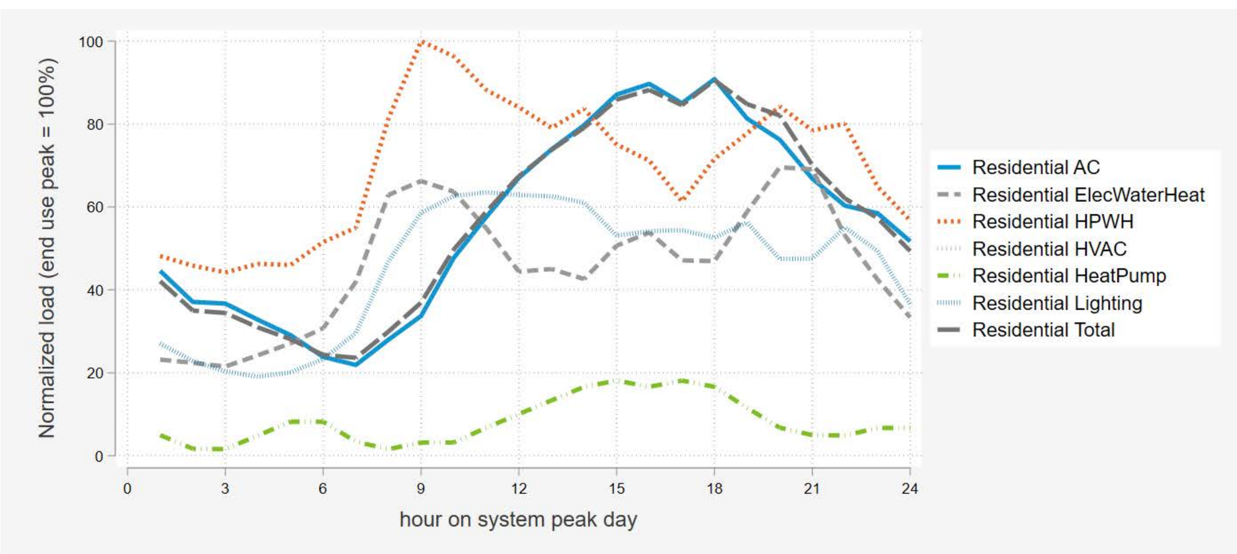


Figure 34: Commercial Non-Lighting Load Shapes by Industry – System Peak Day

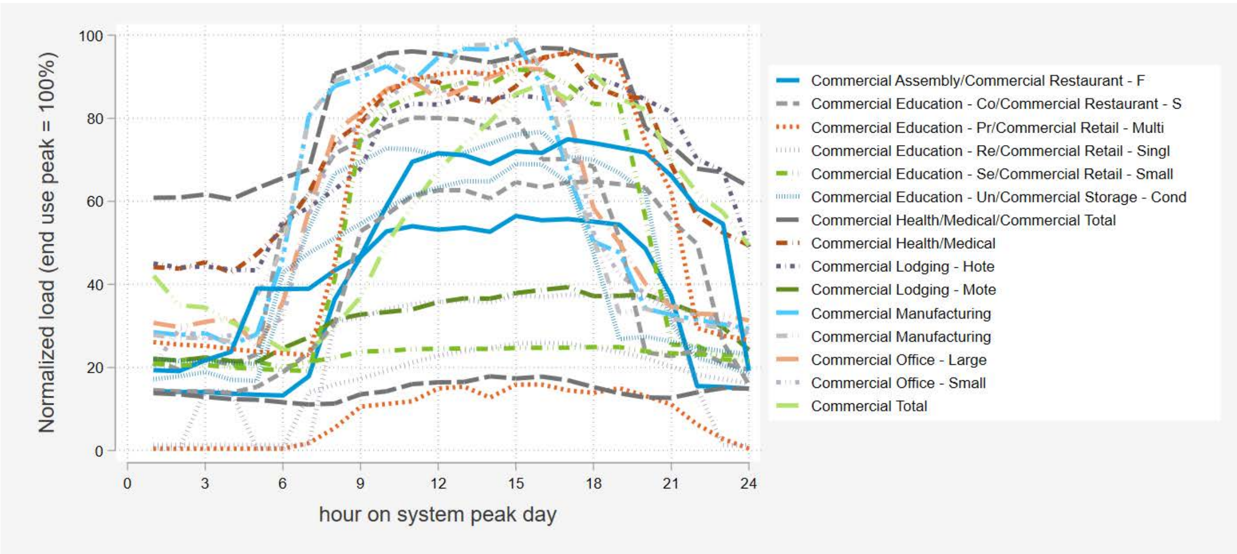
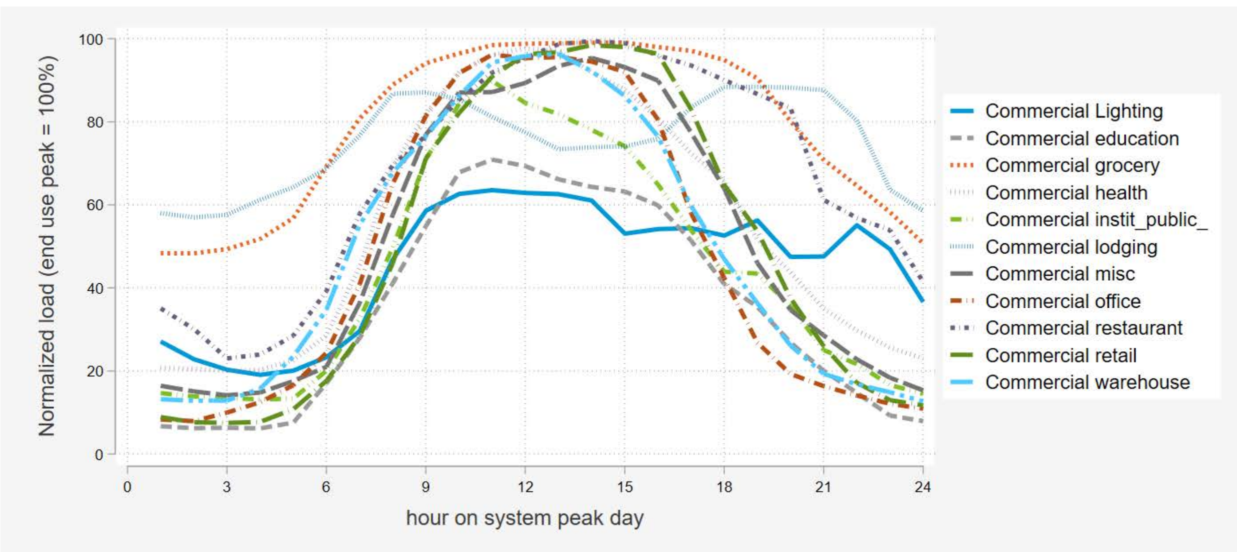


Figure 35: Commercial Lighting Load Shapes– System Peak Day



PRODUCE AGGREGATE AND LOCATION SPECIFIC FORECASTS

The final step in the process was to apply hourly load shapes based on the end-uses of each program and measure to the adoption forecast. The output of this analysis was a ten-year location-specific hourly (8760) forecast of energy efficiency, by sector and end use. A secondary set of outputs are coincidence factors with local peaks by sector and end use.

APPENDIX – SOLAR METHODOLOGY

We forecasted solar capacity for five different categories of solar installations:

1. **Residential solar** – Through January 2020, there were roughly 9,000 residential solar installations with 65 MW of capacity in Central Hudson's territory. An important driver of residential growth was the introduction of the leasing and power purchase agreement models in 2012, which reduced the capital constraint for customers. After an initial growth phase, the pace of adoption has been roughly constant since 2018.

2. **Non-residential solar (on-site and remote net metering)** – Non-residential solar consists of on-site installations and remote net metered solar[14]. For forecasting purposes, we divided non-residential solar into two categories: (a) remote net metered solar of at least 300 kW in size; and (b) other non-residential solar, including remote net metered solar under 300 kW in size and on-site non-residential installations.

    a. **Large (>300kW) remote net metered solar** – Through January 2020, there were 10 non-residential solar installations with 10 MW of capacity in Central Hudson's territory, with 9 active projects in the interconnection queue.

    b. **Onsite non-residential solar and small (<300 kW) remote net metered solar** – Through January 2020, there were roughly 500 non-residential and small remote net metered solar installations totaling 18 MW of capacity in Central Hudson's territory. Similar to residential solar, the pace of adoption for small non-residential solar has been relatively constant in recent years.

3. **Community solar** – Community solar projects are large projects – the most common project size is 2 MW, but can reach up to 5 MW – that are owned and provide financial benefits to multiple members. Through January 2020, there were 17 community solar installations with 34 MW of capacity in Central Hudson's territory, with an additional 75 projects and 197 MW of community solar projects in the application queue. Although not all application will result in completed projects, community solar is expected to account for the majority of additional distributed solar installation in Central Hudson's territory.

4. **NYISO Distribution-Connected solar** – There are two projects projected to interconnect into distribution systems by the end of 2021, totaling 30 MW. The two projects are Hecate 2 (10 MW) at the Coxsackie substation, and Geronimo Blue Stone (20 MW) at the Saugerties substation.

[14] Remote net metering allows customers to apply credits from one facility with the same owner to another facility.

DATA SOURCES

The primary data sources used in this analysis were provided by Central Hudson through billing data and records of historical applications and completed solar facilities. We also obtained external data from NYSERDA and ISO-NE. These data sources are described below.

Central Hudson provided a record of all queued and interconnected solar facilities in their service territory. The interconnection data spans from December 2001 through January 2020. Using the first eight digits of the account number, the interconnection records could be matched with customer billing data. Billing data includes information for 326,933 unique premise locations with 17,095,449 bills in the sample. The date range spans from January 1990 through March 2018, but not for all accounts. Key variables of interest are detailed in Table 11.

Table 11: Central Hudson Data Variable Descriptions

Source	Field	Description
Interconnection	Account Number	Unique ID number for each account. The first 8 digits uniquely identify a premise and were used for matching.
Interconnection	Interconnection Date	The date when the PV system was connected to the grid.
Interconnection	Installed Capacity	The capacity of the installed PV system in kW.
Interconnection	Type of Installation	An indicator of whether the installation was residential, non-residential, community, etc.
Billing	Account Number	Unique ID number for each account.
Billing	Read date	The date the meter was read, corresponding to the end of the billing period.
Billing	Bill Period	The number of days in the billing period.
Billing	Usage	Electricity consumption (kWh) during the bill period.
Billing	Rate	The rate code associated with the bill.
Billing	Zip Code	Zip code the account is located in.
Billing	Circuit	Circuit the account maps to.

The external data sources are described in Table 12. Data on historic solar costs from NYSERDA were used to forecast future solar installations and data on historic hourly solar generation from actual solar facilities in ISO-NE were used to develop the 8760 solar production profiles.

Table 12: External Data Sources

Data Type	Data Source	Data Description
Historic Solar Costs	NYSERDA[15]	Used as variable for predicting future solar adoption
Historic Solar Production	ISO-NE[16]	Hourly actual solar production from utility-scale solar installations in ISO-NE

RESIDENTIAL AND NON-RESIDENTIAL SOLAR

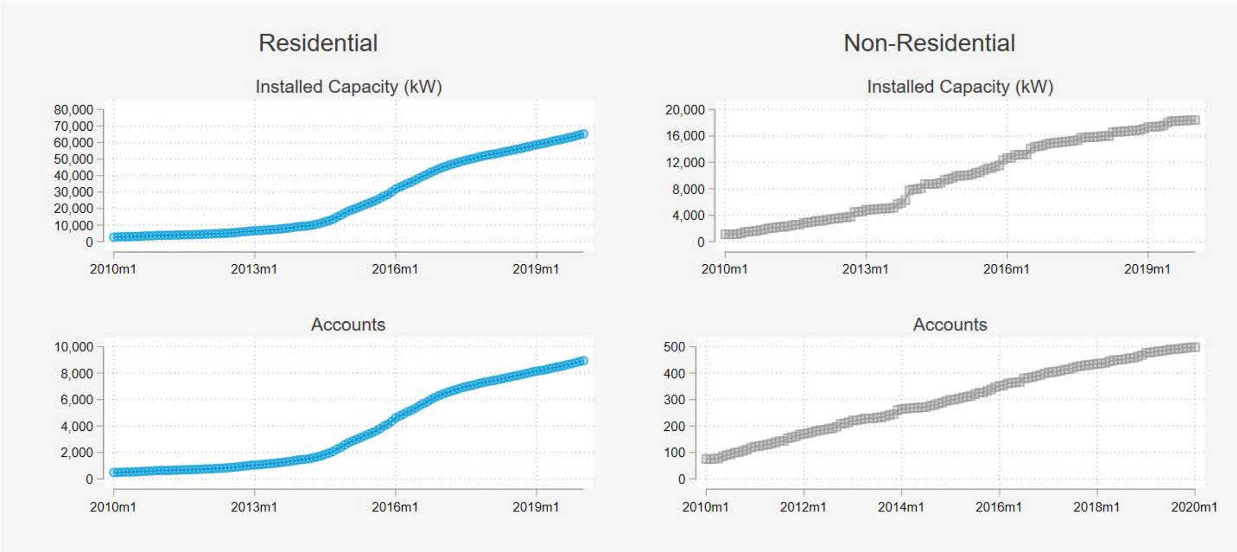
Residential and non-residential[17] solar installations represent the majority of solar facilities interconnected to Central Hudson's territory today, and are expected to continue to increase in upcoming years. In this section, we describe the methodology for producing granular residential and non-residential solar capacity forecasts and 8760 shapes at the substation level.

HISTORICAL DATA ANALYSIS

Figure 36 depicts the historic trend in residential and non-residential solar installations in terms of installed capacity and number of installations. Residential installations accelerated from 2014 to 2017, and have continued at a more moderate linear pace ever since. Important drivers of residential growth include the introduction of the leasing model in 2012, which reduced capital constraints for customers, as well as policy incentives, which are being phased down. Non-residential additions have followed a more consistent linear trend in capacity and installations.

[15] Available to download from: https://data.ny.gov/Energy-Environment/Solar-Electric-Programs-Reported-by-NYSERDA-Beginn/3x8r-34rs.
[16] Available to download from: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type.
[17] In this section, non-residential solar consists of traditional onsite non-residential solar as well as small (<300 kW) remote net metering installations. We describe the methodology for forecasting large remote net metering solar in the next section.

Figure 36: Residential and Non-Residential Solar Historic Installations



Forecast New Installations

The historic installation data formed the foundation for forecasting new residential and non-residential installations. In particular, we defined and tested various time series models on monthly historic installation data, then made predictions for future installations using the best-fitting models.

We relied on the Auto Regressive Moving Average (ARMA) class of models, which are widely used in time series forecasting. ARMA models predict the values of a given time series based on that time series' own past values, or lags, as well as the lagged forecast errors, and have two terms, commonly written as ARMA(p,q). The first term, 'p' is the order of the 'Auto Regressive' (AR) term, which refers to the number of lagged time series observations, or "lags," to be used as predictors. The second term, 'q' is the order of the 'Moving Average' (MA) term, which refers to the number of lagged forecast errors to be used as predictors. For instance, an ARMA(2,1) model would rely on the previous two observations and the previous one lagged forecast error to predict the value for a given month. To start, we fit the following five time series models:

ARMA(1,0) ARMA(1,2) ARMA(12,0) ARMA(6,1) ARMA(12,1)

We fit five additional models (for a total of ten for each sector) that included a time trend, excluding the 2014-2017 growth phase, to capture the secular trends in solar installations over time. In addition, all five models included two more explanatory variables:

- An indicator variable, marked as one for all months after January 2013 – used to denote the start of the lease period in solar financing, which served to reduce credit requirements for customers and accelerate adoption of solar

- The cost per watt of residential solar – used to capture the effect of declining solar costs on adoption. Historic values were calculated from the NYSERDA data, and were forecast for the study period by fitting an exponential curve, with future costs are expected to continue to decrease, though at a slower rate than was observed in the 2010s.

We selected the model used for prediction for each solar type by identifying the three models with the lowest absolute percent bias and then selecting the model with the lowest error (as measured by the relative root mean square error, or RRMSE), using the years from 2008 to 2018 to fit the data and 2019 as the testing data. The best-fitting model was ARMA(6,1) without the time trend for residential installations and ARMA(12,0) with the time trend for non-residential installations. The model fits on the historic data and predictions are shown in Figure 37, which shows the monthly incremental installations; Figure 38 shows the cumulative installations. We predict that both sectors will continue to grow at relatively steady rates, with substantial uncertainty (represented by the 95% confidence interval in purple). Note that we are forecasting installations, rather than capacity; in we convert from installations to capacity in a later step, based on the historic average system sizes at each substation.

Figure 37: Residential Solar Installation Time Series Model Fit and Forecast

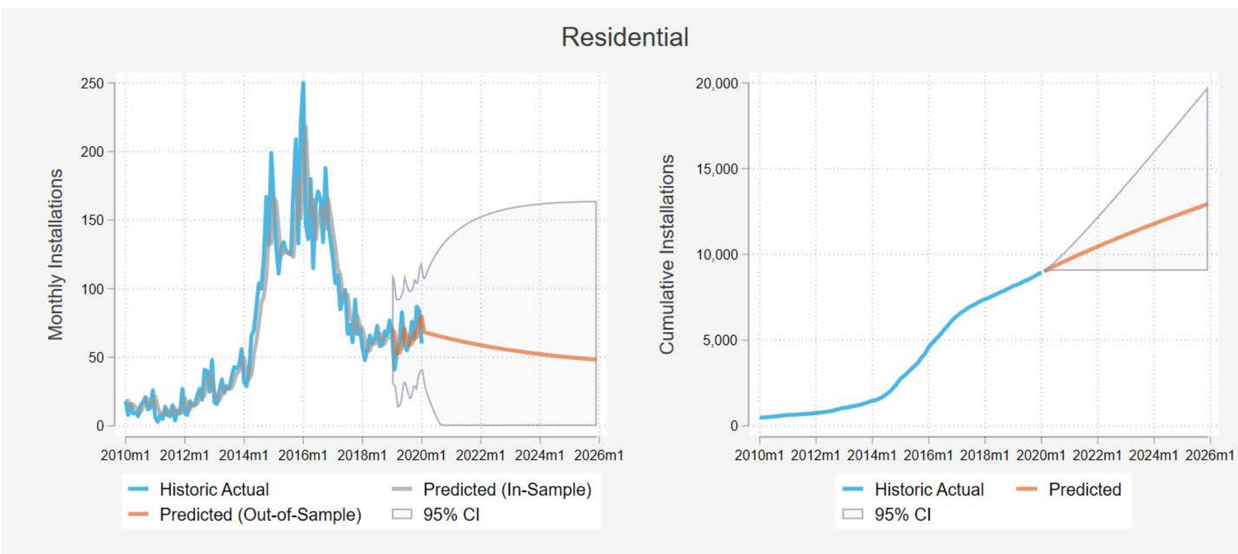
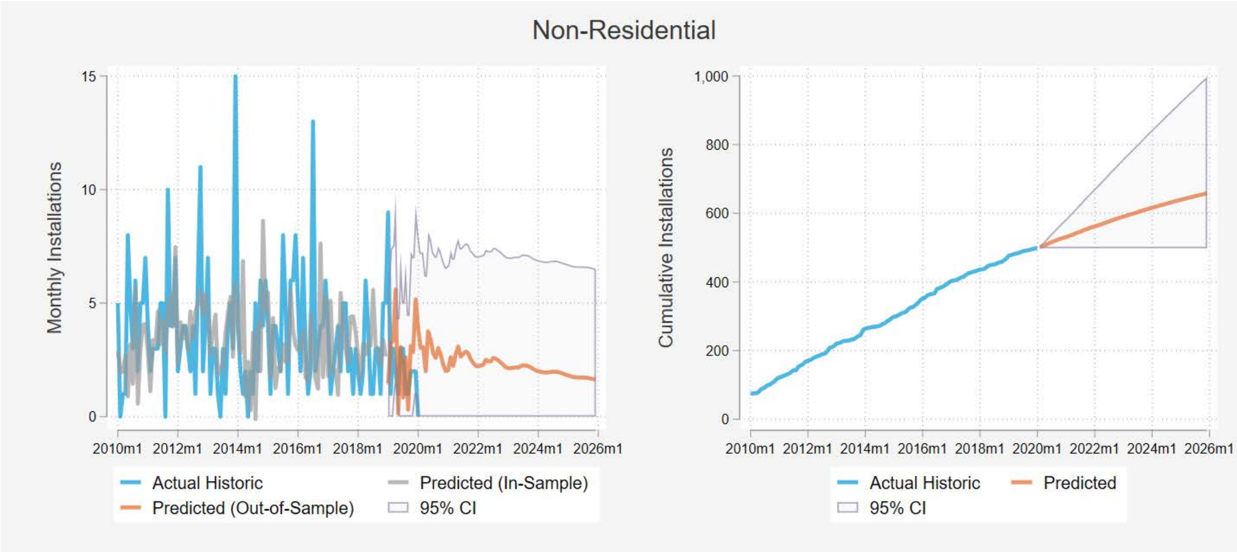


Figure 38: Non-Residential Solar Installation Time Series Model Fit and Forecast



Model Adoption Propensity at a Granular Level

To develop a more granular model capable of forecasting the impact of solar penetration at the substation level, it was necessary to model individual customer adoption probabilities. Modeling propensity to adopt requires pre-adoption data for both installers and non-installers. Based on the availability of billing data, January 1, 2016, was chosen as an adoption cut-point. This threshold provided three full years of billing data for nearly every customer while leaving enough adopters in the model to provide significant test results. To determine adoption probabilities a probit regression model was used. In this model, the dependent variable, solar adoption, can take only two values (install or not). We explored a number of independent variables likely to be correlated with the adoption of solar which are detailed below. The output of the probit model is a probability estimate of how likely a premise is to install solar. These estimates can then be compared to the actual data on adoptions through 2018 for validation.

Weather Sensitivity

One potential predictor of solar adoption is the degree to which a customer's load is correlated with temperature. We investigated this weather sensitivity separately for both hot and cold temperatures using heating and cooling degree days. For each bill period in winter months, we calculated the number of heating degree days (HDD) using a 55-degree base. For summer months, the number of cooling degree days (CDD) using a 60-degree base was calculated. This data was then merged with the kWh usage during the bill period to generate a set of correlation coefficients for each customer. A correlation of 1 would indicate that the customer's load was perfectly correlated with the number of degree days. A coefficient of zero indicates the two are not linearly related. Figure 39 shows a scatter plot of the correlation between temperature and load for residential customers. The absence of customers in quadrant 3 indicates that nearly all customers use more electricity when it is very hot and/or when it is very cold.

Figure 39: Weather Sensitivity of Residential Customers

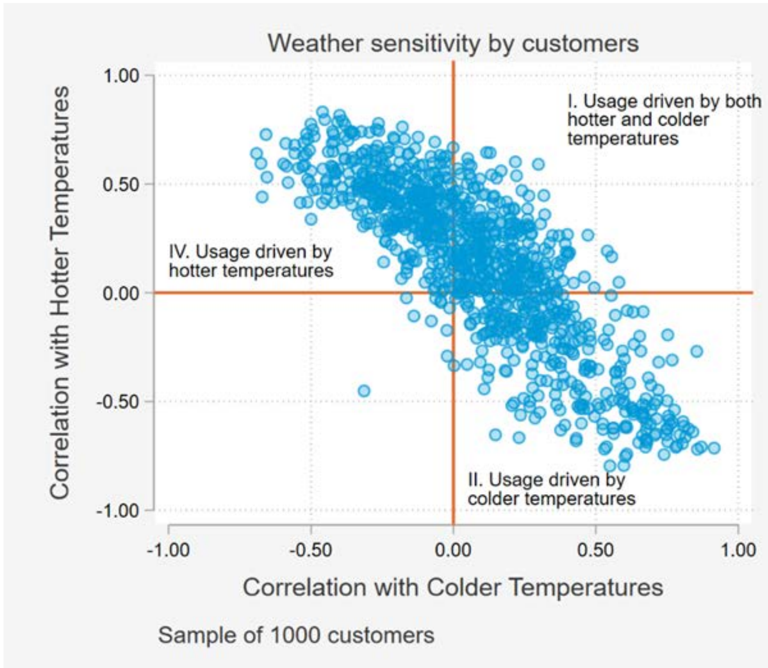
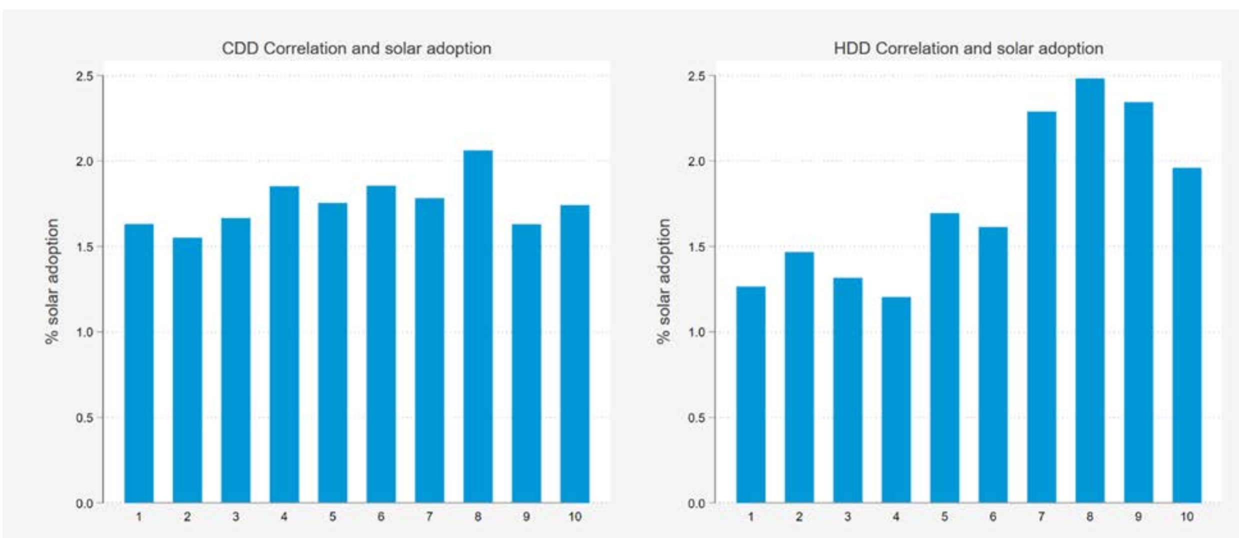


Figure 40 shows the relationship between weather sensitivity and solar adoption for residential customers . It is evident that a load more correlated with HDD increases the rate of solar adoption. However, there is no clear relationship between CDD correlation and adoption.

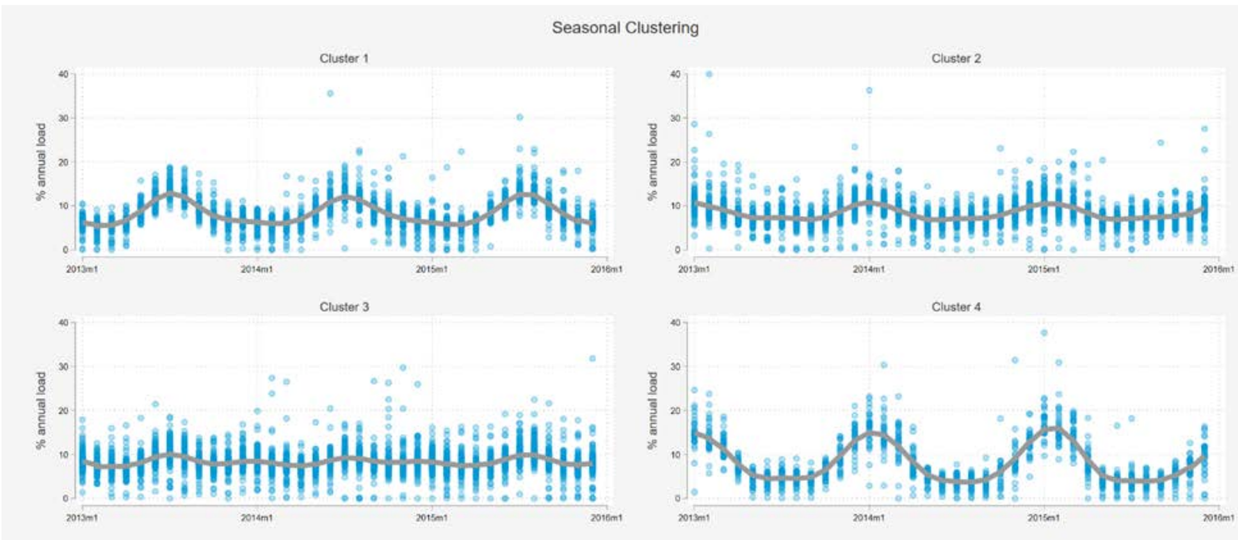
Figure 40: Residential Weather Sensitivity vs. Solar Adoption



Seasonal Load Shape

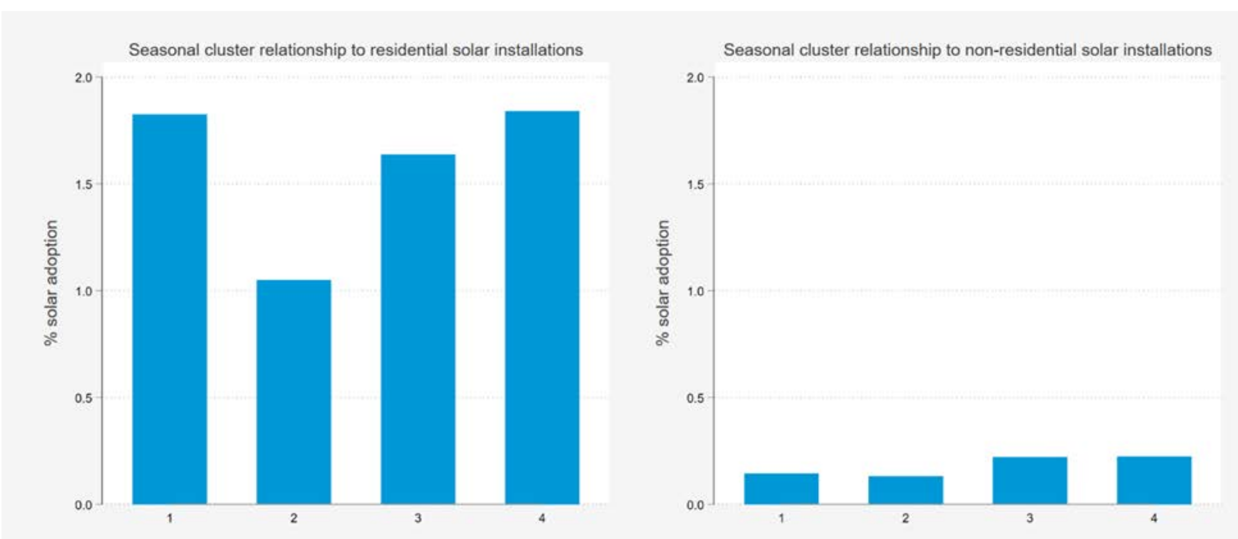
Another predictor of solar adoption is a customer's seasonal load pattern. To create clusters of usage patterns, the data were first transformed from billing periods to monthly usage. From there, data was normalized such that each month represented a percentage of annual consumption. Thus, clustering is based on shape as opposed to magnitude, and residential and non-residential customers can be clustered together. A k-means cluster algorithm was employed to identify four clusters. The results are shown in Figure 41. Cluster 1 represents customers whose usage peaks in the summer, Cluster 2 and Cluster 4 those who peak in the winter, and Cluster 3 those whose load is relatively even throughout the year.

Figure 41: Seasonal Load Clusters



The relationship between seasonal use pattern and solar adoption is displayed in Figure 42. For both customer classes, cluster 2 – which have higher winter consumption – is associated with a lower probability of solar adoption.

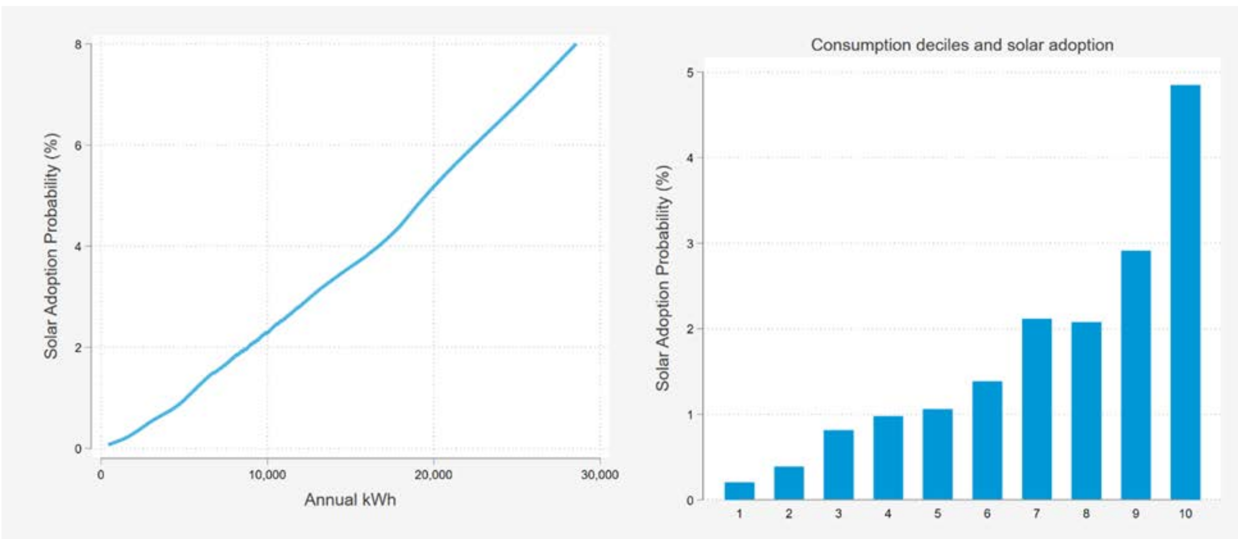
Figure 42: Residential and Non-Residential Adoption Probability by Usage Cluster



Annual Usage

Customers with larger load are more likely to install solar. This can be seen for residential customers in Figure 43. The left panel shows the Loess curve which represents a locally weighted moving average. There is a nearly linear moving average between annual electricity consumption and probability of solar adoption. When binned into deciles, as is done in the right panel, the relationship remains strong, with nearly 5% of those customers in the top decile of use adopting solar. The nonresidential pattern shows a similar pattern, with higher usage customers having higher probability of adoption.

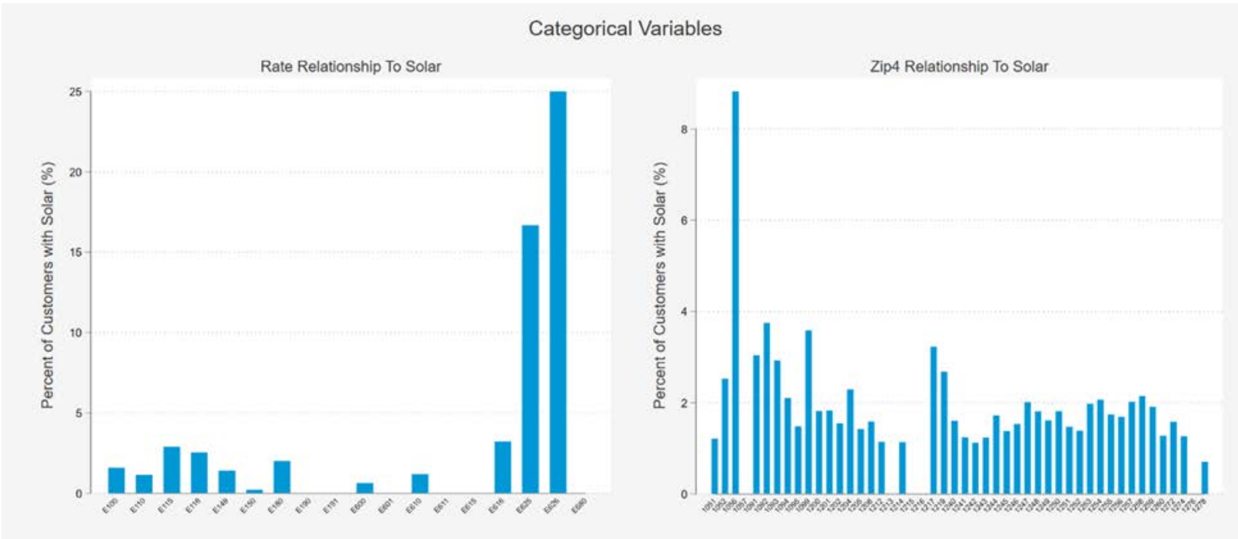
Figure 43: Residential Solar Adoption Probability by Electricity Consumption



Customer Type and Location

Finally, we investigated the relationship between solar adoption and categorical variables such as rate class and four-digit zip code. Figure 44 demonstrates that customers in certain rate classes and certain zip codes are more likely to adopt solar. The highest percentage of adopters are from customers in the residential time of use rate classes (rates E625 and E626). Certain zip codes also host higher levels of adopting customers.

Figure 44: Residential Solar Adoption on Categorical Variables



Model Specification

Using the variables described in the previous section, we employed a probit model to estimate the probability of adoption for each customer. Probit models are preferable to regression models when the dependent variable is binary rather than linear. In this case, the dependent variable is binary – whether a customer has solar or not. The suite of independent variables selected for the final model were: HDD weather sensitivity, electricity usage percentile, seasonal cluster, rate class, and zip code. The model output produces a propensity score for each customer indicating their likelihood of adopting solar. Figure 45 shows the model results overlaid on the actual data for residential customers.

Figure 45: Residential Model Fit

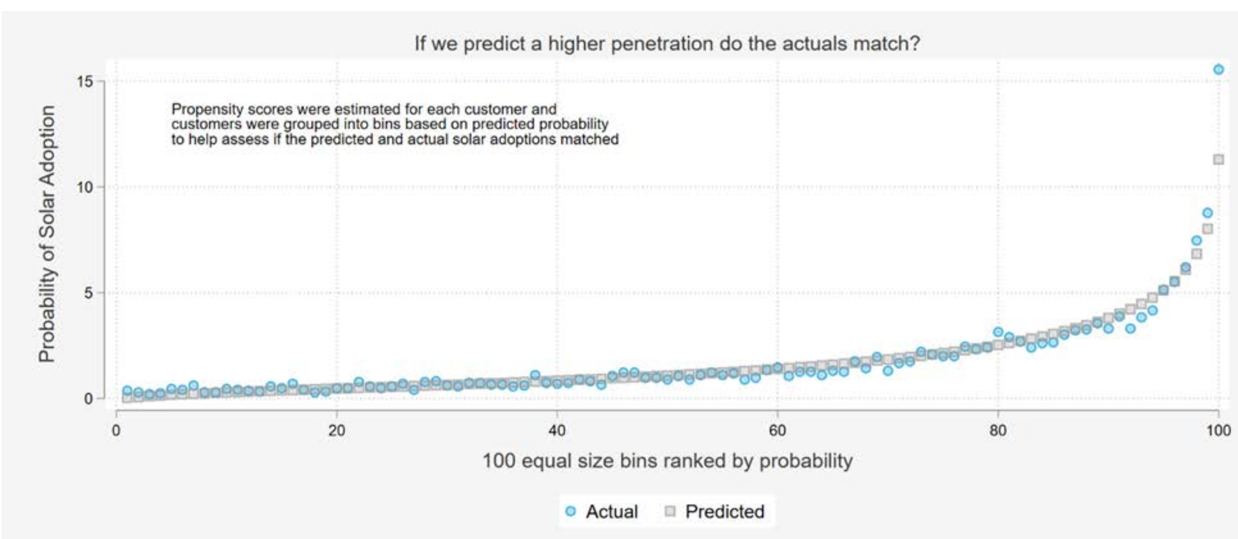
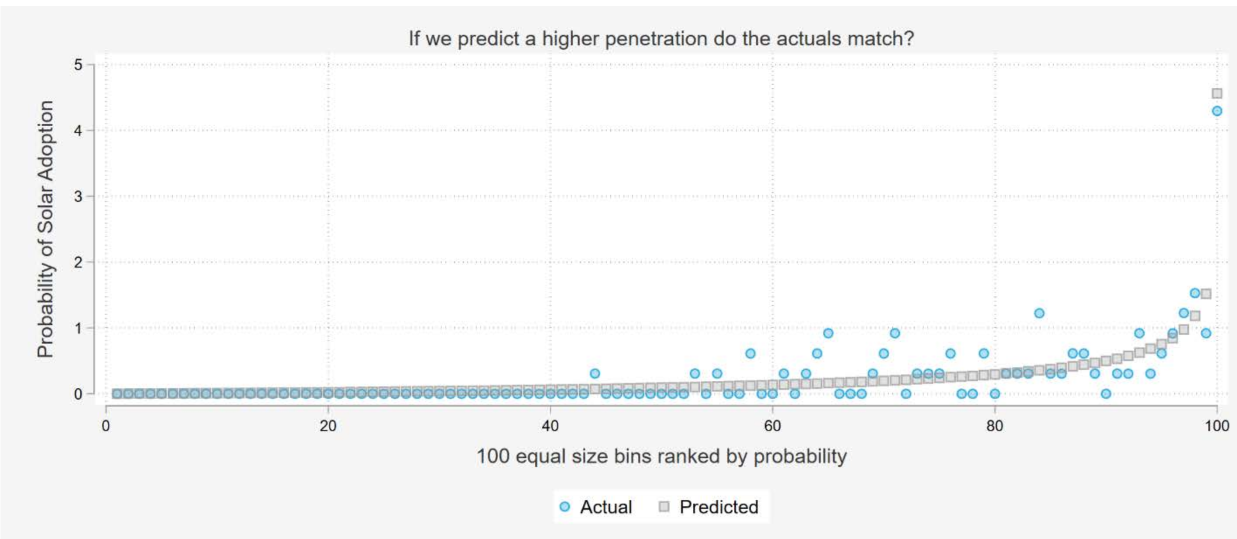


Figure 46 displays the fit of the non-residential probit regression. There is more noise in the non-residential model as a result of fewer solar installations, fewer customers overall, and weaker relationships between the independent variables and solar adoption for non-residential customers. Nonetheless, the model still captures the shape of the curve. Finally, or a small subset of customers, data on one or more of the independent variables was missing or not complete during the time frame, and they were dropped from the model. The substation mean probability of adoption was used for these customers. For those few accounts without a substation listed, the system-wide mean probability of adoption was used.

Figure 46: Non Residential Model Fit



Calibrate to System Forecast

Once a model of customer adoption was generated, the results could be calibrated to follow the system-wide forecast. Each customer's probability of adoption was summed and the result was scaled to 100%. The rank order of probabilities for the customers remains the same over time, but as the forecast calls for more installations, each customer's probability is shifted accordingly such that the sum of predicted installations equals the forecast.

With each customer having a probability of adoption for each month in the forecast, the probabilities are simply aggregated by customers to the substation level to provide estimates of the number of installations and installed capacity at each substation.

COMMUNITY AND REMOTE NET METERED SOLAR

Community solar installations provide power and/or financial benefit to, or is owned by, multiple members. Community solar can be applied through several different sponsorship models and are an increasingly popular means of providing access to solar for customers who may not otherwise have access to solar (for instance, renters). As of January 2020, Central Hudson had 17 projects totaling 34.1 MW of community solar, with all but one projects interconnected after January 2019. There were an additional 75 projects and 197.0 MW of community solar projects in the application queue.

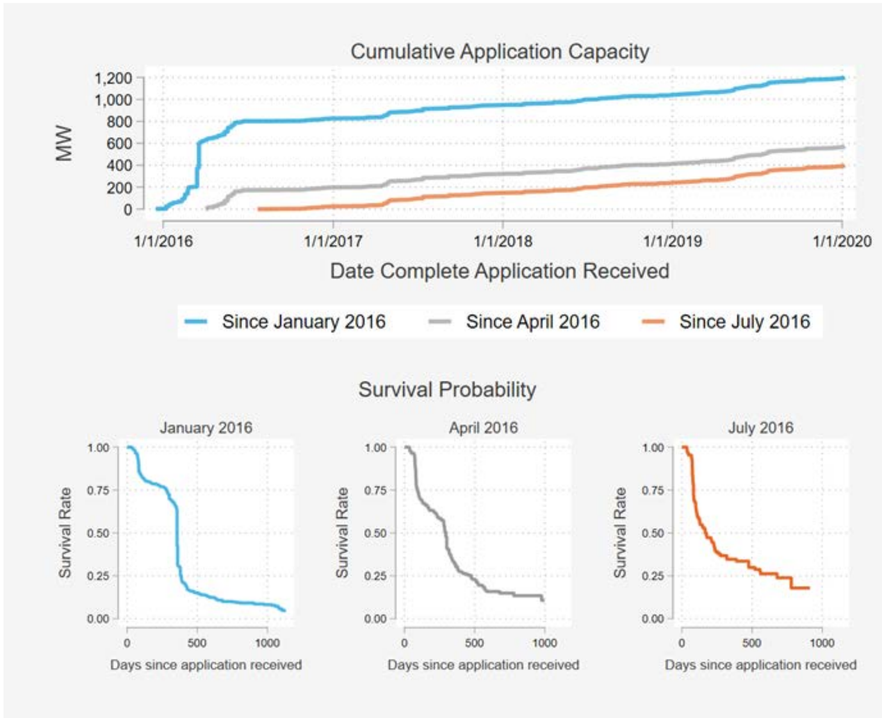
Remote net metering allows customers to apply credits from one facility with the same owner to another, and also exhibits a growth trend different from that of distributed solar. Like community solar, remote net metering facilities are often large and many individual facilities have 1 or more MW of installed capacity. Large remote net-metering projects have timelines that approximate those of the community solar projects and do not fit well into the forecast of more standard non-residential solar growth. We employed a similar process to community solar for forecasting the addition of remote net-metered projects greater in size than 300 kW (remote net metering projects under 300 kW were included in the prior non-residential method). The forecast for remote net-metered projects was incorporated into the non-residential forecast for the final reporting.

Historical Data Analysis

Whereas the residential and non-residential solar process relied on historic interconnection data, for community solar and large remote net metering, we look at historic project application data because a substantial portion of these applications do not proceed to interconnection, due to a longer application process (at least 2 years, without construction). The historic application data had detailed data on the type of project and the application steps completed for each project, including if the project was withdrawn from the queue.

The top panel of Figure 47 shows the cumulative application capacity received since 2016 (in MW). There was a very large increase in applications at the beginning of the program in 2016 – 600 MW of applications were received between January and April of 2016 – and discussions with Central Hudson revealed a queuing effect in which developers were anxious to secure an early place in line and submitted many applications that were incomplete or inaccurate. A process change to the New York State Standardized Interconnection Requirements in March 2016 provided a more standardized format for processing applications and introduced screening tests for applications above 50 kW. Following this change, many applications were dropped from the queue. As can be seen in Figure 47, the rate of applications received slowed after March 2016, and the bottom panel of Figure 47 shows the cumulative survival rate of applications depending on the analysis start date (the survival rate is lowest if the analysis begins in January 2016). Based on our observation that nearly all applications submitted before July of 2016 were eventually withdrawn, July 2016 was chosen as the start date of the interconnection queue analysis.

Figure 47: Historical Community Solar Application Analysis



Forecast New Applications

A key distinction between the method used for forecasting future installations for large community and remote net metered solar and other types of solar the use of detailed interconnection queue data to estimate the probability that a given application will proceed to interconnection, because many community solar and remote net metering project applications are eventually withdrawn and do not result in an interconnected facility. The difference in methodology for forecasting future solar capacity is summarized in Figure 48.

Figure 48: Forecast Installed Capacity: Methodology by Solar Type

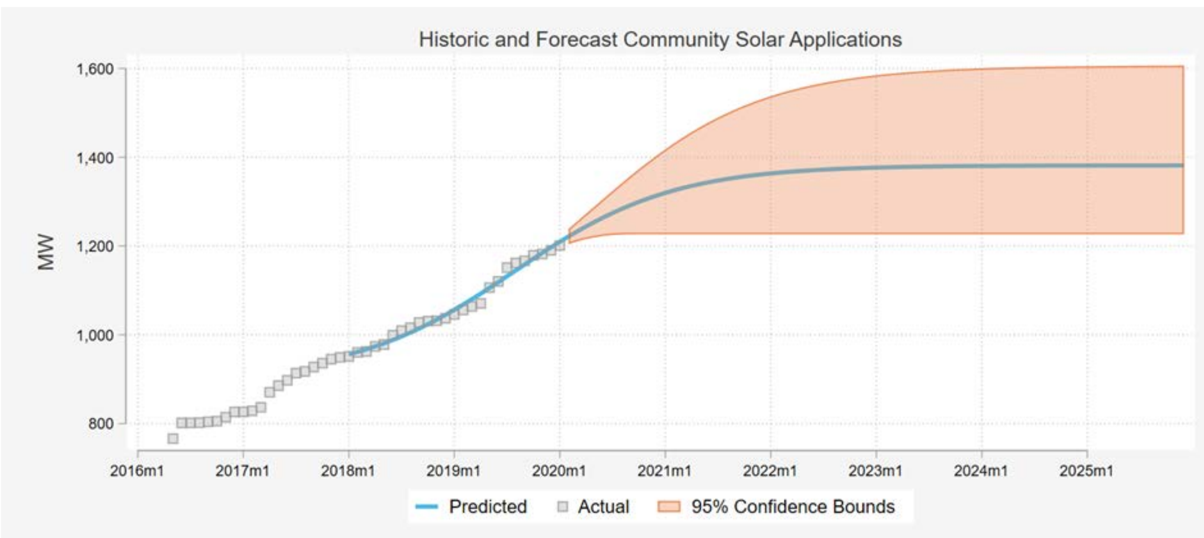
Residential Solar & Small Non-Residential Solar	• Future capacity predicted via time series models on historical *installation* data
Community Solar & Large (>300kW) Remote Net Metered Solar	• Future capacity predicted based on existing and new *applications*, accounting for probability of proceeding to interconnection
NYISO Distribution-Connected Solar	• Future capacity consists of two projects, totaling 30 MW, assumed to come online in 2020 and 2021

Our analysis considers the probability that applications currently in the interconnection queue (197 MW as of January 2020) proceed to interconnection as well as the probability that new applications proceed to interconnection. This requires a prediction of new applications. After experiencing rapid growth from

January to April of 2016, growth in community solar application capacity has steadied. Key factors driving community solar growth include ongoing system cost reductions, integration with utility billing systems, and policy support. To predict future application capacity, a Bass diffusion model was fitted to application data starting from January 2018. The Bass diffusion model is a commonly used technique to describe the adoption of new products in a population, and produces an S-curve that models the eventual saturation of the new product. The resulting forecast is shown in Figure 49. Note the vertical axis starts at 800 MW, reflecting the spike in applications before April 2016. Based on this curve, we forecast that an additional 180 MW of community solar applications will enter the queue by the end of 2025.

For large remote net metering projects, no new remote net metering interconnections were forecast over the time period, due to the relatively low number of historic applications (6 per year since 2017, compared to 53 community solar applications per year since 2017), as well as the relatively small pool of eligible customers (customers must have large amounts of electricity usage across multiple sites).

Figure 49: Community Solar Application Capacity Forecast



Predict the Probability that an Application Becomes an Implemented Project

Not all community solar and large remote net metering applications result in interconnections. These projects go through seven different stages following the receipt of the application: (0) Application Received, (1) Preliminary Analysis Started, (2) Preliminary Analysis Completed, (3) Coordinated Electrical System Interconnection Review (CESIR) Started, (4) CESIR Completed, (5) Partial Payment Received; (6) Full Payment Received; and (7) Interconnection Complete. To predict final interconnected capacity from application capacity, we implemented a Markov chain, or transition matrix, which estimates the probability of reaching a different state given the presence in the starting state. The resulting values can be interpreted as follows: given that an application reaches a certain stage in the process, what is the likelihood that it reaches the next stage compared to the likelihood that it withdraws from the queue? Table 13 shows the results of the Markov chain analysis, for community solar applications received on or after July 1, 2016. For example, of applications that completed the preliminary analysis, 59.4% proceeded to begin the CESIR while 40.6% were withdrawn. Of note, for applications with full payment completed, a full 42.9% were eventually withdrawn. This could be attributable to problems obtaining building permits or subscribing customers.

For each stage of the application, there is also data on the date that stage was reached. Using this information, we could ascertain how long an average application takes to make it through each stage. The values at the bottom of Table 8 served as the mean survival rate at each stage; to generate confidence bands around these estimates a Monte Carlo simulation technique was used. At each stage, the number of observations was set at the number of applications in that stage and an observation was said to move on based on a random yes/no draw, with the probability set to the average likelihood of transition to the next stage. In each simulation the survival rate was the percentage of applications that "move on." 100 simulations were run and the results from these simulations provided a distribution of the survival rate for projects. The mean approximated the value from the transition matrix, and the 5th and 95th percentile were used as the lower and upper bound respectively. Because few applications have reached the completion stage, we used a Beta PERT distribution with long tails to estimate the days from full payment to construction, based on observed completion times in the data. The Beta PERT distribution is very flexible and use inputs about the minimum, most likely, and maximum values to construct the distribution. For the beta distribution, the minimum number of days was set at 180; the maximum set at 1,825; and the mean at 750 days. In total, our analysis predicts that it takes an application an average of 3.5 years from the date of application submission until the project is interconnected and operational.

Table 13: Transition Matrix

Stage	Analysis Start	Analysis Comp	CESIR Start	CESIR Comp	Partial Payment	Full Payment	Interconnected	Withdrawn	Total
Application Received	100	0	0	0	0	0	0	0	100
Analysis Started	0	99.4	0	0	0	0	0	0.6	100
Analysis Completed	0	0	59.4	0	0	0	0	40.6	100
CESIR Started	0	0	0	100	0	0	0	0	100
CESIR Completed	0	0	0	0	67.7	0	0	32.3	100
Partial Payment	0	0	0	0	0	86.1	0	15.9	100
Full Payment	0	0	0	0	0	0	57.1	42.9	100
Average Duration (Days)	3	21	140	88	127	178	-	-	-

Because the number of completed remote net metering projects was low (27 applications received since July 2016, compared to 205 for community solar) but the interconnection process is similar, these parameters were also used for large remote net metering applications.

Forecast New Interconnections

Given the existing application queue, a forecast of new applications, the probability of an application making it through the application process, and the duration that process would take, we can forecast the future expected community solar and remote net metering capacity. Figure 50 shows the community solar installed capacity forecast. The left panel shows the prediction with 95% confidence intervals; the right panel shows the breakdown between capacity provided by projects currently in the queue versus capacity from new applications. Projects that are currently in the queue are expected to begin coming online in the near term, with new applications providing additional capacity starting in 2023. Figure 51 shows the large remote net metering installed capacity forecast, with confidence intervals. By the end of 2025, we predict that community solar installed capacity will be roughly 175 MW and large remote net metered solar capacity will be 15 MW.

Figure 50: Community Solar Installed Capacity Forecast

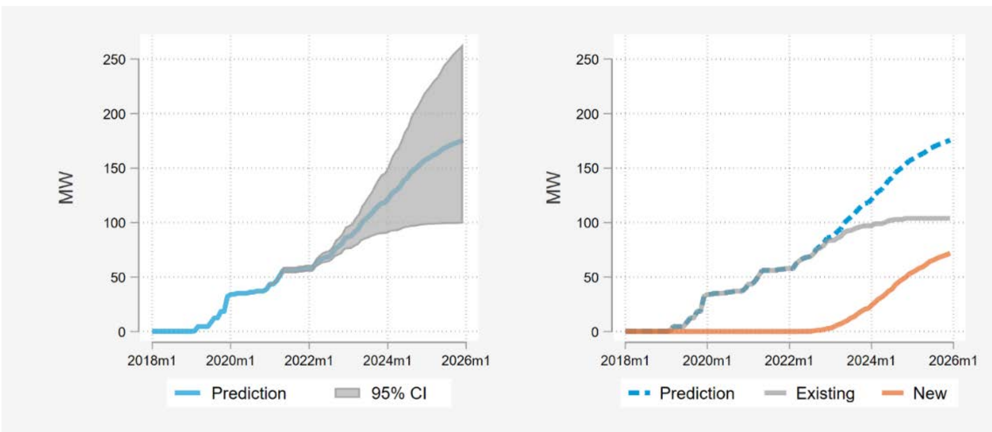
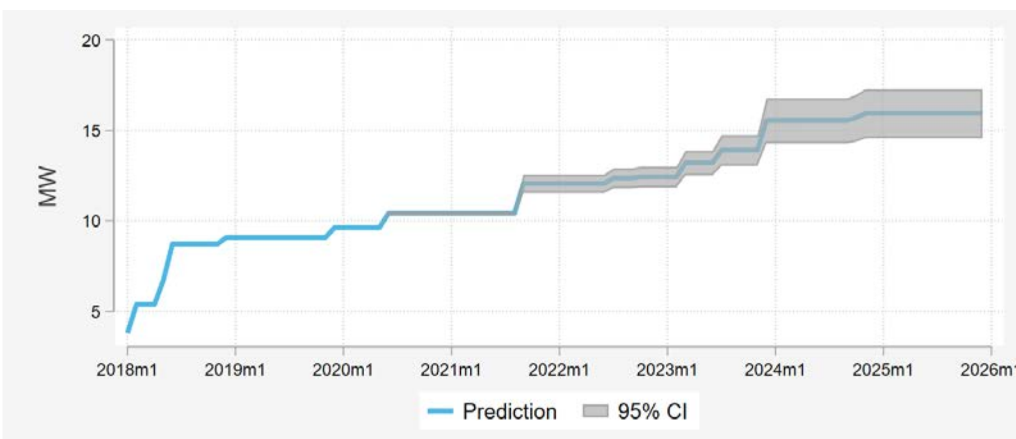


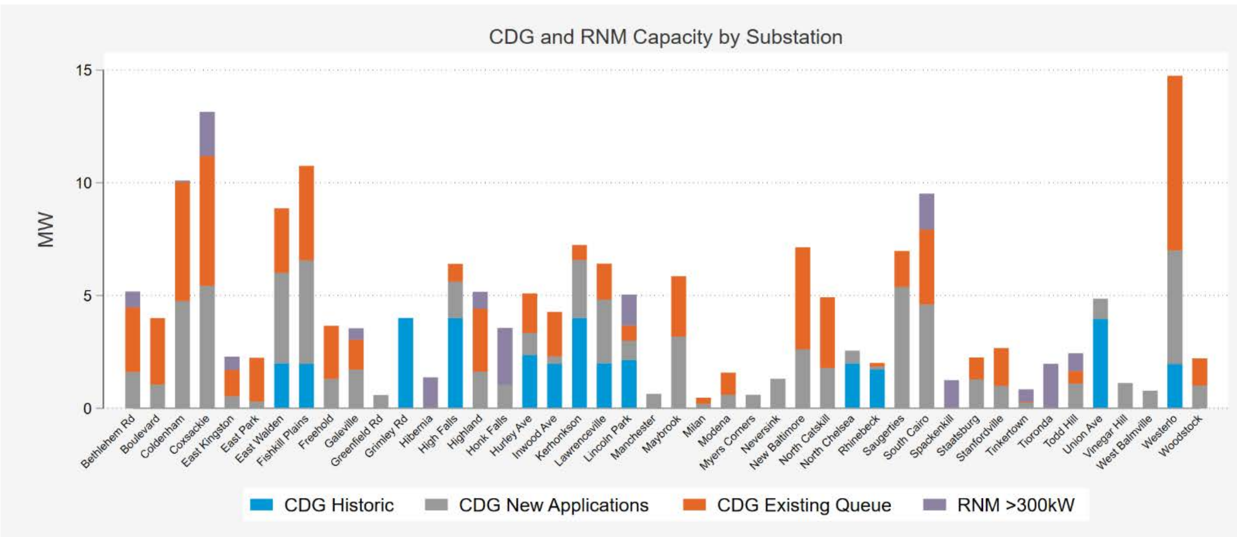
Figure 51: Large Remote Net Metering Solar Installed Capacity Forecast



Model Adoption at a Granular Level

For applications already in the queue, the information on which substation they will be installed at is included with the application, and it is straightforward to create a more granular forecast at the substation level. For predicted applications, the distribution of forecasted applications to the substation level was made on the basis of the historic distribution of total application capacity among different substations since July 2016. Figure 52 shows the capacity forecast by substation at the end of 2025, divided into historic community solar installations, forecast community solar capacity from existing projects and new applications, and large remote net metering capacity.

Figure 52: Community Solar Capacity by Substation: December 2025



NYISO SOLAR FORECAST

There are two projects projected to interconnect into distribution systems, totaling 30 MW. The two projects are Hecate 2 (10 MW) at the Coxsackie substation, and Geronimo Blue Stone (20 MW) at the Saugerties substation. We assume an interconnection date of December 1, 2020 for Hecate 2 and December 1, 2021 for Geronimo Blue Stone, based on input from Central Hudson and the project developers.

APPENDIX – ELECTRIC VEHICLE METHODOLOGY

DATA SOURCES

Several data sources were used to develop the electric vehicle forecasts presented in this chapter. The more prominent data sources, highlighted in Table 14, are discussed in the following sections.

Table 14: Data Sources

Data	Source
EV[18] Rebate Data	Central Hudson
Charging Station Data	Publicly available (data.ny.gov)
Billing Data	Central Hudson
Vehicle Registration Data	Publicly available (data.ny.gov)
VIN Data	Publicly available (vpic.nhtsa.dot.gov)

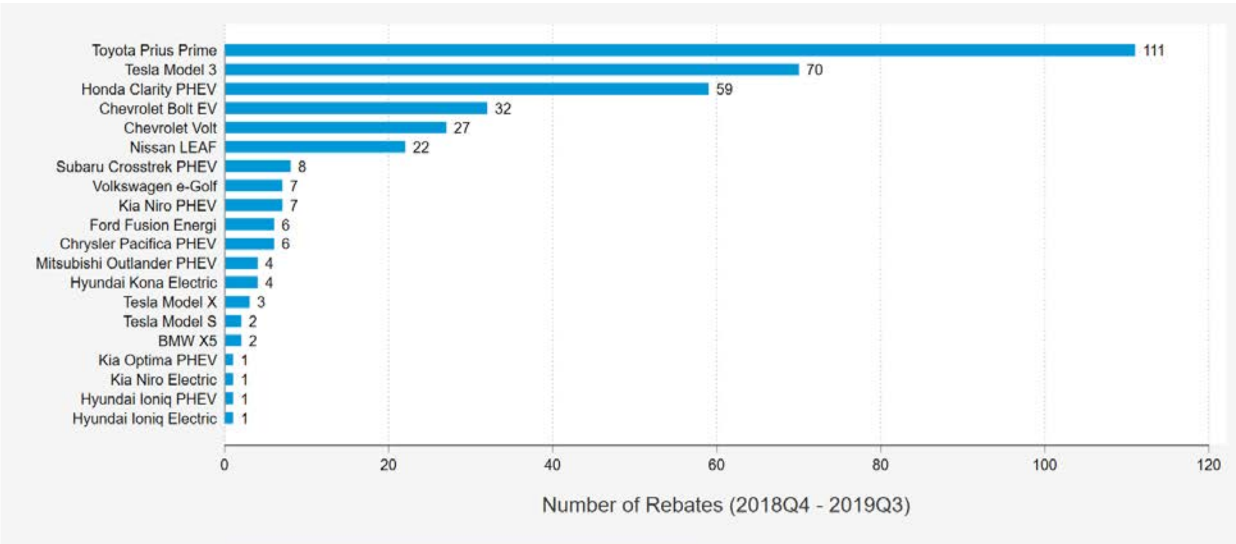
REBATE DATA

The research team was provided with data describing the electric vehicles that were rebated by Central Hudson accounts. This data contained information related to when the vehicle was purchased, when the rebate application was submitted, the vehicle make, the vehicle model, the vehicle year, and the location (latitude and longitude) of the account submitting the rebate. This data was leveraged in developing a granular forecast of electric vehicle adoption.

The rebate data showed that 374 vehicles were rebated from the fourth quarter of 2018 through the third quarter of 2019. Out of these 374 vehicles, 142 were all electric (38%) and 232 were plug-in hybrids (62%). The most popular models were the Toyota Prius Prime (PHEV), the Tesla Model 3, and the Honda Clarity PHEV. These three models accounted for approximately 64% of the rebates. Figure 53 shows a complete list of the rebated models, as well as the number of rebates for each model.

[18] Throughout this analysis, "EV" is used to represent any type of electric vehicle. "PHEV" represents plug-in hybrids and "BEV" represents Battery all-electric vehicles. Thus, PHEVs and BEVs fall under the EV umbrella.

Figure 53: Rebated EVs



CHARGING STATION DATA

Charging station data, which is publicly available through data.ny.gov, was downloaded and merged with a list of Central Hudson zip codes. This data showed that there are 131 charging stations across Central Hudson territory, and these stations account for a total of 335 chargers. The GPS coordinates of these stations are plotted in Figure 54.

Figure 54: Charging Station Map

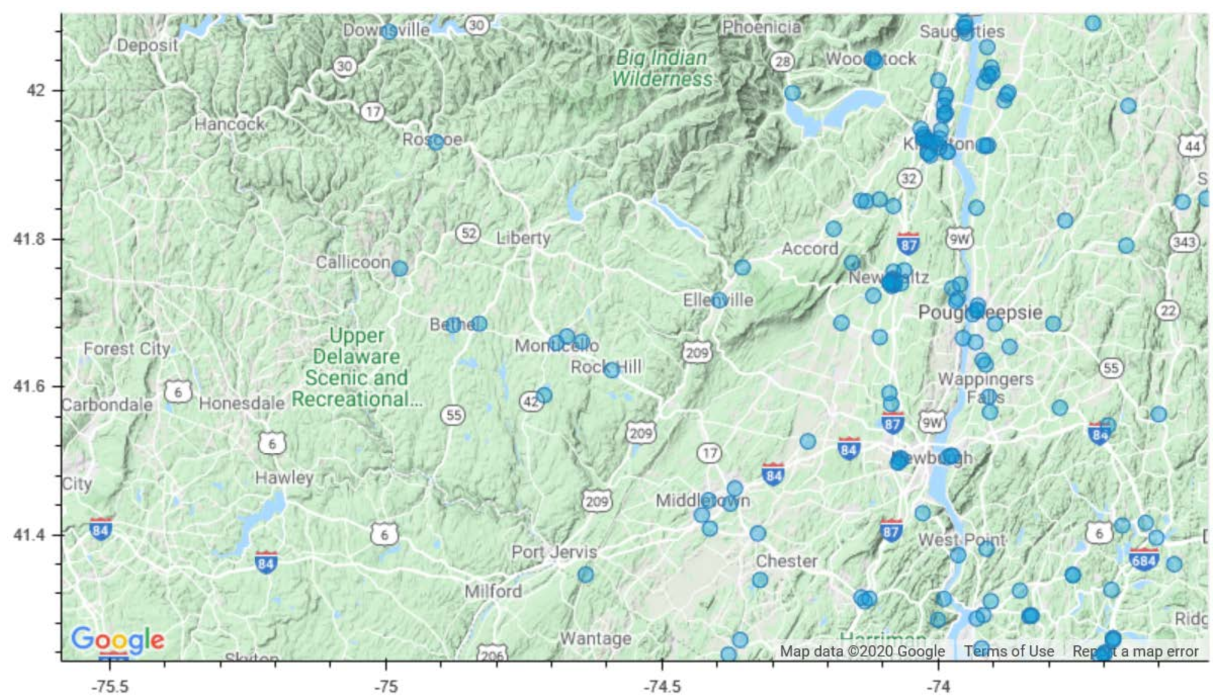
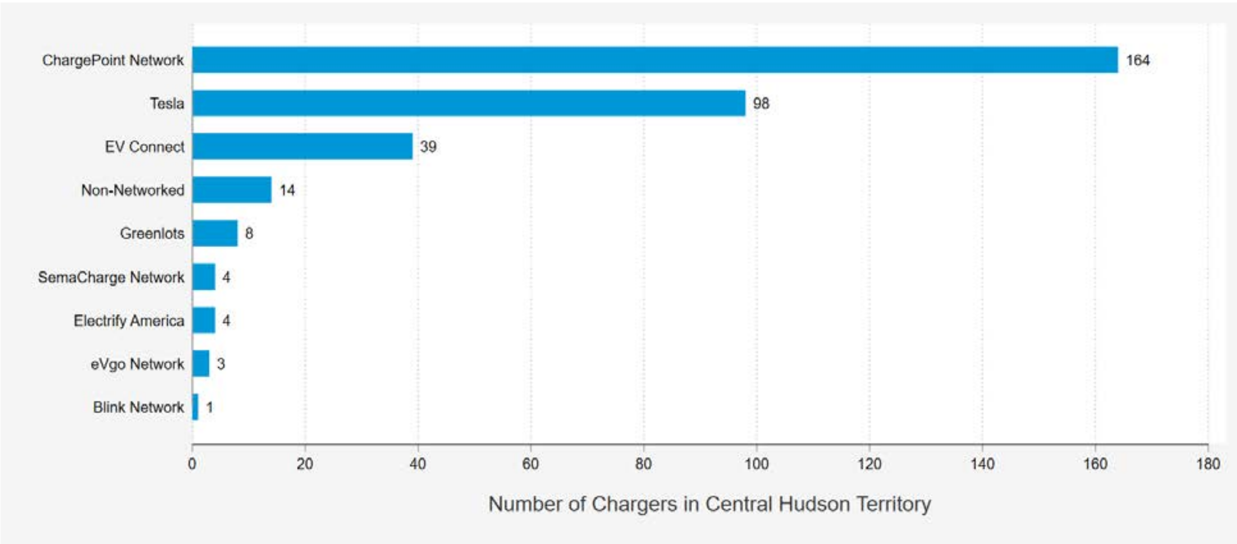


Figure 55 shows the distribution of networks for the 335 chargers in Central Hudson territory. Note that the Tesla chargers are for Tesla vehicles only.

Figure 55: Charging Station Types



Billing Data

The research team received and analyzed historical billing data for the full Central Hudson population. For the EV adoption forecast, the billing data was primarily used to create a map between Central Hudson zip codes and substations. This map was then used to project zip-specific adoption forecasts onto substations.

Vehicle Registration and VIN Data

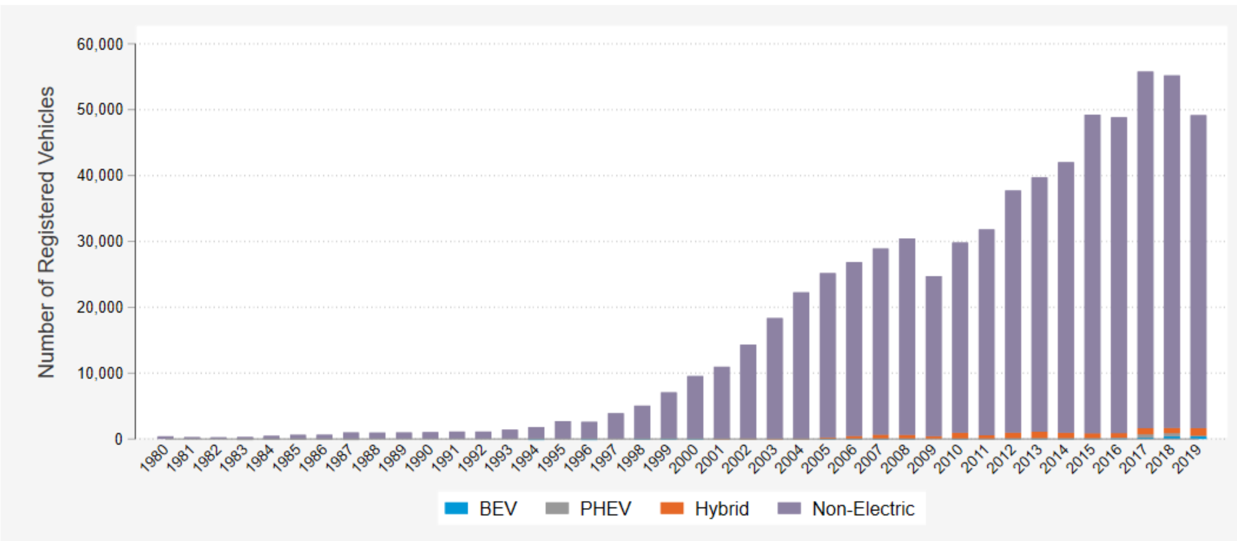
New York vehicle registration data is publicly available through data.ny.gov.[19] This data includes VIN numbers and zip codes for all registered vehicles in New York. The research team downloaded the most recent version of this data and trimmed the data to Central Hudson zip codes. The research team then ran each of the VIN numbers from the trimmed registration data set through the National Highway Traffic Safety Administration's vehicle API.[20] This provided our team with additional details about each vehicle in the registration data set (the make, the model, the series and/or trim, the vehicle type, primary and secondary fuel sources, etc.).

[19] https://data.ny.gov/Transportation/Vehicle-Snowmobile-and-Boat-Registrations/w4pv-hbkt
[20] https://vpic.nhtsa.dot.gov/api/

HISTORICAL DATA ANALYSIS

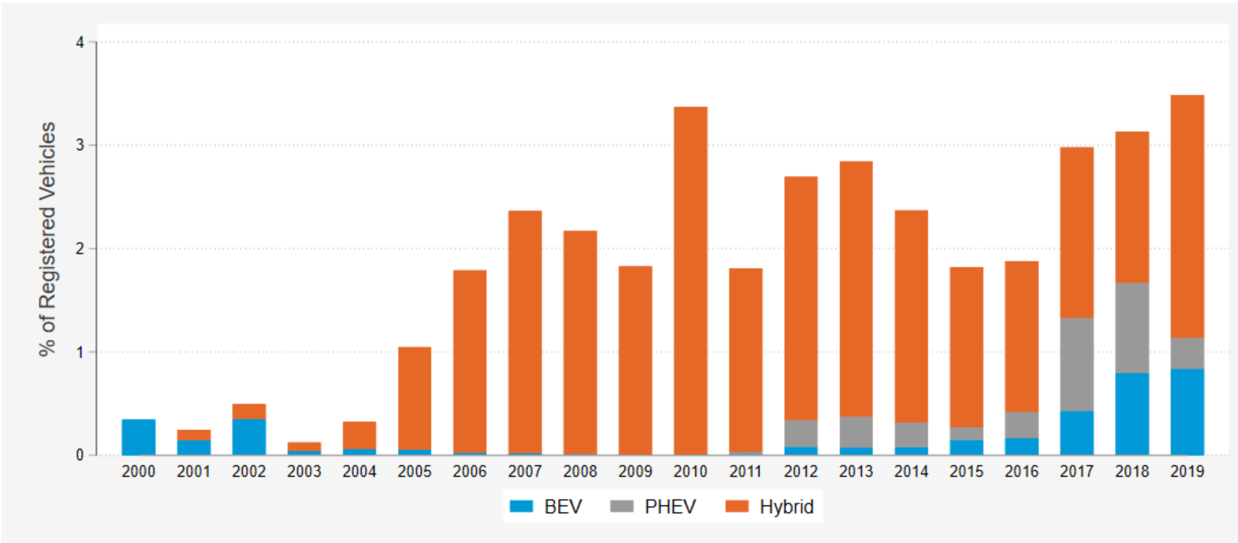
Inspection of the car registration data for vehicles registered in the Central Hudson territory revealed several key findings regarding vehicle stock in Central Hudson territory. First, although the market share of "green" vehicles (electric vehicles and hybrids) has generally increased over the past few years, the market share (as a percentage of total vehicles) remains small – less than 4% for each model year. Historic counts are shown in Figure 56. One important note regarding the figure is that there is a difference between the number of new vehicles purchased in 2016 and the number of new vehicles purchased in 2016 that were still on the road in 2019. The figure represents the latter. This analysis uses historic market shares as a proxy for new car sales in that year (e.g., the market share of PHEVs among 2016 model years that are still registered in 2019 is used as a proxy for the market share of PHEVs among new vehicle sales in 2016.)

Figure 56: Vehicle Model Year and Engine Type in Central Hudson Territory



The second key finding was that green vehicles represent about 2-3% of new vehicle purchases (again, consider the note on using this data as a proxy for new vehicle purchases). The dispersion of this 2-3% between hybrids, BEVs, and PHEVs leans towards hybrids, though there is some shifting towards BEVs in recent years. Note that Figure 57 shows registered vehicles, not rebated vehicles.

Figure 57: Percentage of Green Vehicles by Engine Type and Model Year



A third key finding was that the Tesla Model 3 disrupted the BEV market. This vehicle single-handedly doubled BEV sales from 2017 to 2018 – see Figure 58. Other popular BEV models include the Chevrolet Bolt and the Nissan Leaf. Among hybrids, Toyotas dominate the market. The hybrid RAV4 and the Prius are the most popular options (Figure 59).

Figure 58: Vehicle Diversity – BEVs

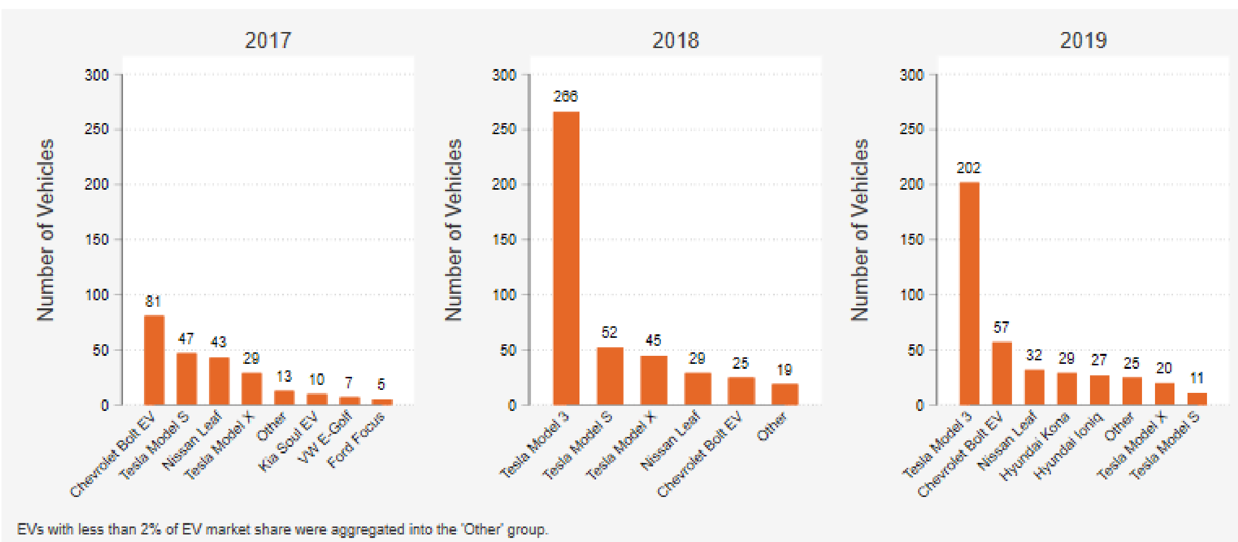
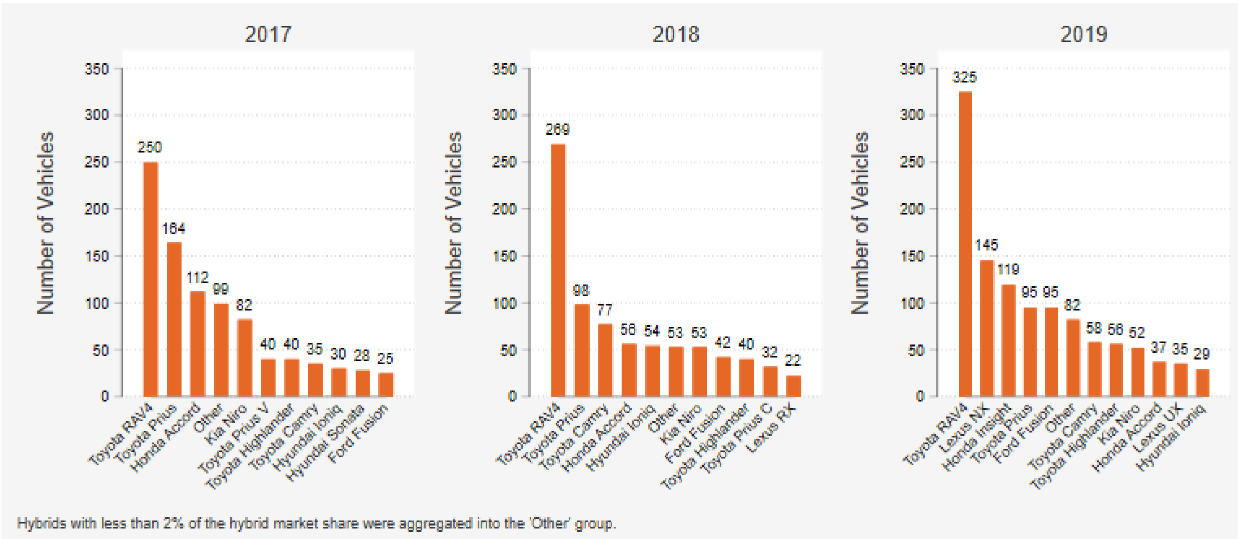
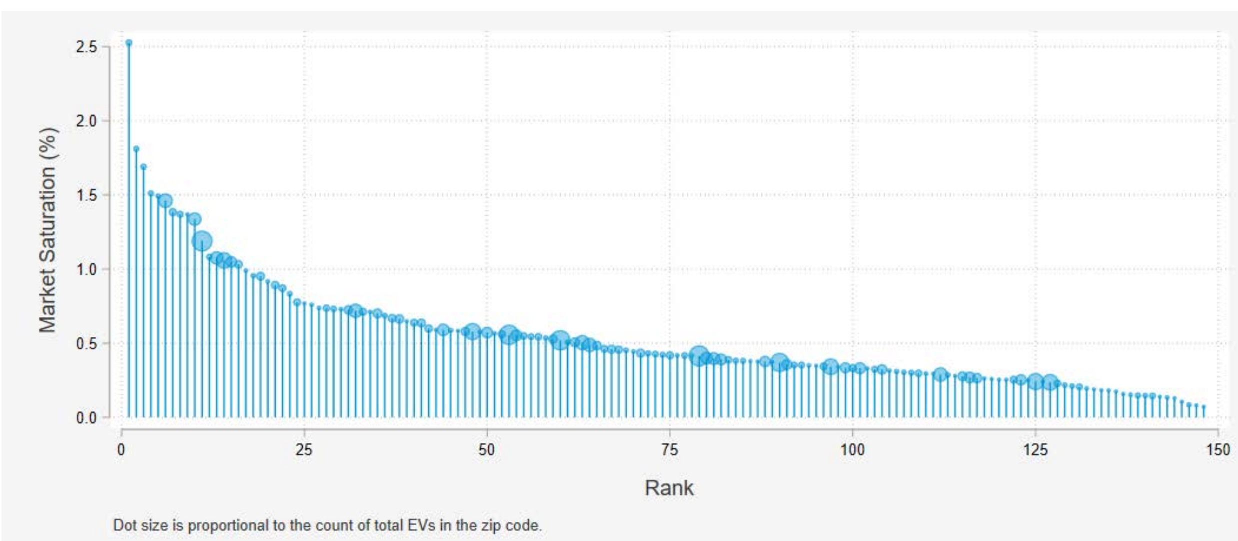


Figure 59: Vehicle Diversity – PHEV & Hybrids



One final finding is that the highest saturation of total EV's (BEVS plus PHEV's) within a zip code is 2.5%. This statistic considered total EV's as a share all registered vehicles within a zip code and does not control for model year. In most zip codes, the total EV saturation is less than 1% (Figure 60). For the Central Hudson service territory as a whole, the total EV saturation is 0.45%. When other green vehicles are folded into the mix, the market share for most zip codes remains below 4% and the average market share is 2.07% (weighted by the number of registrations per zip code).

Figure 60: EV Market Share by Zip Code



FORECAST EV ADOPTION

Our forecast of electric vehicle adoption entailed four key steps:

1. Determine (1) how many new vehicles are registered in Central Hudson territory per year and (2) the total number of registered vehicles in Central Hudson territory.
2. Determine the rate at which older vehicles leave the roads.
3. Use the vehicle registration data to model the split between fully electric vehicles and PHEVs over time.
4. Use the vehicle registration data to model the market share of electric vehicles by year.

Combined, these steps allowed the research team to develop EV, BEV, and PHEV forecasts that follow historical trajectories and account for natural vehicle churn. Each step will be discussed in greater detail in the subsequent sections.

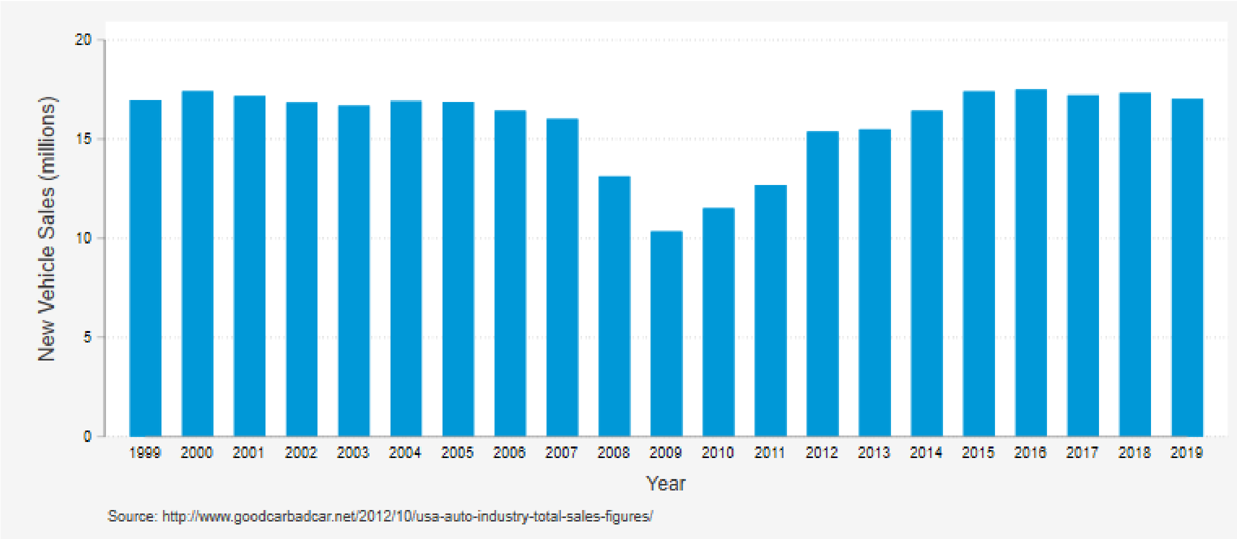
VEHICLE REGISTRATIONS AND NEW ENTRY

Two key components in forecasting electric vehicle adoption are (1) the total number of new vehicles registered in Central Hudson territory per year and (2) the total number of registered vehicles in Central Hudson territory. Two data sources were used to inform these inputs. The primary data sourced used was the vehicle registration data for all registered vehicles in New York (which is publicly available). After filtering this data set down to vehicles in Central Hudson territory (a process that leveraged zip codes) and removing the small share of vehicles that were built before 1980, we found that there are approximately 673,000 registered vehicles in Central Hudson territory. Additionally, approximately 50,000 of these vehicles were 2019 models. Our forecast assumes a fixed number of registered vehicles and a slight increase in the number of new vehicle registrations per year. (A discussion on vehicle churn comes in the next section.)

To assess the reasonableness of these assumptions, our team looked at the number of new car sales in the United States over the past couple of decades. Ignoring the impacts of the 2009 recession, the number of new vehicle sales in the US has hovered around 17 million (Figure 61). Over the long term, the Energy Information Administration's 2019 Annual Energy Outlook shows an increase in annual new car sales.[21] And according to Statista, the number of registered vehicles in the US has shown slight increases from year to year.[22] If this pattern holds, our assumptions are slightly conservative.

[21] https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf
[22] https://www.statista.com/statistics/183505/number-of-vehicles-in-the-united-states-since-1990/

Figure 61: New Vehicle Sales in the US

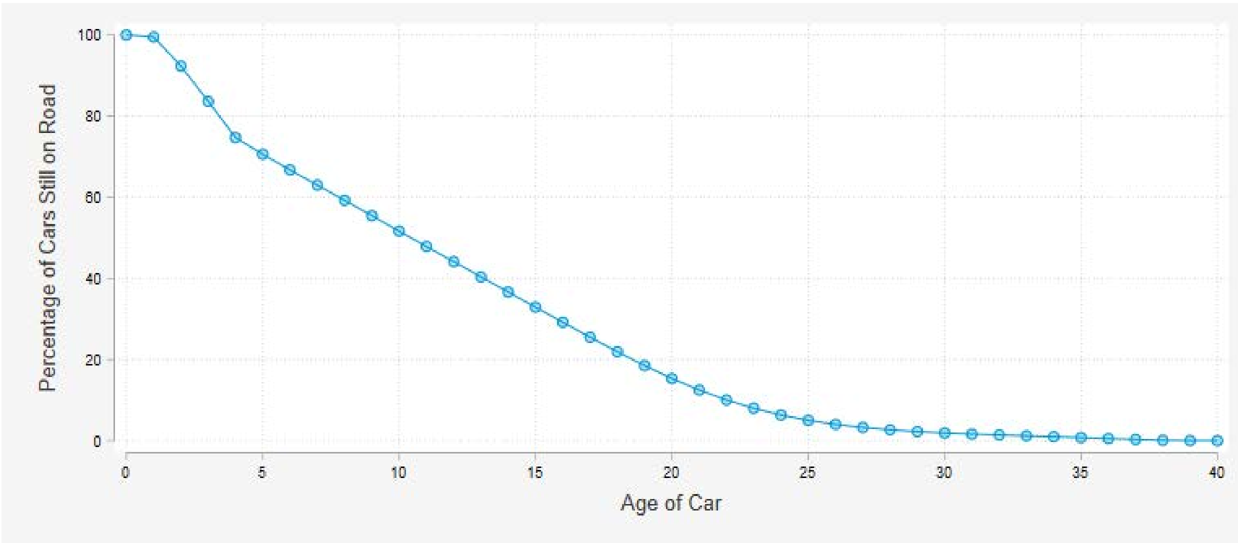


VEHICLE CHURN

As new vehicles are manufactured and sold, older vehicles leave the roads. This statement, which is likely believable with or without empirical evidence, is supported by New York's vehicle registration data – see Figure 62. Newer vehicles are decidedly more prevalent than older vehicles.

The key question for our analysis deals with the rate at which vehicles leave the roads. In other words, what proportion of the new vehicles that were registered in 2019 will still be on the road in 2021 (or 2022, or 2023, etc.)? Our approach to accounting for vehicle churn entailed developing a decay model. With this model, our goal was to answer questions like the one posed in the previous paragraph. The model we developed leveraged the decaying trend shown in Figure 62, though efforts were made to smooth out the dip that occurs around 2009. The logic here is that the 2009 dip was likely an effect of the economic conditions, not an abrupt change in car buying behavior. The smoothed decay model is shown in Figure 62. An example of how to interpret the figure is as follows: Approximately 70% of the new vehicles purchased in 2019 will still be registered in Central Hudson territory when those cars are five years old. By the time those cars are 10 years old, just over 50% will still be on the roads.

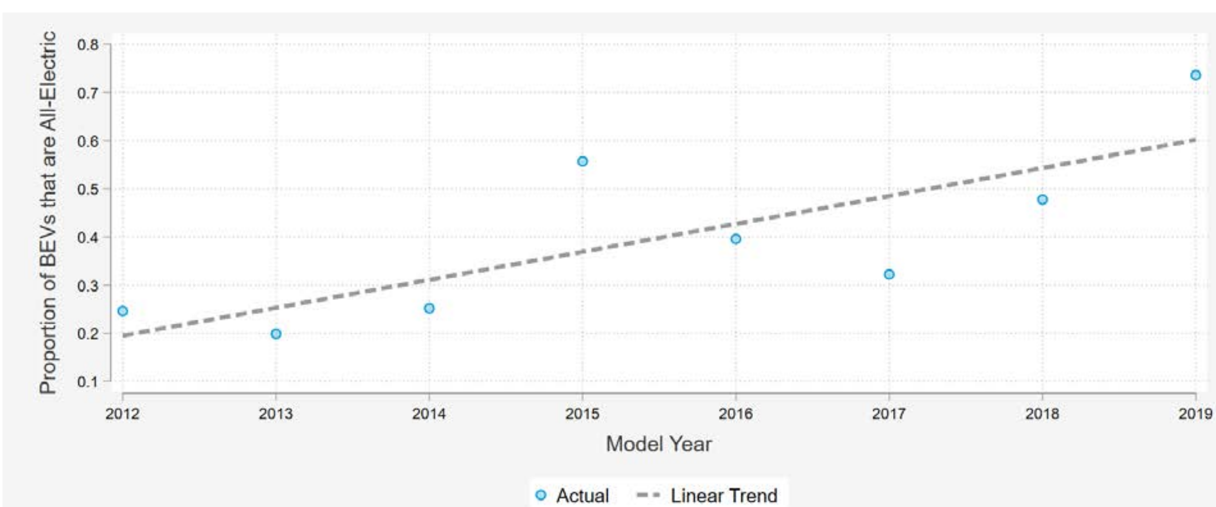
Figure 62: Modeled Vehicle Churn



SPLIT BETWEEN ALL-ELECTRIC AND PLUG-IN HYBRID VEHICLES

Another critical component of the forecast revolves around how EVs should be split into all-electric vehicles (BEVs) and PHEVs. (Note that our team did not have sufficient data to develop forecast models for EVs and PHEVs separately.) The approach to partitioning EVs into BEVs and PHEVs relied on the vehicle registration data. For each model year, we calculated the percentage of EVs that were BEVs, then plotted this relationship in time. Figure 63 shows the results for the Central Hudson territory. The gray regression line, which represents the trend in the Central Hudson territory, was carried into the future and used to determine the split between BEVs and PHEVs in the forecasts. Obviously, the percentage of BEVs that are all electric cannot exceed 100%, so the trend was capped at 90%.

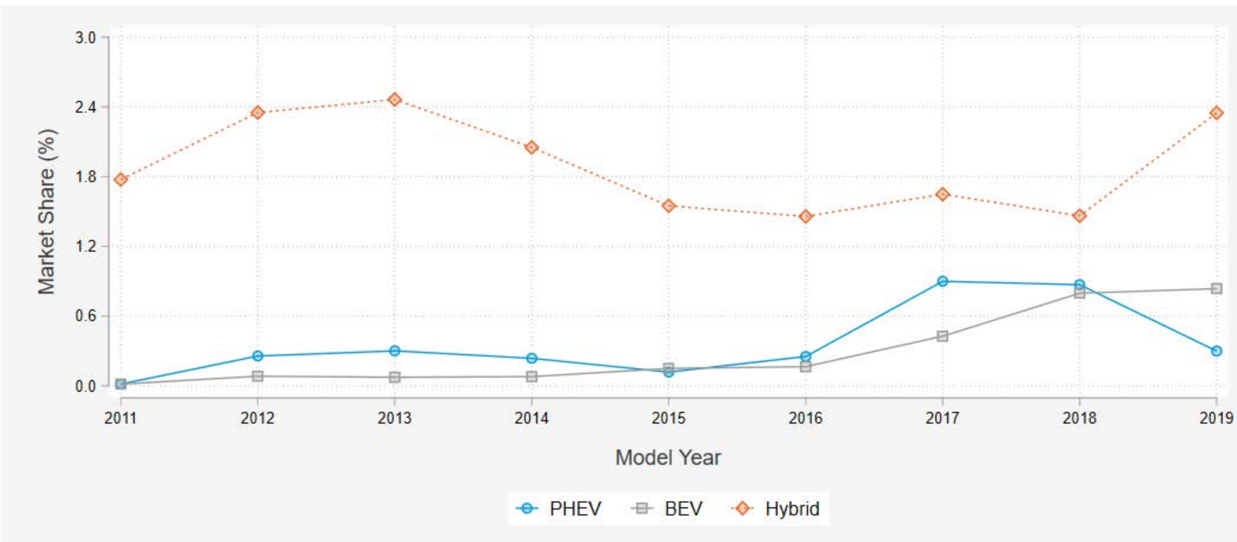
Figure 63: Split Between BEVs and PHEVs



Modeling Market Share

The final (and most important) piece of the EV adoption forecast concerns modeling the market share of EVs in time. Figure 64 shows historic market shares for hybrids, BEVs, and PHEVs within the Central Hudson territory. Within the past few years, the market share for EVs is clearly on the rise. The key question is: What trajectory will EV market share follow in the future? (Note that these market shares are based on vehicles registered in 2019. Thus, the market shares for 2012, for example, represent the market share for 2012 model year vehicles that are registered in 2019. Though not perfect, these market shares are being used as a proxy for new car sales.)

Figure 64: Green Vehicle Market Shares



Regarding the question posed in the previous paragraph (What trajectory will EV market share follow in the future?), our team leveraged the bass diffusion curve in forecasting the adoption of electric vehicles. The bass diffusion curve posits that adoption will follow the shape of an S curve in time and is defined by three parameters: p (the "coefficient of innovation"), q (the "coefficient of imitation"), and m (which represents the market size or the top of the "S"). Our team used the historical trajectory of green vehicle market shares to estimate p and q – these parameters determine the shape of the S. The third parameter, m, was estimated separately using the historical trajectory of electric vehicle market shares.

The approach described above was our base case forecast. We also considered two other scenarios. In the second scenario, we doubled the base case forecast. The third scenario was a pressure test scenario. In this scenario, the forecast was scaled such that Central Hudson's share of the 2030 statewide EV target (2,000,000 EVs) is met. Central Hudson's share of this target was estimated to be approximately 100,000 vehicles (~5% of the target). This estimate was developed by approximating the percentage of vehicles registered in New York that fall in the Central Hudson territory.

The results from the base case are shown in Figure 65. By 2025, electric vehicles are forecasted to represent nearly 4% of new vehicle sales in the Central Hudson territory. By 2030, the forecast is approximately 6.5%. Note that this trajectory does not account for possible disruptions in the market, such as a rapid decline in the price of EV batteries, the rapid increase in the price of gasoline, changes in fuel efficiency standards or environmental regulations, etc.

Figure 65: Bass Diffusion Modeling

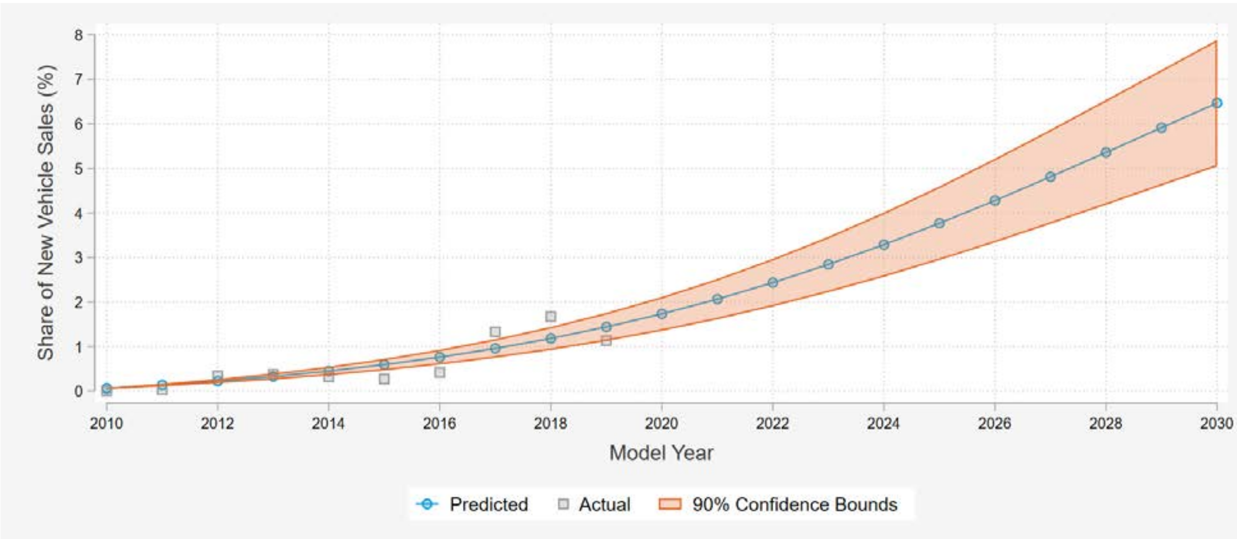


Table 15 shows the forecasted market share over the next few years under the three scenarios described above. Note that the percentages shown represent new vehicle market shares, not total vehicle stock.

Table 15: Forecasted Market Shares for EVs

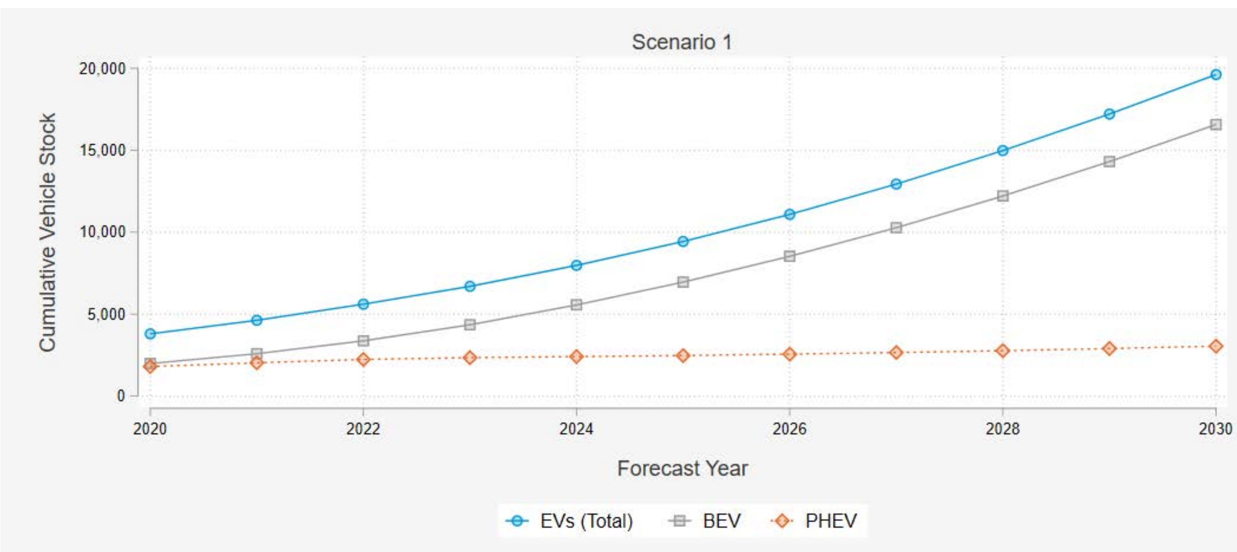
Year	Predicted Market Share – Base Case	Predicted Market Share – Double Base	Predicted Market Share – Pressure Test
2020	1.73	3.47	9.45
2021	2.07	4.13	11.25
2022	2.43	4.87	13.27
2023	2.84	5.69	15.50
2024	3.29	6.56	17.92
2025	3.77	7.54	20.54

The pieces described in the previous sections were used in tandem to develop the forecast for EV adoption (and, separately, BEV and PHEV adoption). Results for the base case scenario and the double base scenario are shown in Table 16. Note that the values shown in the table and figure are cumulative totals, not the number of new electric vehicles per year (however, readers can use the table to calculate non-cumulative vehicles). Figure 66 shows cumulative vehicle stock for the base case forecast.

Table 16: Cumulative Vehicle Stock Forecasts

Year	Scenario 1			Scenario 2		
	EVs	PHEVs	BEVs	EVs	PHEVs	BEVs
2020	3,799	1,809	1,990	4,627	2,091	2,536
2021	4,626	2,037	2,589	6,414	2,590	3,824
2022	5,613	2,238	3,375	8,474	3,024	5,451
2023	6,698	2,347	4,352	10,752	3,310	7,442
2024	7,976	2,410	5,566	13,475	3,520	9,955
2025	9,433	2,476	6,957	16,550	3,732	12,818
2026	11,087	2,560	8,527	20,016	3,982	16,034
2027	12,934	2,661	10,274	23,866	4,264	19,602
2028	14,981	2,772	12,209	28,113	4,568	23,545
2029	17,208	2,901	14,306	32,717	4,906	27,811
2030	19,615	3,049	16,567	37,681	5,281	32,401

Figure 66: Electric Vehicle Forecasts



CONVERTING THE VEHICLE FORECAST TO AN ENERGY FORECAST

To convert the vehicle forecast to an energy forecast, we had to rely on assumptions about the number of vehicle miles driven and the efficiency of batteries. The Department of Energy (DOE) reports average kWh/mile is 0.367 for PHEVs and 0.32 for BEVs.[23] These averages are based on 2016 vehicles and are sales weighted. With an estimate for average annual miles driven per vehicle, these averages can be converted to estimates for average electricity consumption per electric vehicle per year. The Department of Traffic (DOT) reports an average annual miles driven per vehicle of 12,610 in New York.[24] For BEVs, this translates to 4,035 kWh annually. For PHEVs, this translates to 2,545 kWh annually assuming the sales weighted PHEV all electric range is 33 miles (per the DOE) and the percentage of annual PHEV miles driven on electricity is 55% .[25]

To convert the vehicle forecast to an energy forecast, we simply used the conversion factors in the paragraph above. Each BEV in the forecast translates to 4,035 kWh and each PHEV in the forecast translates to 2,545 kWh. Note these are annual values, not lifetime values.

MODELING GRANULAR ADOPTION

The next step in the analysis was to project the energy forecast onto the substations. We assumed an 80/20 split between home charging load and charging station load. In other words, 80% of the energy forecast was attributed to home charging and 20% to charging stations. Our approach for each track is discussed in the sections below.

HOME CHARGING

To project the home charging portion of the energy forecast onto substations, the research team leveraged geography in a two-step process. At a high level, the first step was to divide the forecast among zip codes and the second step was to map zip codes to substations. More details are provided in subsequent paragraphs.

To disperse the forecast among zip codes, our team assumed that the dispersion of future EVs will follow the geographic dispersion of historic green vehicles. Using the Central Hudson vehicle registration data, we determined the percentage of green vehicles that were in each zip code. These percentages were then applied to the energy forecast to disperse the forecast to different geographic regions.

After dividing the forecast among the zip codes, our team needed to project the zip-specific forecasts onto substations. Ideally, the relationship between zip codes and substations would be one-to-one, but

[23] https://www.afdc.energy.gov/vehicles/electric_emissions_sources.html

[24] https://www.fhwa.dot.gov/ohim/onh00/onh2p11.htm

[25] Bradley, T. H., & Quinn, C. W. Analysis of plug-in hybrid electric vehicle utility factors; see Figure 2

this is not the case. To develop a map, our team leveraged Central Hudson billing data. This data contains the zip code of each account as well as the substation each account connects to. Usage data was removed from the billing data and only one record per account was retained. Using those records, a map was created that assigned a portion of each zip code to a substation. To illustrate, suppose there were just three accounts with a zip code of 12345. Suppose further that two of the accounts were connected to substation A and the third was connected to substation B. 66.7% of the forecast for zip code 12345 would then be mapped to substation A, and 33.3% of the forecast for zip code 12345 would be mapped to substation B.

With the zip-to-substation map in hand, the research team converted the zip-specific energy forecast to a substation-specific energy forecast.

Charging Stations

The method used to distribute charging station load among Central Hudson substations was relatively straightforward. The location of all charging stations in New York is publicly available. Using (1) the geolocations of the charging stations located in Central Hudson and (2) polygon shape files for each substation, we were able to determine which substation each charging station maps to. Using this mapping, we developed substation-specific energy forecasts.

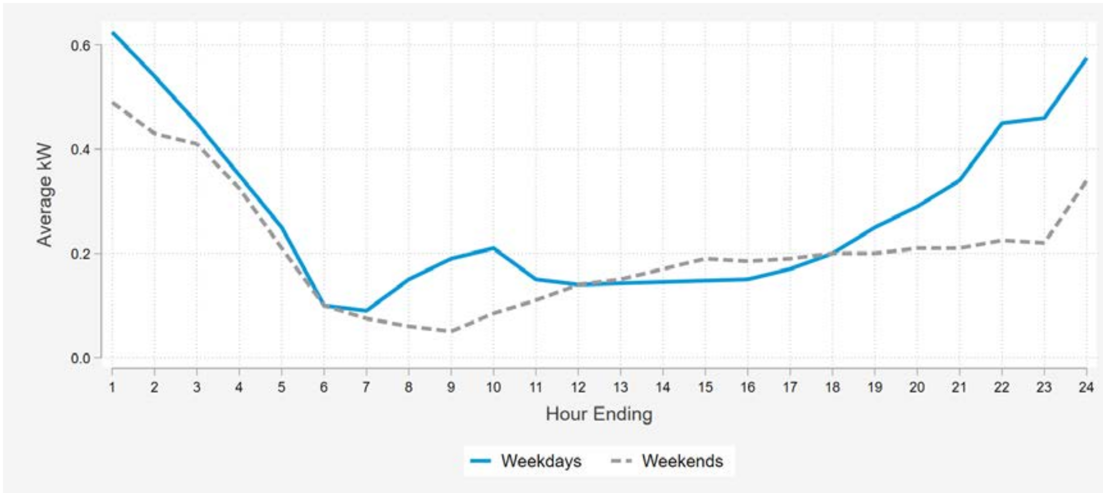
CONVERTING THE ENERGY FORECAST TO A DEMAND FORECAST

The last step in the process was to convert the substation-specific energy forecasts to substation-specific 8760 forecasts. To accomplish this, EV charging load profiles were used. As noted, our team assumed an 80/20 split between home charging loads and charging station loads. Thus, we needed load profiles for each charging type.

For home charging, the load profile was drawn from the Electric Power Research Institute (EPRI) research on electric vehicle customers in Arizona.[26] Weekday and weekend load shapes are shown in Figure 67. As one would expect, the load shape peaks around midnight, tails off throughout the morning, and increases again after regular business hours.

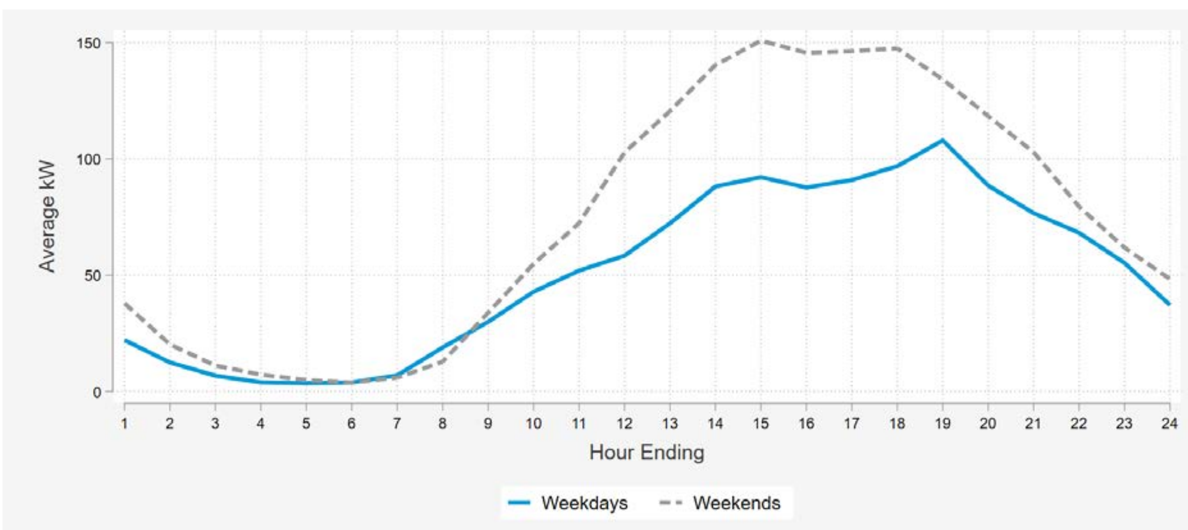
[26] Electric Vehicle Driving, Charging, and Load Shape Analysis. EPRI. July 2018. Figure 6-11. Available at http://mydocs.epri.com/docs/PublicMeetingMaterials/ee/000000003002013754.pdf

Figure 67: Home Charging EV Load Shapes



For charging stations, the load profiles were created using charging station interval data from three charging stations in the Central Hudson territory. Load shapes for weekdays and weekends are shown in Figure 68. The pattern for charging station loads is quite distinct from the pattern for home charging. Rather than peaking overnight, charging station loads peak in the late afternoon – more coincident with Central Hudson peaks. Average weekend loads are larger than average weekday loads. The difference occurs primarily during the afternoon and early evening hours.

Figure 68: Charging Station EV Load Shapes



Though Figure 67 and Figure 68 both show demand (kW) on the Y axis, it is important to note that only the shapes were used, not the magnitude of the demand. The load profiles were converted to weekly load shares and then applied to the annual energy forecasts. For a given substation, home charging 8760 profiles were aggregated with charging station 8760 profiles to produce substation-specific 8760 load forecasts.

C. Long Range Electric System Plan

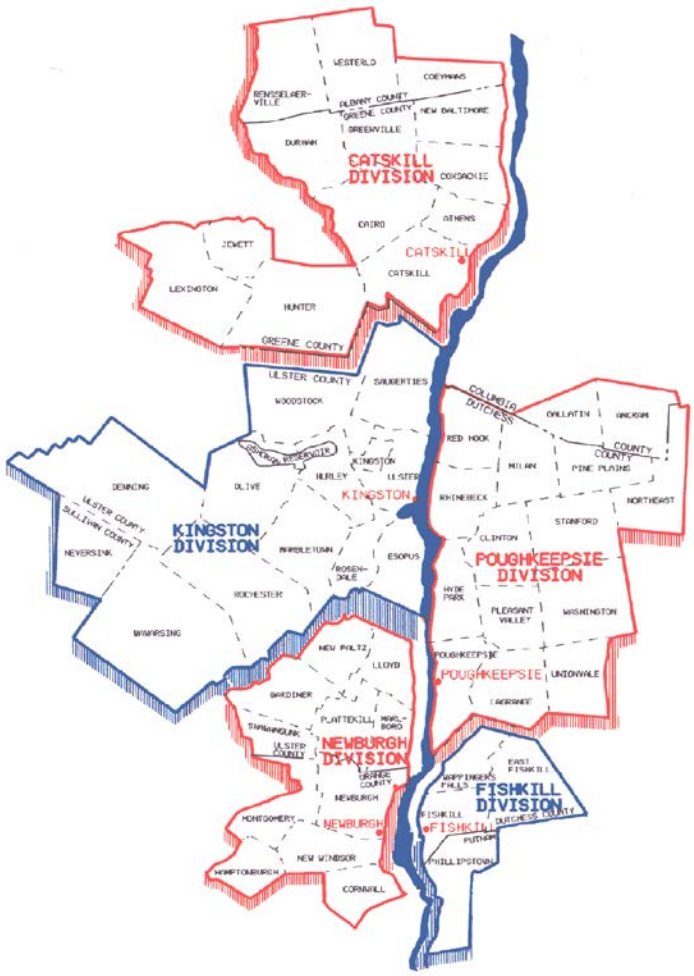
Central Hudson Gas & Electric

Long Range Electric System Plan

June 2020

1. Introduction

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving approximately 307,000 electric customers and 82,000 natural gas customers in New York State's Mid-Hudson River Valley. Central Hudson delivers natural gas and electricity in a defined service territory that extends from the suburbs of metropolitan New York City north to the Capital District at Albany. Central Hudson is a leader in promoting regional economic growth, improving system reliability, and effective cost management.



Central Hudson owns substations having an aggregate transformer capacity of 5.5 million kilovolt amps. Central Hudson's electric transmission system consists of 600 circuit miles of line. The electric distribution system consists of 7,200 pole miles of overhead lines and 1,565 trench miles of underground lines, as well as customer service lines and meters.

The transmission system operates at voltages of 69 kilovolts, 115 kilovolts and 345 kilovolts. The distribution system operates at voltages of 13.2 kilovolts, 34.5 kilovolts, 4.8 kilovolts, and 4.16 kilovolts. It also encompasses sub-transmission systems that operate at 14.4 kilovolts in three urban areas of our service territory, feeding into secondary networks. Central Hudson has approximately 75 electric substations that contain power transformers that change the voltage from one level to another.

This document provides a long-term roadmap for the electric transmission, substation, and distribution system to optimize the amount and allocation of capital expenditures for the next 7 to 10 years. It is an output of the Electric System Planning Process that was developed to support the corporate and departmental goals, and includes a comprehensive load and infrastructure assessment and capital budget plan. The document is broken down into nine sections subsequent to the Introduction:

(2) Mission, Vision, Strategy, and Goals
(3) System Reliability and Infrastructure
(4) Distribution Smart Grid
(5) Long Term System Load Forecast
(6) Transmission (Category 12) and Substation (Category 13) Areas
(7) Sub-transmission, Distribution (Category 15) and Substation (Category 13) Infrastructure and Load Growth Plan
(8) Summary of Projects
(9) Emerging Opportunities
(10) Conclusion

2. Mission, Vision, Strategy, and Goals

2.1 Introduction – Corporate Mission, Vision, and Strategy

Central Hudson's mission is to deliver electricity and natural gas to an expanding customer base in a safe, reliable, courteous and affordable manner; to produce growing financial returns for shareholders; to foster a culture that encourages employees to reach their full potential; and to be a good corporate citizen. The vision of the parent company, CH Energy Group, is to be recognized as the best energy provider by customers, investors, and employees.

Central Hudson provides exceptional value to its customers by:

- Practicing continuous improvement in everything we do.
- Investing in T&D infrastructure, technology solutions, and non-wires alternatives to enhance reliability, improve customer satisfaction, and reduce risk.
- Moderating cost pressures that increase customer bill levels and variability.
- Advocating on behalf of customers and other stakeholders.

2.2 Electric Service Reliability and Capital Expenditures – Mission and Goals

To support the corporate mission and strategy, the Electric Engineering Services division seeks to safely plan, design, construct, operate, and maintain a reliable and affordable electric transmission and distribution system that optimizes value for all stakeholders. It develops prudent capital investments and recommends evaluation of non-wires alternatives which enhance reliability, improve customer satisfaction, and reduce risk. The Electric Energy Services division also identifies and implements process improvements that enable us to continuously improve the way in which we fulfill our mission and moderate costs pressure that impact customer bills.

The Electric Engineering Services division accomplishes its mission by setting challenging service reliability and net plant goals.

Reliability goals are focused on SAIFI (frequency) and CAIDI (duration), which are defined as follows:

SAIFI = System Average Interruption Frequency Index $= \frac{\text{Total \# of Customers Interrupted}}{\text{Total \# of Customers Served}}$

CAIDI = Customer Average Interruption Duration Index $= \frac{\text{Sum of Customer Interruption Duration}}{\text{Total \# of Customers Interrupted}}$

Through the Electric Ratemaking Process, the Public Service Commission establishes targets with penalty mechanisms for each of these metrics. As of the Company's 2018 approved Joint Proposal, the 2020 target for SAIFI = 1.30, and the 2020 target for CAIDI = 2.50. The table below provides the current three-year targets for the SAIFI and CAIDI indices.

Performance Indicator	2019 Actual	2020 Target	2021 Target	2022 Target	2023 Target
SAIFI – System	1.245	≤ 1.30	≤ 1.30	≤ 1.30	≤ 1.30
CAIDI – System	2.38	≤ 2.50	≤ 2.50	≤ 2.50	≤ 2.50

To achieve a balance between reliability and affordability, a Capital Plan is reviewed and approved by Company's Board of Directors and filed with the Public Service Commission on July 1 of each year.

2.3 Electric System Planning – Mission and Goals

The mission of the Electric System Planning at Central Hudson is to safely plan for a reliable and affordable electric transmission and distribution system by: identifying prudent capital investments to continuously improve our system and support design, construction, and operations, recommending evaluation of non-wires alternatives, and planning for grid automation and integration of distributed energy resources.

We strive to achieve our mission by:

- Maintaining design criteria to minimize risk and plan for reliable system growth and DER integration.
- Performing reliability analysis and leveraging the use of new technology to continuously improve our transmission and distribution system.
- Completing system studies and developing recommendations to maintain and improve reliability of service and support the capital budget and non-wires alternative investment plan.

The Electric Planning Guides provide information on the routine tasks, current and emerging programs and technologies, and design criteria that enable us to identify capital investments that achieve our mission. The results of the System Planning process are then incorporated into this document.

3. System Reliability and Infrastructure

3.1 Introduction

This section provides an overview of the basic infrastructure, reliability issues and long term plans associated with our distribution, sub-transmission, and transmission systems. The infrastructure lists are categorized by asset and provide information regarding inventory, age, condition, assessment process, plans, and costs. This section is broken down into the following subsections for each asset class: transmission lines; substations; sub-transmission; and secondary networks and distribution.

3.2 Transmission Lines

Central Hudson began constructing transmission lines in the mid 1910's and has designed its lines in accordance with the applicable National Electric Safety Code ("NESC") at the time of construction. The NESC identifies design criteria for these lines. Specifically, it identifies the minimum required clearance from ground for specified conductor loading conditions. The minimum clearance required also is a function of whether the area below the conductor is accessible by pedestrians only or is a roadway.

3.2.1 Inspection Programs

Inspection programs are described in Section 5.2.1 of Central Hudson's Electric Planning Guides. Results of transmission line inspections are rated by condition severity. These conditions are tracked and appropriate replacements and repairs are made as part of the High Priority Replacement Program (HPR). If inspection results indicate that greater than 50% of a particular transmission line's structures are in need of replacement, then further analysis is conducted by the Electric Transmission Planning Department to evaluate the benefits of rebuilding the line.

3.2.2 Equipment

Central Hudson's transmission lines are operated at 69 kV through 345 kV with approximate total circuit length shown in the following table:

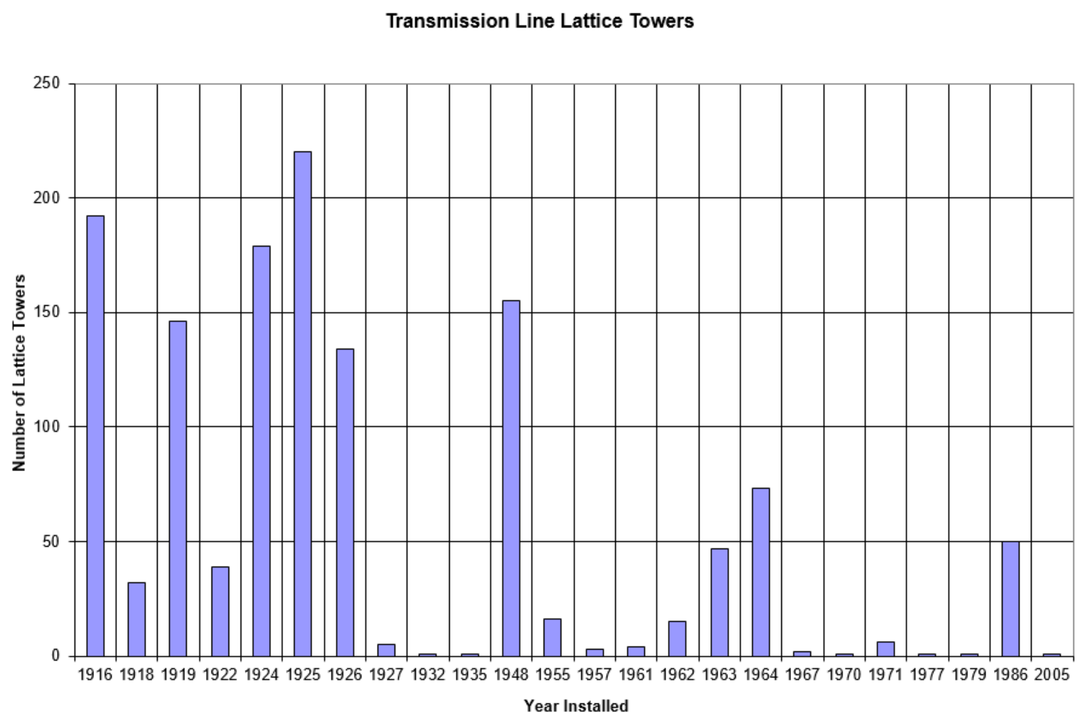
Operating Voltage	Design Voltage	Overhead Circuit Miles	Pipe-Type Cable Circuit Miles	Total Circuit Miles
345 kV	345 kV	76	0	76
115 kV	115 kV	211	4.1	215.1
69 kV	69 kV	248	0	287
	115 kV	39		
Total		**574**	**4.1**	**578.1**

3.2.2.1 Lattice Towers

Inventory
Central Hudson's transmission lines include 1,324 lattice towers.

Age and Condition
Steel lattice towers typically are very long-lived. Central Hudson's lattice towers were installed in the years shown in the histogram below. One group of towers (i.e., 1920's vintage 69 kV E Line) was analyzed in detail[1] in 2004 and the results indicate significant remaining life.

[1] EDM International, Inc. "Latticed Steel Tower Assessment for 'E' Line Reconductoring Project." December 2004.



Plans
Based upon the E Line results it appears that lattice towers are not limiting elements. Other factors likely will precipitate action. Accordingly, the approach will be to address condition of lattice towers at the time these other factors require attention.

General
In the short-term, the need to address lattice tower issues will be included in consideration of individual projects. Given that a large portion of our lattice towers were built in the 1910's and 1920's, the towers' condition will continue to be monitored to determine if it may be appropriate in the longer term to move to a more systematic approach.

H & SB Lines
Originally built in the 1920's, inspection reports indicate that 68% of the structures require replacement, repair or the addition of a mid-span structure (to correct sag issues). To remedy the numerous structure issues associated with the 12.5 mile H line & 11.4 mile SB Line, these majority lattice tower lines will be rebuilt using steel poles and 795 ACSR conductor. This project is scheduled to be completed in 2024.

SL, SD, & SJ Lines
The 12.1 mile SL Line and 11.4 mile SD/SJ Common Tower Line were built in the 1920's. These lines are in poor condition, however repairs are not planned at this time since the retirement of these lattice tower lines is planned as part of a future project. There are currently discussions on-

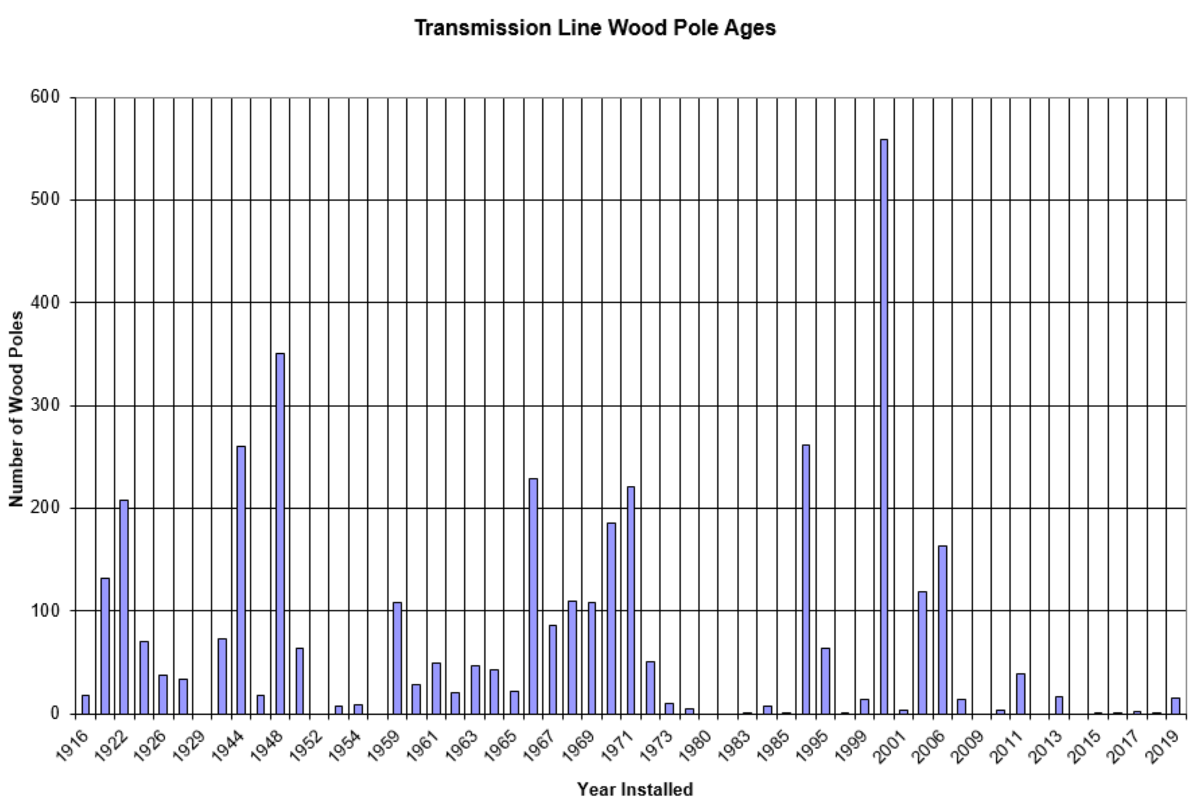
going with third parties regarding the use of the ROWs/re-purposing the corridor associated with these lines.

3.2.2.2 Wood Poles

Inventory
Central Hudson's transmission system includes 3,882 wood poles.

Age and Condition

<u>General</u>
These wood poles were installed in the years shown in the following histogram. Wood poles are relatively short-lived and often times require replacement prematurely due to damage from lightning, woodpeckers, etc. Several years ago, inspections discovered a large number of problems with the spar-arms on H-frame structures; a program was implemented to replace these spar-arms. While almost all remaining spar-arms were removed from the system, they are encountered occasionally during inspections. When encountered, they are coded severity "4" and are included in HPR[2] projects as appropriate.



[2] High Priority Replacement

<u>CL Line</u>
The 11.7 mile 69kV CL Line from North Catskill to South Cairo was built in the late 1940's with single pole double cross arm structures. In 2008, a 1.54 mile section of the line was rebuilt just outside of North Catskill. In 2016, a condition assessment on the remaining portion of line determined that approximately 70% of the structures are in need of replacement due to poor pole and cross arm condition.

<u>KM & TV Lines</u>
Originally constructed in the 1920's and 1930's, the 2.85 mile KM and 6.3 mile TV Lines require a rebuild. Inspections have identified 58% and 53%, respectively, of the lines' wood pole structures needing replacement.

<u>HF Line</u>
Inspections have identified that over 83% of the structures on the 2.05 mile HF Line require replacement. The line was originally constructed in 1968.

<u>HG Line</u>
The 16.25 mile HG line was originally built in 1937 and extended to Neversink in 1948. Recent condition assessments have shown that 54% of structures have Severity Level 3, 4, or 5. This level of structure issues, considered with the operational issues for local generation during transmission outages, warrants rebuild.

<u>TR Line</u>
The TR line, originally constructed in the 1920's, is another of Central Hudson's oldest wood pole transmission lines. Inspections, excluding the Poughkeepsie Galleria Mall reroute, have identified more than 50% of the structures would require some level of work or need to be replaced.

<u>Q Line</u>
The 20.5 mile Q Line was originally constructed in 1950 and is comprised of a 4 mile section of existing lattice towers as well as a 16.5 mile section of vintage wood poles. Despite on-going maintenance activities, inspection reports still show that approximately 65% of the wood poles require replacement or repair.

<u>SK Line</u>
The 2.4 mile SK Line was constructed during the 1960's and is currently showing inspection findings that would require over 50% of the line to be repaired and/or replaced. The line is also off-center in the existing ROW necessitating the acquisition of additional ROW. A rebuild of the line is being planned to both mitigate the ROW deficiencies by re-centering the line in existing ROW and replacing the structures with steel poles.

Plans

<u>General</u>

Generally, the timing of wood pole replacements would be expected to mimic the inspection program cycle. Where cyclical comprehensive inspections have recorded severe damage due to age or mechanical damage, replacements have been prioritized to remove the worst performers prior to an in-service failure. In the interest of efficiency, surrounding wood poles of similar condition and vintage are also replaced as part of the HPR Program to maximize mobilization and access costs in difficult stretches of R.O.W.

<u>CL Line</u>

To remedy the numerous structure issues associated with the CL line, and to increase the thermal load serving capability in the Westerlo Loop area, the CL line will be rebuilt (except for the new 2008 section). The new line will employ the use of 795 ACSR conductor and an OPGW static wire. The rebuild will be completed in 2020.

<u>KM & TV Lines</u>

To remedy the numerous structure issues associated with the KM & TV Lines, and to increase the transmission supply to the Myers Corner Substation, the KM & TV Lines will be rebuilt. The new lines will employ the use of 795 ACSR conductor and an OPGW static wire. The KM & TV line rebuilds are scheduled to be completed in 2022 and 2021, respectively.

<u>HF Line</u>

Based on the number of structures identified as needing replacement, a more comprehensive approach to the rebuild will take place. A full rebuild and re-conductor with 1033.5 ACSR will take place in 2020.

<u>HG Line</u>

Although a number of structures on the HG line have been replaced as part of the HPR program, all sections of the HG line are over 50 years old. Due to the poor condition assessment, sag limitation, and to mitigate future generation curtailment, a complete HG line rebuild is warranted with 397.5 ACSR and an OPGW Static.

<u>TR Line</u>

The TR Line supplies a single large industrial customer (Tilcon). The TR Line is being considered for either retirement or rebuild based on its poor condition. A potential option being considered is the retirement of the existing TR Line and the installation of a tapped substation with a 115/69 kV transformer on 115kV SC Line to maintain a transmission supply to this customer. This is currently in discussion with Tilcon as to the viability of this option.

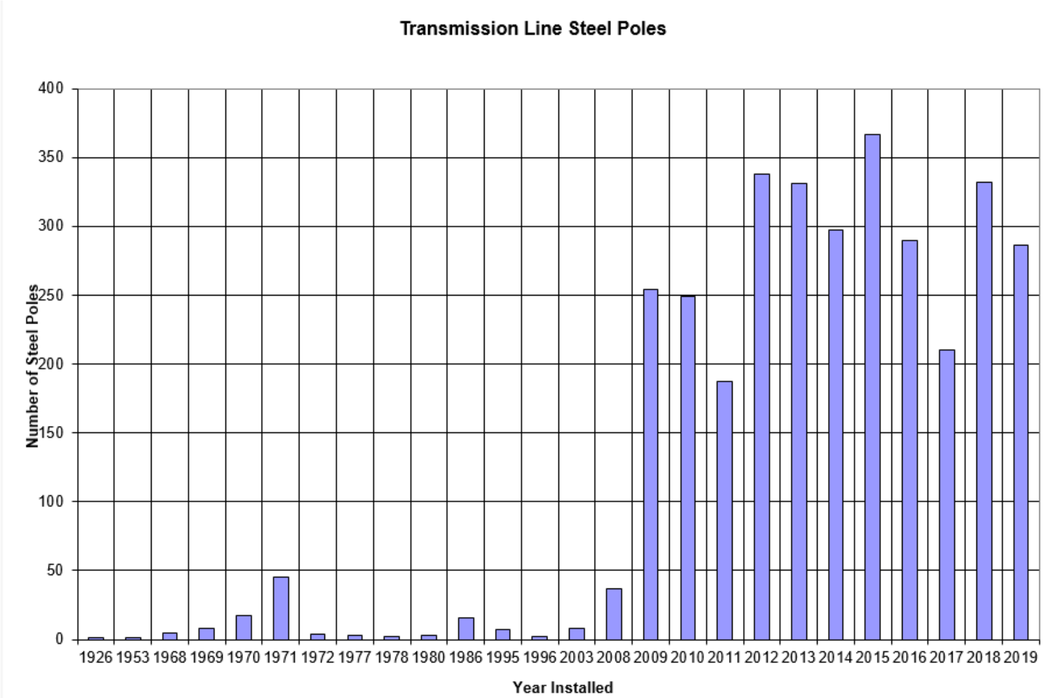
Q Line
A Planning Memo is currently underway to evaluate the best course of action to address the various inspections findings on this line and is anticipated to be completed sometime in 2020.

SK Line
In order to address the various structure condition findings on the line as well as R.O.W. deficiencies as identified as part of CHG&E's Deficiency Program, it is recommended that the line be rebuilt and centered within the existing R.O.W. The Line will be rebuilt utilizing 1033.5 ACSR conductor and an OPGW Static. The SK Line is scheduled to be rebuilt in 2025.

3.2.2.3 Steel Poles

Inventory
Central Hudson's transmission system includes 3,300 steel poles.

Age and Condition
These steel poles were installed in the years shown in the following histogram. The recent increase reflects a change in our standard design from wood to steel poles. This change is due to a proliferation of damage to wood poles from woodpeckers and other wood deterioration due to aging. A steel pole is a long-lived asset with lower maintenance, longer life expectancy, resistance to mechanical deformation, requires no chemical preservatives, and is more uniform than wood. The use of steel poles is consistent with Central Hudson's efforts to storm harden the transmission system.



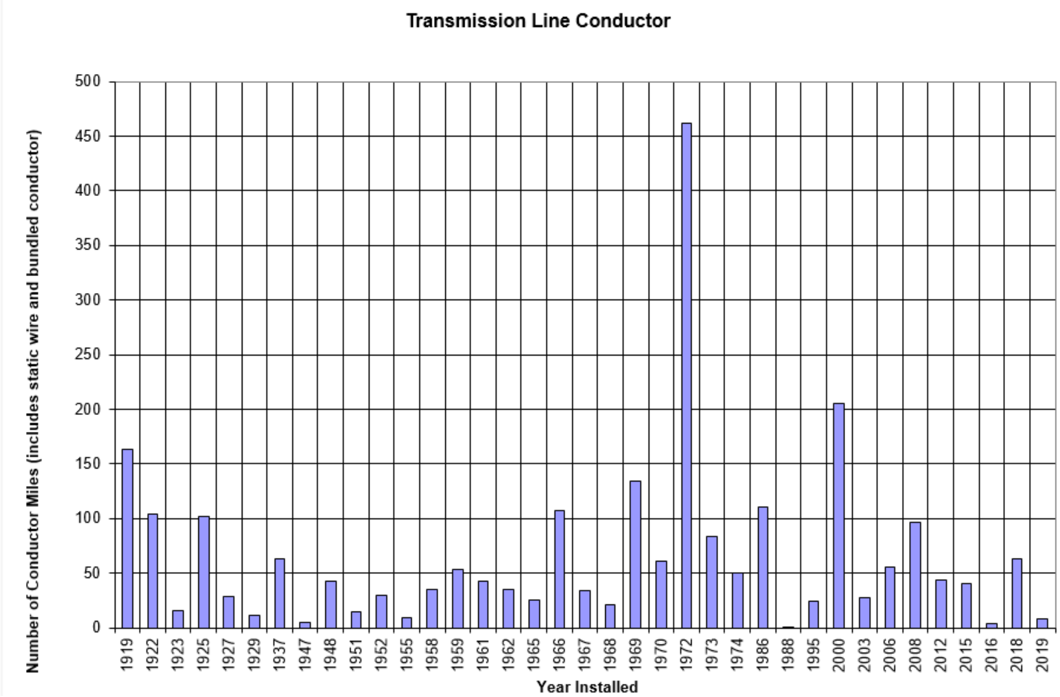
Plans
Given the relatively young age of the steel poles there is no need at this time for a replacement plan. Central Hudson is currently investigating the implementation of a steel pole testing program to evaluate the performance of its current steel pole population and assess the need (if any) to implement supplemental maintenance practices that would ensure the complete utilization of the pole's projected lifespan. CHG&E is also enrolled and is actively participating in an EPRI supplemental project to evaluate and provide maintenance / inspection tools for weathered steel poles. At present the steel poles are inspected as part of Central Hudson's existing inspection program.

3.2.2.4 Overhead Conductors

Inventory
Phase conductors on the Central Hudson transmission system are of the type as follows:

Conductor Type	Percentage of System
Aluminum	12.2
ACSR	75.8
Copper	11.5

Age and Condition
These conductors were installed in the years shown in the following histogram.



For two types of conductor, steel static wire and ACSR[3] conductor, issues have been identified and either have been or are being addressed. These issues include:

- Steel Static Wire: following a failure it was determined that several lines utilized a type of wire commonly used for guying as the static wire. Several years ago, a program was established to replace this sub-par wire (4 miles total). At this point, replacement is complete.

- ACSR conductor: after several failures of this type of conductor, samples were taken and sent to NEETRAC[4] (at the Georgia Institute of Technology) for testing. Based on the results of these tests, an ACSR testing program was implemented to ascertain the general condition of ACSR conductor. Based on these test results, a systematic program has been developed to replace ACSR conductor. This is an ongoing program with conductor already having been replaced on several lines and the remainder prioritized based upon test results and other considerations (i.e. other planned work).

[3] Aluminum Conductor Steel Reinforced
[4] National Electric Energy Testing, Research & Applications Center

No issues with other types of conductors (e.g., copper) have been identified.

Plans
The “WH-1”, “WH-2”, “A” and “C” line re-conductoring projects have all been associated with the ACSR conductor replacement program. These projects were initiated based on the results of NEETRAC testing of each line’s conductor. Those test results showed that the then existing ACSR conductor required replacement. The replacements improved the reliability and load serving capability of the lines.

FV Line
NEETRAC conductor testing on CHG&E’s 4.5 mile portion of the FV Line has demonstrated evidence of steel core corrosion and some annealing of aluminum strands and fatigue. A Planning study is currently underway to evaluate options for replacement of this conductor.

3.2.2.5 Insulators

Inventory
No specific number is available.

Age and Condition
No specific data are available. Central Hudson has experienced very few insulator failures. Most have been a result of external causes (e.g., lightning, gunshot, etc.).

Plans
Given the good performance to-date, no specific replacement plans have been identified. Central Hudson monitors industry experience via participation in EPRI’s insulator task forces. Central Hudson has and will continue to replace existing ceramic insulators in a tangent (vertical suspension) configuration with polymer equivalents as a typical practice. Ceramic bells and Toughened Glass will continue to be used in all dead-end or heavy angle applications where insulator strings are subject to higher tensile loading.

3.2.2.6 Pipe-Type Cable

Inventory
Central Hudson has 5 pipe-type cables that connect the 115 kV systems on the east and west sides of the Hudson River. These cables are as follows:

Line Designation	Operating Voltage	Length (Miles)	Conductor Type	Year Conductor Installed	Year Pipe Installed
AC	115 kV	0.81	3-1/C 1250 MCM	1972	1947
DC	115 kV	0.837	3-1/C 1250 MCM	1958	1958
DR	115 kV	0.63	3-1/C 2000 MCM	1985	1985
ER	115 kV	1.28	3-1/C 1500 MCM	1988	1988
HR	115 kV	0.63	3-1/C 2000 MCM	1985	1985

Age and Condition
A 2007 condition assessment of the oldest and most heavily loaded of these cables (the AC and DC) concluded that the equivalent insulation age is approximately 30-40% less than the actual cable age. This assessment also made recommendations associated with the cables' ampacity, cathodic protection systems, and pumping plant. A memo was prepared to address these recommendations.

The ER cable was replaced in 1988 following damage from an anchor-dragging incident.

The AC/DC pumping plant was replaced in 1998 based on operational concerns with the original plant.

Based on the 2007 condition assessment of the AC and DC cables and the historic operation and maintenance of these facilities, the condition of the DR, ER and HR cables is assumed good as well.

In 2012, during Superstorm Sandy, flooding occurred at several of the pumping plant locations for the oil-o-static cable systems. This included the pumping stations for the AC and DC cables in the Danskammer switchyard, for the ER cable in the Kingston termination yard and for the HR and DR in the Reynolds Hill termination yard in Poughkeepsie.

Plans
An action plan for the pipe-type cables was developed based on the 2007 condition assessment for the AC and DC cables. The plan was developed to ensure the continued reliable operation of these systems. In addition, due to the flooding that occurred during Super Storm Sandy, projects are

planned to be completed in 2020 to mitigate the effects of flooding at the AC, DC, DR, HR and ER pumping plants.

3.2.2.7 Cable Terminations (Potheads)

Inventory
Central Hudson currently has ten sets of high voltage transmission cable terminations for the river crossings.

Age and Condition
The AC and DC cable terminations were installed in the 1940's (AC) and 1950's (DC), the ER cable terminations were installed in the 1970's and the HR and DR cable terminations were installed in the mid-1980's. The AC and DC cable terminations at the Danskammer Substation are leaking and are nearing the end of their useful life. The remainder of the terminations are in acceptable condition.

Plans
The AC and DC cable terminations at Danskammer and the East Shore Transition Stations are being evaluated for potential replacement.

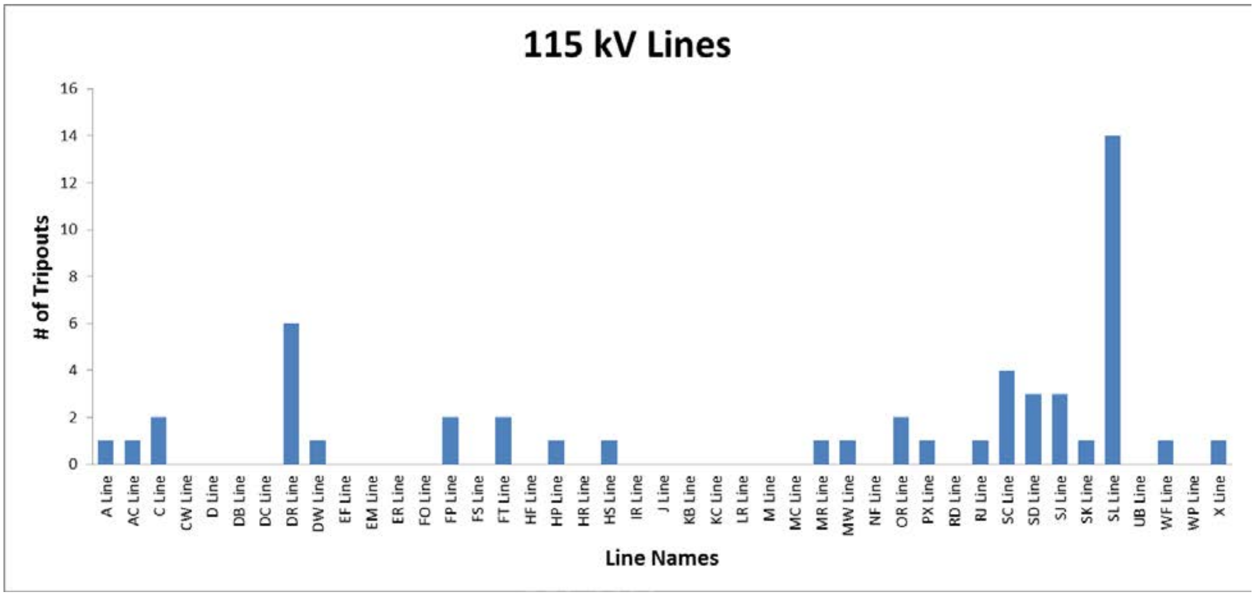
3.2.3 Reliability Performance Data

The System Operations tripout database was used for this analysis. Transmission trips from 2015 through 2019 were reviewed with the following results.

<u>345 kV</u>
Central Hudson owns three 345 kV lines. From 2015 through 2019, there was only 1 tripout on the 311 line. There were no tripouts on the 301 or 303 lines during this time frame.

No systemic issues, therefore, can be discerned from these data.

<u>115 kV</u>
The chart below depicts the number of tripouts on our 115kV transmission lines for the period of 2015 through 2019. This data helps identify potential negative reliability trends and areas for further study



Since the SL, SD, and SJ are being considered for retirement, tripouts for these lines were not examined further. The SL, SD and SJ circuit breakers at the Sugarloaf Substation were removed in 2017. The SL Line tripouts included faults that occurred on the SD and SJ lines after this was completed. Due to the high number of DR and SC line tripouts, these events were examined in greater detail and are summarized in the following table.

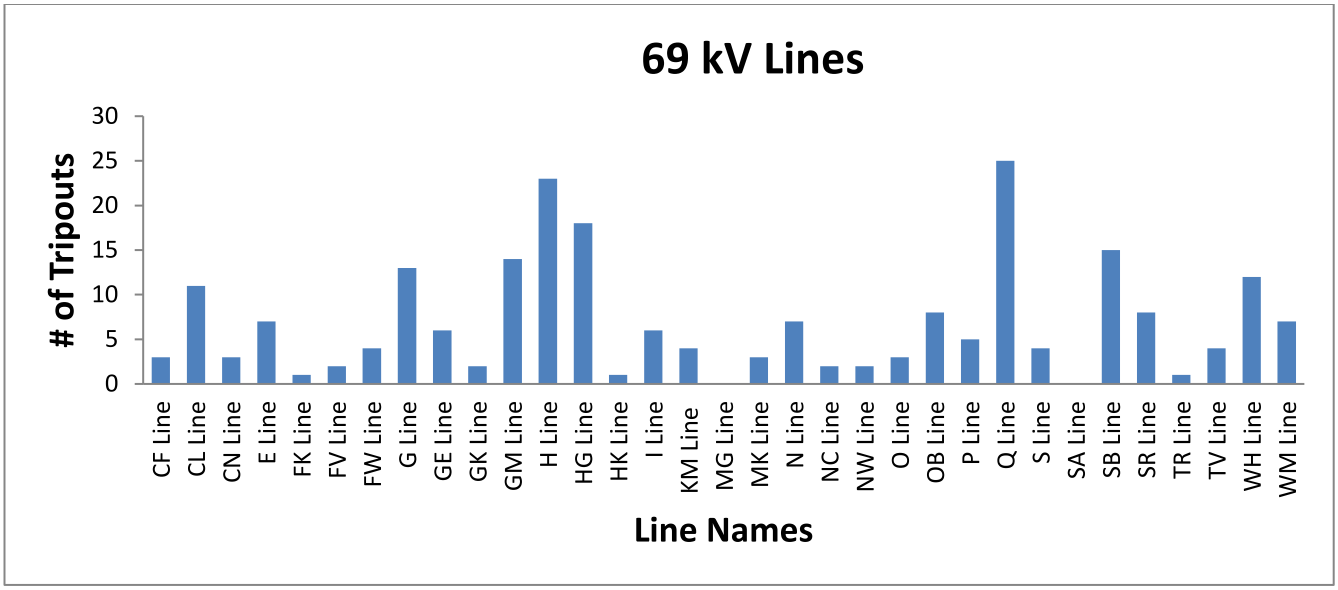
Cause	DR Line	SC Line
Equipment	1	
Animal	1	
Tree	2	4
Lightning	1	
Unknown	1	
Total	6	4

All of the outages on the SC Line were caused by trees. SC line vegetation management work was performed in 2018 and 2019. There is a small section of work remaining on the line. This is scheduled to be completed by year-end 2021.

No systemic issues can be discerned from these data on the DR Line tripouts. The line will continue to be monitored to track reliability trends and identify potential corrective actions if necessary.

69 kV

The chart below depicts the number of tripouts on our 69kV transmission lines for the period of 2015 through 2019. This data helps identify potential negative reliability trends and areas for further study.



Tripouts for the HG, Q, CL, H & SB lines were not examined further since there are plans to rebuild these lines. Since the G and WH lines have recently been rebuilt, tripouts for these lines were not examined further. In addition, portions of the GM line will be retired by 2022 and the portions of OB Line have been retired with the remainder being re-designated the O Line.

Due to the high number of E, SR, WM and N line tripouts, these events were examined in greater detail and are summarized in the following table.

	E Line	SR Line	WM Line	N Line
Wires Down				1
Human Interference			1	
Lightning Arrester	1			
Snow Storm			3	
Tree	2	6	1	5
Lightning	3	1	1	
Unknown	1	1	1	1
Total	7	8	7	7

- Over half of the events occurring on the SR line were associated with tree contacts. In response to these events, additional trimming was completed on this line. This included clearing an additional 25 feet of right-of-way where four of the five outages occurred. The right-of-way could not be extended in the area of the 5th outage location.
- The N Line had five tree related outages. The line is undergoing routine maintenance that will be completed this year. Several trees on customer's

property will be removed at the location where four of the five tree related outages occurred after speaking with the landowner.

- An investigation of lightning performance for the E Line will be completed in 2021 to determine corrective actions.
- Two of the WM Line faults occurred on the tap to Blooming Grove. This section was not rebuilt with the remaining WM Line rebuild and is currently being evaluated for retirement. No other systemic issues can be discerned from these data on the WM Line tripouts. The line will continue to be monitored to track reliability trends and identify potential corrective actions if necessary.

3.2.4 Summary of Reliability Improvement and Infrastructure Replacement Programs

The High Priority Replacement and ACSR Conductor Replacement programs are described in Section 5.2.2 of Central Hudson's Electric Planning Guides.

High Priority Replacement (HPR)
As indicated in Section 3.2.1, the HPR program actively addresses inspection findings. Capital funds are allocated to HPR work within our five-year forecast based on historic findings and planned inspections.

ACSR Conductor Replacement
This program was created after testing showed aging infrastructure issues with older installations of this conductor. The remaining FV Line Re-conductor Project is summarized in section 3.2.2.4 above.

3.3 Substation

Central Hudson has approximately 75 substations spread throughout our service territory supplied predominately via 345kV, 115kV, 69kV and 14.4kV transmission and sub-transmission systems. The substations are operated and maintained by our Operations Services Division with internal and external resources as needed.

3.3.1 Inspection Programs

Inspection cycles for substation equipment vary significantly depending on the asset class and anticipated maintenance and replacement. The current state of the major substation assets is described in this section, and additional details on the process are available in the Electric System Planning Guides.

3.3.2 Equipment

3.3.2.1 General Substation Equipment

3.3.2.1.1 Circuit Breakers

Overview

Central Hudson's electric power system consists of transmission lines, substations, and distribution lines. These lines and substation equipment are protected by relays and circuit breakers. Circuit breakers are critical parts of the electric system. A number of years ago, an overall review was performed on our existing fleet of circuit breakers based on age, duty/duty rating, condition, criticality and availability of spare parts. It was identified at that time that many of the existing circuit breakers on the Central Hudson electric system have been in-service for over 40 years; some of these breakers were over-dutied and others no longer have spare parts available for maintenance. To maintain the current levels of reliability of our substations, an Electric Circuit Breaker Replacement Program was developed to address these issues.

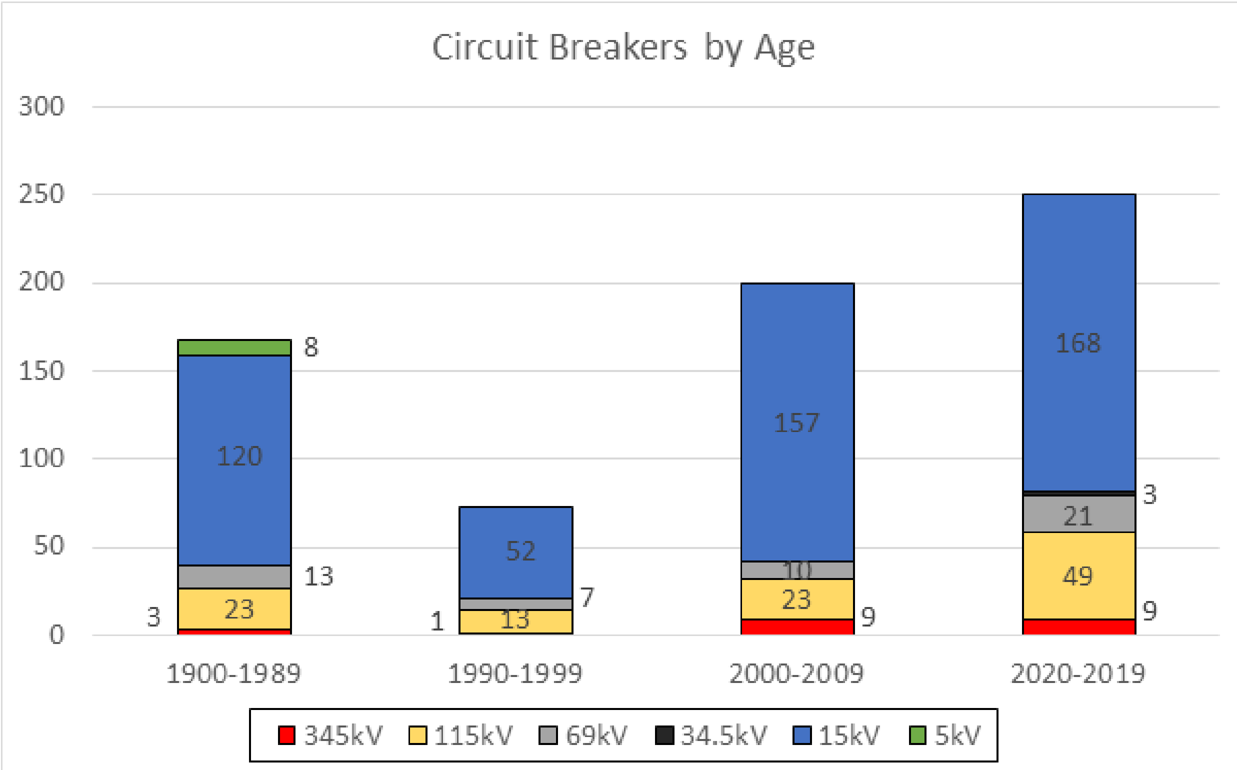
Inventory

The following chart depicts the current inventory of circuit breakers on our system (the chart does not include circuit breakers listed as retired, junked, EC spare, spare, deleted, or undated); (source Cascade).

Operating Voltage	Number
345 kV	22
115 kV	109
69 kV	51
15 kV	497
5 kV	8
Total	687

Age and Condition

The following chart depicts the number of circuit breakers vs. date of manufacture:



The condition of the circuit breakers varies and the ability to maintain them is closely tied to their age. On a whole, ongoing O&M has kept the circuit breakers in good working order; however troubles and failures have identified several specific breaker types which should be replaced. Problematic circuit breakers, as identified by our assessment process are all part of the breaker replacement program. These specific types of breakers include:

345kV –	Westinghouse Type SFA (3)
115kV –	General Electric Type FK (4)
69kV –	Allis Chalmers Type FZO (2) General Electric Type FK (2)
15kV-	General Electric Type AM (18) General Electric Type FK (15) Westinghouse Type 150-DH (39) Westinghouse Type 150-DHP (40)

The criteria for the selection of the circuit breakers for the replacement program are prioritized as follows:

Breaker Duty: All circuit breakers with duties within 3% of their rating have been selected; highest priority is given for those circuit breakers with duties greater than 100% of their rating. All circuit breakers within 3% of their rating have been replaced. Breaker duty studies are performed as our system changes, as new breakers are installed and periodically on a system wide level. Any breakers identified as approaching their duty limit will be given priority in the replacement program.

Condition: All of the circuit breakers identified on the breaker list are given the next priority based on the recommendations from our Operations Services Division. These recommendations are based upon operating experience or reports of failures or poor testing results.

Obsolescence: Several of the circuit breakers on our system employ outdated technology, specifically relating to interrupter design. Others suffer from extended service lives and parts are no longer available for many others.

Other Factors: Circuit breakers that meet the above breaker duty or condition criteria are selected for this replacement program if they will be replaced with new circuit breakers as part of other substation construction projects.

Program Maintenance: It is envisioned that this program will represent a living process. The circuit breakers selected at the present time represent equipment that we feel, given the current information and conditions, will require replacement. Should system conditions change, failures occur or testing results indicate problems with specific types of breakers, additional breakers may need to be added to the program and/or the order of replacements may need to be modified. Some of the breaker replacement projects from previous lists have been advanced and some have been deferred due to other emergent work, as well as revised condition assessments, priorities, and scheduling availability. As condition assessments are continuously updated, the program may need to be extended to include longer-term requirements.

Plans

As indicated, Central Hudson has an ongoing multi-year circuit breaker replacement program. The chart below outlines all of the remaining circuit breakers included in our replacement program. The current five-year forecast includes the planned replacement of approximately 102 circuit breakers.

Circuit Breaker Replacement Plan (# of breakers)				
Year	345kV	115kV	69kV	15kV
2021	1	1	5	8
2022	1	2	0	26
2023	1	4	1	21
2024	0	0	0	31
2025	0	0	0	0
Total	3	7	6	86

Based on the field condition and the above breaker replacement prioritization, it is planned to complete the breaker replacement program by 2025.

3.3.2.1.2 Disconnects and Motor Operated Switches (MOS)

Inventory

The following chart depicts the inventory of Disconnect, Motor Operated, and Ground Switches on our system:

Operating Voltage	Quantity
345 kV	139
115 kV	384
69 kV	253
34.5 kV	28
13.8 kV	324
7.5 kV	29
4.16 kV	8
Total	1,165

Age and Condition

No specific data is available. Generally, ages and conditions vary. Due to the criticality of our 345kV system and identified problems, a program was previously developed to replace the 345kV TTT-7, EA, VR2 and VT-1 style motor operated disconnects. Limited to no replacement parts are available for these style switches. Additionally the Memco EA 345kV style motor operated disconnects have experienced reoccurring hotspots.

345 kV --	Brown Boveri	Type TTT-7	(1)
	Memco	Type EA	(16)
	Memco	Type VR2	(10)

Plans
Central Hudson has developed a multi-year 345kV switch replacement program. The 345kV switch replacement program will replace twenty 345kV switches in the next five years. The breakdown of the program is as follows:

345kV Switch Replacement Plan (# of switches)

Year	345kV
2021	5
2022	5
2023	4
2024	5
2025	5
Total	24
Future	11

The program will continue addressing the remaining ~11 disconnects within the next five year cycle.

With the developing trend of issues and consideration given to the criticality of the 115kV and 69kV system, Central Hudson is evaluating a multi-year 115kV/69kV disconnect replacement program. Currently, these disconnects are replaced as needed during other major substation projects. A more defined program that would replace 115kV and 69kV motor operated disconnects as part of larger substation projects and as standalone projects is being evaluated.

Similar to the circuit breaker replacement program, it is envisioned that this program will represent a living process. The switches selected at the present time represent equipment that we feel, given the current information and conditions, will require replacement. Should system conditions change or failures occur the order of replacements may need to be modified and the program may need to be extended to include longer-term requirements.

3.3.2.1.3 Insulators

Inventory
No specific number available.

Age and Condition
Generally, ages and conditions vary. The general condition of this equipment is considered good. A problem with vertical pin-cap insulators in two of our substations (Marlboro and West Balmville) was previously identified. The insulators at the Marlboro Substation have been replaced in conjunction with a major rebuild of the substation. Approximately half of the insulators at the West Balmville substation have been replaced. The remaining 115kV pin-caps located at the West Balmville Substation will be replaced with the substation upgrade in 2020.

Plans
The insulators at Pleasant Valley Substation will be replaced as part of a larger modernization project in 2021.

3.3.2.1.4 Transformers

Inventory
The following chart depicts the inventory of Power Transformers on our system (excluding spare and retired units):

Power Transformers	
Operating Voltage	Quantity*
345 kV	8
115 kV	85
69 kV	45
34.5 kV	5
13.8 kV	12
Total	155
* Single Phase Transformers are counted individually	

Age and Condition
The condition of the power transformers varies and the ability to maintain them is closely tied to their age. The overall condition of this equipment, based on our ongoing assessment program, is considered good. During our ongoing assessment process, however, the following issues were identified:

(1) McGraw 550 Transformer Load Tap Changers. Specifically, it has been shown that significant loading and the number of operations of the 550B and 550C LTCs results in considerable contact deterioration over time. LTC filters have been installed at stations deemed necessary where McGraw 550B and 550C LTCs exist to ensure the LTC oil remains in good condition. During routine maintenance, replacement of moving and stationary parts is being completed with upgraded parts on an as needed basis.

(2) Type U bushings. The failure pattern of GE Type U bushings has been well documented and can be identified by a power factor test of the bushing that shows an increase in capacitance of more than 5% over nameplate and with a power factor over 1.0.

(3) Transformers that have outlived their useful life. This includes transformers that receive a poor condition evaluation and/or are trending towards potential failure and higher risk. These types of repairs or replacements are handled on an as needed basis dictated by diagnostic test results and inspections.

3.3.2.1.5 Testing Plans/Inspection Programs

McGraw 550 Transformer Load Tap Changer (LTC) Rebuild Program: Using the existing LTC overhaul schedule, this program allows for a rebuild of one 550 LTC per year over the next five years.

Type-U bushing replacements: As these bushings begin to test poorly during routine power factor testing, they are scheduled for replacement.

3.3.2.1.6 Transformer Watch List and Plans

Central Hudson's Operations Services Division utilizes a variety of preventive and predictive maintenance programs to maintain the integrity of its high voltage power transformers. Operations Services' Annual Transformer Watch List is used to provide infrastructure condition assessment to identify a need for or to support equipment replacement, as part of Central Hudson's System Planning Process. Transformers are reviewed based on criticality factors such as: presence/severity of a problem, significance to transmission, significance to distribution, availability of sister / adequate substitute unit.

Based on condition assessment, age and risk the following transformers are within the 5 year forecast for retirement/replacement:

- Knapps Corners Substation Transformer #1, #2, and #3 (install a 56 MVA 115/69 kV autotransformer and two 22 MVA 115-13.8 kV transformers as part of the substation rebuild);
- Greenfield Road Substation Transformer #1, Phases #1, #2, #3 and Greenfield Road Substation

Transformer # 2 (replace with two existing 69-13.2 kV 10MVA units);
- Clinton Avenue Substation Transformer #1 (station to be retired/transformer scraped);
- Converse Street Substation Transformer #2 (replace with new 14.4 kV transformer).

In addition to these condition based replacements, two new 56 MVA 115/69 kV autotransformers will be installed at the Kerhonkson Substation as part of the P & MK voltage conversion to 115kV, new transformers will be installed at the Coxsackie and South Cairo Substations based on the planned retirements of the Combustion Turbines at these locations and a new 12MVA 69-13.2kV transformer will be installed at the New Baltimore Substation to address reserve capability concerns and provide operational flexibility to this area.

3.3.2.1.7 Capacitor Banks

Inventory
The following chart depicts the inventory of Capacitor Banks on our system:

Substation Capacitor Banks	
Operating Voltage	Quantity
345 kV	2
115 kV	3
69 kV	6
34.5 kV	1
13.8 kV	13
Total	24

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
No specific rebuild/refurbish/replacement programs identified.

3.3.2.1.8 Substation Batteries/Battery Chargers

Inventory
Central Hudson currently has 81 substation batteries and 81 substation battery chargers.

Age and Condition
Most equipment is age 20 years or less. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
Battery replacement program: Central Hudson replaces any batteries that have been in service for 20 years or are testing poorly due to operational or equipment failure. Currently 31 battery replacements are anticipated over the next 10 years based upon remaining service life.

As tests and inspections are conducted and additional condition information is obtained, this plan is modified.

3.3.2.1.9 Voltage Regulators

Inventory
The following chart depicts the inventory of Substation Voltage Regulators on our system:

Voltage Regulators	
Operating Voltage	Quantity
34.5 kV	3
13.8 kV	102
4.16 kV	3
Total	108

Age and Condition
Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
Substation Voltage Regulator Maintenance Program: Central Hudson currently has a program in place to maintain all single-phase voltage regulators every 20 years or 100,000 operations.

3.3.2.1.10 Circuit Switchers

Inventory
The following chart depicts the inventory of the Circuit Switchers on our system:

Circuit Switchers

Operating Voltage	Quantity
345 kV	1
115 kV	11
69 kV	22
Total	34

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
The previous program identified to replace all S&C Mark II, III, IV circuit switchers has been completed. No specific rebuild/refurbish/replacement programs identified.

3.3.2.1.11 Substation Reclosers

Inventory
The following chart depicts the inventory of Substation Reclosers on our system:

Substation Reclosers (Three Phase Installations)	
Operating Voltage	Quantity
34.5 kV	1
13.8 kV	9
Total	10

Age and Condition
No specific data available. Generally, ages and conditions vary. Operation Services has identified problems (age, condition, availability of spare parts) with several families of older three phase recloser installations.

Plans
No specific rebuild/refurbish/replacement programs identified for the remaining 13.8kV substation reclosers. The 34.5kV recloser (Hunter Z-666 switch) will be evaluated for potential replacement in the future.

3.3.2.1.12 Control Houses / Switchgear

Inventory
Central Hudson currently has 59 control houses and 61sets of switchgear.

Age and Condition

A program has been developed to evaluate the condition of both control houses and switchgears, specifically the rust, roof and wiring condition. Historically it has been shown that, to ensure that our control houses remain in good condition, we are required to refurbish 2-3 control house roofs per year.

Plans
Roof maintenance program: Control Houses and Switchgears will continue to be evaluated during routine substation inspections and refurbished or replaced as needed. On average 2-3 roof refurbishments are completed annually. In addition, as our control houses and switchgears age, candidates for replacement will be identified as part of Operations Services assessment process. Currently the Coxsackie Substation, Woodstock Substation, and Myers Corners Substation switchgears were evaluated and identified for replacement in 2021.

3.3.2.1.13 Power Control Center (PCC)

Inventory
Central Hudson currently has 16 power control centers.

Age and Condition
Central Hudson began installing PCCs in 1997 and all of our PCC are less than 25 years old. Inspections of PCCs have shown that the PCCs are in good condition and functionally sound. Currently there is no formalized program for PCC replacement. PCCs will continue to be evaluated through routine substation inspection specifically for rust, roof, wiring condition, or any other form of deterioration.

Plans
PCCs will continue to be evaluated during routine substation inspections and refurbished or replaced as needed.

3.3.2.1.14 Coupling Capacitors

Inventory
The following chart depicts the inventory of Coupling Capacitors on our system:

Coupling Capacitors	
Operating Voltage	Quantity
345 kV	40
115 kV	191
69 kV	104

Total	335

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good.

Plans
No specific rebuild/refurbish/replacement programs identified.

3.3.2.1.15 Arresters

Inventory
No specific number available.

Age and Condition
No specific data available. Generally, ages and conditions vary.

Plans
Central Hudson has a program in place to replace all spark-gap arresters with MOV type arresters. MOV arresters are an improved technology and provide lower losses and superior overvoltage protection over spark-gap arresters. At this time, almost all spark-gap arresters have been replaced with Polymer MOV type arresters. The remaining gap arresters will be identified and targeted for replacement during existing project designs.

3.3.2.1.16 Non-Electrical Assets

Inventory
<u>Substation Fences</u>
Central Hudson currently has 75 substation fences.

Age and Condition
No specific data available. Generally, ages and conditions vary. The general condition of this equipment is considered good. Fence condition is evaluated through routine inspections and replacement/repairs are made as identified.

Plans
No specific rebuild/refurbish/replacement programs identified.

3.3.2.2 Protective and Communication Equipment

Inventory
Central Hudson has approximately 4,100 protective relays, communication devices and network devices installed in

substations. This inventory is constituted primarily of a conglomeration of generations of electromechanical and microprocessor based devices and in recent years network communication devices.

Device Type	Count	%
Microprocessor Relays	1279	31%
Electromechanical (Non Digital) Relays[5]	918	22%
Lockout Relays	772	18%
Auxiliary Relays	360	9%
Tele-protection Units	146	4%
Transformer/Regulator Relays & Controls	365	9%
Network Devices	291	7%
Total	4131	100%

Age and Condition

The ages and conditions generally vary. Older equipment is electromechanical, mid-aged equipment is static or solid state, and newer equipment is microprocessor based. The microprocessor based devices are in good condition. The static/solid state relays are outdated, and these devices do not support event collection, metering and advanced protection schemes. The electromechanical relays are based on older technology than the static/solid state relays, yet have proven somewhat more reliable. The condition of the electromechanical relays is mixed. As such, the static/solid state and electromechanical relays are ready for replacement as soon as possible.

Plans

Central Hudson's plan is to replace all static/solid state relays, and all electromechanical line relay packages on the 345kV system. To date all but one Alternate #1 345kV Line package, and one Alternate #2 345kV Line package have been replaced. The remaining replacements are scheduled for completion by the end of the five year forecast. Consideration on timing has been given to perform relay replacement work in conjunction with previously scheduled line work to minimize the number of line outages.

Central Hudson has proactively replaced relays in conjunction with substation upgrades. It is anticipated that approximately 75% of electromechanical/non digital protective relays will be replaced with microprocessor relays at the end of the five year forecast. In conjunction with other planned capital work and/or in support of

Distribution Automation, electromechanical relays replacements are being added to scope where appropriate.

3.3.2.3 Substation Meter Devices

Inventory
Central Hudson currently has approximately 130 substation meter devices.

Number of Meter Points[51]				
No Meters	Chart Meters	Grid Sense	MV-90	SCADA
7	17	7	57	439

Age and Condition
No specific data available. Generally, ages and conditions vary. Older equipment is chart based, mid-aged equipment is recorder based, and newer equipment is microprocessor based. The microprocessor based metering is in good condition. The other metering leaves gaps in data.

The existing chart-type meter devices have reached their useful life span. Parts are no longer available and the devices cannot be properly maintained. Non-revenue metering can be accomplished through the microprocessor relays.

Plans
Central Hudson will continue to replace outdated metering (non-revenue) and integrating the meter functions into the microprocessor relays as part of capital improvement projects. These plans will provide hourly metering for approximately 98-99% of our system load by the end of the five-year forecast.

3.3.2.4 Digital Fault Recorders (DFR)

Inventory
Central Hudson currently has six functioning Digital Fault Recorders (DFR). The plan is to remain with six DFR's through the five year forecast.

Age and Condition

[5] Data source from Distribution Engineering Excel Spreadsheet: "Metering Data" 9/26/2019

Three of the DFRs are new (Ametek) and three are more than 15 years old (BEN/Qualitrol). The three older units use an outdated computer technology and are in poor condition. These units are targeted for replacement by 2022. Electric System Protection performed an evaluation for replacement DFR's and chose Ametek as the manufacturer for DFR replacement.

3.3.2.5 Remote Terminal Units (RTU)

Inventory
Central Hudson currently has 85 Remote Terminal Units (73 main RTU's and 12 sub RTU's) in its electric substations and customer hydro facilities. The desired RTU and SCADA infrastructure to support real-time monitoring, control, and metering is in place in 67 stations at this time.

RTUs

RTU Style	Count
Preferred	67
Outdated	6
NONE	2

Age and Condition
No specific data available. Generally, ages and conditions vary. DNP RTUs are in good condition; the two remaining CDC RTU's are 30 plus years old. Also, Harris D20 and M4000 RTUs have reached the end of their useful life. In addition, Central Hudson ceased installing Harris units 20 plus years ago.

Plans
Central Hudson has adopted the SEL Axion as the standard and preferred replacement RTU. It is cost effective, reliable and both Engineering and field personnel have extensive experience with these RTU's. To provide the operability to support Distribution Automation, and the increasing data needs resulting from customer DER interconnections the following upgrades and replacements will be performed and completed within the forecast period: The CDC unit, and the Harris D20's and M4000's will be replaced with SEL Axions. In order to allow the Modicon BM85's to have full operability they will either be replaced with SEL Axions during planned substation upgrades or a SEL RTAC will be installed on the front end. The Telvent Micro1C's and 2100's will either be replaced with SEL Axions during planned substation upgrades or the CPU card will be upgraded to the 2400 version. The remaining System Northwest unit at Wappingers Hydro will be replaced. All

dialup RTU's will be replaced using real time connections via network strategy when available. Additionally, the two substations without SCADA will be reviewed on a case by case basis.

3.3.3 Summary of Infrastructure Programs

The infrastructure replacement programs at the substation level vary by individual piece of equipment, as well as integration with existing plans at a location.

Desired Future State:
New equipment, properly implemented and integrated, will better support current functions and create flexibility for added future functions as follows:

- Provide for robust planning capabilities and switching operations through use of trending and real-time data. Continuous meter data for the entire system will eliminate information "gaps."
- Enable more accurate forecasting of area loads to increase risk tolerance, possibly resulting in deferral of substation and distribution projects.
- Offer the needed operability for DA initiatives.
- Improve reliability and reduce CAIDI through automated event reporting and fault location.
- Provide a means of ensuring compliance with mandatory NERC Reliability and CIP Standards.

The ultimate future state is one where the minimal use of devices and space will provide all metering and fault data to engineers and operators in real-time for every available point on the system.

Standalone meters have been eliminated, except in the case of revenue/interchange meters. Metering is measured and reported through digital relays wherever possible. This design provides a cleaner, more compact design that minimizes the amount of wiring, minimizes the number of failure points.

- Event reports and metering data are transmitted to the SCADA master for use in planning, operating, and timely fault location. Real-time meter data is available by circuit for operators and engineers.

- Non-value added work, such as reading & repairing chart meters and MV-90 meter recorders and manually entering meter data is eliminated, reducing expenses.

- Central Hudson has standardized on digital relay equipment, limiting the variety of relays / relay manufacturers on the system. This reduction more easily increases both the technicians' and the Engineers' familiarity with the relays, leading to a quicker mastery of the relay settings, installation & testing methods, and relay operation. Also, this standardization creates a deeper familiarity with the functions of the relays, enabling more innovation in using the relays and their schemes.

- Time synchronization of all relays thru a standardized network.

- The RTU replacement program is complete and all of the CDC, Harris D20 and M4000 RTUs have been replaced as well, providing a more easily configurable and user-friendly RTU while reinforcing standardization.

Plan

In order to reach the desired future state, nearly all of the program must be completed. The program is based on the premise that the majority of modernization work can be accomplished incrementally with existing Category 13 projects or through DA preparation projects. There are exceptions where the specific conditions of a substation deem it important to address the infrastructure through stand-alone projects.

3.4 Underground – Cable, Equipment and Infrastructure

This section discusses the plans and programs for all sub-transmission and secondary network infrastructure, as well as padmount transformers and switches. Replacement programs were developed based on a combination of age of equipment, data from the inspection program, operational flexibility, and reliability. Due to the nature of the underground system, infrastructure replacement plans were developed as a proactive way to maintain the reliability of the sub-transmission system.

3.4.1 Inspection Programs

The majority of the high voltage sub-transmission cables and all low voltage secondary network cables run through an underground conduit system through manholes and pull boxes. As part of the Central Hudson Facilities Inspection Program, manholes and pull boxes are inspected once every 5 years. These inspections help identify equipment and infrastructure associated with the sub-transmission system, secondary network system and underground highway crossings that are in need of repair. A severity value is provided for the plant assessed ranging in value from 1 to 6, with 6 being the most severe. Repairs are prioritized based on this value. Items addressed include wall reinforcements, broken covers, major ceiling repair, rusted I-beams, tripping hazards, clearing of debris, cable fire-proofing, transformer oil leaks, oil switch leaks, network protector replacements and cable repairs. As repairs are needed, budget projects are developed or work orders are drawn up on an individual basis.

3.4.2 Equipment

3.4.2.1 Cable – Primary URD Cable, Underground Network Systems and Highway Crossings

There are approximately 1,612 miles of primary URD cable. The oldest URD cable asset is approaching 50 years, with the majority being newer. Although failures have not had a large impact on SAIFI and CAIDI, their number has been consistent over the past 5 years. The industry as a whole has been concerned with the future performance of this critical asset. Some utilities have tried cable rejuvenation, while others have opted for wholesale replacement of specific vintages of cable. Central Hudson is looking into testing as a potential means of cable health assessment in order to target specific repairs. A Research and Development project was conducted in 2017 using partial discharge detecting technology from a Company called IMCORP. The R&D program was successful and was able to prove the effectiveness of the test in finding the location of actual cable defects, which would provide the capability to target repairs. Cable sections that exhibit no partial discharge can be recertified as new and are guaranteed for 25 more years. Central Hudson is in the process of investigating the ability to utilize IMCORP's services. Additional plans are outlined in Section 3.4.4.5 URD Cable Replacement and Repairs.

There are approximately 215 miles of underground network cable, 12 miles of which are primary sub-transmission feeds to the secondary networks. Portions of the primary feeders range in age from 40 to 80 years old with portions being well over 60 years old (see Table 3.4.2). The older portions of these feeders are comprised of paper-insulated-lead-cable (PILC) conductors. The underground infrastructure for both the primary and secondary network cables is in some cases older than the associated cables.

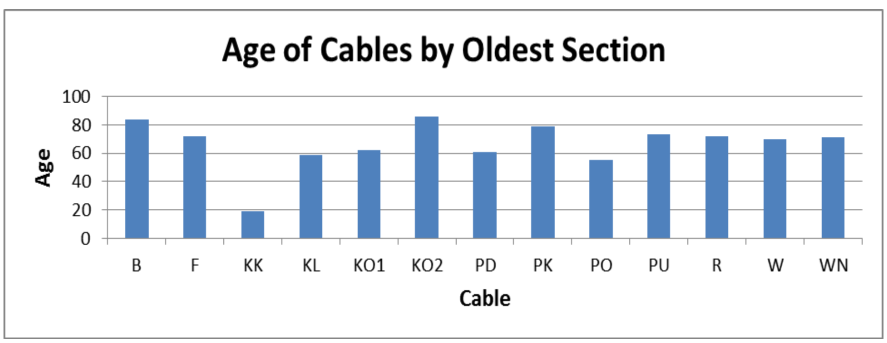


Table 3.4.2 – Age of Cables by Oldest Section (2020)

Due to an increase in failure rates of the PILC cables and failing underground infrastructure, targeted replacement programs were developed in 2008 and 2011 to address the age and condition of the primary and secondary network cables. As these programs were completed, additional ones were developed in subsequent years for inclusion in the Capital Budget. These programs are discussed in section 3.4.4.

Due to an underground cable failure crossing the Taconic Parkway, in 2014 the remaining Taconic Parkway crossings were inspected in order to update our cable and infrastructure records. Both cables and infrastructure (pull boxes and conduit) were found to be in need of repair at these locations. The program to address these repairs, as well as locate and address the remaining highway crossings on our system is discussed in section 3.4.4.2.

3.4.2.2 Network Protectors

Central Hudson currently has 40 network protectors on the system. Network Protectors are both electrically and mechanically tested once every 6 years. Their condition is assessed once every 5 years as part of the Facility Inspection Program.

3.4.2.3 Communicating Network Relays

Since 2009, Central Hudson has been monitoring the secondary networks using a system called CEMesh Meshed Network System. This system is installed at each transformer secondary bushing that monitors the total load on the transformer at any given time. The load at each transformer is collected using a Meshed Network Sensor (MNS). Data from these devices are transmitted via CDMA cellular service to a remote server, which is hosted and maintained by a company called Power Systems Integrity (PSI). The data can then be accessed through the PSI website. In 2012 it was realized that significant upgrades would be needed to the CEMesh system in order to use it for monitoring load growth and planning network upgrades. CEMesh is also limited in that it does not have the capability to collect transformer health data from oil and pressure sensors, and would not be able to communicate through our new Network Strategy communications network.

In 2014, it was determined that upgrading the existing CEMesh MNS devices, as well as the PSI server interface was not the most cost effective way to improve the network monitoring capabilities, as it would not provide additional transformer health monitoring capabilities, and access to data would still be restricted to the PSI website. After a thorough evaluation, it was decided to replace the non-communicating CMD protector relays with communicating ETI relays, along with a Sensus CDMA cellular communications system until they can be transitioned to the Network Strategy communications. Installation of these new relays began in 2014. A project to link the relays to the Network Strategy communications network is being completed in 2020. As of the end of 2020, it is expected that 21 of the 26 network transformers in the Poughkeepsie network will have new communicating relays.

The network relay replacement and communications program is a multi-year program that will enhance the value of the data obtained from each of the three secondary networks, as well as feed this data into Central Hudson's DMS system in the long term. This will assist in maintaining the reliability of the secondary networks by allowing Engineering to better prioritize equipment and infrastructure upgrades, as well as better plan for load growth. The relay replacement program is in the Capital Budget through 2025, and will include the completion of the Poughkeepsie network relay retro-fits, as well as the Kingston and Newburgh network retro-fits.

3.4.2.4 TGRAL Oil Switches

In 2008 Central Hudson identified 23 TGRAL oil switches in service (overhead and underground) on the system. The majority of these switches are associated with the 14.4kV cables. The age and condition of these units is unknown, however they are no longer serviceable and parts are no longer available. Replacement designs were identified for these switches, and as of 2019, there are no remaining TGRAL oil switches in service.

3.4.2.5 Manholes and Pull Boxes

Central Hudson currently has 916 manholes and 867 pull boxes on the system. The age and condition of this type of infrastructure is not easily determined. Some of these manholes are in excess of 60 years old and have over time been repaired. One of the issues that arise is the support structures of the ceilings tend to wear down over time due to weather conditions. Ice, salt and water take their toll on these structures. The condition of each manhole and pull box is assessed once every 5 years. The details of the inspection process are discussed in the prior section 3.4.1.

3.4.2.6 Pad Mounted Transformers and Switches

Central Hudson has 15,529 pad-mounted transformers and switches on the system. The oldest pad mounted asset is 70 years old, with the majority being newer. Currently, there are no systemic problems with the pad mounted transformers and switches. They are inspected once every 5 years. Repairs are prioritized based on inspection severity rating. Costs for repairs are covered within the annual capital program as the need arises.

3.4.3 Reliability Performance Data

The Central Hudson sub-transmission and secondary network systems are designed for redundancy. Sub-transmission feeders supply substations that either currently supply, or at one time have supplied, low-voltage 4.16kV distribution feeders.

<u>Newburgh</u> – The B, F, R and WN sub-transmission feeds emanate from the West Balmville Substation and supply the Montgomery St. Substation, which supplies a combination of 13.2kV and 4.16kV distribution, including the Newburgh secondary network (see Figure 3.4.3-1). In 2018, an alternate plan to supply the Montgomery Street Substation with only two feeds was developed, and is further discussed in section 3.4.4.4.

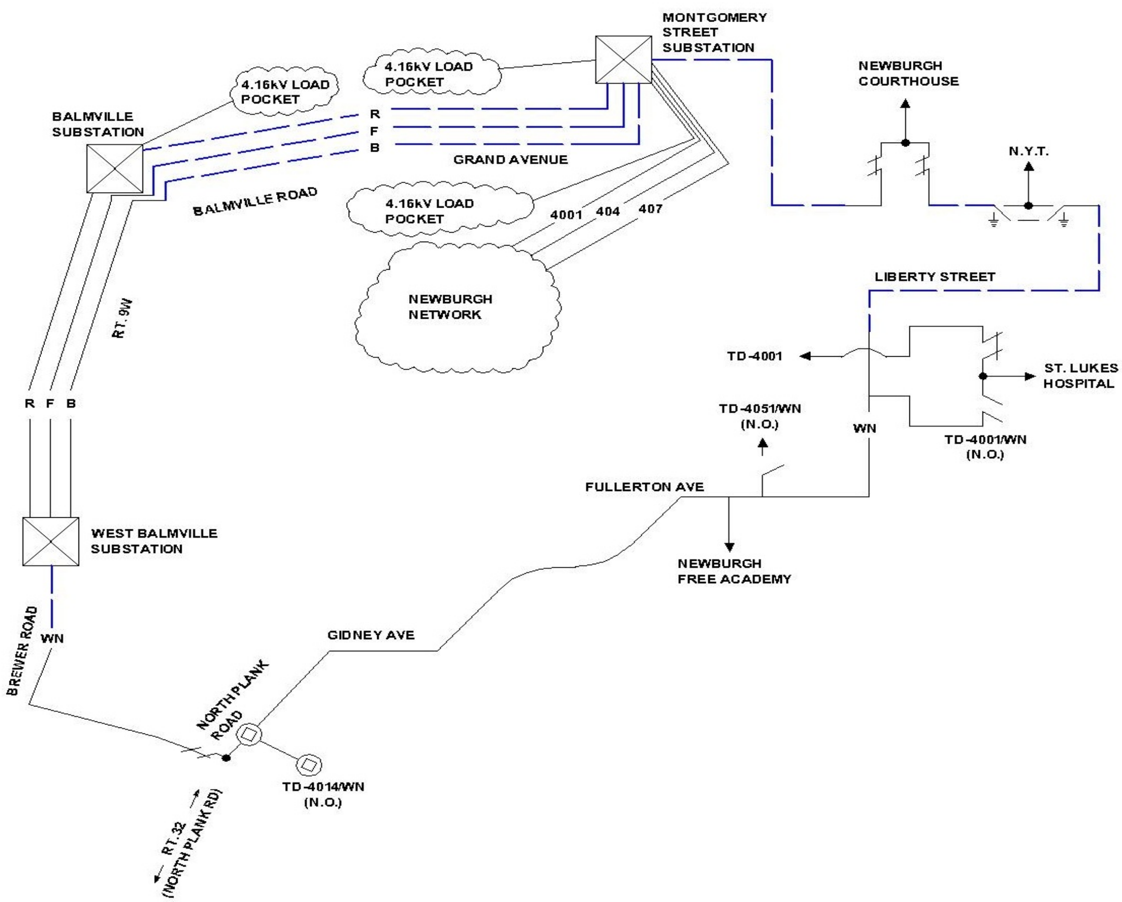


Figure 3.4.3-1: Newburgh 14.4 kV System

Poughkeepsie – As of 2020, the Poughkeepsie District has 5 sub-transmission feeds, all of which emanate from the Reynolds Hill Substation (see Figure 3.4.3-2). Three feeds (PO, PK and PU) from the Reynolds Hill Substation supply the Poughkeepsie secondary network. The PD cable feeds a portion of the Central Hudson main campus and is primarily rubber cable. The W cable is primarily overhead spacer cable and only feeds a sewage plant. There are currently no plans to upgrade the PD or W cables; however the W cable could be reclassified for 13.2kV distribution should the need arise. Plans to replace the primary PILC cables feeding the Poughkeepsie network are discussed in Section 3.4.4.3.

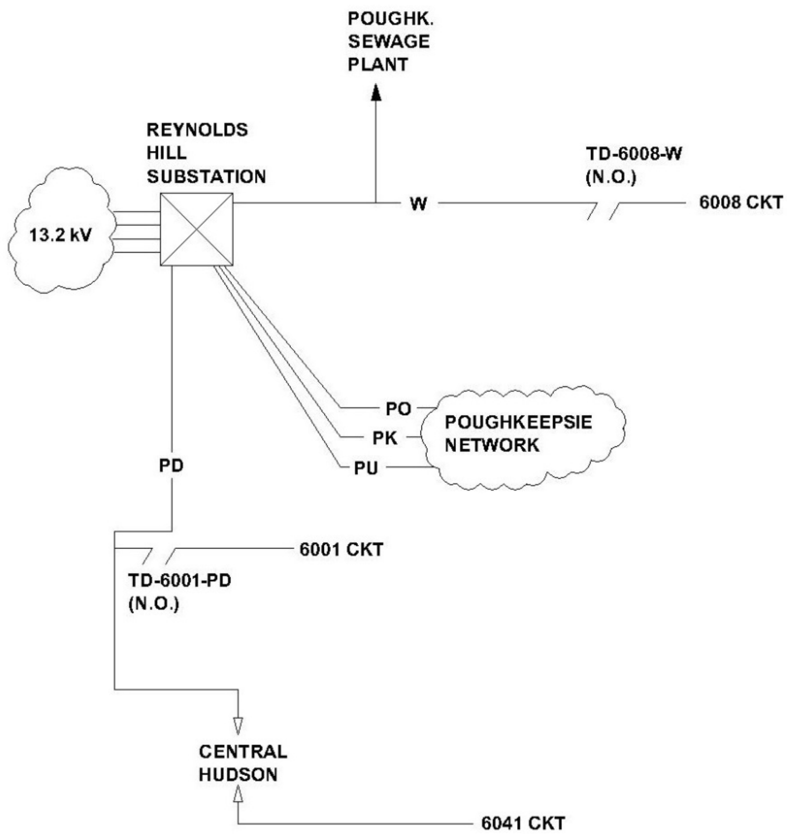


Figure 3.4.3-2 - Poughkeepsie 14.4kV System

As noted, there are three secondary networks in our system located in the cities of Kingston, Newburgh and Poughkeepsie. Each secondary network has 3 primary feeds and consists of multiple parallel secondary cable runs that are interconnected for an electrically continuous secondary grid. The secondary network systems are designed in a manner such that a first contingency loss of any single primary feeder or loss of one or more secondary runs would not result in any customer outages. There are unique situations where a large commercial or industrial customer is tapped directly off of a sub-transmission cable. Switching procedures (either manual or automatic) are in place for these unique situations to minimize outage times in the case of contingencies for this small handful of customers.

Central Hudson has a total of 9 network feeders serving the 3 networks that serve less than 1% of our customers. All 3 networks experienced 10 primary or secondary cable failures combined in the past 10 years that have had a negative impact on network customer reliability. Both the Newburgh and Kingston networks experienced an outage in 2014 and 2015, respectively that were not due to infrastructure or equipment condition, but rather events external to the networks. The loss of the Newburgh network in 2014 was due to a City of Newburgh snow plow breaking a manhole cover and pushing it into live primary and secondary cables. The Kingston network outage in 2015 was due to inadequate fusing during a temporary switching event resulting in loss of the substation that feeds the network. The Kingston and Newburgh networks also each experienced an outage in 2018. A direct lightning strike to one of the substation transformers feeding the Kingston Network resulted in a large portion on the downtown Kingston area, both network and non-network, losing power. A tornado event caused a transmission outage to the substation that feeds the Newburgh network primary feeders, resulting in loss of the substation. When the transmission line was put back in service and the substation energized, only one of the four network primary feeders held. The other three locked out due to damage caused by the tornado.

Cable Failure Outages

The Newburgh network experienced 2 permanent outages in 2012 due to primary and secondary cable failures. A network contingency plan has been put in place and extensive inspections of the Newburgh Secondary Network underground system were completed in January, 2013. Specific upgrades and improvements were identified and completed in 2015 (see section 3.4.4.2).

In 2013, a secondary cable fault on the Kingston secondary network flashed over and damaged numerous other secondary cables as well as one of the primary circuits feeding the network. The network had to be dropped to cut the damaged secondary network cable in the clear in order to isolate the damaged 121 circuit to make repairs. All permanent repairs were completed immediately. Subsequent inspections of the Kingston network were performed and areas needing repair were prioritized. More of this is discussed in the following section.

The Poughkeepsie network experienced an outage in 2017. As a result of repairs being made on the PO Cable due to a Contractor dig-in, the circuit was de-energized and the Poughkeepsie Network was being fed by the PU and PK Cables. A secondary cable failure occurred between a manhole and pull box on Catharine Street. The secondary cable was above 2 primary feeders. The explosion from the secondary fault directly impacted the remaining primary feeders. The resulting fire from the explosion caused damage to the closest network transformer. Both remaining network feeders locked out resulting in an interruption to all network customers. Work was done to put the PO Cable back into service to restore the network, since it was not impacted by the fault. A capital budget project for 2018 was developed to replace the infrastructure and cables on Catharine St. Plans for future improvements to the Poughkeepsie network are discussed in the next section.

The Newburgh network experienced an outage in 2018 when the 4001 circuit (one of the three Newburgh network feeders) experienced a cable fault in a pull box on Broadway. The fault flashed over to the 407 circuit (another one of the three Newburgh network feeders), which was in close proximity in the pull box. This resulted in two of the three Newburgh network feeders locking out, leaving only the 404 circuit feeding the network. The 404 circuit was opened due to secondary network loading concerns, dropping the entire network. Emergency switching was performed to isolate the faulted sections of the circuits and restore affected customers, for a total outage duration of 5 hours, 9 minutes.

The Poughkeepsie network experienced a single outage in 2019. In December, smoke was found to be coming out of two adjacent network manholes. The workers on the scene were able to identify from the surface burned secondary conductor in both manholes, however, they were unable to fully determine the extent of the damage without entering each structure. To allow for safe access, all three primary cable feeds to the network needed to be de-energized, which resulted in an interruption for the entire Poughkeepsie Secondary Network, Saint Mary's Church, and the Verizon Building. There was no damage to the primary cables in either manhole. In addition to the burned secondary conductors, the workers identified several damaged conduits which required immediate replacement. Two of the primary cables were re-energized to restore the network, while the third cable feed remained out of service in order to facilitate repairs. 867 network customers experienced a 58 minute outage. A single customer experienced a 1 hour, 1 minute outage. The final customer to be restored experienced a 4 hour, 29 minute outage to facilitate repairs.

Despite the 10 network outages in the past 10 years, the reliability of the sub-transmission and secondary network systems is well above the system average reliability. Programs have been developed to address aging equipment and infrastructure. An analysis of the age and failure rate of each cable, as well as the age of the underground infrastructure was conducted to identify and prioritize replacements under these programs. This is a proactive measure to ensure that the existing level of reliability can be maintained. These programs are discussed in the next section.

3.4.4 Summary of Reliability Improvement, Infrastructure and Equipment Replacement Programs

In 2008, a 14.4kV Cable Rejuvenation Program was developed to address portions of the underground and overhead PILC primary feeders (sub-transmission feeders). Portions of these cables are over 60 years old and have experienced numerous failures due to cracks in the lead shield. Portions of the duct banks that these cables run through are in some cases even older and have been collapsing. A plan to replace TGRAL oil switches and oil fused cutouts, which are primarily associated with the 14.4kV system, was also developed. These switches are no longer serviceable and spare parts are no longer available.

The following is a list of programs that have been put in place to address sub-transmission and network infrastructure, and equipment replacement.

3.4.4.1 TGRAL Oil Switches and Oil Fused Cutouts

Periodic review of TGRAL switches and underground oil fused cutouts is performed. All TGRAL switches have been replaced or determined as no longer needed and removed from service. Recommendations to replace or retire oil fused cutouts are made if they are deemed inoperable. Capital funds have been budgeted for 2020 through 2025 to cover as needed oil switch replacements.

3.4.4.2 Underground Infrastructure and Secondary Network Cable Replacement

Prior to 2013, an increase in secondary cable failures had been identified. A plan to replace missing sections of secondary runs as well as secondary runs found to be in poor condition began in 2012. Approximately $1.4 million was spent between 2013 and 2017 to address secondary cable in all three networks. This included major upgrades to the infrastructure and cables in the Newburgh Network as a result of the 2012 cable failures. An additional $400,000 was spent in related conduit, manhole and pull box repairs in all three networks.

In 2014, underground infrastructure for the Taconic highway crossings were inspected and a scope of work or repairs were identified. In 2020, all other highway crossings will be identified and inspected. Between 2021 and 2025, capital funds have been budgeted to address underground highway crossings in need of repair.

Through the inspection program, secondary network infrastructure, cable and equipment in need of repair will be addressed. Between 2020 and 2025, capital funds are budgeted for this work, as well as for identified projects in Newburgh and Poughkeepsie. Secondary network portions of Market St. in Poughkeepsie will be rebuilt, as well as the north eastern portion of Broadway in Newburgh. Budgeted dollars were determined based on the average cost for secondary network repairs in the prior 5 years.

3.4.4.3 Poughkeepsie Network Primary Feeder PILC Cable Replacement

In 2008, a 5-year replacement program was developed to address the age and condition of the primary feeders to the Poughkeepsie Secondary Network, as well as the infrastructure. Approximately 3.6 circuit miles of mainline primary feeder cable was replaced by 2014. There are four (4) lateral branches remaining that are PILC cable. In 2019, the City of Poughkeepsie announced plans to repurpose the major road (Market Street) where these lateral branches reside. As a result, it was deemed cost effective to expedite the major infrastructure repairs along Market Street, prior to the City of Poughkeepsie repurposing this area. This infrastructure work is anticipated to be completed prior to the end of 2020. To allow for the replacement of the remaining PILC cables in future years, capital funds have been budgeted for 2021 and 2022 to replace these lateral branches with EPR rubber cable to match what has been installed in prior years.

3.4.4.4 14.4 kV Cable System Replacement

The Poughkeepsie 14.4 kV and Newburgh 14.4 kV area studies were performed to determine if the existing 14.4 kV cables (the majority of which are PILC) were still needed, and if so, to prioritize replacement based on failure rates and risk.

Poughkeepsie 14.4 kV Area Study – All of the Poughkeepsie 14.4 kV non-network PILC cables identified for retirement in the Poughkeepsie 14.4 kV Area Study have been retired. Retirement of the Maryland Avenue 4.16kV Substation was completed in 2019, eliminating the need for the MS cable.

Newburgh 14.4 kV Area Study – The B, F, R and WN cables emanate from West Balmville and feed the Montgomery Street Substation, which is a combination 13.2 kV - 4.16 kV substation that feeds the Newburgh Secondary Network. It was determined that the B, F, R cables could be retired and replaced with a single overhead circuit. This new overhead circuit would work with the WN cable to feed the Montgomery Street Substation and the Newburgh Network, provided that the WN is re-conductored to match the wire and cable of the new circuit.

The project to build the new circuit to replace the B, F and R cables has been divided into 5 phases. The majority of the circuit (approximately 2.9 miles) will be overhead construction. Approximately 0.8 miles will be underground cable, in part, utilizing existing, relatively new, underground infrastructure. New underground infrastructure is needed in front of the Montgomery Street Substation to accommodate the new cable, as well as the upgrades to the remaining WN cable PILC that currently runs under the Newburgh Free Library.

3.4.4.5 URD Cable Replacement and Repairs

Specific URD's have been identified in the Capital Budget as being in need of complete replacement due to numerous failures and loss of the primary neutral conductor. In addition to those identified repairs, Central Hudson is looking into working with IMCORP to test URD cables of specific vintages in order to proactively detect defects that may lead to failure. Three URD's were identified as potential locations to test and target repair work based on an analysis of 5 years of outage data and dollars per customer minute avoided. The scheduling of targeted repairs with no impact to customer service is preferred over reactive repairs to failures that cause customer outages. Central Hudson is reviewing the ability to utilize IMCORP's services to target repairs. In addition to reserving capital funds for potential IMCORP testing, additional funds have been budgeted for traditional cable replacements.

3.5 Distribution

This section discusses the distribution system inspection process as well as the plans and programs related to Central Hudson's overhead electrical equipment and structural equipment for voltages less than 69 kV. In addition, there is a section that focuses on Central Hudson's ongoing reliability analysis, reliability improvement and infrastructure upgrade programs.

3.5.1 Inspection Programs

As mandated by the NYS PSC Safety Standards Order 04-M-0159 and subsequent revisions, Central Hudson targets inspections on a minimum of 20% of company-owned facilities on an annual basis. The purpose of Central Hudson's facility inspection program is to visually evaluate equipment and verify that it is in safe, operational and reliable condition. This inspection program is ongoing and includes a reporting and documenting procedure that allows for any observed deficiencies to be recorded and prioritized for timely repair. Notable conditions found in the field as part of the inspections are categorized into specific areas relative to each facility type. Each condition finding is given a rating code that allows Central Hudson to prioritize any corrective action required.

Central Hudson uses a severity rating ranging from 1 to 6 as noted below:

Severity Rating	Description
1	Insignificant – No action needed
2	Very minor condition - No action needed at this time
3	Monitor for future action
4	Serious Condition – may cause a circuit outage or problem in the future
5	Critical Condition – likely to cause an interruption of service

6	Immediate Condition – Immediate threat to life, property, or will cause a circuit outage or problem

The following are examples of items which fall under severities 4-6:

Category	**Condition**	**Severity Value (or Range)**
Poles	Rotted	4
	Broken	5-6
	Leaning	4
	Washed Out	4
	Woodpecker Holes	3-5
	Evidence of Flashover	4
Conductor	Damaged Primary	5
	Damaged Secondary	4
	Damaged Neutral	4
	Slack Primary	5
	Slack Secondary	5
	Slack Neutral	5
	Broken Tie Wire	4
	Phase Wire off Pin	6
	Phase Wire on the Ground	5-6
	Insufficient Clearance	5-6
Trimming	Vines	4
	Needs Trimming	4
	Limb/Trees on Line	5-6
	Danger Trees	4
Hardware	Broken Guy	4
	Broken Cross Arm	5-6
	Broken Cross Arm Brace	4
	Broken Insulator	4
	Broken Cutout	5
	Broken/Blown Lightning Arrestor	4
	Rotten Cross Arm	4
	Rotten or Corroded Anchor	4

Central Hudson has continually identified the inspection process as an area for review and possible improvements. In 2012, Central Hudson began identifying 3rd party attachments on each pole as a part of the inspection process. The data is reviewed against our records to determine appropriate steps in response to unauthorized attachments. The increase in pole loading due to the unauthorized attachments not properly reviewed by Central Hudson has potentially resulted in installations that do not meet our design specifications and could contribute to pole failures during storm events. Central Hudson will continue to analyze this data and determine additional processes or programs that may be required to mitigate the impact of 3rd party attachments on pole loading that contributes to failure during storm events.

The above listed Central Hudson severity rating values correspond to the PSC Repair Priority Levels as follows:

Company Rating	PSC Rating
1	IV
2	IV
3	IV
4	III
5	II
6	I

Summary of Conditions Resulting from the Inspection Process

Year	**Priority Level / Repair Expected**		**Deficiencies Found (Total)**
2015	I	Within 1 week	32
	II	Within 1 year	264
	III	Within 3 years	5,988
	IV	N/A	5,028
2016	I	Within 1 week	21
	II	Within 1 year	164

	III	Within 3 years	4,148
	IV	N/A	2,636
2017	I	Within 1 week	7
	II	Within 1 year	263
	III	Within 3 years	3,924
	IV	N/A	4,902
2018	I	Within 1 week	18
	II	Within 1 year	280
	III	Within 3 years	8,412
	IV	N/A	5,545
2019	I	Within 1 week	7
	II	Within 1 year	192
	III	Within 3 years	6,064
	IV	N/A	6,337

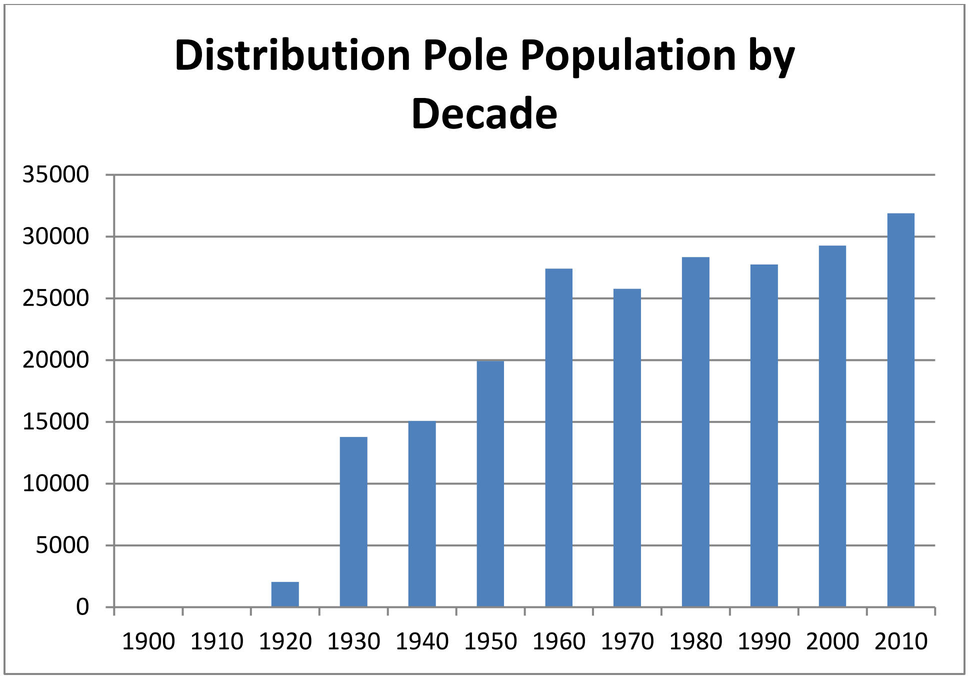
In addition, comprehensive thermal inspections of the three phase distribution system are completed on an annual basis.

3.5.2 Equipment

3.5.2.1 Wood Poles

Inventory
Central Hudson currently has approximately 221,312 distribution poles. With a few exceptions, theses distribution poles are composed of wood.

Age and Condition
The following chart depicts the age of Central Hudson's poles. The average age of the distribution pole plant is 40 years old.



Plans
As noted, Central Hudson has a 5-year inspection program to assess its distribution facilities, which provides a severity value in accordance with the PSC Safety Standards Order for the plant assessed ranging in value from I to IV with I needing immediate attention. As a result of this assessment program, Central Hudson replaced 3,523 poles in 2019, and approximately 2,000 poles are scheduled for replacement in 2020. In addition to the poles identified during the inspection process, there are additional poles that will be repaired or replaced throughout the year for reasons such as condition, third party attachments, relocation for road rebuilds, or as a part of larger capital projects. Central Hudson has seen a significant acceleration of distribution pole replacements based on the increased number of inspection findings. This trend is expected to continue based on the age distribution of our pole plant. As a result, Central Hudson has incorporated the impacts of this increase within the company's capital budget forecast.

3.5.2.2 Street Lights/Area Lights

Inventory
Central Hudson currently has approximately 42,972 streetlights and area lights on the distribution system.

Age and Condition
Central Hudson does not have age of these devices. However, they are visually inspected as part of the distribution circuit inspections program.

Plans
Based on reduced cost and improved energy efficiency, Central Hudson's Electric Tariff now includes LED-equivalent fixtures for all non-LED streetlight and area light options. For complete fixture failures, Central Hudson replaces non-LED with LED fixtures. However, the Company is still performing maintenance and repairs to non-LED streetlights and area lights such as lamps and photo eyes. Municipalities have the option to complete a mass replacement program to change all streetlight fixtures to LED, but must first pay for the stranded value of existing lights to be replaced. After early adoption by numerous municipalities to complete these mass replacements, requests have recently slowed. In 2019, less than 1,000 streetlights were mass replaced from non-LED to LED.

3.5.2.3 Pole Top Insulators

Inventory
Central Hudson currently does not have inventory of these devices.

Age and Condition
Central Hudson does not have age of these devices. However, they are visually inspected as part of the distribution circuit inspections program.

Plans
Porcelain insulators have a similar failure mechanism to that of porcelain cutouts (see Section 3.5.2.8 below), though the reliability impacts are significantly less. Porcelain insulator failures averaged approximately 0.95% of total System SAIFI between 2015 and 2019, compared to 1.6% for porcelain cutout failures over the same time period. Central Hudson will continue to inspect these devices with the Distribution Condition Assessment Program and at this time the need for a replacement program is not warranted. New installations are completed utilizing either polymer tie-top insulators or polymer vice-top insulators.

3.5.2.4 Wire (Primary and Secondary Overhead Conductor)

Inventory
The following chart depicts the inventory of wire by voltage class:

Conductor	Pole Miles of Line
34.5 kV Overhead	208
13.2 kV Single Phase	4,541
13.2 kV Multi Phase	2,373
5 kV and Under	45

Age and Condition
Age is not readily available for conductor.

Plans
Central Hudson has not had any systematic modes of failure based on wire type and as issues arise they are handled within the confines of the existing capital program. Three programs have been developed to replace conductor types that are linked to aging infrastructure.

Copper Wire Replacement
The transition from copper to aluminum overhead conductors occurred during World War II due to shortages in copper resources. The copper conductors of this vintage have lower thermal ratings which makes operational switching challenging. In addition, the pole plant on which the conductor resides is typically of advanced age and a failure risk. A Copper Wire Replacement program was developed in 2016 to phase out this antiquated infrastructure.

Open Wire Secondary Replacement
Because most storm damage in Central Hudson’s service territory is caused by trees, open wire secondary creates an increased risk of a phase to neutral contact which can result in outages to small groups of customers that require a relatively large amount of time to repair. In addition, a break in the neutral wire can cause the customer’s voltage to swing out of range and damage equipment. Finally, the use of open wire secondary stopped approximately 50 years ago, so it is another source of aging infrastructure. A program was created in 2013 to replace problematic locations where open wire secondary exists.

5 kV Aerial Cable Replacement
Much of the 5 kV aerial cable in the Central Hudson service territory dates back to the 1930s and is prone to failure. The cable has also been the cause of many voltage issues on the system. Additionally, the cable typically contains lead and asbestos which pose environmental concerns. Repairs on this cable can be difficult and lengthy.

A 5 kV aerial replacement program was created to mitigate the reliability, loading, environmental, and safety concerns associated with this cable. When this type of cable is replaced, the typical practice is to convert the customers over to 13.2 kV voltage class circuitry. This aids in Central Hudson's goal to move away from 5 kV operation to flatten the voltage profile, better enabling CVR and increasing hosting capacity of DERs.

Primary and secondary overhead conductors are continually assessed as part of Central Hudson’s inspection program.

3.5.2.5 Transformers

Inventory
Central Hudson currently has 85,003 overhead distribution transformers and step-down transformers on the system.

Age and Condition
The current average age of these facilities is 29 years. The overall condition of these assets is good. Newly purchased step-down transformers are equipped with Magnex breakers to limit the potential for thermal overload.

Plans
Step-down transformers limiting operational flexibility are evaluated for potential downstream voltage conversion or replacement with larger units through the regular capital budget program. Overloaded service transformers are evaluated for replacement with larger units or splitting of services.

Transformers are included in Central Hudson’s inspection cycle utilized to assess the condition of our distribution facilities. This plan will continue in the future.

3.5.2.6 Voltage Regulators

Inventory
Central Hudson currently has 642 voltage regulators installed on the distribution system not including substation regulators. Regulators installed in the substation are detailed in Section 3.3.2.1.9.

Age and Condition
The current average age of these facilities is approximately 12 years. The overall condition of these assets is good.

Plans
Regulators are used until the devices become inoperable (run to failure). They are then replaced as needed. Future plans call for the control panels to be retrofitted to allow for two way communication and control as a part of Distribution Automation described in Section 4. Retrofitting of controllers provides the added benefit of allowing the voltage regulator to operate in cogeneration mode to manage the back feed due to distributed energy resources.

3.5.2.7 Capacitors (Fixed and Switched)

Inventory
Central Hudson currently has approximately 2,621 distribution class overhead capacitor units installed at 803 locations.

Age and Condition
The current average age of these facilities is approximately 20 years. The overall condition of these assets is good. Capacitor banks are inspected annually by distribution engineering interns.

Plans
Central Hudson's target 115/69kV transmission system power factor is 0.96. In order to achieve this, distribution feeder capacitors are deployed such that summer peaking circuits achieve an on-peak power factor of approximately 0.98 to 0.99 and winter peaking circuits achieve an on-peak power factor of approximately 1.00. Each year Central Hudson reviews the power factor needs in each Operating District. Each Operating District submits recommendations to either install new switched capacitors or replace fixed capacitors with switched capacitors. Approximately 5-6 locations are chosen each year system-wide. Additionally, through the Distribution Automation program described in Section 4, the quantity of fixed and switched capacitors banks on each circuit is being fine-tuned to allow for Volt-VAr Optimization through the Distribution Management System that is under development. This will enable the voltage profile on the system to be flattened and then reduced to optimize customer energy usage.

3.5.2.8 Cutouts

Inventory
Central Hudson currently has 49,256 distribution cutouts on the primary distribution system.

Age and Condition
The age of the cutouts is not readily available. Porcelain style cutouts have an approximate failure rate of 0.3% per year on the Central Hudson system and a change out program was developed that targeted 3 phase locations that would impact 500 customers or more due to a failed cutout. This program has been completed.

Plans
On an ongoing basis, if one or more phases experience a failure of a cutout, the cutouts on the other phases are replaced during the outage. Cutouts are included in Central Hudson's inspection cycle utilized to

assess the condition of our distribution facilities. This plan will continue in the future.

In addition, Central Hudson will continue to monitor the reliability impact of porcelain cutouts to determine if additional replacement programs are cost effective. New installations are completed with polymer cutouts.

3.5.2.9 Fuses (overhead primary)

Inventory
Central Hudson has 41,329 fuses protecting our overhead facilities.

Age and Condition
Age of these devices is unknown and they typically do not fail due to age.

Plans
Fuses are added to the system in order to help sectionalize outages during fault conditions. This minimizes the number of customers interrupted for an interruption in addition to decreasing the patrol area for the trouble crew.

3.5.2.10 Reclosers / Sectionalizers

Inventory
Central Hudson currently has approximately 745 distribution reclosers consisting of hydraulic reclosers (Type WE, L, V4L and D), electronic reclosers and FuseSavers. There are also 27 Type GV, CRS and ScadaMate Sectionalizers.

Age and Condition
The age range for most hydraulic reclosers is between 0 and 12 years and the average age range for electronic reclosers is 0 to 10 years. The overall condition of these assets is good.

Plans
Central Hudson currently replaces approximately 6 three-phase hydraulic recloser installations (18 reclosers) with electronic reclosers each year. These devices have improved outage prioritization and notify key personnel of momentary and permanent interruptions. The electronic reclosers have the ability to record fault data to allow for troubleshooting along with more flexible protection schemes. These devices will also allow for 10,000 operations before maintenance is needed. Additional reclosers are replaced or added to the system as a part of the Distribution Automation program described in Section 4 as well as installed for

monitoring, control, and protection purposes for DER systems 500kW and greater.

3.5.2.11 Automatic Load Transfer Switches (ALTs)

Inventory
Central Hudson currently has 90 individual ScadaMate Switches that operate as 40 teams and 4 sectionalizers. Also, Central Hudson has 7 padmount ALTs. In addition, Central Hudson has configured 42 additional Electronic Reclosers into 21 teams. These automated switches transfer pockets of load to alternate feeds for loss of primary feed. They have contributed to system SAIFI improvements by saving an average of 25,623 customers per year from outages over the past five years.

Age and Condition
The maximum age of the ScadaMate switches is approximately 18 years and their condition is considered good. The average age of the Electronic Reclosers within ALT teams is 6 years and their condition is considered good.

Plans
The default device utilized to create new ALT teams is now the electronic recloser. The electronic recloser ALT installations have the added value of protection in addition to providing for load transfer.

3.5.3 Reliability Performance Data

Reliability performance on the distribution system at Central Hudson is primarily measured utilizing the SAIFI (frequency) and CAIDI (duration) indices. These standard IEEE indices are defined as follows:

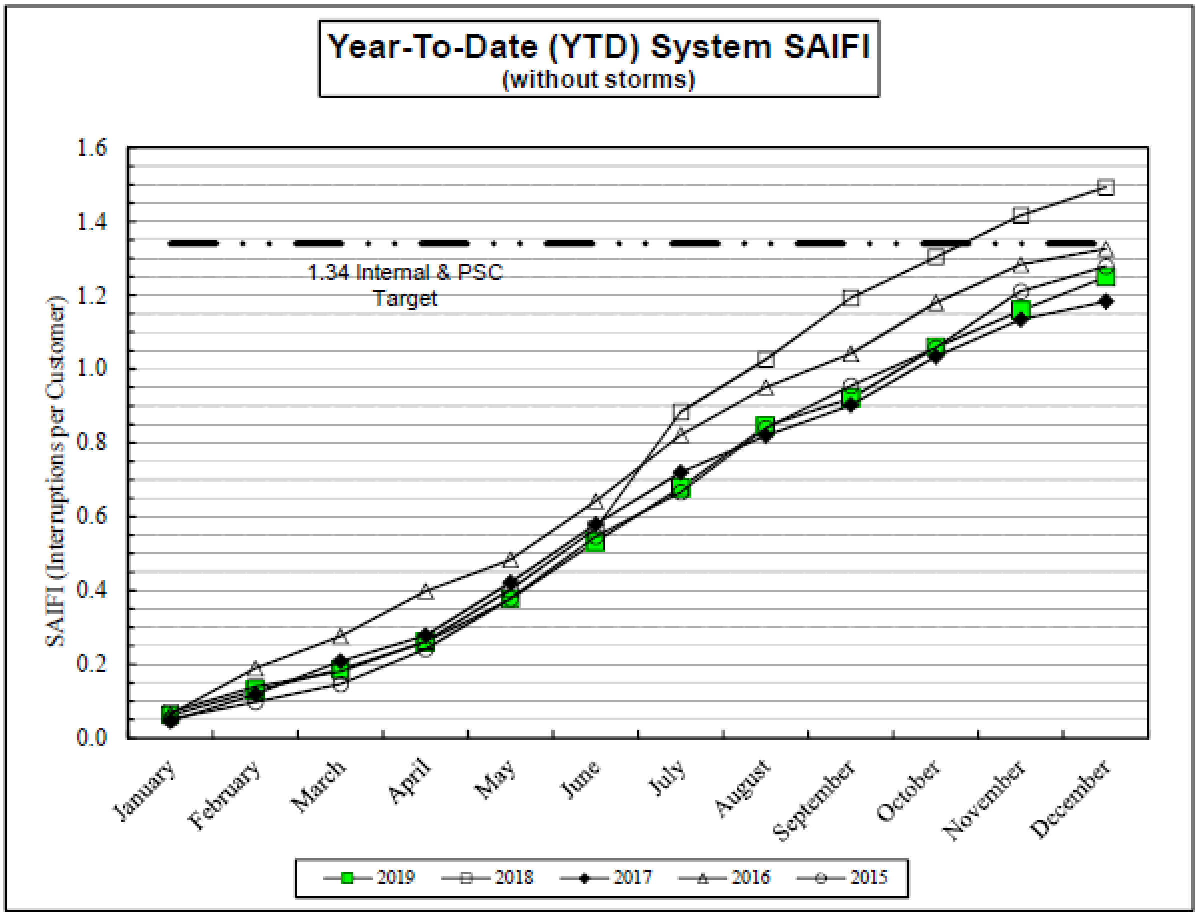
SAIFI = System Average Interruption Frequency Index =

$$\frac{\text{Total \# of Customers Interrupted}}{\text{Total \# of Customers Served}}$$

CAIDI = Customer Average Interruption Duration Index =

$$\frac{\text{Sum of Customer Interruption Duration}}{\text{Total \# of Customers Interrupted}}$$

The Public Service Commission monitors these indices and can levy fines if SAIFI or CAIDI exceed predetermined thresholds (for 2019, the non-storm SAIFI target was 1.34 and the CAIDI non-storm target was 2.50).



Non-storm system SAIFI averaged 1.31 over the five-year period from 2015 through 2019. The highest SAIFI over this period occurred in 2018 (1.49) and the lowest occurred in 2017 at 1.18. 2019 yielded a SAIFI value of 1.25, or 5% below the five-year historical average.

3.5.4 Additional Reliability Improvement and Infrastructure Programs

The Electric Distribution and Standards organization is responsible for analyzing reliability and recommending improvement opportunities. The infrastructure assessment and replacement program and associated technology upgrades described in Section 3.5.2 are major contributors to reliability improvement. There are also several programs which are not infrastructure-related or that fall outside of the scope of the more general infrastructure replacements that are described here.

3.5.4.1 Vegetation Management Program

Trees and tree branches falling on distribution lines are consistently the number one cause of power outages for Central Hudson customers. The best way to defend against these potential hazards is with a dedicated and thorough program of tree clearing and trimming performed on a regular basis. Central Hudson's program is carefully designed to reduce the incidents of power outages due to tree damage while also protecting the natural beauty of the Hudson Valley.

In 2016, Central Hudson identified and initiated processes to help improve tree-related outage performance. This included collecting and reviewing tree-related data after breaker lockouts, further reviewing trends related to tree species (particularly ash trees), as well as establishing an effective process for identifying and removing danger trees.

Also in 2016, Central Hudson engaged a consultant to assess Central Hudson's line clearance program. Some of the consultant's recommendations included: obtaining increased funding to return to a four-year trimming schedule, creating a separate schedule for circuits affected by the residency of protected bat species, and obtaining funding for a widespread removal of danger trees -- the majority of which are ash trees -- along three-phase circuitry in order to combat tree mortality caused by the Emerald Ash Borer and other tree diseases. As part of the Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service in Case 17-E-0459, Central Hudson requested incremental funding to address the recommendations from the consultant in order to improve the system reliability. This incremental funding request sought to address the following distribution vegetation management items: routine trimming backlog, general danger tree removals, Emerald Ash Borer danger tree removals, off-cycle spot trimming and completion of the original enhanced line clearance areas. Incremental funding was partially granted.

Prior to implementation of the new rates, on May 5, 2017, Central Hudson petitioned the Public Service Commission ("Commission") for deferral accounting authority incremental funding for additional transmission line clearance and danger tree removal funding. The Commission ruled on this petition in Case 17-E-0250 on September 28, 2017, granting, in part, deferral accounting and recovery for this purpose. The Commission approved up to $2 million for the removal of danger trees along 262 miles of three-phase circuitry on the twelve highest-priority circuits, which was substantially completed in 2018 with some work carrying over into 2019.

As part of Central Hudson's most recent rate case filing, Case 17-E-0459 filed June 29, 2017, Central Hudson requested significant additional funding for distribution vegetation management (a total of approximately $26M annual funding). While only a portion of the additional dollars requested was approved (a total of approximately $20M annual funding), Central Hudson has already seen a positive impact to tree-related SAIFI as a result of the increased funding. Tree-related SAIFI showed a significant improvement in 2019, coming in at 9% lower compared to 2018 and 8% lower than the 5-year average. Distribution Engineering continues to work in conjunction with Line Clearance to identify the worst performing circuits that should be targeted for danger tree removal. To date, more than 30 circuits have been identified and addressed. On the highest-priority circuits where danger trees were removed in 2018 and 2019, a preliminary analysis indicates a 17% non-storm SAIFI reduction for tree contact outages, on average, compared to three-year historical averages for those circuits. It will take several additional years to fully realize the effect on tree-related SAIFI as a result of the additional funding received.

3.5.4.2 3X and Customers Experiencing Multiple Interruptions (CEMI) Outages

The 3X and CEMI programs allow engineers to focus in on areas of the distribution system that experience multiple outages per year that are not always mitigated under larger scale capital improvement programs.

The 3X Report, which is completed on a monthly basis, is designed to identify those protective devices that have operated at least three times within a rolling 12-month period. Once the initial report is compiled, each Electric Operating Engineer goes through the listed devices for their district to justify the operations and/or suggest a plan of action. This is particularly valuable in capturing non-capital improvements, such as the installation of squirrel guards and spot tree trimming that can result in dramatic reductions in the number of outages in these load pockets.

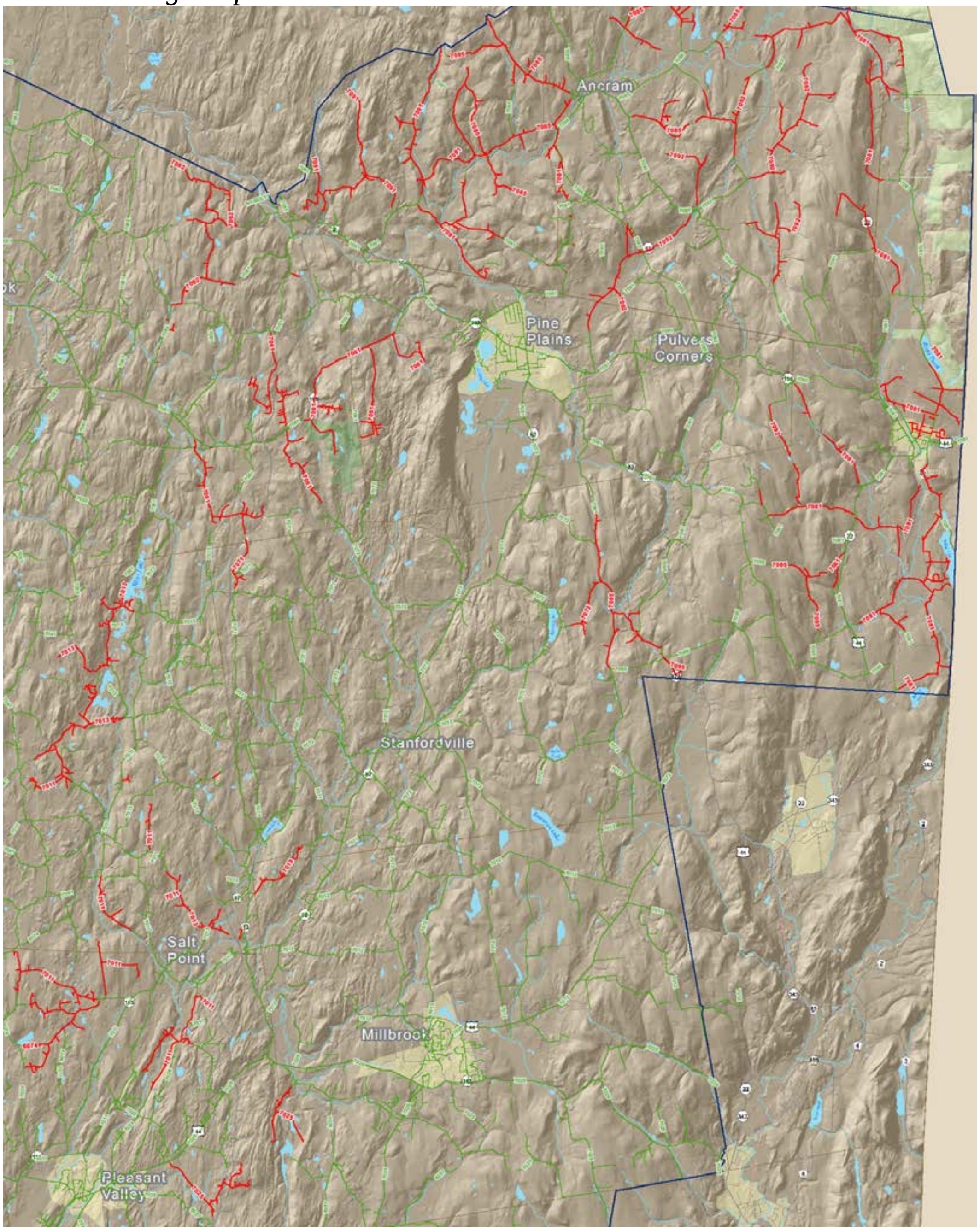
In addition to the 3X Report, the 10X Report was developed in 2008 as a way to identify customers on Central Hudson’s system that experience ten or more outages within a calendar year. The 10X Report provides Central Hudson with an opportunity to address areas that normally would not justify Capital Budget Projects, since they typically have a $/COA above the normal range for reliability projects. Over time, this has evolved to a CEMI program where lower numbers of interruptions are considered that are still well above average (e.g. 8X, 9X). In some cases, Capital Budget Projects are needed to address underlying infrastructure problems.

3.5.4.3 4800V Delta Circuitry Upgrades

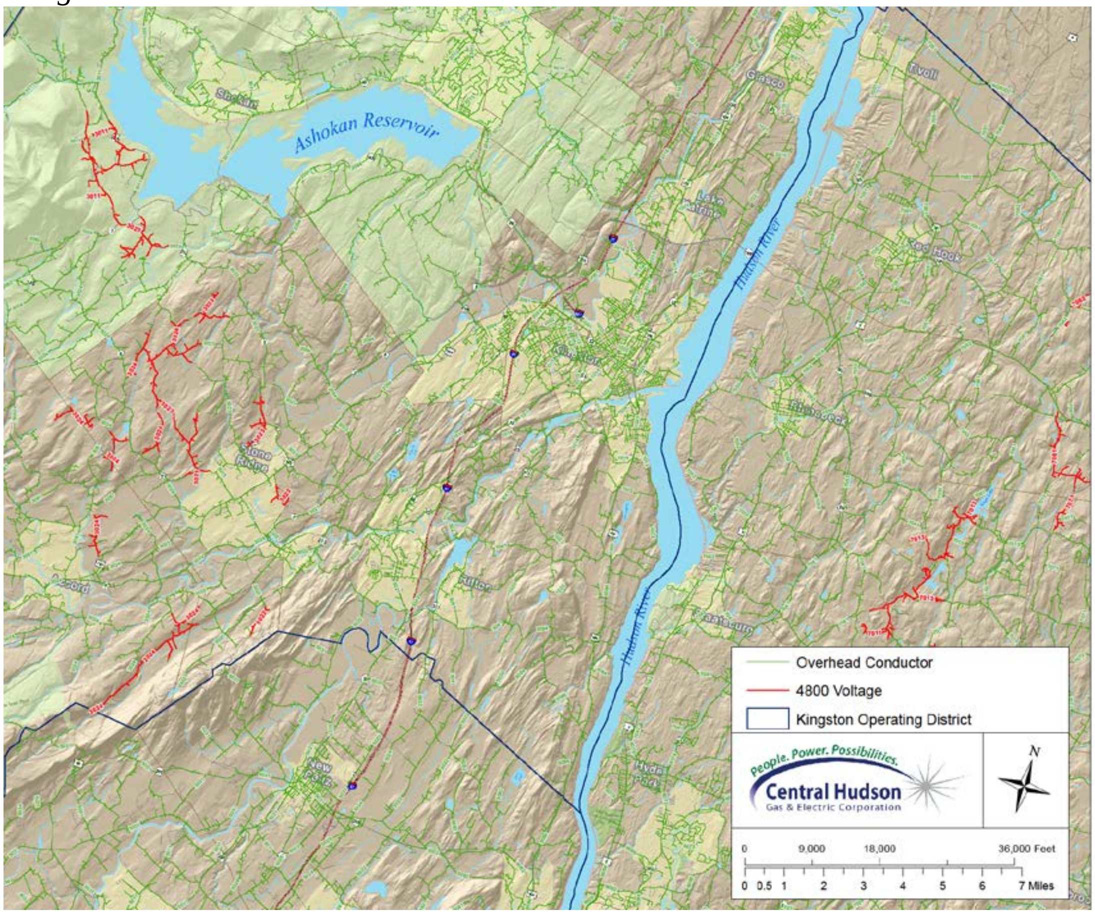
Central Hudson has approximately 262 miles of 4800V delta circuitry remaining on its distribution system. The Company abandoned the practice of installing 4800V circuitry in the 1940s, so much of the infrastructure is aged. In addition, capacity and operational flexibility is limited by the low voltage circuitry as well as by step-down transformers, and delta circuitry is more prone to faults that do not trip protective devices. Hosting capacity for DERs is also limited by this low voltage circuitry.

Approximately three-quarters of this circuitry is located in the Northeast Dutchess County area, and the Northeast Dutchess Area Study (E.P. #2012-06) recommended that a program be developed to replace this infrastructure. The following maps show the 4800V delta circuitry in red for the Poughkeepsie, Kingston, and Fishkill districts:

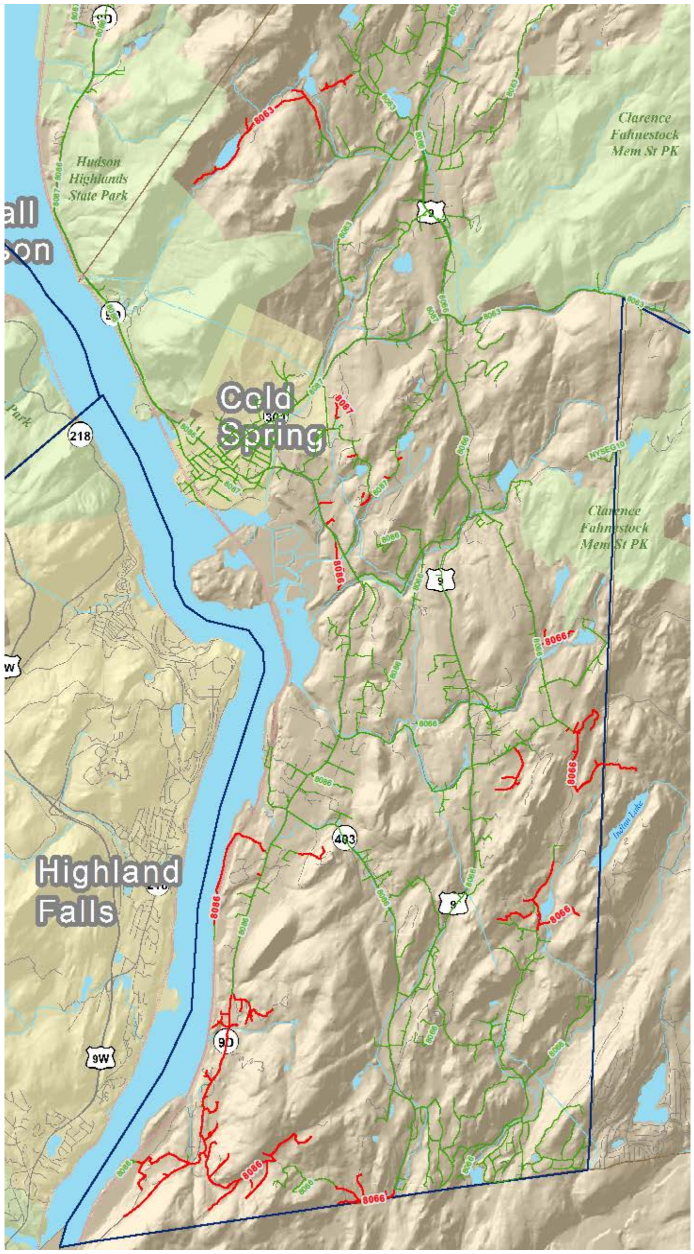
Northern Poughkeepsie District:



Kingston District:



Fishkill District:



A long term replacement program was developed beginning in 2016 to address the 4800V delta infrastructure. Replacement is prioritized based on other ancillary benefits, particularly reliability and operational flexibility, along with improved DER hosting capacity.

3.5.4.4 Worst Circuit Reports

Each year, Central Hudson analyzes the worst 5% of circuits based on 5-year weighted average SAIFI, and the worst 5% of circuits based on 5-year weighted average SAIDI. The weights are applied to maintain a stronger emphasis on new problems while still addressing recurring issues, without emphasizing special one-time events. The weights applied are as follows: previous year (50%), two years ago (25%), three years ago (15%), four years ago (5%), and five years ago (5%).

The circuits on the list are reviewed in detail to determine if any action is required in addition to the capital program. For example, spot trimming or installation of squirrel guards may be required.

3.5.4.5 Distribution Automation

The Distribution Grid Modernization program is described in detail in Section 4.

3.5.5 Summary of Reliability Improvement and Infrastructure Programs

As described within this section, Central Hudson has “reliability” centered culture and our reliability improvement programs stem from a plethora of areas that are balanced and integrated into the Electric System Plan.

3.6 Storm Hardening Techniques

Central Hudson has historically maintained a core focus on customer reliability. With this focus, Central Hudson has developed and implemented a number of programs aimed at improving reliability that date back to the early 2000s. With the increase in the number of recent major storms and cases of extreme weather events, there has been a heightened attention on storm hardening and grid resiliency. Central Hudson has ongoing programs as well as new initiatives that fall under the category of storm hardening. This section provides documentation for the various forms of storm hardening and/or grid resiliency Central Hudson utilizes in its current construction and maintenance practices.

It should be noted that any type of T&D construction is vulnerable to outages under adverse conditions regardless of construction type. Overhead systems are particularly vulnerable to weather-related events such as high winds, rain and lightning. These events commonly cause structural failure of trees which may fall on the distribution lines from outside of the right-of-way. Underground systems are vulnerable to dig-ins and flooding conditions. Both types of construction have advantages and disadvantages, and choosing the appropriate construction type should be done based on good engineering judgment, reliability analysis and economics.

Since weather-related events have the most severe impact on the distribution system, this section focuses on the storm hardening techniques specific to that system. The various components of Central Hudson’s operating practices for the distribution system are broken down into the following categories:

(1) Design/Construction
(2) Enhanced Reliability Program & Distribution Automation
(3) Storm Circuit Hardening
(4) Maintenance
(5) Emergency Response & Repair
(6) Weather Prediction Tools

Each of these areas is reviewed below along with associated storm hardening practices.

3.6.1 Design/Construction

Central Hudson adheres to the NESC for its construction practices and has historically designed its distribution system to Grade C for strength and loading. In 2004, we began to shift to a Grade B design with the transition of our prior specification of standard distribution pole from a class 4 to a class 2 rating. In 2008, this became the standard installation practice. This transition was made due to the capability of the larger class poles to handle larger loads and the potential for a longer life. In addition, span lengths were shortened to further reduce pole loading and limit the effects of galloping conductors under fault conditions.

Central Hudson has also been testing and evaluating the use of steel, composite, concrete and raked poles for various reasons. These poles have been installed in locations where there is inadequate clearance for guying or where the need for a lighter weight pole is required due to terrain or access. All non-wood poles are being evaluated against wood poles for both short term (ease of installation) and long term performance (strength retention, resistance to external damage, etc.). It is felt that in some cases these type poles may also withstand the elements better than their wood counterparts. As we obtain more data on these new structures at the distribution level we may identify specific areas within our service territory that could benefit from this type of construction.

3.6.2 Enhanced Reliability Program and Distribution Automation

Central Hudson embarked on its enhanced reliability program in the early 2000s, identifying and implementing a number of programs that would have a positive impact on reliability. All of the programs discussed below began in 2002 and the individual circuit projects were ranked and prioritized utilizing a $/COA methodology. Since the programs' inception, they have been refined to incorporate newer technologies and modern practices as appropriate, and Central Hudson's plans continue to evolve. Many of these programs have become a part of normal maintenance and construction practices, as described in other sections of this document. The following is an outline of these programs:

- **Enhanced Line Clearance**
  Initially, a program was developed to trim each circuit's first zone of protection with an Enhanced Line Clearance specification to limit tree interruptions along the three phase backbones of Central Hudson's distribution circuitry. Since the onset of that program, Central Hudson has substantially modified its routine trimming practices for all three phase mainlines as well as laterals. This program has had a direct correlation to the improvement in system SAIFI for interruptions caused by trees. See the "Vegetation Management" section for additional information.

- **Relocation of off-road facilities to on-road**
  The relocation of off-road distribution circuitry to on-road was also developed as a program to update aged infrastructure that ran cross-lot throughout Central Hudson's service territory. This resulted in a reduction of vegetation-related interruptions as well as a decrease in the duration of interruptions due to the ability to more quickly identify the interruption cause and make repairs utilizing on-road equipment. A secondary benefit has been significant cost reduction in maintenance trimming for locations where circuitry has been moved on-road.

  Today, relocation of off-road facilities continues to be a key component in the reliability improvement portfolio of capital budget projects. Whenever practical and cost-effective, synergies are realized to align this program with the five-year distribution inspection program to identify and relocate facilities on-road where multiple poles are also identified as rotten. Recently, there has been difficulty in obtaining necessary easements to perform these relocations.

- **Establishing three-phase ties with neighboring circuits**
  Efforts have been made to develop additional tie points between circuits throughout Central Hudson's system to allow for better maintenance and emergency planning. As a part of the Grid Modernization program, Central Hudson continues to add stronger distribution circuit ties to improve resiliency during storms and simultaneously replace aging infrastructure.

- **Enhanced Lightning Protection**
  Areas prone to lightning were identified and additional lightning arrestors were added every quarter mile to minimize the effects of lightning strikes. This practice has become part of Central Hudson's standards for new and rebuilt construction.

- **Distribution Automation**
  Central Hudson commenced the Distribution Automation program in 2002 as a part of the Enhanced Reliability program. Central Hudson continues to shape this program as new technology becomes available. While there are many aspects of Distribution Automation described in detail in Section 4, this

section focuses on those components which are currently incorporated into our strategy and that directly contribute to grid resiliency.

- **Installation of Automatic Load Transfer Switches**
  The installation of ALTs also began in the early 2000s to improve reliability of load pockets with nearby alternate sources. With this program, Central Hudson has installed over 63 ALT teams and has seen a cumulative non-storm SAIFI improvement of 1.391 and a SAIFI improvement of 1.731 including storms through December 2019. At times, successful ALT operations have reduced the number of customers affected during weather-events, preventing Central Hudson from coding those events as storm.

- **Recloser Program**
  Central Hudson began an aggressive program to install hydraulic reclosers as the first fuse points on most of its distribution feeders in 2002. As most outages on a distribution system are transient in nature, this was done to improve system SAIFI. In 2008, Central Hudson transitioned to the installation of electronic reclosers which added additional functionality and real time communication of operations and maintenance requirements. In addition, the Operating Engineers have been able to correlate recloser operations with cases of downstream fuse operations. By increasing the fuse sizes and the speed of the recloser fault clearing curves where possible, the reclosers are able to clear transient faults prior to the fuse operations preventing permanent outages.

  In 2010, Central Hudson began to leverage the communications capabilities of electronic reclosers to also perform automatic load transfer functionality at a 22% lower capital cost compared to the previous technology and with protection integrated into the device.

  Hydraulic reclosers continue to be replaced with electronic reclosers on a case-by-case basis with the roll-out of Distribution Automation as part of Central Hudson's Grid Modernization program and as the distribution system evolves to include more integrated DER.

- **Micro-Grid Technology**
  In 2010, Central Hudson completed an R&D project with NYSERDA funding to install a micro-grid in one of the remote areas of the service territory. Frost Valley has historically had poor reliability and the construction of additional distribution feeders utilizing conventional distribution improvements for the limited load in this area was determined to be cost-prohibitive. The installation of a micro-grid diesel generator near the load pocket was a viable solution to restore service to this area for the loss of the mainline supplying these customers. For the loss of the preferred mainline distribution feeder, these customers are transferred to the generator as the alternate source of power. Since going into service, this scheme has operated successfully 42

times during major and minor storms, beginning with the Twin Peaks storm in February 2010. Central Hudson is evaluating additional locations where the installation of a micro-grid may be a cost-effective solution to improving reliability and providing storm hardening.

Central Hudson is currently working toward a similar model in the Four Corners area of East Fishkill using a natural gas-fired turbine along with battery storage. The Four Corners Microgrid project is part of a 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. The Phase 1 Engineering Design was submitted to the DHS on August 14, 2018. This design included 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. The project will include optionality to use the BESS for other services (i.e., demand reduction, frequency regulation) during parallel operation.

The Phase 1 design was approved by DHS, and on February 15, 2019, Central Hudson received approval from DHS to proceed with Phase II, project construction. In February 2020, Central Hudson issued an RFP for the completion of Phase II permitting and construction work. Bids were received and Central Hudson has engaged with one of the bidders to perform preliminary work based on the proposal. The project is currently scheduled for a completion date of February 2022.

3.6.3 Storm Circuit Hardening

In 2019, in response to the NY State Public Service Commission's Order Instituting Proceeding to Show Cause issued April 18, 2019 in Case 19-E-0109, ("Storm Order"), Central Hudson filed an actionable plan detailing future storm hardening measures. The plan included two major components: a vegetation management (expense) component and a capital investment component. A significant portion of the plan proposed performing circuit hardening within the mainline zones of the top 25 Worst Performing Circuits as determined by a metric incorporating storm (Code 1) performance. The circuit hardening includes an increased focus on vegetation management and a review and replacement of distribution equipment to bring circuits up to current construction standards. These efforts are focused on reducing outage frequency and duration during major weather events/Code 1 storms. Central Hudson completed a pilot of the circuit hardening program in 2020 to improve SAIFI on the 3012 circuit. Fed by the Woodstock Substation near the edge of the service territory, the 3012 circuit had historically been susceptible to interruptions caused by large danger trees and infrastructure not adhering to current construction standards. As this project was completed in Q1 2020, more time will be needed to fully realize the reliability impact on this circuit.

3.6.4 Maintenance

Vegetation Management
Central Hudson maintains a four-year trimming cycle for mainline and lateral distribution lines that is consistent with industry best practices. In March 2007, Central Hudson implemented new tree-related specifications to clear as much foliage from ground to sky as feasible. See Section 3.5.4.1 for additional efforts to improve vegetation management.

Damage to vegetation caused the Emerald Ash Borer has become a problem in recent years. As stated previously in section 3.5.4.1, Central Hudson requested significant additional funding for distribution vegetation management (a total of approximately $26M annual funding). While only a portion of the additional dollars requested was approved (a total of approximately $20M annual funding), Central Hudson has already seen a positive impact to tree-related SAIFI as a result of the increased funding. Tree-related SAIFI showed a significant improvement in 2019, coming in at 9% lower compared to 2018 and 8% lower than the 5-year average. Distribution Engineering continues to work in conjunction with Line Clearance to identify the worst performing circuits that should be targeted for danger tree removal.

3.6.5 Emergency Response and Repair

Comprehensive emergency plans by utilities minimize the duration of weather-related outages and ensure that all key stakeholders remain informed of the utility's actions before and during the event. Central Hudson has a complete Electric Emergency Plan that can be expanded to meet the requirements of any situation. The plan is reviewed and updated on an annual basis. Central Hudson conducts annual training and storm drills to ensure that modifications to the plan are effective and to ensure that employees understand their responsibilities during a major event.

3.6.6 Weather Prediction Tools

Central Hudson commenced work with FleetWeather on a storm prediction model in 2008. FleetWeather delivered several preliminary reports based on correlating weather data with historical outages. The study also determined that the weather data available in the Hudson Valley region was not sufficient to provide the data for a good storm prediction model, and recommended the installation of 24 weather stations. The installation of these weather stations was completed in 2012 and provides another source of weather data for the Central Hudson service territory.

3.6.7 Future Plans

In 2019, in response to the NY State Public Service Commission's Order Instituting Proceeding to Show Cause issued April 18, 2019 in Case 19-E-0109, ("Storm Order"), Central Hudson filed an actionable plan detailing future storm hardening measures. The plan included two major components: a vegetation management (expense) component and a capital investment component. A significant portion of the plan proposes performing circuit hardening within the mainline zones of the top 25 Worst Performing Circuits as determined by a metric incorporating storm (Code 1) performance. The circuit hardening includes an increased focus on vegetation management and a review and replacement of distribution equipment to bring circuits up to current construction standards. In addition to hardening mainline zones, this plan also includes a focus on lateral line rebuilds in remote areas and/or the edges of Central Hudson's service territory, along with incremental DA efforts to reconductor additional portions of circuitry to create strong distribution ties for additional automation. These efforts are focused on reducing outage frequency and duration during major weather events/Code 1 storms. There is no funding for this program in Central Hudson's current rate settlement agreement. The funding for this plan will be requested as part of the Company's next rate plan. Once approved, Central Hudson will initiate this program.

3.6.8 Summary

Central Hudson has many operating practices, procedures, and programs in place to improve grid resiliency and perform storm hardening. However, Central Hudson continuously seeks to improve its processes and investigate innovations to mitigate the impact of weather events. Central Hudson is committed to performing further storm hardening via programs that target areas with aging infrastructure and poor reliability using a data-driven approach.

4. Distribution Smart Grid

4.1 Background

Central Hudson's Grid Modernization Program is comprised of the six major components listed below. Distribution Automation, Distribution Management System, and Network Communications Strategy are discussed further in this section.

- Distribution Automation (DA) – automated devices and distribution infrastructure (poles and wires)
- ESRI System Model Geographic Information System (GIS) - provides a single consolidated mapping and visualization system
- Distribution Management System (DMS) – the centralized software "brains"

- Distribution System Operations (DSO) – the organization responsible for monitoring and controlling the electric distribution system through the use of the DMS
- Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS.

- Substation Metering Infrastructure – Substation feeder metering upgrades required for accurate ADMS power flow calculations.

Central Hudson began implementing this centralized Grid Modernization Program over the past five years. This program aims to reduce customer bill pressure, improve system safety and efficiency, and improve customer reliability.

Approximately 800 Intelligent Electronic Devices (IED; e.g. electronic reclosers, switched capacitors, and voltage regulating devices) and sensors are being installed through Distribution Automation and other programs along with associated Network Strategy communication equipment in order to provide real time data to the DMS. This will allow the system to become a centralized decision maker based on real time system conditions.

Please see the Distribution System Implementation Plan (DSIP), Sections III Integrated Planning and V Grid Operations, filed on June 30, 2020 for additional information.

4.2 Long Range Plan (2020-2025)

The Grid Modernization Program has made significant progress since its inauguration. The following items summarize the current progress of the program:

Distribution Automation

- Field installations of DA devices have been completed in the Fishkill area (Phase I and II).
- Field installations of DA devices have been completed in the Newburgh area (Phase I and II).
- A majority of the Poughkeepsie DA devices will be installed in 2020.
- A majority of the Catskill DA devices will be installed in 2020.
- A majority of the Kingston DA devices will be installed in 2021.

Distribution Management System

- The DMS Factory Acceptance Testing was completed in 2016.
- The DMS Site Acceptance Testing was completed in 2017.
- The DMS ‘Go-Live’ milestone was reached in 2017.
- The final commissioning of the DMS system was completed in 2018.
- Construction of the initial Distribution System Operations Control was completed in 2018.

Network Communications Strategy

- A majority of the Tier 2 network has been completed in the Fishkill district.
- A majority of the Tier 2 network has been completed in the Newburgh district.
- A majority of the Poughkeepsie Tier 2 network will be completed in 2020.
- A majority of the Catskill Tier 2 network will be completed in 2020.
- A majority of the Kingston Tier 2 network will be completed in 2021.

OMS/Control Center Implementation

- The Outage Management System (OMS) features of the DMS will be implemented and the beginning of the transition away from the legacy OMS is expected to take place in 2022.
- Construction for the new Primary Control Center for Transmission and Distribution System Operations is expected to start in 2022. Once complete, the Distribution System Operations organization is expected to be fully staffed.

5. Long Term System Load Forecast

5.1 Introduction

The upgrade of facilities or the construction of new facilities may be driven by regulatory compliance, aging infrastructure, or load growth. This section describes the load growth scenarios that assist Central Hudson in identifying areas that may require further study. As described in more detail in Section 5.3, Central Hudson is transitioning to a probabilistic forecasting approach.

For this probabilistic approach, Central Hudson's consultant, Demand Side Analytics, performed a historic analysis of substation growth patterns as well as a probabilistic forecast of Central Hudson's distribution substations using hourly load data from 2014 through 2019.

The historic load patterns were estimated using econometric models designed to disentangle year by year growth rates from differences in weather patterns, day of week effects, and seasonality. The forecasts utilized *Monte-Carlo* simulations to predict potential load growth based on the historic analysis.

5.2 Description of Load Groups

Central Hudson's distribution substations have been categorized into 10 different load groups, as follows:

#	Name	Substations	#	Name	Substations
1	Northwest	Coxsackie Freehold Lawrenceville North Catskill New Baltimore South Cairo Westerlo	6	Northeastern Dutchess	East Park Milan Rhinebeck Staatsburg Millerton Pulvers Corners Smithfield Stanfordville Tinkertown Hibernia
2	Kingston - Saugerties	Boulevard Cement Companies East Kingston Hurley Avenue Lincoln Park Saugerties Woodstock	7	Poughkeepsie	Todd Hill Inwood Avenue Manchester Reynolds Hill Spackenkill
3	Ellenville	High Falls Honk Falls Kerhonkson Clinton Avenue Greenfield Road Grimley Road Neversink Sturgeon Pool	8	Fishkill	Knapps Corners Myers Corners Sand Dock Tr. 4 Trap Rock North Chelsea Fishkill Plains Forgebrook Merritt Park Shenandoah Tr. 7 Tioronda
4	Modena	Galeville Highland Modena Ohioville	9	Large Customer-Poughkeepsie	Barnegat Sand Dock (not Tr. 4)
5	Newburgh	Coldenham East Walden Maybrook Montgomery Bethlehem Road Marlboro Union Avenue West Balmville	10	Large Customer-Fishkill	Shenandoah (not Tr.7) Wiccopee
Note: Transmission System areas may include substations from only one load group or may include portions of several load groups.					

These groupings were selected largely based on the ability to transfer load among the various substations in a group. By grouping the distribution substations this way, changes in individual substation loadings due to load transfers could be excluded from any calculated growth rate since the load still would be supplied from a substation within the group.

5.3 Substation Loading Forecast Spreadsheet

The following table is used as a screening tool for the Distribution Planning department to identify areas that may become deficient and require System Planning Studies; this screening tool, by itself, is not used to determine the need for a reinforcement. The individual substation growth rates are taken from the historic load pattern analysis performed by Demand Side Analytics. As indicated, Central Hudson has transitioned to probabilistic forecasting techniques. The table below utilizes a deterministic methodology and is utilized as high level screening tool/reference. Where hourly data was not available for a specific substation, the results of analyses for the transmission area where the substation is located were utilized.

	Substation	Type	MVA Rating		Growth Rate	MVA 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Northwest Load Group																				
1	Coxsackie	13.2 kV	16.4		2.80%	13.9	87.4%	89.8%	92.3%	94.9%	97.6%	100.3%	103.1%	106.0%	108.9%	112.0%	115.1%	118.4%	121.7%	125.1%	128.6%
1	Freehold	13.2 kV	15.78		3.50%	8.4	55.1%	57.0%	59.0%	61.1%	63.2%	65.4%	67.7%	70.1%	72.5%	75.1%	77.7%	80.4%	83.3%	86.2%	89.2%
1	Hunter	13.2 kV	16.065	F	-5.20%	1.7	9.8%	9.3%	8.8%	8.3%	7.9%	7.5%	7.1%	6.7%	6.4%	6.0%	5.7%	5.4%	5.2%	4.9%	4.6%
1	Lawrenceville	34.5 kV	15.036		-4.50%	4.2	26.6%	25.4%	24.3%	23.2%	22.2%	21.2%	20.2%	19.3%	18.4%	17.6%	16.8%	16.1%	15.3%	14.6%	14.0%
1	New Baltimore	13.2 kV	25.8		5.60%	11.0	44.9%	47.4%	50.1%	52.9%	55.9%	59.0%	62.3%	65.8%	69.5%	73.4%	77.5%	81.8%	86.4%	91.2%	96.3%
1	North Catskill	13.2 kV	35.12	F	0.40%	24.6	70.3%	70.6%	70.8%	71.1%	71.4%	71.7%	72.0%	72.3%	72.6%	72.8%	73.1%	73.4%	73.7%	74.0%	74.3%
1	South Cairo	13.2 kV	19.9		2.50%	13.2	68.0%	69.7%	71.4%	73.2%	75.0%	76.9%	78.9%	80.8%	82.8%	84.9%	87.0%	89.2%	91.4%	93.7%	96.1%
1	Vinegar Hill	34.5 kV	15.375		0.30%	4.1	27.0%	27.1%	27.2%	27.2%	27.3%	27.4%	27.5%	27.6%	27.6%	27.7%	27.8%	27.9%	28.0%	28.1%	28.2%
1	Westelo	13.2kV	27.05		1.00%	8.6	31.9%	32.2%	32.6%	32.9%	33.2%	33.6%	33.9%	34.2%	34.6%	34.9%	35.3%	35.6%	36.0%	36.3%	36.7%
	Kingston-Saugerties Load Group					0.0															
2	Boulevard	14.4 kV	30.597	F	-3.90%	17.8	56.0%	53.8%	51.7%	49.7%	47.8%	45.9%	44.1%	42.4%	40.7%	39.1%	37.6%	36.2%	34.7%	33.4%	32.1%
2	Converse Street	4 kV	7.071	F	-3.90%	3.2	43.5%	41.8%	40.2%	38.6%	37.1%	35.6%	34.3%	32.9%	31.6%	30.4%	29.2%	28.1%	27.0%	25.9%	24.9%
2	Hurley Avenue	13.2 kV	23.1	F	1.20%	18.7	81.9%	82.9%	83.9%	84.9%	85.9%	86.9%	88.0%	89.0%	90.1%	91.2%	92.3%	93.4%	94.5%	95.6%	96.8%
2	Jansen Avenue	13.2 kV	7.86	F	-1.40%	4.9	61.4%	60.6%	59.7%	58.9%	58.1%	57.2%	56.4%	55.7%	54.9%	54.1%	53.4%	52.6%	51.9%	51.1%	50.4%
2	East Kingston	13.2 kV	47.97	F	-0.70%	15.9	33.0%	31.7%	31.5%	31.2%	31.0%	30.8%	30.6%	30.4%	30.2%	30.0%	29.7%	29.5%	29.3%	29.1%	28.9%
2	Lincoln Park	14.4 kV	84	F	-1.40%	37.1	43.5%	24.8%	24.4%	24.1%	23.8%	23.4%	23.1%	22.8%	22.5%	22.1%	21.8%	21.5%	21.2%	20.9%	20.6%
2	Saugerties	13.2 kV	54.112	F	-0.20%	23.0	42.4%	42.3%	42.3%	42.2%	42.1%	42.0%	41.9%	41.8%	41.8%	41.7%	41.6%	41.5%	41.4%	41.3%	41.3%
2	South Wall Street	4 kV	5.765		-3.90%	2.0	32.7%	31.4%	30.2%	29.0%	27.9%	26.8%	25.7%	24.7%	23.8%	22.8%	21.9%	21.1%	20.3%	19.5%	18.7%
2	Woodstock	13.2 kV	19.125	F	1.70%	19.4	103.4%	105.1%	106.9%	108.7%	110.6%	112.5%	114.4%	116.3%	118.3%	120.3%	122.4%	124.4%	126.6%	128.7%	130.9%
	Ellenville Load Group																				
3	Clinton Avenue	4 kV	7.687	F	3.60%	0.9	12.6%	13.1%	13.5%	14.0%	14.5%	15.0%	15.6%	16.1%	16.7%	17.3%	17.9%	18.6%	19.3%	20.0%	20.7%
3	Greenfield Road	13.2 kV	15.375		2.40%	7.9	52.6%	53.9%	55.2%	56.5%	57.9%	59.2%	60.7%	62.1%	63.6%	65.1%	66.7%	68.3%	69.9%	71.6%	73.3%
3	Grimley Road	13.2 kV	7.171	F	1.80%	5.3	75.7%	77.0%	78.4%	79.8%	81.3%	82.7%	84.2%	85.7%	87.3%	88.9%	90.5%	92.1%	93.7%	95.4%	97.2%
3	High Falls	13.2 kV	34.5	F	1.00%	20.0	58.5%	59.1%	59.7%	60.3%	60.9%	61.5%	62.1%	62.8%	63.4%	64.0%	64.7%	65.3%	66.0%	66.6%	67.3%
3	Honk Falls	13.2 kV	18.2		-1.90%	5.8	31.0%	30.4%	29.9%	29.3%	28.7%	28.2%	27.7%	27.1%	26.6%	26.1%	25.6%	25.1%	24.6%	24.2%	23.7%
3	Kerhonkson	13.2 kV	44.6	F	4.80%	10.8	25.4%	26.6%	27.9%	29.2%	30.6%	32.1%	33.6%	35.2%	36.9%	38.7%	40.5%	42.5%	44.5%	46.6%	48.9%
3	Neversink	13.2 kV	4.92		0.90%	2.9	59.4%	59.9%	60.4%	61.0%	61.5%	62.1%	62.7%	63.2%	63.8%	64.4%	64.9%	65.5%	66.1%	66.7%	67.3%
3	Neversink	4 kV	2.46		0.90%	0.4	16.4%	16.6%	16.7%	16.9%	17.0%	17.2%	17.3%	17.5%	17.6%	17.8%	17.9%	18.1%	18.3%	18.4%	18.6%
3	Sturgeon Pool	13.2 kV	29.7		3.80%	2.6	9.2%	9.6%	9.9%	10.3%	10.7%	11.1%	11.5%	11.9%	12.4%	12.9%	13.4%	13.9%	14.4%	14.9%	15.5%
	Modena Load Group																				
4	Galeville	13.2 kV	28.7	F	1.80%	11.4	40.5%	41.2%	42.0%	42.7%	43.5%	44.3%	45.1%	45.9%	46.7%	47.5%	48.4%	49.3%	50.2%	51.1%	52.0%
4	Highland	13.2 kV	32.93	F	0.90%	20.2	61.8%	62.4%	63.0%	63.5%	64.1%	64.7%	65.2%	65.8%	66.4%	67.0%	67.6%	68.2%	68.9%	69.5%	70.1%
4	Modena	13.2 kV	21.1		2.10%	14.4	69.8%	71.2%	72.7%	74.3%	75.8%	77.4%	79.0%	80.7%	82.4%	84.1%	85.9%	87.7%	89.5%	91.4%	93.3%
4	Ohioville	13.2 kV	29.68	F	0.00%	21.0	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%	70.8%
	Newburgh Load Group																				
5	Bethlehem Road	13.2 kV	47.8	F	-0.60%	35.4	73.7%	73.2%	72.8%	72.3%	71.9%	71.5%	71.0%	70.6%	70.2%	69.8%	69.4%	68.9%	68.5%	68.1%	67.7%
5	Coldenham	13.2 kV	47.8	F	-2.10%	29.4	60.2%	58.9%	57.7%	56.4%	55.3%	54.1%	53.0%	51.9%	50.8%	49.7%	48.7%	47.6%	46.6%	45.7%	44.7%
5	East Walden	13.2 kV	26.17		0.70%	15.7	60.5%	61.0%	61.4%	61.8%	62.2%	62.7%	63.1%	63.6%	64.0%	64.5%	64.9%	65.4%	65.8%	66.3%	66.7%
5	Marlboro	13.2 kV	30.91	F	2.30%	19.2	63.6%	65.1%	66.6%	68.1%	69.7%	71.3%	72.9%	74.6%	76.3%	78.1%	79.9%	81.7%	83.6%	85.5%	87.5%
5	Maybrook	13.2 kV	20.9	F	4.30%	19.7	98.3%	102.5%	106.9%	111.5%	116.3%	121.3%	126.6%	132.0%	137.7%	143.6%	149.8%	156.2%	162.9%	169.9%	177.2%
5	Montgomery	13.2 kV	19.5		0.70%	0.0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	Montgomery Street	13.2 kV	15.2	F	0.60%	5.0	33.1%	33.3%	33.5%	33.7%	33.9%	34.1%	34.3%	34.5%	34.7%	34.9%	35.1%	35.3%	35.6%	35.8%	36.0%
5	Montgomery Street	4 kV	5.76	F	0.60%	4.0	70.2%	70.6%	71.0%	71.5%	71.9%	72.3%	72.8%	73.2%	73.6%	74.1%	74.5%	75.0%	75.4%	75.9%	76.3%
5	Union Avenue	14.4 kV	94.482	F	2.00%	70.0	75.6%	77.1%	78.6%	80.2%	81.8%	83.4%	85.1%	86.8%	88.5%	90.3%	92.1%	94.0%	95.8%	97.8%	99.7%
5	West Balmville	14.4 kV	47.8	F	0.60%	34.3	72.1%	72.5%	73.0%	73.4%	73.8%	74.3%	74.7%	75.2%	75.6%	76.1%	76.5%	77.0%	77.5%	77.9%	78.4%

	Substation	Type	MVA Rating		Growth Rate	MVA 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Northeastern Dutchess Load																				
6	Ancram	13.2 kV	4.65		0.90%	1.5	32.5%	32.8%	33.1%	33.4%	33.7%	34.0%	34.3%	34.7%	35.0%	35.3%	35.6%	35.9%	36.2%	36.6%	36.9%
6	East Park	13.2 kV	24.2		1.20%	13.7	57.4%	58.0%	58.7%	59.4%	60.2%	60.9%	61.6%	62.4%	63.1%	63.9%	64.6%	65.4%	66.2%	67.0%	67.8%
6	Hibernia	13.2 kV	17.84		2.70%	13.2	76.2%	78.3%	80.4%	82.6%	84.8%	87.1%	89.4%	91.8%	94.3%	96.9%	99.5%	102.2%	104.9%	107.8%	110.7%
6	Milan	13.2 kV	25.86		3.00%	7.7	30.7%	31.7%	32.6%	33.6%	34.6%	35.6%	36.7%	37.8%	38.9%	40.1%	41.3%	42.5%	43.8%	45.1%	46.5%
6	Millerton	13.2 kV	8.3		1.00%	4.8	58.9%	59.5%	60.1%	60.7%	61.3%	61.9%	62.5%	63.1%	63.8%	64.4%	65.0%	65.7%	66.4%	67.0%	67.7%
6	Pulvers Corners	13.2 kV	5.765		2.30%	5.3	94.0%	96.2%	98.4%	100.6%	102.9%	105.3%	107.7%	110.2%	112.7%	115.3%	118.0%	120.7%	123.5%	126.3%	129.2%
6	Pulvers Corners	34.5 kV	17.21		0.90%	2.3	13.4%	13.5%	13.7%	13.8%	13.9%	14.0%	14.1%	14.3%	14.4%	14.5%	14.7%	14.8%	14.9%	15.1%	15.2%
6	Rhinebeck	13.2 kV	47.8	F	0.10%	29.9	62.5%	62.6%	62.6%	62.7%	62.8%	62.8%	62.9%	63.0%	63.0%	63.1%	63.2%	63.2%	63.3%	63.3%	63.4%
6	Smithfield	13.2 kV	5.765		-2.40%	0.9	15.9%	15.5%	15.1%	14.8%	14.4%	14.1%	13.7%	13.4%	13.1%	12.8%	12.5%	12.2%	11.9%	11.6%	11.3%
6	Staatsburgh	13.2 kV	26.5		1.70%	9.1	35.0%	35.6%	36.2%	36.9%	37.5%	38.1%	38.8%	39.4%	40.1%	40.8%	41.5%	42.2%	42.9%	43.6%	44.4%
6	Stanfordville	13.2 kV	6.26		3.30%	3.9	64.0%	66.1%	68.3%	70.6%	72.9%	75.3%	77.8%	80.3%	83.0%	85.7%	88.6%	91.5%	94.5%	97.6%	100.8%
6	Tinkertown	13.2 kV	19.125	F	1.10%	14.6	77.2%	78.0%	78.9%	79.8%	80.6%	81.5%	82.4%	83.3%	84.2%	85.2%	86.1%	87.1%	88.0%	89.0%	90.0%
	Poughkeepsie Load Area																				
7	Inwood Avenue	13.2 kV	51.22	F	0.60%	26.6	52.2%	52.5%	52.9%	53.2%	53.5%	53.8%	54.1%	54.5%	54.8%	55.1%	55.5%	55.8%	56.1%	56.5%	56.8%
7	Manchester	14.4 kV	47.8	F	1.30%	27.9	59.2%	60.0%	60.8%	61.6%	62.4%	63.2%	64.0%	64.8%	65.7%	66.5%	67.4%	68.3%	69.2%	70.1%	71.0%
7	Reynolds Hill	14.4 kV	47.8	F	1.60%	35.1	74.6%	75.8%	77.0%	78.2%	79.5%	80.7%	82.0%	83.4%	84.7%	86.0%	87.4%	88.8%	90.2%	91.7%	93.2%
7	Spackenkill	13.2 kV	47.8	F	-0.80%	33.2	68.9%	68.3%	67.8%	67.3%	66.7%	66.2%	65.7%	65.1%	64.6%	64.1%	63.6%	63.1%	62.6%	62.1%	61.6%
7	Todd Hill	13.2 kV	47.8	F	0.20%	26.0	54.6%	54.7%	54.8%	54.9%	55.0%	55.1%	55.2%	55.3%	55.4%	55.5%	55.7%	55.8%	55.9%	56.0%	56.1%
	Fishkill Load Group																				
8	Fishkill Plains	13.2 kV	47.8	F	1.30%	43.4	91.9%	93.1%	94.3%	95.6%	96.8%	98.1%	99.3%	100.6%	101.9%	103.3%	104.6%	106.0%	107.3%	108.7%	110.1%
8	Forgebrook	14.4 kV	47.425	F	0.00%	28.2	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%	59.4%
8	Knapps Corners	14.4 kV	47.8	F	-1.60%	18.5	38.2%	37.6%	37.0%	36.4%	35.8%	35.2%	34.7%	34.1%	33.6%	33.0%	32.5%	32.0%	31.5%	31.0%	30.5%
8	Merritt Park	13.2 kV	51.15	F	-0.50%	30.1	58.5%	58.2%	57.9%	57.6%	57.3%	57.0%	56.7%	56.5%	56.2%	55.9%	55.6%	55.3%	55.1%	54.8%	54.5%
8	Myers Corners	13.2 kV	35.12	F	-1.90%	20.2	56.4%	55.3%	54.2%	53.2%	52.2%	51.2%	50.2%	49.3%	48.3%	47.4%	46.5%	45.6%	44.8%	43.9%	43.1%
8	North Chelsea	13.2 kV	48.27	F	0.10%	20.0	41.4%	41.5%	41.5%	41.6%	41.6%	41.7%	41.7%	41.7%	41.8%	41.8%	41.9%	41.9%	41.9%	42.0%	42.0%
8	Sand Dock	13.2 kV	8		2.80%	4.8	61.8%	63.6%	65.3%	67.2%	69.1%	71.0%	73.0%	75.0%	77.1%	79.3%	81.5%	83.8%	86.1%	88.5%	91.0%
8	Shenandoah	13.2 kV	14.5		1.10%	15.6	108.8%	110.0%	111.2%	112.4%	113.6%	114.9%	116.2%	117.4%	118.7%	120.0%	121.4%	122.7%	124.0%	125.4%	126.8%
8	Tioronda	13.2 kV	25.74		1.70%	16.9	66.9%	68.0%	69.2%	70.3%	71.5%	72.8%	74.0%	75.2%	76.5%	77.8%	79.1%	80.5%	81.9%	83.3%	84.7%

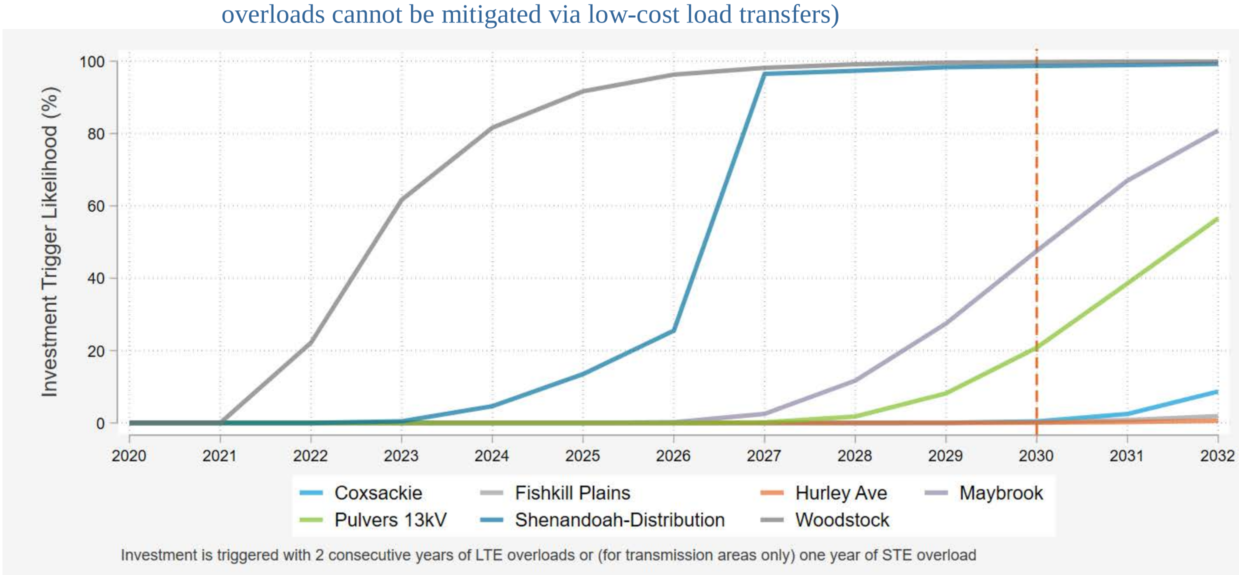
TOTAL:	1041.6

5.4 Probabilistic Load Forecast

As described previously, Demand Side Analytics performed a probabilistic forecast of Central Hudson's substation loads. These forecasts utilized *Monte-Carlo* simulations for each substation where load data was available. The probabilistic forecast is utilized as part the *2020 Central Hudson Location Specific Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods Study* ("Avoided T & D Cost Study"). Within this study, a simulation was counted as needing an investment when an area's forecast load exceeded the area's LTE rating for two consecutive years or its STE rating for any one year.

As shown in the following chart, these analyses determined the potential for several substations (Shenandoah – Distribution, Woodstock, Maybrook, and Pulvers 13.8 kV) to require an upgrade due to load growth at the end of the 10 year planning horizon.

Probability of Growth Related Substation Infrastructure Upgrade
(Shenandoah-Distribution is the only location with risk of at least 5% where overloads cannot be mitigated via low-cost load transfers)



As detailed within the referenced Avoided T&D Cost Study, there are relatively low cost switching options that can be utilized to address the need for upgrades at three of these substations - Woodstock, Maybrook, and Pulvers 13.8 kV.

5.5 Probabilistic Planning Methodology

While the Electric System Forecasting function to provide for the safe and reliable operation of the system will remain, the tools applied and the complexity of the process is rapidly evolving. Central Hudson's all-time peak electric load was 1295 MW in 2006. The load has declined significantly since that time due to a downturn in the economy and industry leaving the Hudson Valley region, as well as the proliferation of DERs, including energy efficiency and solar photovoltaics. Currently, interconnection of DERs is evaluated separately from the long-term planning process. With the increased penetration of DERs, application of a linear forecast with engineering knowledge and judgment may be insufficient to recognize the range of potential generation and load scenarios. Central Hudson is currently transitioning its System Planning process to forecast DERs and gross load independently with separate scenarios for each. DER forecasts will consider not only technical drivers of load shapes, but current and anticipated policy decisions and interconnection queues that will impact the penetration of DERs. Along with a probabilistic approach, this will provide Central Hudson with an improved ability to assess future system needs and develop alternatives and a final solution.

Please see the Distribution System Implementation Plan, Sections III Integrated Planning and IV Advanced Forecasting, filed on June 30, 2020 for additional information.

6. Transmission (Category 12) and Substation (Category 13) Areas

6.1 Introduction

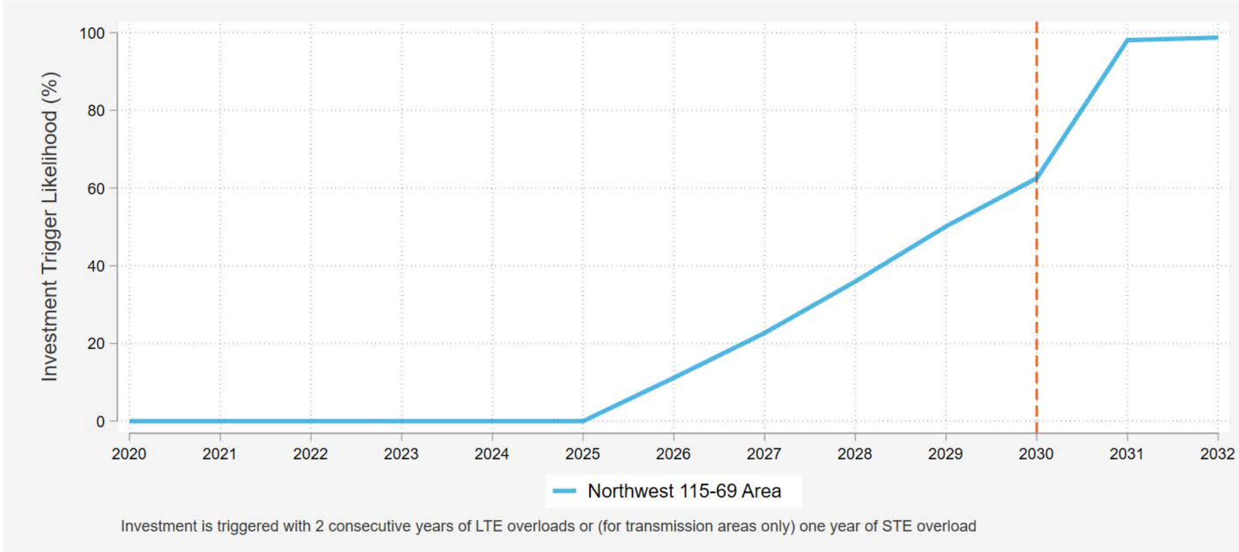
This section outlines the long-term plans for all areas of the transmission network. The long-term plans are based on current information, system conditions and load forecasts and, as such, are subject to change as additional information is obtained. Also, certain areas are in the process of being studied and modifications to the long-term plan may be made as a result of these studies.

6.2 Probabilistic Load Forecast

Central Hudson's consultant, Demand Side Analytics, performed a probabilistic forecast of Central Hudson's transmission areas using hourly load data from 2014 through 2019. These forecasts utilized *Monte-Carlo* simulations for each transmission area. The probabilistic forecast is utilized as part the Avoided T & D Cost Study. Within the Avoided T & D Cost Study, a simulation was counted as needing an investment when an area's forecast load exceeded the area's LTE rating for 2 consecutive years or its STE rating for any 1 year.

As shown in the following chart, these analyses determined the potential for one transmission area (Northwest 115-69 kV) to require an upgrade due to load growth at the end of the 10 year planning horizon.

Probability of Growth Related Infrastructure Upgrade: Transmission Areas



6.3 Load Serving Capability (LSC)

The 115/69 kV transmission network is evaluated using the LSC analysis. Electric Transmission Planning performs system LSC analyses for both the existing and planned Transmission System; LSC analyses also are performed for various levels of internal generation. As a simple example of LSC determination, the ability of an individual substation to serve load may be easily calculated. For a typical two transformer distribution substation, the substation's LSC is set by the lowest transformer summer Long Term Emergency (LTE) rating. In this case, the LSC is based on the ability of a single transformer to serve load should the other substation transformer fail.

Similarly, determination of the LSC for "looped" local transmission systems with only two transmission inputs is similar to determination of LSC for a two transformer distribution substation; the transmission line with the lowest summer LTE rating typically sets the LSC for the area. For looped transmission systems, however, the LSC may be set by a more limiting internal element or by a voltage limit/constraint.

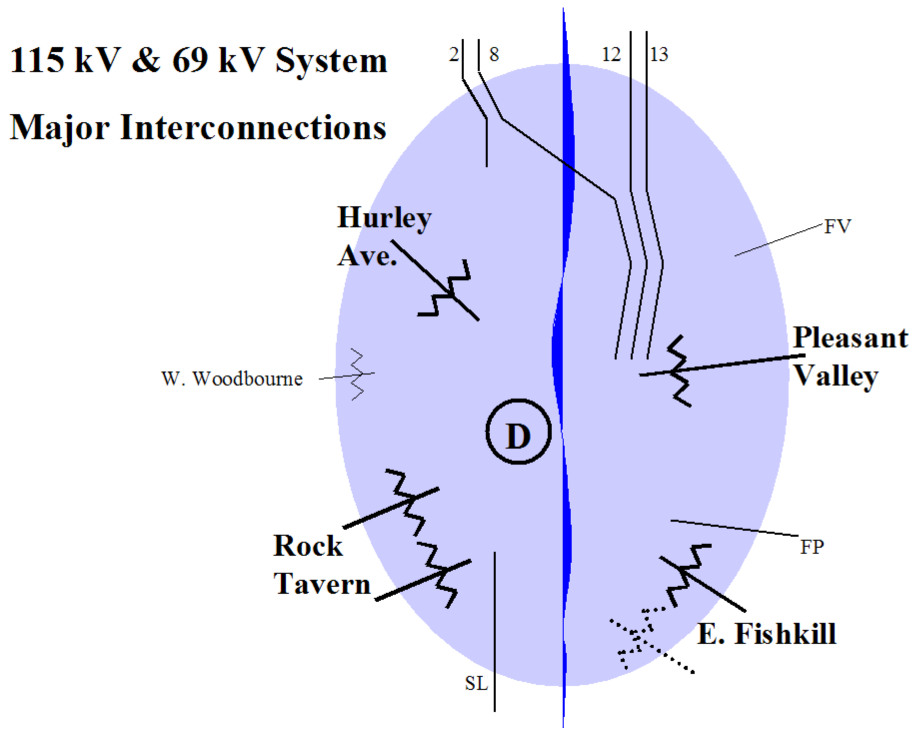
For the 115 kV and 69 kV transmission system as a whole, the determination of System Load Serving Capability is described in Section 3.5.1.1 of Central Hudson's Electric Planning Guides.

6.3.1 115/69 kV Transmission Network

The LSC of Central Hudson's transmission system is its import capability plus the available internal generation as defined in Central Hudson Gas & Electric Corporation's "Transmission Planning Guidelines." LSC is constrained by violation of a thermal or voltage limit following the contingencies specified in the "Transmission Planning Guidelines."

6.3.1.1 Summary of Issues

The major 115 kV & 69 kV interconnections supplying Central Hudson's system are shown in the pictorial below:



Central Hudson's all-time high summer peak load was 1295 MW on August 2, 2006; more recent summer peak loads are shown in the following table:

Year	Date of Summer Peak	MW
2019	July 20 @ 1800	1109
2018	July 2 @ 1800	1114
2017	July 20 @ 1700	1034
2016	August 13 @ 1800	1088
2015	July 29 @ 1800	1059
2014	July 23 @ 1500	1060
2013	July 18 @ 1700	1202
2012	July 17 @ 1800	1168
2011	July 22 @ 1800	1225
2010	July 6 @ 1700	1229

The existing system load serving capability is limited by the 115 kV HF line following the loss of the 115 kV EF line at a system load of approximately 1480 MW. Based on current and forecast load levels, this limitation will not present any issues over the next ten year period. However, recent condition assessments have identified a number of structural issues with the HF line. Based on the number of issues, a complete rebuild of this line has been recommended.

6.3.1.2 Summary of Recommendations

The HF line will be rebuilt with 1033.5 ACSR. This project is scheduled to be completed by the summer of 2020. Following the rebuild of the HF line and any necessary station connection upgrades, the system load serving capability will be limited by the 115 kV D line following a 345 kV East Fishkill stuck breaker at a system load of approximately 1770 MW.

6.4 Individual Transmission Areas

6.4.1 Northwest 115/69 kV System

6.4.1.1 Summary of Issues

The transmission supply to the Northwest 115/69 kV area is from two 115 kV sources (National Grid's '2' line and 'T-7' line) and a 69 kV source (SB line). In the past, the '2' line has been at or above its summer normal rating, pre-contingency. Installation of reactors at North Catskill in series with the '2' line has mitigated these high flow conditions. The proposed 100 MW Flint Mine Photovoltaic facility in the Coxsackie area has the potential to increase 2 line flows depending on their point of interconnection; to interconnect, the developer will need to build a 5 breaker ring bus connecting both 8 & 2 lines.

The NY Transco Segment B Transmission Project will also reconfigure the North Catskill T-7 Line terminal to be designated the 5 Line and rerouted to the new Churchtown Substation.

H & SB Lines
The 69 kV H & SB lines supply the North Catskill, Saugerties, Woodstock and Hurley Avenue Substation. The H & SB lines were built in 1919. Condition assessments have indicated that the lines have sufficient structural issues. The lines are scheduled to be rebuilt starting in 2021.

Woodstock Transmission Reserve
The only transmission supply to the Woodstock area is the 69 kV 'SR' line. Due to the amount of load served from Woodstock (2019 coincident peak = 16.8 MW), it is difficult to reserve the Woodstock Substation through existing distribution ties on peak.

6.4.1.2 Summary of Recommendations

H & SB Lines
The H & SB lines will be rebuilt for 115 kV but continue to operate at 69 kV. This reinforcement is necessary due to infrastructure needs; however, by itself it is insufficient to provide for additional area load (if any). An Article VII filing was submitted to the PSC in 2017 for the rebuild of the lines. A joint proposal has been distributed to all parties for signatures. The lines are scheduled to be rebuilt starting in 2021.

North Catskill 115/69 kV Transformers
Based on their age and condition, the two North Catskill 115/69 kV transformers will be replaced with two three-phase 56 MVA 115/69 kV autotransformers with LTC. The replacement of these transformers should occur prior to the H & SB Lines rebuild to ensure sufficient area load serving capability during the construction. This project is scheduled to be completed in 2020.

Woodstock Transmission Reserve
While a second transmission supply to the Woodstock Substation would increase area reliability, no transmission reinforcement is being considered at this time. Instead, a distribution Smart Grid solution is being pursued (see Section 7.3.1).

6.4.2 Westerlo Loop

Two 69 kV transmission lines (CL line and NC line) supply the Westerlo Loop along with the Coxsackie and South Cairo generators.

Recent peak loads are shown in the following tables. The winter peaks, can be reduced by 7-8 MW if the Hunter Mountain Ski Bowl is transferred to Vinegar Hill or is requested to stop making snow.

Year	Date of Summer Peak	MW	MVAr	MVA
2019	July 20 @ 1800	61.0	-3.3	61.1
2018	July 2 @ 1800	57.2	-5.6	57.5
2017	July 20 @ 1700	48	-4	48.2
2016	August 13 @ 1800	55.4	-7.4	56
2015	July 29 @ 1800	51.4	0	51.9
2014	July 23 @ 1500	49.7	7	50.2
2013	July 18 @ 1700	57.6	-6.5	58.3
2012	July 17 @ 1800	54.6	-7.3	55.1
2011	July 22 @ 1800	55.1	-5.6	55.4
2010	July 6 @ 1700	56.7	-4.0	56.8

Year	Date of Winter Peak	MW	MVAr	MVA
2019-20	Dec 19 @ 1800	62.5	-0.9	62.9
2018-9	Jan 21 @ 1800	60.0	-10.1	61.0
2017-8	Jan 6 @ 1900	55.8	-5.3	56.1
2016-7	Dec 15 @ 1800	51.7	-12.7	53.3
2015-6	Feb 15 @1900	50.2	-2.2	50.2
2014-5	Jan 7 @ 1900	52.3	-6.7	52.7
2013-4	Jan 7 @ 1900	54.8	-14.4	56.6
2012-3	Jan 24 @ 1900	58.5	-2.5	58.6
2011-2	Jan 21 @ 1800	54.6	-11.1	55.7
2010-11	Jan 24 @ 1900	55.9	-4.1	56.1

6.4.2.1 Summary of Issues

CL Line
Recent condition assessments have indicated that the line has sufficient structural issues that the line needs to be rebuilt.

Area LSC
Post rebuild of the CL Line, the area's thermal LSC of 99.5 MW (summer) and 117.4 MW (winter), assume that one area generator will start, post-contingency.

The area is voltage limited to 83.6 MW (summer and winter) for loss of CL line.

Each generator's annual run-time, however, is severely limited by environmental/emissions limitations with the South Cairo CT being limited to 134 hours during the summer ozone season and the Coxsackie CT being limited to 230 hours during the summer ozone season.

DEC Peaker Rule
The emission rules contained in DEC 227-3 have resulted in retiring the Coxsackie and South Cairo combustion turbines by 2024.

Proposed Solar Interconnection Projects
For lines and substations supplied by the NC Line, there are currently 110 MW of projects in the NYISO interconnection process. Additionally, there are approximately 13 MW in service and 53 MW in queue in the New York State SIR process as of April 24, 2020. The 70 MVA rated NC Line will be overloaded if this large amount of solar is placed in service.

6.4.2.2 Summary of Recommendations

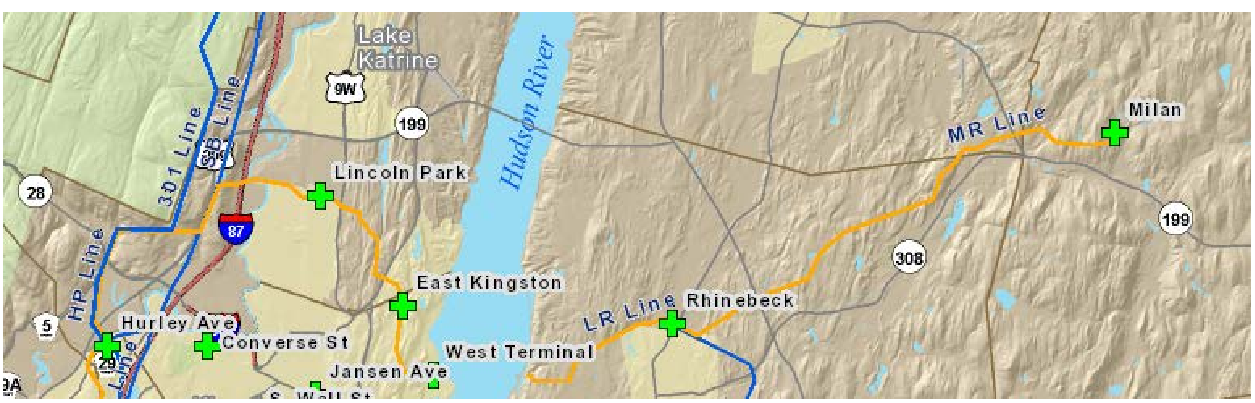
CL Line
Rebuild the CL Line with 795 ACSR. Substation station connections at South Cairo and bus tube at North Catskill be upgraded as part of the line rebuild. CL line disconnect switches for line sectionalizing will be relocated at the Lawrenceville substation or immediately adjacent to the Lawrenceville substation and motorized for supervisory control. Reference the Transmission Lines Section (section 3.2.2.2) for additional information on the CL Line rebuild.

DEC Peaker Rule
Since the combustion turbines are used for voltage support post contingency, options are being considered to alleviate this system constraint. American Superconductor currently is investigating the use of their DVAR product as a replacement for the voltage support provided by the combustion turbines. Another option would be a third input into the transmission system.

Proposed Solar Interconnection Projects
The solar project installations would have to go through NYISO's Class Year Study in which upgrade costs are allocated accordingly.

6.4.3 Kingston-Rhinebeck 115 kV

This area comprises the substations between Hurley Avenue in Ulster County and Milan in Dutchess County but excludes the Milan load.



Recent area summer system coincident peak loads are shown in the following table.

Year	Date of Peak	MW	MVAr	MVA

2019	July 20 @ 1800	83.7	7.8	84.1
2018	July 2 @ 1800	83.5	-6.2	83.7
2017	July 20 @ 1700	73.7	-10.0	74.4
2016	August 13 @ 1800	75.3	-8.3	75.8
2015	July 29 @ 1800	78.3	5.7	78.5
2014	July 23 @ 1500	82.0	-1.1	82.0
2013	July 18 @ 1700	88.6	2.2	88.6
2012	July 17 @ 1800	86.1	-0.9	86.1
2011	July 22 @ 1800	88.6	-1.6	88.6
2010	July 6 @ 1700	88.3	0.2	83.3

6.4.3.1 Summary of Issues

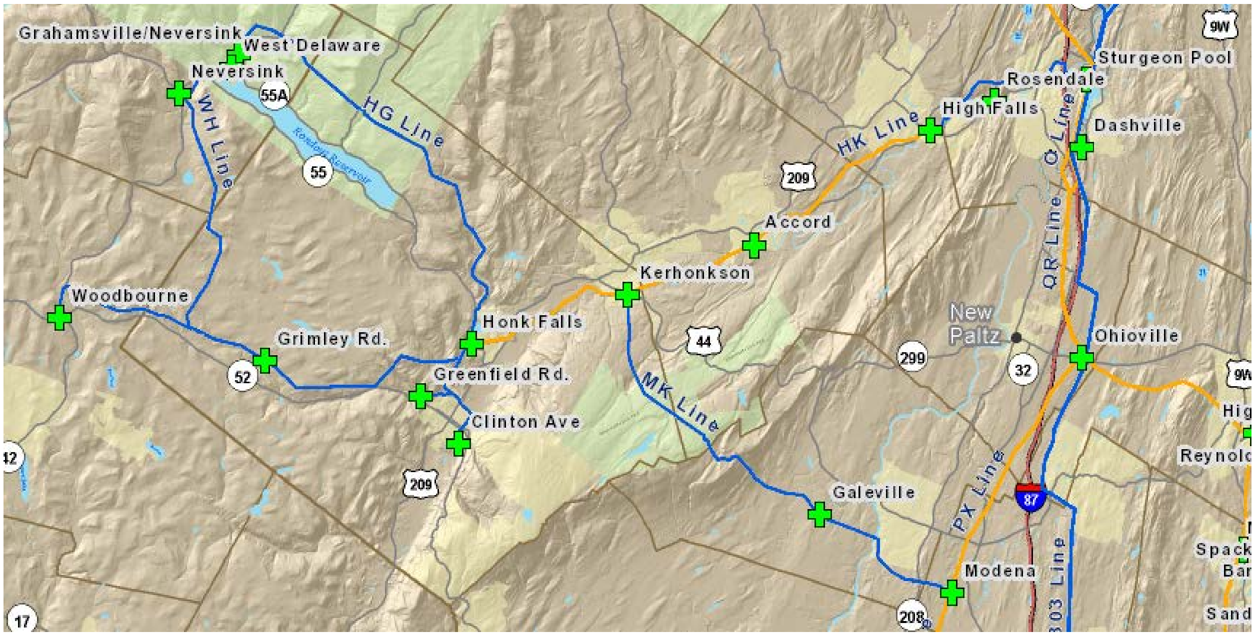
Following loss of the HP line, even with all the Lincoln Park capacitors in-service, this area is voltage limited at approximately 175 MW. Should a large (e.g., 25-35 MW) industrial load come in at Lincoln Park / Tech City, the voltage limit would be 140 MW following the loss of the HP Line.

6.4.3.2 Summary of Recommendations

No action is required at this time. For the future, a third input to Lincoln Park would improve post-contingency voltages, and the area load serving capability.

6.4.4 Ellenville Area

Three 69 kV transmission inputs (P line, MG line and West Woodbourne 115/69 kV transformer) supply the Ellenville area.



6.4.4.1 Summary of Issues

P & MG Lines
For the Ellenville area, condition assessments have prompted a need to continue rebuilding the substations.

HG Line
Recent condition assessments have indicated that the line has sufficient structural issues to warrant a rebuild.

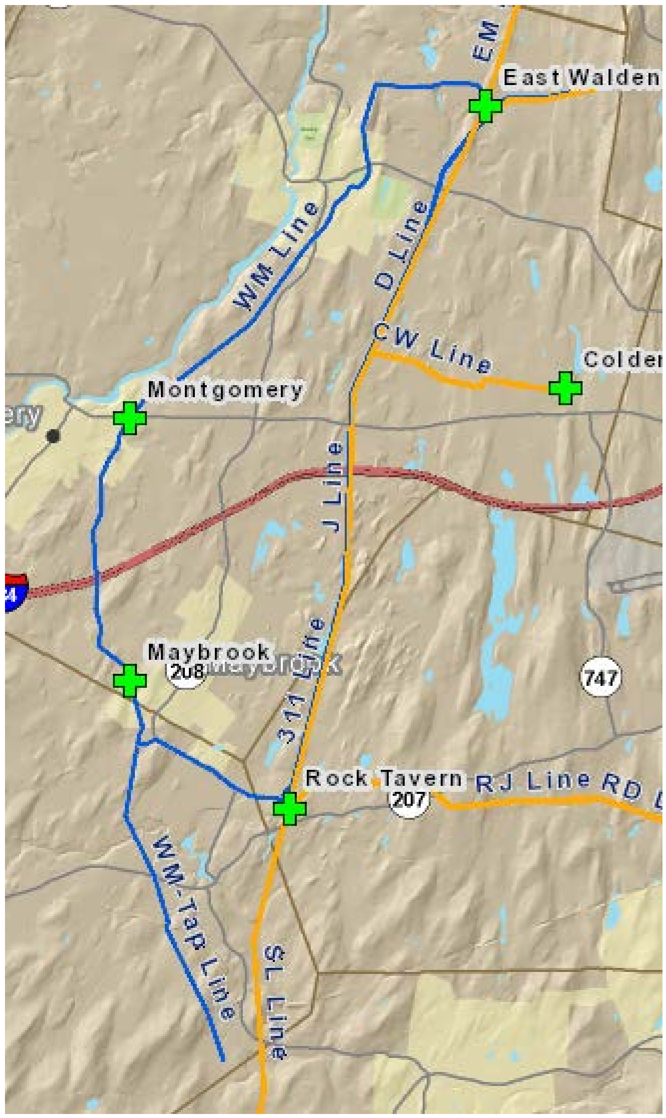
6.4.4.2 Summary of Recommendations

P & MG Lines: Conversion to 115 kV Operation
The P & MG lines already are built for 115 kV operation. The substation work for the conversion to 115 kV that already has been completed includes the following: rebuilding the High Falls Substation; a new 115 kV Modena Substation; a new 115 kV Galeville Substation; a new 115 kV Sturgeon Pool Substation and a new 115 kV Kerhonkson Substation. The remaining substation work includes expanding the Kerhonkson Substation to install two new 115/69 kV transformers and associated breakers, replacing several spans of the HK&MK lines leaving the Honk Falls Substation and the addition of a third 115 kV breaker at the Modena Substation.

HG Line
The HG Line will be rebuilt with 397.5 ACSR Ibis and OPGW static wire. This will mitigate future generation curtailment and remove the sag limitation on the line.

6.4.5 WM Line Area

This area comprises the 69 kV substations between Rock Tavern and East Walden in Orange County. There also is a tap heading south of Rock Tavern that serves as a back-up supply to Orange & Rockland utilities Blooming Grove Substation.



Recent area summer peak loads are shown in the following table.

Year	Date of Peak	MW	MVAr	MVA
2019	July 20 @ 1800	no	mdb	Data
2018	July 2 @ 1800	47.3	17.2	50.3
2017	July 20 @ 1700	41.5	11.8	43.1
2016	August 13 @ 1800	42.0	12.3	43.7
2015	July 29 @ 1800	41.8	12	43.5
2014	July 23 @ 1500	37.3	11.2	38.9
2013	July 18 @ 1700	41.9	13.6	44.1
2012	July 17 @ 1800	41.3	13.7	43.6
2011	July 22 @ 1800	no	mdb	Data
2010	July 6 @ 1700	44.3	15.2	46.8

6.4.5.1 Summary of Issues

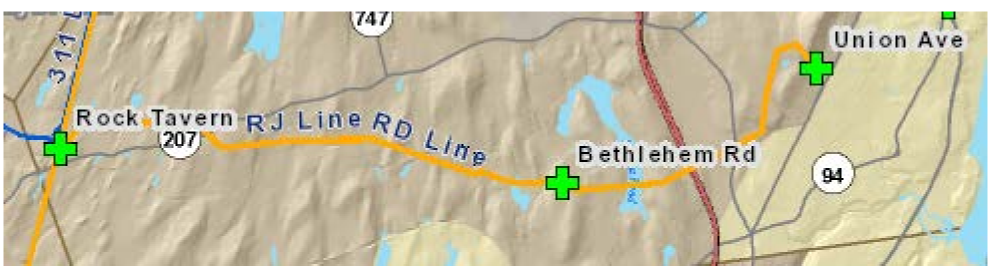
The WM Line was rebuilt in 2012. There are no current issues with the line. The tap to Blooming Grove, however, was not rebuilt and is in poor condition.

6.4.5.2 Summary of Recommendations

The tap to Blooming Grove is being considered for retirement.

6.4.6 115 kV RD-RJ Area

This area comprises the Union Avenue and Bethlehem Road Substations located in Orange County.



Recent area summer peak loads are shown in the following table.

Year	Date of Peak	MW	MVAr	MVA
2019	July 20 @ 1800	96.3	8.7	96.7
2018	July 2 @ 1800	96.3	9.7	96.8
2017	July 20 @ 1700	89.1	10	89.6
2016	August 13 @ 1800	89.4	6.0	89.6

2015	July 29 @ 1800	87.5	0.7	87.5
2014	July 23 @ 1500	82.9	5.1	83.0
2013	July 18 @ 1700	96.4	10.7	97.0
2012	July 17 @ 1800	87.0	7.9	87.3
2011	July 22 @ 1800	93.9	10.6	94.5
2010	July 6 @ 1700	94.7	12.6	100.3

The area load serving capability is 144 MW and is limited by the RD line's 336.4 MCM ACSR conductor.

6.4.6.1 Summary of Issues

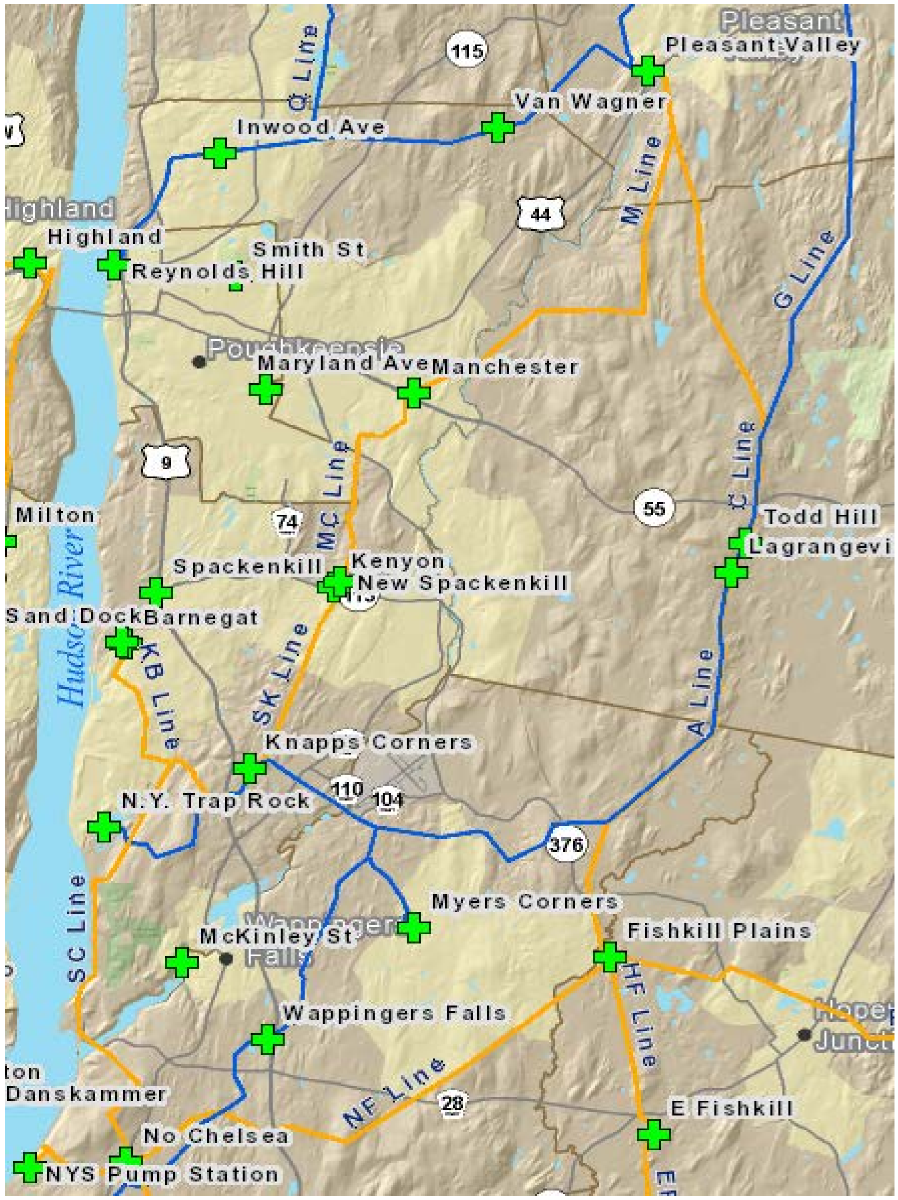
The area has sufficient LSC to provide for future load growth in the near-term. A potential long-term reinforcement option is to reconductor/rebuild the RD lines using a larger conductor (potentially 795 MCM ACSR to match the RJ line).

6.4.6.2 Summary of Recommendations

There are no recommendations for this area at this time.

6.4.7 Mid-Dutchess Area 115 kV

This area comprises the 115 kV substations between North Chelsea and Pleasant Valley in Dutchess County. It includes the IBM load supplied from the Sand Dock and Barnegat substations.



Recent area summer peak loads are shown in the following table.

Year	Date of Peak	MW	MVAr	MVA
2019	July 20 @ 1800	112.5	11.8	113.1
2018	July 2 @ 1800	118.6	14.0	119.4
2017	July 20 @ 1700	114.5	13.2	115.2
2016	August 13 @ 1800	114.3	12.7	115.0
2015	July 29 @ 1800	118.5	14.1	119.3
2014	July 23 @ 1500	105.1	22.1	107.4
2013	July 18 @ 1700	136.8	26.6	139.2
2012	July 17 @ 1800	127.9	17.7	129.1
2011	July 22 @ 1800	129.1	17.5	131.2
2010	July 6 @ 1700	130.3	16.0	131.2

6.4.7.1 Summary of Issues

Two inputs (M line from Pleasant Valley and SC line from North Chelsea) supply the Mid-Dutchess Substations. The area LSC is limited to 226 MW following loss of the SC line. This could be easily increased to 250 MW by changing CT taps and relay settings at the Manchester Substation.

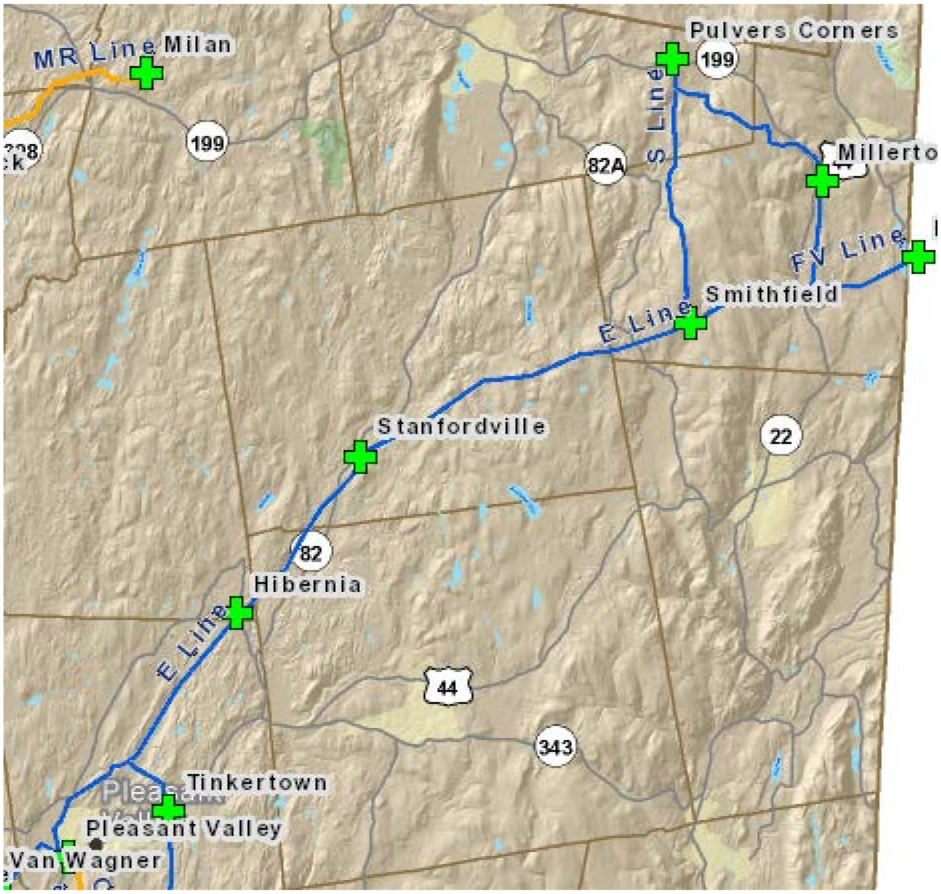
Recent condition assessments for the SK Line have indicated that the line has sufficient structural issues to warrant a rebuild.

6.4.7.2 Summary of Recommendations

There are no transmission reinforcements recommended at this time to increase the area LSC. The SK Line will be rebuilt with 1033.5 ACSR to address the structural issues. This project is schedule to be completed in 2025.

6.4.8 69 kV E Line Reserve

The E line substations are supplied from the Pleasant Valley substation. Under this normal configuration, the Smithfield to Falls Village 690/FV line may be closed at each end or open at one end depending on the transfer level between New York and New England.



Recent area summer peak loads are shown in the following table.

Year	Date of Peak	MW	MVAr	MVA
2019	July 20 @ 1800	32.2	-	-
2018	July 2 @ 1800	31.4	-	-
2017	July 20 @ 1700	40.8	-	-
2016	August 13 @ 1800	33.1	-	-
2015	July 29 @ 1800	36.5	-	-
2014	July 23 @ 1500	35.8	-	-
2013	July 18 @ 1700	32.2	-	-
2012	July 17 @ 1800	32.3	-	-
2011	July 22 @ 1800	27.2	-	-
2010	July 6 @ 1700	28.8	-	-

6.4.8.1 Summary of Issues

Following the loss of the Pleasant Valley to Hibernia section of the E line, only two sources are available to supply the E line load: NYSEG’s Amenia substation via the SA line and Northeast Utilities’ Falls Village area via the 690/FV line. In the past, NYSEG has indicated that they can supply up to 13 MVA via the SA line and Northeast Utilities has indicated that they cannot supply any load from the FV line, during summer peak load conditions. Recent developments in the NYSEG area (i.e., Silo Ridge, construction power for AP Dutchess and Olivet University) suggest that NYSEG may not be able to supply the reserve on peak.

A recent FV Line inspection has shown damage to the section of wire spanning Indian Lake that requires a conductor replacement. Due to the tower configurations, this would require not only pulling the span across Indian Lake but also several spans in both New York and Connecticut.

There have been several NYISO small generator preapplications for the Northeast Dutchess Country Transmission System. For the N-1 loss of the Pleasant Valley 69kV source, the area transmission system could be supplied radially from the ISO-NE system. For this condition, ISO-NE would not have the ability to dispatch area generation.

6.4.8.2 Summary of Recommendations

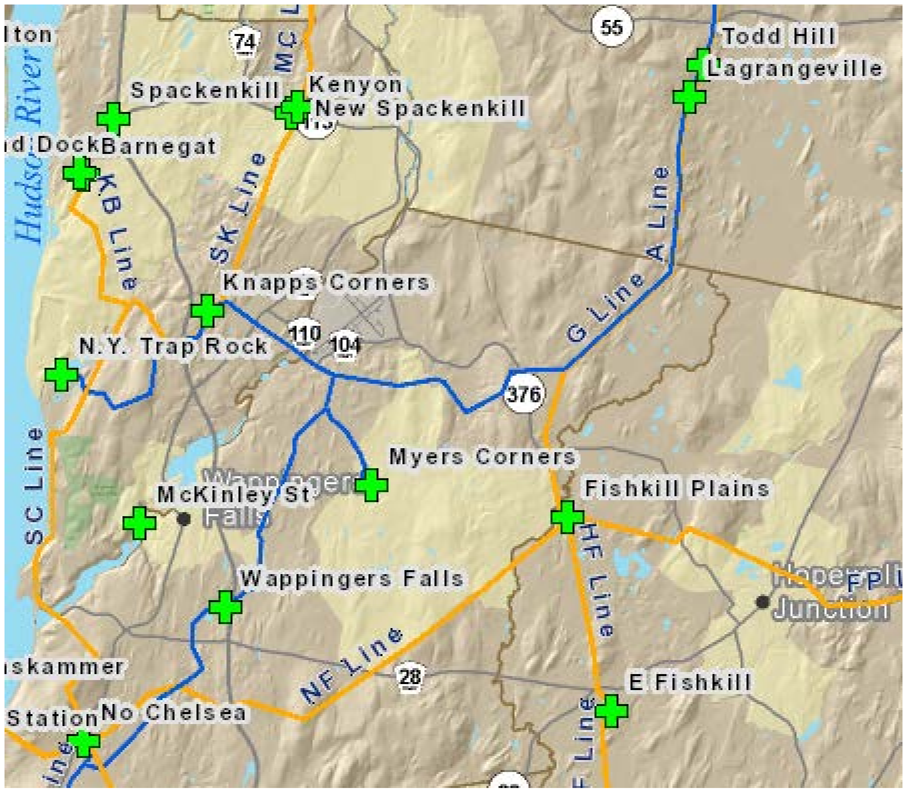
The G line provides the capability to reserve the E Line for a Pleasant Valley Transformer #10 fault, 69 kV bus fault or an E/G common tower failure. This improves the ability to reserve E line loads but does not provide for 100% reserve. This area will be studied in the future. After recent discussions with NYSEG, several options to increase their area transmission system are being explored. One option is to rebuild the E Line at 115 kV and install two autotransformers at Smithfield. Other options are also being considered.

Subsequent to the discovery of the FV Line conductor damage, Eversource approached us with their plan to rebuild their transmission system in Connecticut at 115 kV and operate at 69 kV. Discussions between Central Hudson and Eversource are underway regarding these issues.

For the N-1 loss of the Pleasant Valley 69kV source, the area transmission system could be supplied radially from the ISO-NE system. For this condition, ISO-NE would not have the ability to dispatch area generation. To resolve this issue for projects participating in the NYISO market, an additional transmission supply from the NYCA system would be required.

6.4.9 Myers Corners Transmission Supply

The KM and TV lines supply Myers Corners Substation. The majority of the lines were built in the 1920s. The taps going into Myers Corners were built in 1981.



Recent substation summer peak loads are shown in the following table.

Year	Date of Peak	MW	MVAr	MVA
2019	July 20 @ 1800	22.7	1.7	22.8
2018	July 2 @ 1800	23.2	1.2	23.2
2017	July 20 @ 1700	21.3	.9	21.4
2016	August 13 @ 1800	24.2	4	24.6
2015	July 29 @ 1800	24.0	4.5	24.4
2014	July 23 @ 1500	23.0	3.1	23.2
2013	July 18 @ 1700	25.8	6.8	26.7
2012	July 17 @ 1800	26.1	4.2	26.5
2011	July 22 @ 1800	28.0	5.8	28.6
2010	July 6 @ 1700	29.6	6.5	30.3

6.4.9.1 Summary of Issues

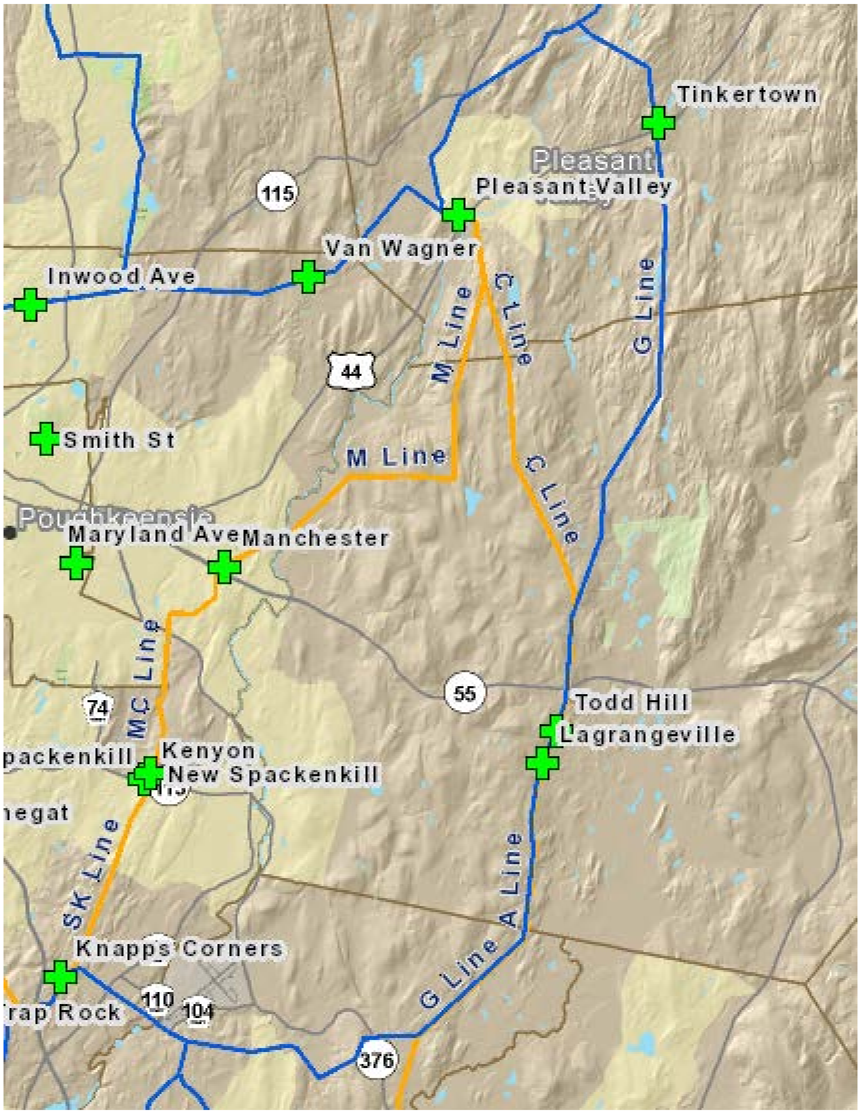
Condition assessments on the TV and KM lines have shown sufficient structural issues to warrant a rebuild. Myers Corners substation firm rating currently is 35.2 MVA with the transmission supply to Myers Corners limited to 41 MVA by the North Chelsea to Myers Corners TV Line.

6.4.9.2 Summary of Recommendations

The KM and TV lines will be rebuilt with 795 ACSR. Reference the Transmission Lines Section (section 3.2.2.2) for additional information on the KM & TV Lines rebuild.

6.4.10 Tinkertown Substation Reserve

Tinkertown Substation is supplied by the G line.



Recent substation summer peak loads are shown in the following table.

Year	Date of Peak	MW	MVAr	MVA
2019	July 20 @ 1800	14.4	1.9	14.5
2018	July 2 @ 1800	14.4	0.6	14.4
2017	July 20 @ 1700	13.1	0.8	13.1
2016	August 13 @ 1800	15.4	1.1	15.4
2015	July 29 @ 1800	13.0	0.8	13.1
2014	July 23 @ 1500	13.0	2.0	13.1
2013	July 18 @ 1700	15.2	1.8	15.3
2012	July 17 @ 1800	14.0	2.6	14.3

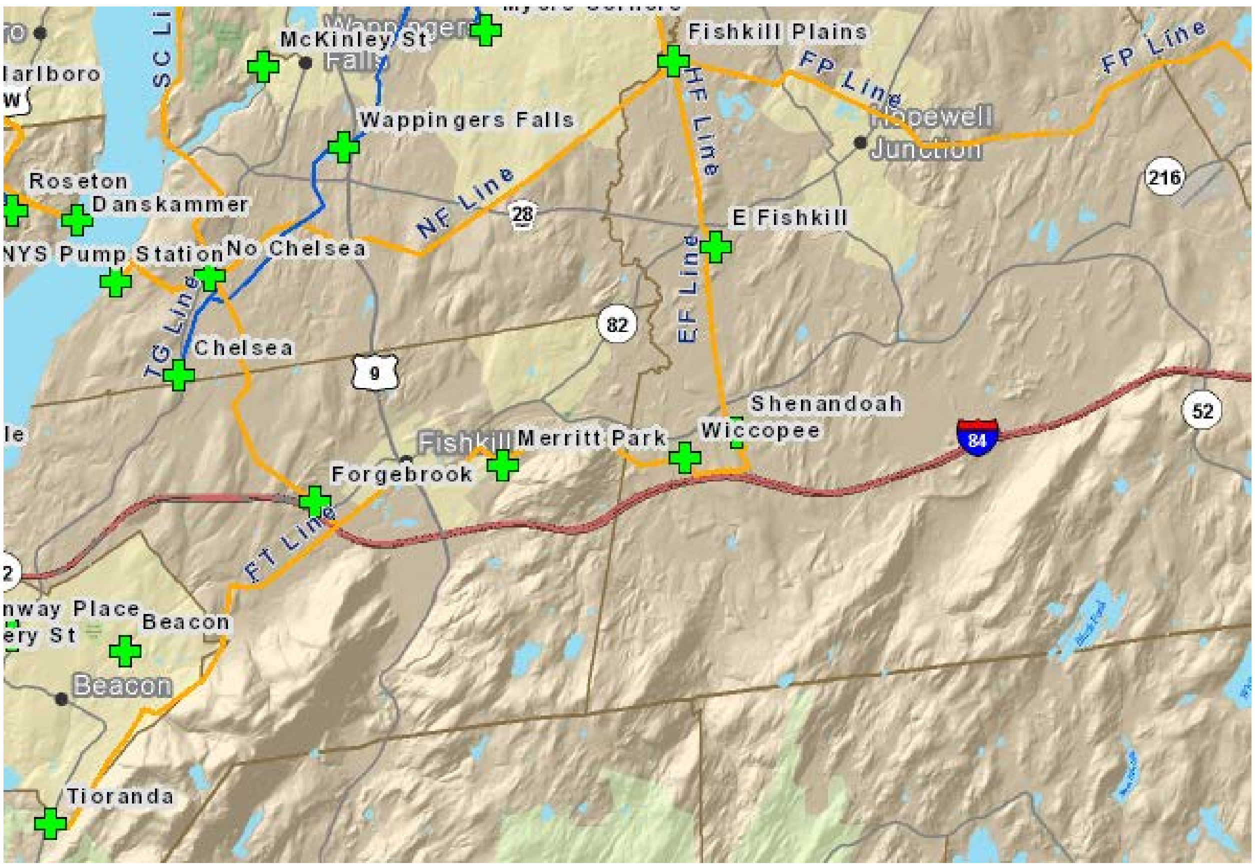
2011	July 22 @ 1800	19.1[6]	2.6	19.3
2010	July 6 @ 1700	14.9	2.9	15.2

6.4.10.1 Summary of Issues and Recommendations

No transmission reinforcement is needed at this time.

6.4.11 Southern-Dutchess Area

This area comprises the 115 kV substations between North Chelsea and East Fishkill in Southern Dutchess County. It includes the Global Foundaries load supplied from the Shenandoah Substation.



Recent area summer peak loads are shown in the following table.

[6] Approximately 4.2 MVA of Hibernia 7011 load was being supplied from Tinkertown at this time.

Year	Date of Peak	MW	MVAr	MVA
2019	July 20 @ 1800	146.0	23.0	147.8
2018	July 2 @ 1800	140.4	15.5	19.5
2017	July 20 @ 1700	136.3	13.4	136.9
2016	August 13 @ 1800	149.7	20.2	151.1
2015	July 29 @ 1800	140	21.5	141.7
2014	July 23 @ 1500	146.9	28.5	149.6
2013	July 18 @ 1700	159.4	34.2	163.0
2012	July 17 @ 1800	152.5	26.3	154.7
2011	July 22 @ 1800	159.2	31.0	162.1
2010	July 6 @ 1700	163.5	41.3	168.7

This area's all-time high coincident peak load is 213.7 MVA on August 2, 2006 (HE 1700). Subsequent coincident peaks have been lower largely due to decreased Global Foundaries load at Shenandoah and the closure of IBM's West Complex that is supplied from the Wiccopee Substation.

6.4.11.1 Summary of Issues

Two inputs (115 kV FO line from North Chelsea and 115 kV EF line from East Fishkill) supply the SDA substations. With one of these two inputs out-of-service, the SDA is able to serve 211 MVA without shedding load. During the summer of 2006, the area loads exceeded the area LSC. The load has decreased since this time and significant growth is not forecast for this area. Additional load serving capability could be needed for the Southern-Dutchess Area in the future if there are significant economic development initiatives in the former IBM West Complex.

6.4.11.2 Summary of Recommendations

Continue monitoring the Southern Dutchess Area for a large load that may come to the former IBM West Complex.

7. Subtransmission, Distribution (Category 15), and Substation (Category 13) Infrastructure and Load Growth Plan

7.1 Introduction

This section depicts the plans for all areas that are anticipated to be deficient within the next 7 years due to either aging or failing infrastructure or thermal limitations due load growth in the area. The discussion of the areas is categorized by the load groups described in Section 5. Please note that not all areas within each load group are listed, only those with deficiencies.

7.2 Load Group 1 - Northwest

7.2.1 Coxsackie/New Baltimore

Reference: New Baltimore Integration Study Draft

7.2.1.1 Summary of Issues

The Coxsackie and New Baltimore Substations are single transformer stations serving a large geographic area that is mostly rural with the exception of village centers. The areas served include the Villages of Coxsackie and Ravena, and Towns of Athens, Coxsackie, New Baltimore, and Coeymans.

The substations are single transformer stations that are loaded as follows:

Substation	Summer Normal Rating (MVA)	2019 Peak Load (MVA)
Coxsackie	16.4	14.48
New Baltimore	25.8	11.45

Although the stations operate below their firm ratings, the rural nature of the area calls for long circuits with few ties, limiting reserve capability between the Coxsackie and New Baltimore substations.

In addition to the limited reserve capability, the aging infrastructure at the Coxsackie has become a concern. The Coxsackie transformer has been operating for over 60 years and the switchgear is nearing 50 years of operation. The transformer and switchgear are both nearing the end of their useful lives. Due to recent DEC emission restrictions, the combustion turbine (CT) at Coxsackie will be retired in 2025. Additionally, several new, significant loads have been introduced to the area. A cryptocurrency mining facility has materialized, an industrial park and a manufacturing facility have been proposed. Along with these, there has been a very large amount of proposed DER reaching levels of almost 45MW across both stations.

7.2.1.2 Summary of Recommendations

- In 2015, a study was drafted by Distribution Planning to address a long-term contingency plan for the area. The draft recommended the installation of a second transformer at New Baltimore and that the Coxsackie CT continue to be used as backup in the event of a transformer failure at the Coxsackie Substation. Since the CT operations were impacted by the recent DEC emissions rule, the unit is now planned for retirement by 2025 and a second transformer has been recommended for the Coxsackie substation to provide reserve capacity for transformer outages. Also as part of the CT retirement, the installation of D-VAR units at Coxsackie to provide voltage support for the transmission loop is being studied. The overall project scope for the substation upgrades regarding the CT retirement has not been finalized yet.

- To address the aging infrastructure concerns at Coxsackie, a new switchgear installation at the Coxsackie substation and replacement of the Coxsackie transformer is planned to occur in Q1 2021. Based on area loading levels, the transformer was planned to be replaced with a 13.4MVA transformer. With almost 30MW of potential DER proposed onto the substation bus, including a 10 MW PV working thru the NYISO interconnection process, a 22MVA transformer is being reviewed. Based on the interconnection review, the incremental cost for the larger transformer will be paid by a developer.

- As recommended in the draft Area Study, the New Baltimore substation is scheduled to have a new 12 MVA Transformer in service by June 2022 to address the reserve capability concerns during contingencies. A new circuit 1084 has also been proposed to help offload some existing circuits in order to improve reliability and operational flexibility. In addition to the new transformer, new relays and 15kV breakers are scheduled to be installed to accommodate the future integration of distribution automation.

7.2.1.3 Anticipated Date of Study

- New Baltimore Integration Study - 2021

7.2.2 South Cairo

7.2.2.1 Summary of Issues

The South Cairo Substation serves the areas of Cairo, Purling, Lawrenceville, East Durham, and Acra. The Substation is home to the South Cairo Combustion Turbine (CT) which is used as a backup for a transformer failure and to provide voltage support to the local transmission area. By 2025, due to DEC emission restrictions, the CT will be retired and South Cairo will not have a backup source in the event of a transformer failure.

7.2.2.2 Summary of Recommendations

A second transformer will be required at South Cairo substation due to the retirement of the CT. Also as part of this retirement, the installation of D-VAR units at South Cairo to provide voltage support for the transmission loop is being studied. The overall project scope for the substation upgrades regarding the CT retirement has not been finalized yet

7.3 Load Group 2 - Kingston

7.3.1 Woodstock

Reference: K-2019-05 - Woodstock Substation Circuit Exits

7.3.1.1 Summary of Issues

The Woodstock Substation serves the majority of the Town of Woodstock, as well as sections of the Towns of Hurley, Olive, Saugerties, and Kingston. The SR transmission line that feeds the Woodstock Substation is a radial feed that has been plagued with outages. The line has experienced 3 permanent interruptions over the past 5 years. The outages affect approximately 8,286 customers each time.

The existing external switchgear and control house switchgear has reached the end of its useful life and replacement parts are difficult to obtain. Maintenance issues have been experienced with racking the 1947 vintage breakers in the external switchgear. Replacement parts for the racking mechanisms are also no longer available.

The dial up RTU housed inside of the control house switchgear is unreliable, due to space constraints and there is no room to add additional equipment or to replace the RTU. The 1972 vintage breakers utilize a puffer with a plastic manifold, this has been a constant maintenance issue.

The external switchgear and control house switchgear have separate DC voltage supplies, a 24 volt and a 48 volt battery system, respectively. There is no room to upgrade either battery system, and maintenance of the system is problematic.

The substation is served by two transformers, with Transformer #1 having the lower Summer LTE at 19.125 MVA. The peak load at the substation was 17.7 MVA in the summer of 2019 (taking into account the Ashokan hydro generation). The Ashokan hydro generators, located on the 3011 distribution circuit, have a nameplate rating of 4.6 MW at 0.9 power factor, but have only generated a peak of 2.5 MW, and are not necessarily available for deployment on a peak day. The Ashokan hydro facility was generating 1.55 MVA at the time of the 2019 peak.

7.3.1.2 Summary of Recommendations

The external switchgear and control house switchgear will be replaced with a new Power Control Center (PCC). The PCC will contain a two bus system separated by a normally open tie breaker, 15kV breakers rated 2000A and 1200A, protective relaying, interconnection cabinet, PT's, station service transformers, RTU, and DC battery system. The PCC will contain provisions for future expansion. Distribution Engineering is currently working with Electric Operations to determine a plan for circuit exists to facilitate the new substation switchgear. This plan will take into account consider substation loading, surrounding infrastructure, and reliability.

In response to the SR Line outages, additional trimming was completed on this line. This included clearing an additional 25 feet of right-of-way in several areas. The right The Distribution Automation rollout in the Kingston District is planned for 2021. By this time, the Woodstock Switchgear replacement will have been completed (2021). These projects, in conjunction with the implementation of automated switching via the DMS system, are expected to improve the reliability of the customers in the area. See Section 4 – Distribution Grid Modernization for additional detail.

7.3.1.3 Anticipated Date of Study

Kingston District Distribution Automation Plans – 2020-2021

7.3.2 Boulevard

- Reference: EP2014-03 Boulevard/Jansen Ave./South Wall St./Converse St. Area Study
- Reference: EP2018-03 Boulevard Integration Study

7.3.2.1 Summary of Issues

In a condition assessment of Central Hudson transformers aged fifty-five years and older, Transformer 1 and Transformer 2 at Boulevard Substation were identified as performing marginally on tests. Transformer 1 has an elevated power factor and unsatisfactory Dissolved Gases-in-Oil Analysis (DGA) results. Transformer 2 has exhibited increases in low-ground and tertiary-ground insulation. These transformers are both in excess of 70 years of age (Transformer 1 was manufactured in 1937 and Transformer 2 was manufactured in 1940). Transformer 1 is composed of three single phase 5,000 kVA transformers connected wye-delta-wye and Transformer 2 is an 8,500 kVA wye-delta-wye zigzag transformer.

7.3.2.2 Summary of Recommendations

In 2014, a study was completed by the Electric Distribution Planning Department to address the long-term needs of the area served by Boulevard Substation. Transformer 1 and Transformer 2 are in the process of being replaced with 12 MVA transformers and Transformer 3 will be removed. This will provide Boulevard Substation with a firm rating of approximately 33 MVA which will serve current and future loading in the area. An integration study was completed in 2018 to determine how to design the new distribution and sub-transmission feeders. In addition to the transformer replacements, distribution circuit exit modifications are recommended for improved reliability and operational flexibility. The transformers were made available for service in Q4 2019 and the station rebuild will be completed in Q2 2020.

7.3.3 Converse Street

- Reference: EP2014-003 Boulevard/Jansen Ave/South Wall St/Converse St Area Study
- Reference: Kingston Grid Network Evaluation for Possible Conversion to Spot Network MEMO

7.3.3.1 Summary of Issues

The Converse Street Substation serves the Kingston Network. It is fed from the KK cable out of the Boulevard substation. The substation is a two transformer, 14kV to 4kV station. Transformer 2 is 63 years old and is scheduled for replacement in 2022 due to a poor condition assessment after exhibiting dielectric breakdown and elevated power factor. Additional modernization of the substation and upgrading of the RTU is within the planned scope of work. In addition, the Kingston Network as a whole is aging and requires review to maintain reliability in the area.

7.3.3.2 Summary of Recommendations

In 2019, a study was conducted to determine the feasibility for moving the Kingston secondary network into three secondary spot networks. Due to the high cost of conversion, design, voltage constraints, and potential negative impacts to reliability; it was recommended not to move forward with the creation of spot networks. As a result of maintaining the Kingston secondary network, it was recommended to proceed with the replacement of Converse Street Transformer 2 scheduled for 2022. In addition to the transformer replacement, replacement of the Converse

Street breakers and switchgear will also be completed in 2022 due to parts constraints, wiring issues, and older generation relaying.

7.3.4 South Wall Street

- Reference: K-2019-04 111 & 112 – Retire South Wall Street Substation

7.3.4.1 Summary of Issues

The equipment at South Wall Street has reached the end of its useful life and is slated for replacement. The transformer has higher than desired saturation, and DGA (dissolved gas-in-oil analysis) indicates there is probable overheating of the isolative paper. The 46-year-old unit has not been Doble-tested since 2009, as there is limited flexibility being a single transformer station. Furthermore, the only spare replacement unit within the company is 60 years old. The station uses oil-filled hydraulic reclosers for circuit breakers as vacuum hydraulic reclosers do not fit in the circuit recloser cubicles. Central Hudson does not procure the oil-filled units anymore, and the low-profile switchgear within which they reside pose safety concerns.

7.3.4.2 Summary of Recommendations

A distribution solution would be more economical and easier to implement than completing the necessary substation work to the metering and relay equipment currently present. Replacement of the South Wall Street unit transformer and hydraulic reclosers can be completed with two 1500 kVA pad-mounted stepdowns along with two electronic reclosers (Vipers) on the output (load) side to maintain transient protection. Replacement is scheduled for 2022. The South Wall St Substation can then be retired.

7.3.5 Lincoln Park

- Reference: K-2020-05 Lincoln Park Substation Circuit Exits

7.3.5.1 Summary of Issues

The Lincoln Park Substation serves the areas of Lincoln Park, Sawkill, Lake Katrine, and Mt Marion. Many of Lincoln Park's outdoor switchgear cables are in poor condition and are potentially out of service. .

7.3.5.2 Summary of Recommendations

A planning study is currently being conducted to determine the optimal bus and circuit configuration for the substation. Three of the four circuit breakers previously used to supply the Tech City industrial park are out of service and no longer used. The capacitor banks are not needed based on current station loading. About half of the substation's circuits are lightly loaded and have low customer counts and there is the potential to combine circuits to eliminate breaker positions. By increasing the customer count per circuit, there is an increased risk for larger outages. The study will aid in the determination of which units should be replaced/upgraded to indoor switchgear and which units can be retired/removed.

7.3.5.3 Anticipated Date of Study

Lincoln Park Integration Study - 2021

7.4 Load Group 3 - Ellenville

7.4.1 Neversink

- Reference: EP2011-004 Evaluation of Neversink Substation Site and Extension of BWS Lease

7.4.1.1 Summary of Issues

The Neversink Substation serves the Town of Neversink, as well as sections of the Towns of Wawarsing and Denning. It is served by two transformers. Transformer #3 has a Summer Normal rating of 4.92 MVA on the lowside winding (13.2kV), and 2.46MVA on the tertiary winding (4.16kV). This transformer serves the 3091 and 391 circuits, which peak around 3.08 MVA and 550 kVA respectively. Transformer #6 has a Summer Normal rating of 2.083 MVA and operates as a spare serving 100A Type L reclosers.

Overloading of the transformer or other equipment under normal conditions is not anticipated within the 10-year horizon. The substation transformers were tested and determined to be in adequate working condition. The Neversink Substation is located in a rural area where it is unlikely there will be significant organic growth or economic development. Historical growth rates have been minimal in this area.

Additionally, our 50 year lease with the Board of Water Supply to operate our substation on their property ended in 2006 and Central Hudson is operating its facilities in the area solely under the Separation Agreement and required notice. Once Central Hudson is notified to vacate the property, Central Hudson has 18 months to complete the transition away from the site.

7.4.1.2 Summary of Recommendations

In the event that the Board of Water Supply notifies Central Hudson to vacate the property, the design and construction of the new Coombe Substation will move ahead. During the interim, it is recommended that Central Hudson extend the existing lease with the New York City BWS at the Neversink Substation site. Distribution Engineering is currently reviewing potential options to improve operational flexibility. Recommendations will incorporate cost-benefit analysis to determine the most appropriate solution. Additionally, solutions may be incorporated as part of the Kingston DA review. This substation previously used Gridsense for metering data. Gridsense stopped providing service in 2014 and in 2019 the SEL-351R relay installed in the Neversink Substation for feeder 3091 was added to Central Hudson's Sensus network in order to obtain metering data.

7.4.2 Greenfield Road/Clinton Avenue

7.4.2.1 Summary of Issues

- Reference: EP2016-012 Spare 10/12MVA Transformer Relocations
- Reference: Greenfield Road/Clinton Ave. Area Study

The Greenfield Road Substation consists of two 69-4.16 kV delta-wye transformers and one 69/13.2 kV wye-wye (delta tertiary) transformer serving portions of the Town of Wawarsing and the Village of Ellenville. The windings on phase two of Transformer #1, one of the 69-4.16 kV transformers, has been slowly losing dielectric strength since 1992. The station is operating well below its thermal rating, but is operationally challenging due to the different operating voltages and lack of phasing.

The Clinton Avenue transformer was manufactured in 1957 and has been recommended for retirement due to unsatisfactory power factor tests and high moisture levels.

7.4.2.2 Summary of Recommendations

It is recommended the Greenfield Road Substation be rebuilt entirely to operate at 69-13.2kV. The substation rebuild will involve the construction of a two 10MVA transformer substation with four circuit exits (3076, New

3077, 3078, Spare). It is recommended that the system spare 10MVA transformer from Modena and the spare 10MVA transformer from Kerhonkson be utilized at Greenfield Road. An integration study will be performed starting in 2020 to determine appropriate path and conversion work required.

Once the Greenfield Road Substation rebuild is complete, the Clinton Avenue 4kV circuitry should be converted and supplied by the Greenfield Road 13.2kV circuitry. The Clinton Avenue substation can then be retired.

7.4.2.3 Anticipated Date of Study

Greenfield Road Integration Study - 2021

7.5 Load Group 4 – Southern Ulster

7.5.1 Modena

- Reference: EP2012-013 Modena Substation Upgrade Assessment
- Reference: EP2016-012 Spare 10/12MVA Transformer Relocations

7.5.1.1 Summary of Issues

The Modena Substation consists of a newer 115kV station which includes a 115 kV-13.2 kV transformer to supply the area load and the “old” station, which is fed by a 115/69 kV transformer and includes the 69-13.2 kV system spare transformer. While stored at the Modena substation, the 69-13.2 kV system spare transformer acts as a backup for the “new” station. The station serves the load in the Town of Plattekill, as well as portions of Gardiner and New Paltz. Once the P & MK Line conversion is completed, the “old” station will be retired.

7.5.1.2 Summary of Recommendations

A backup transformer at the Modena Substation is not required for operational or thermal reasons. Our current 69-13.2 kV system spare transformer will remain at Modena until it is utilized at Greenfield Road as part of the substation rebuild.

7.6 Load Group 5 - Orange

7.6.1 Maybrook/Montgomery

- Reference: EP2011-012 Montgomery/Maybrook Area Study
- Reference: EP2018-008 Montgomery Substation Integration Study

7.6.1.1 Summary of Issues

The Montgomery Substation was rebuilt in 2019. The new substation contains two 69-13.8kV 10/12.5 MVA transformers with LTCs and is located on the existing Montgomery Substation property along Rt. 17K in the Village of Montgomery. Based on infrastructure and operational flexibility issues previously identified within a comprehensive area study, this option addressed the infrastructure issues at Montgomery and provided ability to transfer additional load from the Maybrook Substation thereby addressing some of the area loading and infrastructure issues. This solution represented a lower overall capital cost alternative to the original plan, which involved replacing the transformers at the Maybrook Substation and relocating the old Maybrook transformers to the Montgomery Substation.

Along with the substation construction will be the conversion of two 4kV feeders (571 and 572) to 13.2kV operation and the construction of two new 13.2kV feeders to assume portions of the surrounding area load. While the newly rebuilt Montgomery Substation will allow for portions of the Maybrook Substation to be offloaded, there are currently several new industrial loads, as well as DER systems, proposed in this area.

7.6.1.2 Summary of Recommendations

- Offloading of Maybrook load to the newly rebuilt Montgomery Substation is to be completed in 2020.
- It is recommended to have Distribution Planning conduct an assessment of the loading of the Maybrook area to review the impact of the recent interconnection of several new industrial customers as well as DER systems.

7.6.2 Newburgh Area

- Reference: EP2011-001 Newburgh 14.4kV Area Study
- Reference: EP2013-016 Montgomery Street Transformer Replacement

7.6.2.1 Summary of Issues

There is one 14.4kV loop system in the Newburgh District. It primarily feeds the City of Newburgh. This 14.4kV loop systems is comprised of paper and lead cables that have experienced numerous failures, and have therefore been identified for replacement as part of the 14.4kV Cable Rejuvenation Program. The area was evaluated to determine whether or not upgrades to the remaining 14.4kV loop infrastructure are economical when compared to alternatives that may be available due to available capacity at adjacent substations.

The associated Montgomery Street 14.4kV switchgear is antiquated and in need of repair. The breakers and associated cabling is approximately 60 years old and has exceeded its useful life. The associated relaying and metering are also outdated and in need of modernization.

Additionally, the Montgomery Street Substation transformers are both nearing 80 years old and have exceeded their useful lives. Power factor test results for both transformers indicate high and low side dielectric breakdown. DGA lab results for Transformer # 2 indicates high relative saturation as well as possible overheating of the cellulose paper insulation.

7.6.2.2 Summary of Recommendations

West Balmville – Montgomery Street 14.4kV Loop (2018+)

- All four cables feeding the Montgomery Street Substation were evaluated for replacement based primarily on risk and failure rate. The cables identified for evaluation were the B, F and R cables, as well as the underground portion of the WN cable entering the Montgomery Street Substation. The overhead portion of the WN cable was already replaced as a part of the cable rejuvenation program. The area was restudied in 2019 to determine if all 4 cables were still required.

- Based on the results of the study/evaluation a new circuit will be constructed to replace the B, F and R cables between the West Balmville and Montgomery Street Substations. This work is expected to commence in 2020 and be completed as part of five phases, concluding in 2024.

- The remaining portion of the WN cable feeding into the Montgomery Street substation is scheduled for replacement in 2020. This includes both the lead cable and surrounding infrastructure.

Montgomery Street – Transformer Replacements

- Both Montgomery Street Transformers were replaced in 2018.

Montgomery Street – 14.4kV Switchgear Upgrade

- The Montgomery Street 14.4kV Switchgear is scheduled for replacement in 2022. An integration study may be conducted prior to the switchgear replacement if reconfiguration is deemed necessary.

7.6.3 Union Avenue

- Reference: EP2017-09 Union Avenue Integration Study

7.6.3.1 Summary of Issues

The Union Avenue lower yard switchgear was identified as nearing the end of its useful life and was replaced in 2019. The design as part of this replacement resulted in the majority of the circuits leaving the switchgear and collecting in two man holes in the southeast corner of the yard. A new distribution plan was required to connect the new infrastructure to existing circuit exits. Additionally, the Union Avenue circuits feeding the Cornwall area were identified as not having sufficient operational flexibility, as Cornwall is located at the edge of Central Hudson's service territory.

7.6.3.2 Summary of Recommendations

- A parallel run of conductors was installed for both bus tie cables between the upper and lower yards in 2018.
- A new conduit bank exiting the back of the substation was completed in 2018 to replace aging infrastructure.
- A new express circuit was constructed in 2020 to improve operational flexibility in the town of Cornwall. Additional work to install an ALT team and transfer load is awaiting completion of bridge work being performed by the Department of Transportation which is scheduled to be completed in 2021.

7.7 Load Group 6 – Northeast Dutchess

7.7.1 Northeast Dutchess County

- Reference: EP2012-006 North-East Dutchess Area Study
- Reference: Category 15 Capital Budget Project P-2011-13 – Reconductor circuitry along Rt. 82 (Phase I)
- Reference: Category 15 Capital Budget Project P-2011-17 - Reconductor circuitry along Rt. 82 (Phase II)
- Reference: EP2016-012 Spare 10/12MVA Transformer Relocations

7.7.1.1 Summary of Issues

The Northeast Dutchess and Southern Columbia County area encompasses several rural towns with village centers, such as Northeast, Ancram, Millerton, Pine Plains, Milan, Gallatin, Stanfordville, Clinton, and Washington. The area is experiencing substation and step-down transformer loading issues, aging infrastructure, and below-average electric service reliability. The Stanfordville Substation transformer reached its Summer Normal rating in 2011 and has since remained at near capacity. The Stanfordville Substation transformer and the Smithfield Substation transformer are over 60 years old, and the Stanfordville transformer has experienced problems with overheating. There have been minimal signs of area growth over the recent history, but the abundance of 4800V circuitry in this area poses a safety risk, constraint on operational flexibility, and concerns regarding aging distribution infrastructure.

The Pulvers Corners 7395 34.5kV subtransmission line feeding the Ancram Substation also has age related concerns. The line is comprised primarily of aging 1/0 ACSR conductor that is showing signs of corrosion and degradation. Portions of the line are over 70 years old and the circuit has experienced multiple conductor failures over the past five years.

Additionally, the 34.5kV-13.2kV transformer at the Ancram Substation is over 50 years old, shows signs of overheating, and has minor moisture concerns in the insulation system.

7.7.1.2 Summary of Recommendations

- The new Hibernia 7013 circuit was placed in service in 2017 to offload a portion of the Stanfordville load.
- A sample of the 7395 conductor was tested externally and the analysis results were provided to Central Hudson. These results are currently being assessed and a recommendation will be developed.
- Continue the 4800V conversion program – The practice of installing 4800V circuitry was abandoned in the 1940s, and therefore the infrastructure has exceeded its useful life. It also limits the operational flexibility and hosting capacity of the area. Infrastructure needing replacement will be identified through this program.
- Complete budget project P-2011-13 and P-2011-17 to reconductor circuitry along Rt. 82 scheduled for 2024 and 2025, respectively, to improve the operational flexibility in the area.
- A project will be completed in 2020 to install new RTUs, relays, and a new 10MVA transformer at the Stanfordville Substation.

- Distribution Planning is in the process of conducting an assessment of the Pulvers Corners/Ancram area to address the infrastructure concerns.

7.7.1.3 Anticipated Date of Study

Pulvers Corners/Ancram Infrastructure Assessment - 2021

7.8 Load Group 7 – Mid-Dutchess (North)

7.8.1 Poughkeepsie 14.4 kV System

- Reference: EP2010-002 Poughkeepsie 14.4kV Area Study

7.8.1.1 Summary of Issues

The Reynolds Hill Substation is composed of two 115-13.8 kV transformers, and in addition to distribution circuits, serves 14.4 kV feeders that supply the secondary network transformers and load in the City of Poughkeepsie. The two transformers at the Reynolds Hill Substation were identified as needing to be replaced based on condition and age. These transformers were replaced in 2018. Vassar Hospital is currently expanding its facilities and requires an additional 4.4 MVA of capacity. Additionally, there are four (4) lateral branches remaining of aging PILC cable on the Poughkeepsie 14.4kV system. In 2019, the City of Poughkeepsie announced plans to repurpose the major road, Market St., where these lateral branches reside.

7.8.1.2 Summary of Recommendations

To supply Vassar with additional capacity and mitigate the issues with the PILC cable, the following projects have been completed/are expected to be completed within the upcoming years:

- The existing PS breaker position at Reynolds Hill was reclassified as a 13.2kV circuit serves as a dedicated feeder to Vassar Hospital. This project was completed in 2018.
- Capital funds have been budgeted for 2021 and 2022 to replace the lateral PILC branches.

7.9 Load Group 8 – Mid-Dutchess (South)

7.9.1 Beacon/Conway Place

- Reference: EP2013-008 Beacon Area Study
- Reference: Category 15 Capital Budget Project F-2021-07 8018L/8085L – Beacon Conversion (Phase V)

7.9.1.1 Summary of Issues

The City of Beacon in southern Dutchess County was primarily served by the Beacon and Conway Place Substations. These stations were fed by a 14.4 kV loop originating at the Forgebrook Substation. Due to age and infrastructure condition, the Beacon Substation was retired in 2016; the CM/NM and BF sub-transmission lines were re-classified and utilized as the 8017 and 8018 13.2kV distribution circuits in 2017; the Conway Place 881 and 882 circuits were converted to 13.2kV operation; and the Conway Place substation was retired in 2019.

7.9.1.2 Summary of Recommendations

Based on the retirement of the 4kV Beacon and Conway Place Substations, the following projects are expected to be completed within the upcoming years to improve reliability:

- An automatic load transfer team will be installed at the former Beacon Substation location by December 2020.
- Complete capital budget project F-2021-07 to convert remaining low voltage circuitry between the 8018 and 8085 and re-establish ties.

7.9.2 Knapps Corners

- Reference: EP2009-001 Knapps Corners Substation Breaker Study
- Reference: SR 2012-01 Knapps Corners 15kV Bus Reconfiguration

7.9.2.1 Summary of Issues

The Knapps Corners Substation was originally put in service in 1941 and expanded in 1953. A large portion of the equipment currently in the station has exceeded its useful life. Equipment identified as in-need of replacement includes 11 breakers, 63 relays, and all associated metering. Also, the three substation transformers are mid-60s vintage units and have exceeded the accepted industry standard life of 50 years.

Additionally, when the Spackenkill Substation was placed in service in 2010, the associated Knapps Corners 14.4kV system was retired. This retirement left the existing regulators, reactors, and phase shifting transformers unnecessary and obsolete.

7.9.2.2 Summary of Recommendations

A new Knapps Corners Substation will be built by 2021 in order to address all infrastructure related concerns. The new substation will be built on an adjacent piece of property since the existing substation cannot be removed from service during the construction of the new station and the existing footprint is constrained.

The existing Knapps Corners Substation will be retired following the in service of the new Substation. A distribution plan has been developed for circuit exits out of the new substation location and construction will be completed in coordination with substation work.

7.9.3 Myers Corners

7.9.3.1 Summary of Issues

The current relaying at the Myers Corners substation is antiquated and requires replacement in order to meet the current relaying and metering requirements for the Distribution Automation program.

Additionally, it has been determined that the existing switchgear, housing, doors, and breakers in the Myers Corners Substation are nearing the end of their useful life. The substation is nearing 40 years old and, based on condition assessment the switchgear requires replacement.

7.9.3.2 Summary of Recommendations

The relaying at the Myers Corners Substation was upgraded in 2018.

Due to the condition of the switchgear, a new Power Control Center will be installed in 2021.

8. Summary of Projects

To optimize the expenditure of ratepayer contributions and plan for the future, the Electric Engineering Capital Budget is developed based upon Electric Planning Studies, compliance requirements, infrastructure programs, and reliability improvement programs that are integrated into this Long Range Electric System Plan. Each year, the Company develops a 5-Year Corporate Capital Forecast and an annual Capital Plan/Budget for upcoming five and one year time frames. The 5-Year Capital Budget for the Transmission (Category 12), Substation (Category 13), and Distribution (Category 15) categories serves as a summary of all of the major near-term integrated components described in this document, as well as additional minor projects identified through the Electric System Planning Process. This Capital Plan is reviewed and approved by the Company's Board of Directors and filed with the Public Service Commission on July 1 of each year. The current version of this document is the "2021-2025 Corporate Capital Forecast and 2021 Capital Budget".

9. Emerging Opportunities

Through areas like our R&D committee, industry meetings, and through benchmarking/interactions with other utilities, Central Hudson is continually identifying and evaluating new and emerging technologies that may be applicable to our business. While this document contains many emerging opportunities detailed in other sections, a number of emerging opportunities are receiving significantly increased attention based on the New York State Reforming the Energy Vision (REV) initiative. Specifically, Distributed Energy Resources (DER) are growing at a rapid rate and are forecast to continue to grow within the state. These resources include the following technologies: Electric Vehicles (EVs), standalone Photo-voltaic (PV systems), standalone Battery Energy Storage Systems (BESS), PV paired with BESS, Demand Response, and Energy Efficiency. Central Hudson has begun incorporating DER into our planning processes as these resources begin to have an impact on our system. There will most likely be sections dedicated to these technologies in subsequent Long Range System Plans. The Central Hudson DSIP, being filed with the PSC on June 30, of this year, contains the current status and long range plans for these emerging technologies.

A more recent initiative impacting our business has been the passing of the Climate Leadership and Community Protection Act (CLCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act (Renewables Act). Among other topics, these documents present global and ambitious New York State goals in the areas of renewables (including solar, land based and off-shore wind), and energy storage. Central Hudson is actively working with the Department of Public Service (DPS), the New York State Energy Research and Development Agency (NYSERDA), Public Power Agencies (NYPA and LIPA/PSEG-LI) and the New York State investor owned utilities (Con Ed, National Grid, NYSE&G/RGE and O&R) in a number of forums to help facilitate the achievement of the goals outlined in these documents. These, and other emergent State policy initiatives will continue to inform and impact Central Hudson planning and business processes. Based on the timing, a number of uncertainties and ongoing discussions regarding these initiatives, the impacts from these acts have not been reflected to any great degree in this plan. However, it is anticipated that these initiatives will have significant impacts to our long range system plans and planning processes in the near future to meet the goals of the CLCPA and Renewables Act.

10. Conclusion

Central Hudson has developed a comprehensive Long Range Electric System Plan that provides sufficient vision and detail to effectively evaluate and prioritize capital expenditures, while allowing flexibility to integrate emerging trends, technologies, and policies with for the benefit of our customers. This Long Range System Plan in conjunction with our 2020 DSIP filing outlines our most current plans to address system and locational growth, infrastructure issues, and to plan for and accommodate significantly increased penetration levels of DER onto our transmission and distribution system into the foreseeable future

D. Location Specific T&D Avoided Cost Study Report

DRAFT REPORT

2020 Central Hudson Location Specific Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods

Prepared for Central Hudson

By

Demand Side Analytics

June 2020

ACKNOWLEDGEMENTS

Principal Consultants

- Josh Bode
- Alana Lemarchand

Senior Quantitative Analyst

- Mark Noll

ABSTRACT

The focus of the study is in quantifying the T&D costs associated with an increase or decrease of kW coincident with location specific peaks. It does not include costs associated with aging or failed equipment, reliability improvements, and grid modernization. The study estimates location specific growth patterns and avoidable T&D costs for individual substations and transmission areas. The load growth forecasts and avoided cost estimates were develop using probabilistic methods and account for the reality that there is much greater uncertainty ten years out than one year out.

Most substations and transmission areas in Central Hudson territory are experiencing declining loads, have ample room for growth over the next 10 years, or are in non-wire-alternative project areas. However, one substation, Shenandoah-Distribution, and one transmission area, the Northwest 115-69kV area, may require future load relief, as both locations have currently contracted NWAs that will expire over the next ten years, increasing the risk of overloads and of triggering an infrastrucutre investment. Avoided costs are not included in the 2020 study because both beneficial locations identified are currently under feasibility review for Non-Wires Alternatives. Instead, the annual and hourly peak day need is shown for both locations.

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1 INTRODUCTION

One vital role of the electric utility is to ensure that electricity supply remains reliable. By projecting future demand and reinforcing the local distribution network so that distribution capacity is available to meet local needs as they grow over time, costly outages are avoided.

A key focus of the New York Public Service Commission's REV proceeding is to defer or eliminate the need for traditional T&D infrastructure investments by using DERs. This requires quantifying the potential to avoid or defer infrastructure upgrades based on load growth as granularly as possible.

The growth of DERs is fundamentally changing the nature of distribution system forecasting, planning, and operations. Forecasting location specific loads and DERs using probabilistic methods is becoming increasingly critical for T&D planning. However, local demand trajectories based on historical loads are inherently uncertain and those forecasts grow more uncertain further into the future. Location specific, granular forecasts are also essential to establishing the location specific value of DERs and identifying locations where DERs are beneficial. Simply put, location specific forecasting and planning methods have direct implications for DER integration.

To our knowledge, Central Hudson was the first New York State utility to implement a location specific avoided T&D cost study that relies on probabilistic analysis and quantifies the option value of reducing peak demand. This is Central Hudson's third time implementing this type of study and we have looked to make enhancements with this iteration. We emphasize that the development of probabilistic load forecasts and avoided T&D costs at a granular, local level is a still a relatively new endeavor and continues to be refined and improved since it was first used for the 2016 Avoided Cost Study.

The focus of the study is in quantifying the T&D costs associated with an increase or decrease of kW coincident with location specific peaks. The study focuses on substation and transmission costs (it does not include circuit feeders) and was designed to meet the following objectives:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level;
- Develop location specific forecasts of growth with uncertainty;
- Quantify the probability of any need for infrastructure upgrades at specific locations;
- Calculate local avoided T&D costs by year and location using probabilistic methods; and
- Identify beneficial locations for DERs.

There are several aspects of the study that make it unique. First, the T&D avoided cost estimates are produced by substation and transmission area. Most T&D marginal cost and avoided costs studies produced system wide values or at most region specific results, often concentrating on historical T&D expenditures rather than future infrastructure investments. Second, the study estimates historical year-to-year growth patterns and variability in growth for individual substation and transmission areas. Third, load growth forecasts and avoided cost estimates are develop using probabilistic methods rather than straight-line forecasts. The approach takes into account that there is greater uncertainty 10 years out rather than a year out and accounts for the risk mitigation value of resources that manage local peak loads.

As a general rule, only growth-related T&D investments that are shared across multiple customers and a small subset of reliability based projects can be avoided by DERs or demand management. When loads grow, the excess distribution capacity that may exist dwindles. If a customer helps reduce coincident demand, either by injecting power within the distribution grid or by reducing demand, 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 investments are driven by local, coincident peak loads. Some investments are tied to customer additions and are essentially fixed. Other investments must take place because of equipment nearing the end of its useful life, the need to improve reliability, or the need to modernize the grid. These investments typically cannot be avoided by managing loads with DERs.

The value of transmission and distribution 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 unavoidable distribution upgrades;
- The design of the distribution system; and
- The ability to make fairly inexpensive upgrades (i.e. switching alternatives) 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, since the system peak of 1,295 MW was set in 2006 and system load has dropped significantly since that time, such that investments are not needed in the foreseeable future.

In 2016 and 2018, Central Hudson implemented location specific avoided T&D cost studies that relied on probabilistic analysis and quantified the option value of reducing peak demand. This study updates the avoided T&D Costs. This study updated the 2018 avoided T&D costs by incorporating additional years of load data. In comparison to the 2018 study, the 2020 T&D avoided costs differ along the following dimensions:

- Growth rates were based on a more recent period of data, 2014-2019, and additional data cleaning procedures were implemented;

- To a smaller extent, growth rates were higher because we forecasted gross loads (adding back historical DER generation), rather than net loads as in the 2018 study;
- We represented existing NWAs in a more detailed manner and incorporated expected changes to ratings resulting from non-NWA-related reasons ;
- The two locations with value in the 2018 study (Hunter and Lawrenceville substations) no longer trigger upgrades, due to declining loads;
- The two locations with value in the 2020 study are both relatively highly loaded, have positive growth rates, and have ratings decrease expected in the study (due to expirations of currently contracted NWA and generation load serving capability), resulting in a high investment trigger likelihood (in the absence of further NWAs); and
- Avoided T&D costs are classified into three mutually exclusive categories: projects for NWA solutions which provide contractual resources for a specific location and need, Location Specific Relief Value (LSRV) which can be used to incentivize resources in a specific location not associated with an NWA, and Distribution Relief Value (DRV) which represents can be used to incentivize non-contracted resources that provide system wide load relief. Because all projects underlying the T&D avoided costs have been classified for NWA solutions, the LSRV and DRV T&D values are zero.

The remainder of this report is organized in five sections.

- Section 2 provides an overview of the methodology.
- Section 3 presents the historical growth estimates.
- Section 4 details the avoided costs and the risk of triggering infrastructure upgrades or load transfers by location and discusses differences between the 2018 and 2020 study.
- Section 5 reviews the Beneficial Locations.
- Section 6 summarizes the key findings and conclusions.

2 METHODOLOGY

This section details the risk tolerance for different types of systems, data sources used, and key steps in developing location specific forecasts and avoided T&D cost. Before doing so, we discuss why probabilistic methods are critical not only to forecasting, but also to quantifying location specific avoided T&D costs.

2.1 T&D LOAD PATTERNS AND INFRASTRUCTURE UPGRADES

When demand exceeds normal and emergency equipment ratings, equipment can become overloaded and degrade more quickly, considerably increasing the risk of an adverse reliability event. With the exception of single transformer rural substations, most of Central Hudson's system is designed to withstand the loss of the highest rated source (e.g., the loss of a transmission line, transformer, or other component) without violating thermal or voltage limits – that is, the substation or area design rating is often equal to the rating of the lowest equipment rating. As a result, loads in excess of the load serving capability, or design rating, do not automatically result in overloads or an infrastructure upgrade. However, depending on the level of risk of impacted customers and load, Central Hudson may not wait for loads to exceed a reasonable level of risk to begin construction.

To assess future upgrade likelihood, it was necessary to define structured criteria for when upgrades might be triggered in the future. The criteria were designed to reflect the reality that forecasting load levels that have the potential to result in exceeding a normal or emergency equipment ratings from time to time does not automatically trigger an infrastructure upgrade, though it does increase equipment failure risk. Specifically, the upgrade trigger was defined as occurring when a location's long-term emergency rating is forecast to be exceeded in two consecutive years; a single occurrence of the forecast exceeding the short term emergency rating would also trigger an upgrade. The future loads for this analysis were modeled using 1 in 2 weather conditions.

Figure 1 illustrates a fundamental feature of peak energy demand. The graphs reflect the 2019 load duration curves for Central Hudson's 10 transmission areas (non-weather-normalized). Load duration curves sort electricity demand from highest to lowest and are a good way to visualize how 'peaky' a system is. The graph only shows the top 5% of hours in 2019. All of the load duration curves show hourly demand as a percent of each area's 2019 peak, allowing side-by-side comparisons for areas with a different magnitude of demand. For most locations, the top 20% of loads are associated with 2% (175 hours) or less of the hours in the year. Figure 2 shows the same load duration curves as a percent of each transmission area's design rating (including NWAs), highlighting the varying degree of loading within each transmission area. The results for individual substations are similar but with a wider range of diversity.

Figure 3 illustrates the diversity in peak day load shapes for Central Hudson using substation loads. The substations were classified as summer peaking or winter peaking based on the season of top 10 highest load days in 2019, and the plots show the average peak day hourly load profile in that season. The plots were normalized, and show the percentage of usage for the day in each hour (the area under each curve adds up to 100%), allowing comparison of substations of different sizes. For summer peaking substations, the peak falls sometime in the afternoon or early evening. Most winter peaking substations are dual peaking, with the highest load occurring in the afternoon or early evening and a secondary peak occurring in the morning.

Figure 1: Normalized Load Duration Curves – Percent of Peak Load

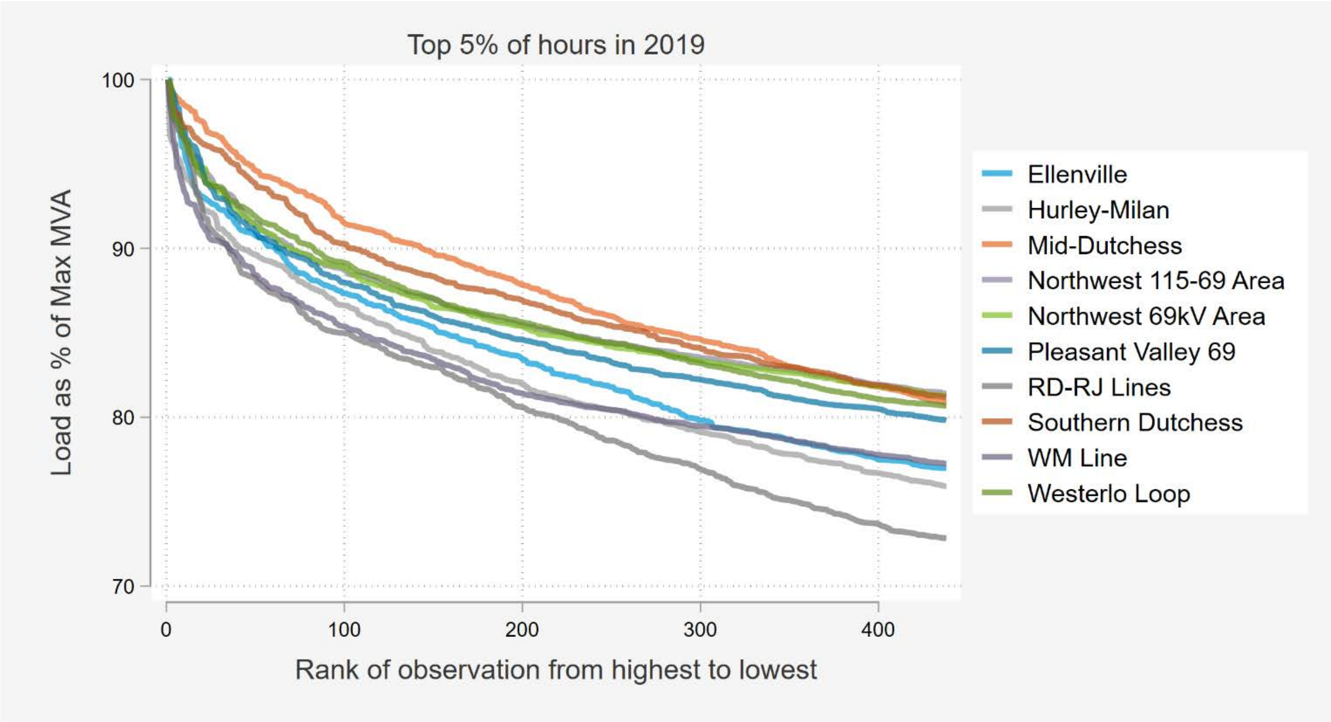


Figure 2: Normalized Load Duration Curves – Percent of Design Rating

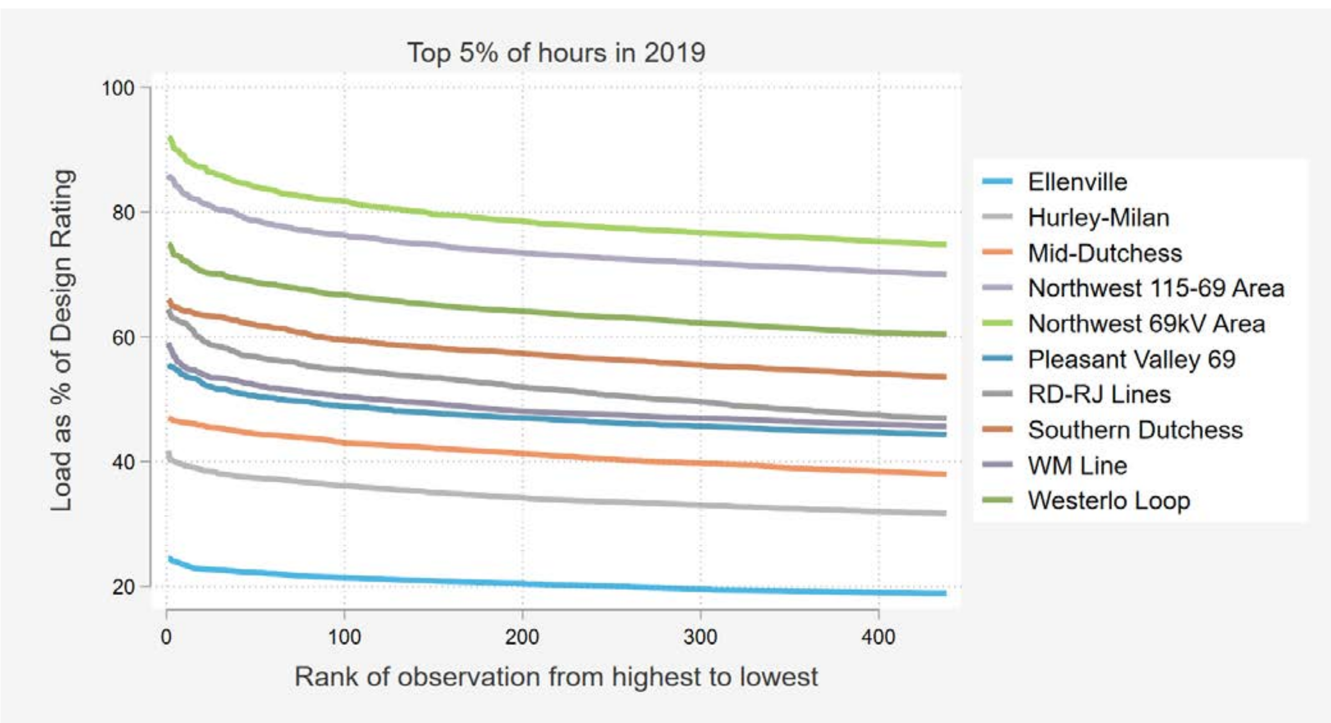
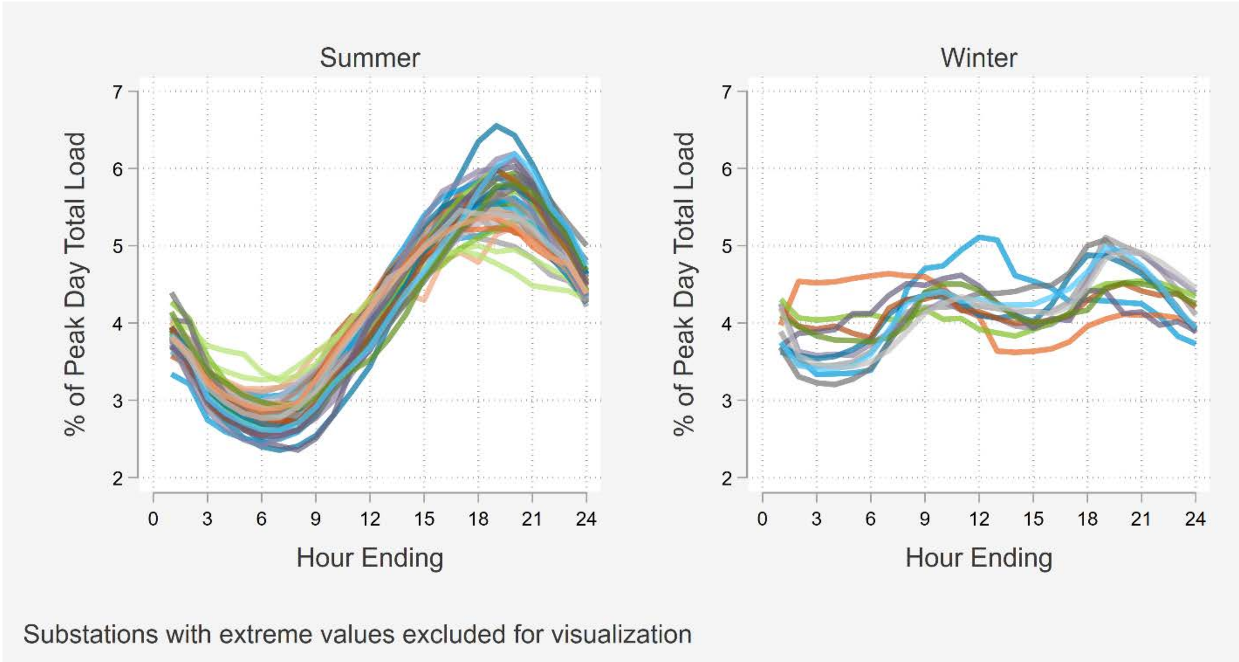


Figure 3: Central Hudson Location Specific Peak Day Load Shape Classification

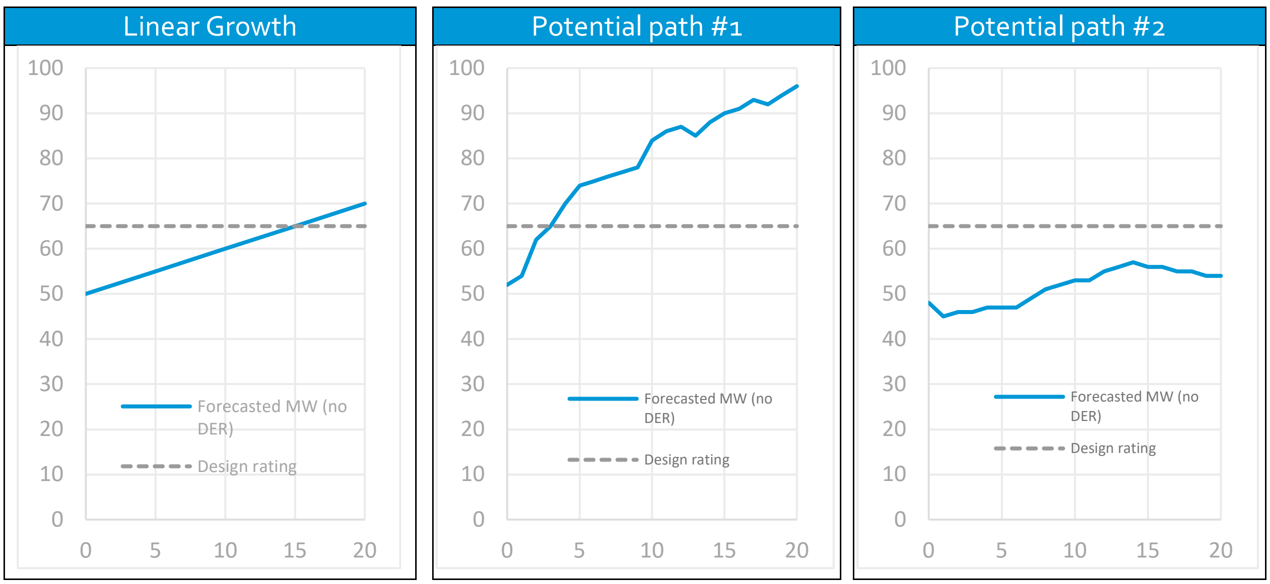


2.2 WHY USE PROBABILISTIC FORECASTING AND PLANNING METHODS?

No one knows in advance 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.

Figure 4 contrasts a linear forecast against two simulated potential growth trajectories, all using the same 1.0% growth rate. The linear forecast indicates loads will exceed the design rating in 15 years. But actual growth rarely follows a linear pattern. Loads could exceed the design and risk tolerance far earlier, as shown by Path 1, or never at all, as shown by Path 2. But the two potential outcomes are not equally probable.

Figure 4: Comparison of Linear Forecast and Potential Growth 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 investment 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.

2.3 DATA SOURCES

The study relied on nine main data sources:

1. 2014–2019 hourly interval data for most substations and each transmission area;
2. 2014-2019 annual sales data for all Central Hudson accounts, mapped to the appropriate substation and transmission area;
3. 2014–2019 weather data from the Dutchess County Airport;
4. 1-in-2 weather year peak conditions data;

5. 1-in-2 forecasted Central Hudson System loads;

6. Design rating information for each substation and transmission area;

7. Detailed data on NWAs, including the division between dispatchable and non-dispatchable portions;

8. Historical solar interconnections through 2019; and

9. Costs and financial assumptions for infrastructure upgrades.

With the exception of the 2014–2019 weather data, all of the above data was supplied by Central Hudson. A few points are noteworthy, however. First, the 2014–2019 time period was selected because of data availability and due to the significant shift in loads that occurred with the 2009 economic downturn. While data were available back to 2010, we relied on data from 2014 and later to better estimate recent growth trends.

Secondly, not all substations have hourly interval data, and the quality and availability of the data degrades when longer time spans are included. For Central Hudson, substations with hourly interval data available covers approximately 95% of the cumulative system load. The quality of the data improves for larger aggregation points, such as transmission areas, where all of the historical data is available. For five substations without detailed interval data, we relied on annual historical sales data to produce growth rates.

Third, resources that have been procured as part of Central Hudson's NWA projects are incorporated by adjusting the design rating. The additional resources reduce loads, thereby leading to additional room for growth.

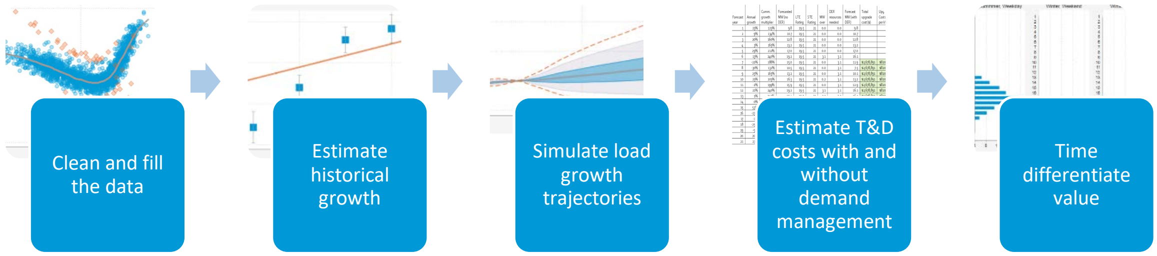
Forecasts and location specific estimates of T&D avoided costs were developed for all 10 transmission areas and 64 distribution substations[1]. The 2018 study focused only on the 55 substations with at least three years of valid hourly data. For the 2020 study data gaps were filled such that 6 years of load data were prepared for all 64 substations. Given the high correlation between loads within the same load area, load patterns from substations in the same load area were used to fill in anomalous or missing data.

2.4 KEY ANALYSIS STEPS

Figure 5 describes the main steps in developing location specific avoided T&D costs using probabilistic methods. The process was implemented for substation, load area, and transmission area. Importantly, the 5,000 simulations of potential growth trajectories are critical to both the forecast and to estimating T&D costs with and without demand management.

[1] The report summarizes results for 60 substations. Analysis was also conducted for 4 additional substations dedicated to large industrial customers but the results are not published to ensure customer privacy.

Figure 5: Key Steps in Estimating Location Specific Avoided Costs



2.4.1 CLEAN AND FILL THE DATA

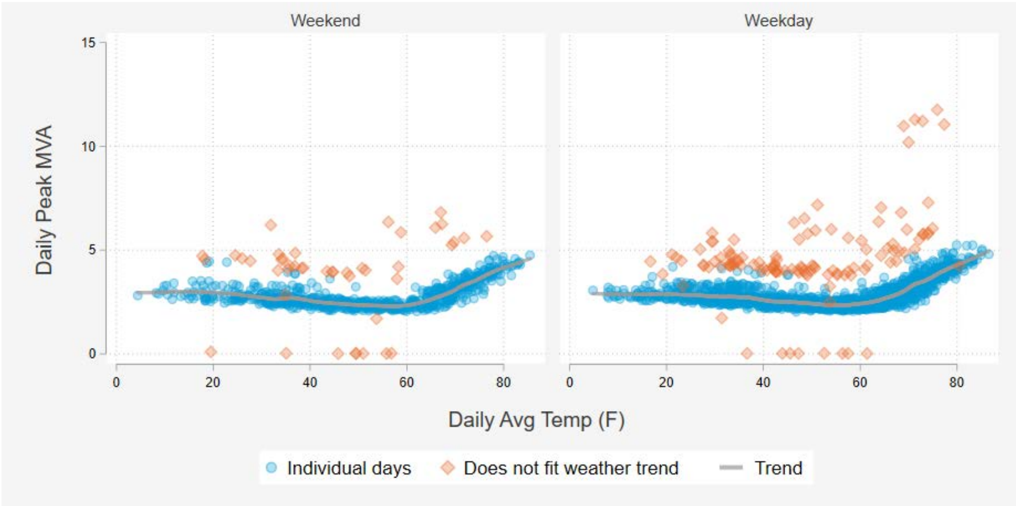
One of the key challenges in estimating load patterns and growth at granular locations is the quality of data. Not all substations have useable metered data over the relevant historical period and, for those that do, it is important to identify and remove load transfers, outages, data gaps, and data recording errors. DSA used data analytics to identify loads with irregular patterns, load transfers, data gaps, and outages from substation level data. Central Hudson's engineers subsequently reviewed those loads to confirm dates where load transfers occurred.

Next, we filled the data points identified as outliers in the cleaning step with synthetic data based on load data from substations in the same load area for substations and system loads for transmission areas. In particular, for a given location, we developed a regression equations relating the load at that location to the load at surrounding areas as well as day of week, month, and outdoor temperature. System loads were used if there was sufficient data available in the surrounding regions. For five substations without detailed interval data, we combined annual historical sales data with a normalized 8760 load shape created from neighboring substations to fill in hourly interval data.

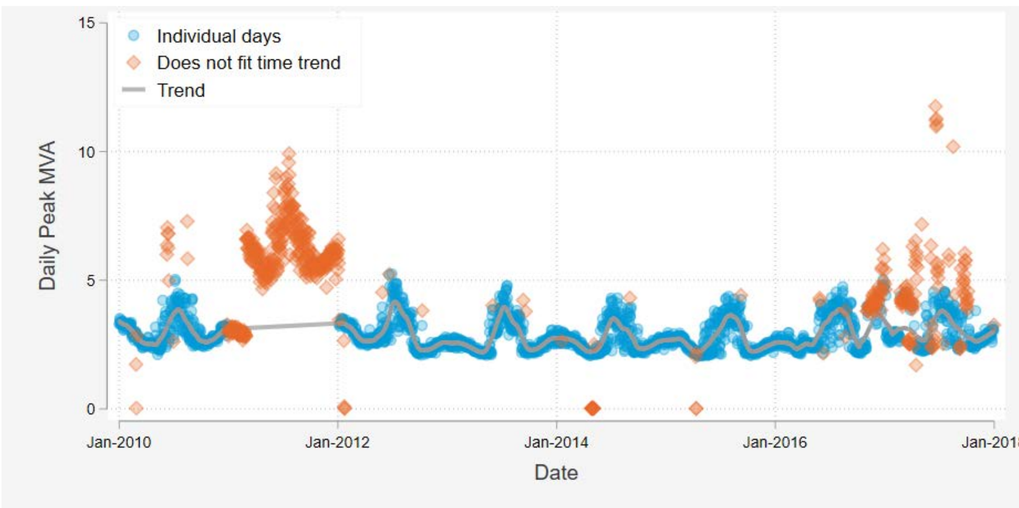
Figure 6 below illustrates the data cleaning process with an example of a location with load transfers, which, unless detected, can be mistaken for a load increase and distort the sensitivity of the area's loads to weather.

Figure 6: Example of Data Cleaning

Weather Trend: Excluded vs not Excluded



Time Trend: Excluded vs not Excluded

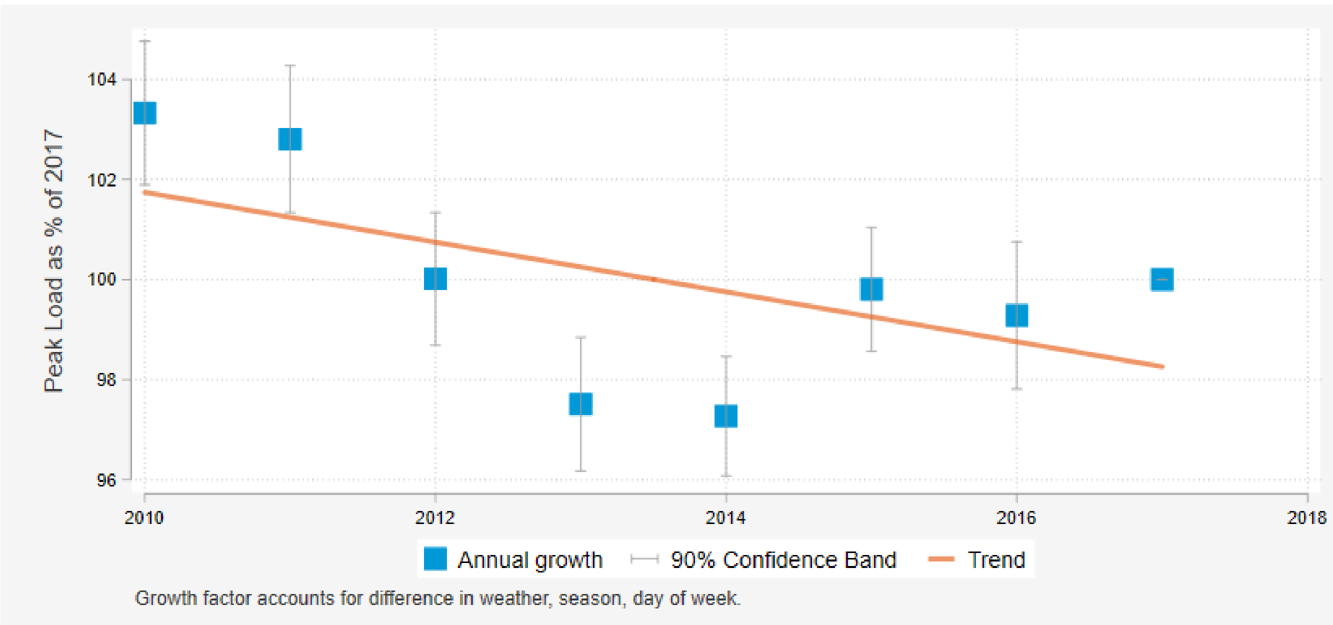


2.4.2 Estimate Historical Load Growth

The objective of this step was to estimate historical load growth for each year in 2014–2019 in percentage terms. The year-to-year growth patterns were then used to assess the growth trend and the variability of load growth patterns; the degree of growth in a given year was related to growth during the prior year— technically known as auto-correlation. The econometric models were purposefully designed to both estimate historical load growth and allow us to weather normalize loads for 1-in-2 weather peaking conditions. The 2014–2019 peaks were normalized for 1-in-2 weather peak conditions based on the Central Hudson criteria for distribution and transmission design. Appendix A describes the econometric models.

Figure 7 illustrates some of the key outcomes from this analysis. First, the analysis produces year-by-year estimates of the historical growth or decline in loads after controlling for differences in weather, day of week, and season. Second, the year-by-year estimates allow us to estimate the growth trend. In the below example, loads are declining at a rate of 0.5% per year. Third, the results enabled us to estimate of the variability in year-to-year growth patterns (also known as the standard error of the forecast).

Figure 7: Year-by-year Estimates of Historical Growth



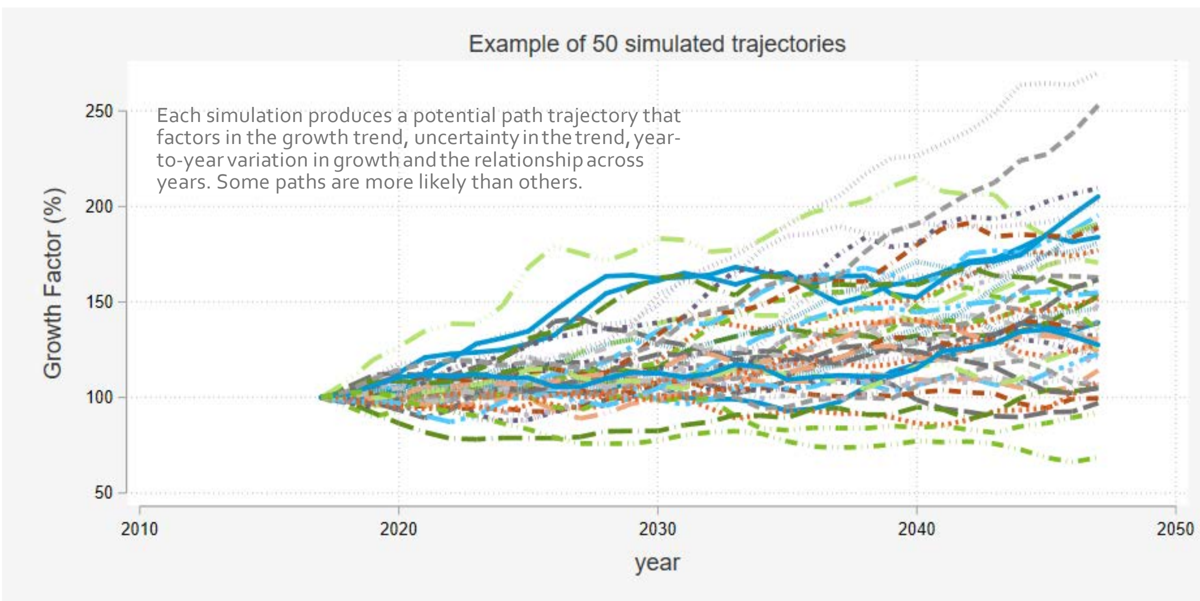
2.5 SIMULATE POTENTIAL LOAD GROWTH TRAJECTORIES

The load growth forecasts were developed using probabilistic methods—Monte Carlo simulations—that produced the range of possible load growth outcomes by year. It simulates the reality that the near-term forecast has less uncertainty than forecasts 10 years out. A total of 5,000 simulations were implemented for each substation and transmission area. Each simulation produced a distinct growth trajectory that took into account the historical trend, variability in growth patterns, and the fact that growth patterns are auto-correlated.

The simulations are based on historical growth patterns from the econometric models. Each forecast year's growth is a combination of an independent growth component and the prior year's growth trajectory.[2] The independent growth component is based on a random draw that factors in the historical trend, the uncertainty around the trend, and the year-to- year variation at the location. The forecasts are cumulative, meaning that each simulation's forecast trajectory builds on the prior year, producing a path. The process was repeated 5,000 times for each substation and for each transmission area. The result is a full picture of the possible load growth outcomes by year. Each of the 5,000 simulated growth trajectories produces specific information about if and when the design rating would be exceeded, and the amount of demand management required to maintain loads below the design ratings.

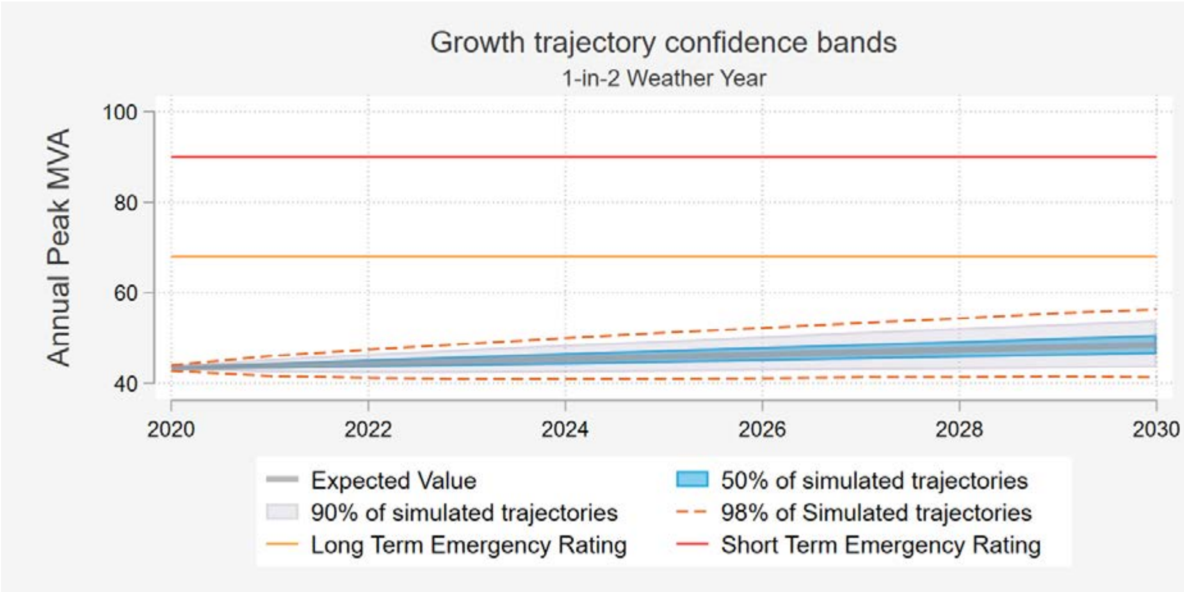
Figure 8 illustrates the critical role of probabilistic, location-specific forecasts. This type of forecasting requires estimating historical load growth patterns and simulating potential load growth trajectories thousands of times, as shown in the top panel. Some outcomes are far more likely than others and are summarized into probabilistic bands that identify the likelihood of load growth falling within specific confidence bands, as shown in Figure 9.

Figure 8: Illustration of Location Specific Simulations and Probabilistic Forecasts



[2] *Annual growth$_t$ = Independent growth$_t$ · (1 - autocorrelation) + Annual growth$_{t-1}$ · autocorrelation*

Figure 9: Annual Peak Forecast Confidence Bands



2.6 ESTIMATE COSTS WITH AND WITHOUT DEMAND MANAGEMENT

The estimates of the avoided T&D costs are based on the load growth forecast and the outcome of each simulation run. The process involved applying the below four steps to each of 5,000 simulation runs for each location:

1. **Identify the timing of the infrastructure investments for each simulation run, location, and year.** For each location, each simulation run produced a potential growth trajectory, which either exceeded the design rating or remained below it. As noted earlier, when forecast loads exceed design ratings, they do not automatically trigger infrastructure upgrades. Forecast loads can exceed design ratings without triggering investments. Because load growth does not follow a perfect linear trajectory, forecast loads also can exceed the design ratings for a year or two, but revert to levels below the design rating. To reflect this complexity, the timing of infrastructure upgrades was simulated to occur the year after forecast loads exceeded design ratings for two consecutive years.

2. **Identify the magnitude of demand management needed to maintain loads below the design rating**. Once demand management resources were needed, we assumed they were in place for up to 10 years or until the magnitude of reductions needed exceed 20% of peak loads, whichever came first. This reflects the reality that projects may be postponed indefinitely, and the length of deferral may be shorter in areas with rapid growth.

3. **Model T&D infrastructure costs with and without demand management for each simulation run, location, and year.** When the design ratings were exceeded for two consecutive years, the costs of the infrastructure investments were included in the third year and allocated based on the revenue requirement of the upgrade. For example, equipment upgrade costs of $15 million with a 50-year book

life would be spread or annualized over 50 years. This approach replicates how T&D costs are incorporated into the rate base. We implemented the same cost calculations but instead assumed the investment could be deferred for up to 10 years or until 20% of the peak was managed through DERs, whichever came first.

4. **Calculate the avoided costs per kW for each simulation run and location.** If loads were not projected to exceed the respective design rating, no costs are avoided since a growth-related infrastructure investment would not have taken place anyhow. If the loads in a particular simulation exceeded the design rating, reducing loads to levels below the design rating would avoid or defer growth related infrastructure investment. Thus, the avoided costs are the difference between the costs with and without the reduction in loads necessary to avoid or defer the upgrade. T&D deferral value took into account when the capital costs, carrying costs, and the magnitude of the required load reduction.[3] The deferral value was levelized over the deferral years.[4]

The detailed calculations for each of the 5,000 simulations at each site were subsequently used to estimate the expected avoided costs per kW at each location for each year.[5] Because the analysis relied on probabilistic methods, the avoided cost estimates reflects the risk mitigation value of managing loads to remain below the design rating. That is, the probabilistic method assigns T&D avoided costs to location and year with, for example, a 10% likelihood of an upgrade. In contrast, a linear forecast would not assign any value to that year.

2.7 INTEGRATION OF DERS

One of the most important considerations is accurately reflecting the locational value of incremental resources. This creates a paradox: including DERs which have not yet been built and installed into forecasts impacts load forecasts and can dilute the locational value of future DER resources. A key methodology refinement in the 2020 study was to isolate growth trends from the effect of solar interconnections which modify loads—this was not done for other DERs but could be a further refinement of the methodology in the future. Importantly, only

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[3] The below equation reflects the deferral value calculations for each simulation run and location. In the equation, i reflects the inflation rate, r reflects the discount rate, and Δt reflects the deferral period. In practice, Central Hudson provided fixed charge rates (a % value) and DSA implemented the calculations. The fixed charge rates annualize the share of capital costs over the book life and include the revenue requirement adjustments.

$$Total\ Deferral\ Value\left(\frac{\$}{kW}\right) = \frac{Capital\ Cost\ (\$)\ \cdot Revenue\ Requirement\ Adjustment\ \cdot\left(1-\left(\frac{1+i}{1+r}\right)\right)^{\Delta t}}{Load\ Reduction\ Needed\ for\ Deferral\ (kW)}$$

[4] The total deferral value was annualized over the deferral period for each simulation run and location using the following equation, were r equals the discount rate, i is the inflation rate and n is the number of deferral years:

$$Annualized\ Deferral\ Value = Total\ Deferral\ Value\left(\frac{\$}{kW}\right)\cdot\frac{(r-i)}{(1+r)}\cdot\frac{(1+r)^n}{[(1+r)^n-(1+i)^n]}$$

[5] The expected avoided cost is calculated by taking the average across all simulation runs (r) for each year (t) at an individual location (i).

$$Expected\ Avoided\ Cost_{i,t} = \frac{\sum_{r=1}^{5{,}000} \$\frac{kW}{year}_{i,t,r}}{5{,}000}$$

existing resources were incorporated into the avoided T&D cost study. Resources that are yet to be built were not included because doing so would impact the estimated value of future resources.

To isolate load growth trends from DER, DER impacts from historical information was added to the cleaned load data to derive gross loads. Then the gross load data and weather data were used to estimate the relationship between load and demand on peak hours for each location, so as to isolate the growth rate that is unrelated to weather differences from year to year.

3 HISTORICAL LOAD GROWTH TRENDS

This section presents the data on historical peak loads, design ratings, and load growth estimates. The results are presented separately for transmission and distribution areas. A key distinction between probabilistic and straight-line forecasts is that the former approach explicitly accounts for the chance that forecasts are less certain further into the future.

Growth can slow down or accelerate in comparison to recent growth patterns and, in practice, actual growth trajectories rarely are linear. When a location has more room for growth, the chances it will exceed the design rating and trigger the need for infrastructure upgrades is lower. The results presented in this section focus on the growth rates, loading factors, and the standard error of the forecast.[6]

3.1 TRANSMISSION AREA LOAD GROWTH ESTIMATES

Locations with potential T&D infrastructure deferral value are areas where loads are growing but there is limited room to accommodate growth. Areas with sufficient load serving capability and areas where local, coincident peaks are declining are less likely to trigger growth related infrastructure upgrades.

Figure 9 compares the annual load growth rate to the 2019 loading factor (weather-normalized peak divided by the location's design rating including NWAs) 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. All other things equal, a location with a 2% annual growth rate will exceed ratings in approximately half the time as a location with a 1% growth rate. Note, however, that the chart does not factor in the uncertainty of future growth patterns.

Both the Northwest 69 kV and Northwest 115-69 kV transmission areas are loaded above 80% and have positive growth; all other transmission areas are experiencing slowing or declining loads or have ample room for growth without having to upgrade the transmission system. However, upgrades to transmission areas will be required due to efforts not related to load growth such as aging equipment or grid modernization.

More specifically, transformer upgrades are already planned for the Northwest 69 kV transmission area with an expected in service date in the 2025 timeframe. This planned upgrade will address a variety of non-growth related needs, not least of which bolstering of hosting capacity required to support substantial recent and planned growth in solar interconnections in this area. Further, some load serving generation capacity will be retired in the same time frame. This generation currently serves both the Northwest 69kV and the Northwest 115/69kV areas. The net effect of the generation retirement and the Northwest 69kV transformer upgrade will be a net increase in LTE and STE ratings for the Northwest 69 kV are and a net decrease for the Northwest 115/69 kV areas. Figure 9 shows 2019 loading relative to current LTE ratings. Future changes to ratings are taken into account in the avoided cost estimates discussed below.

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[6] The standard error of the forecast factors in both the accuracy of the historical load growth estimates and the volatility in the historical growth.

Figure 9: Transmission Area Growth Rates Versus Room for Growth

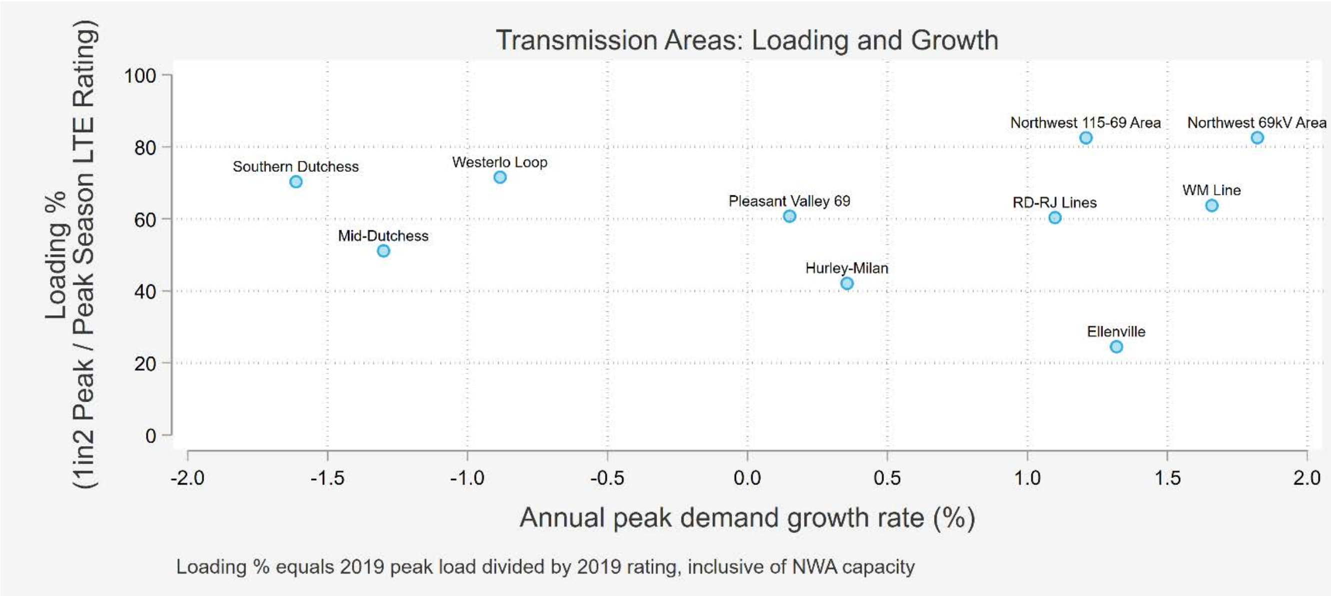


Figure 10 shows heat maps of the growth rate and the loading factor (peak / design rating) for each of Central Hudson's transmission areas. Darker orange colors indicate higher growth rates and higher loading factors. Location with high loading factors typically do not have high growth rates (and vice-versa). Note that the planned transformer upgrade in the Northwest 69 kV area is expected to decrease loading by 2030 in the northernmost area of the territory.

Figure 10: Heat Map of Transmission Area Growth Rates and Loading Factors

Historical Growth Rates | Loading Factors 2019 | Loading Factors 2030

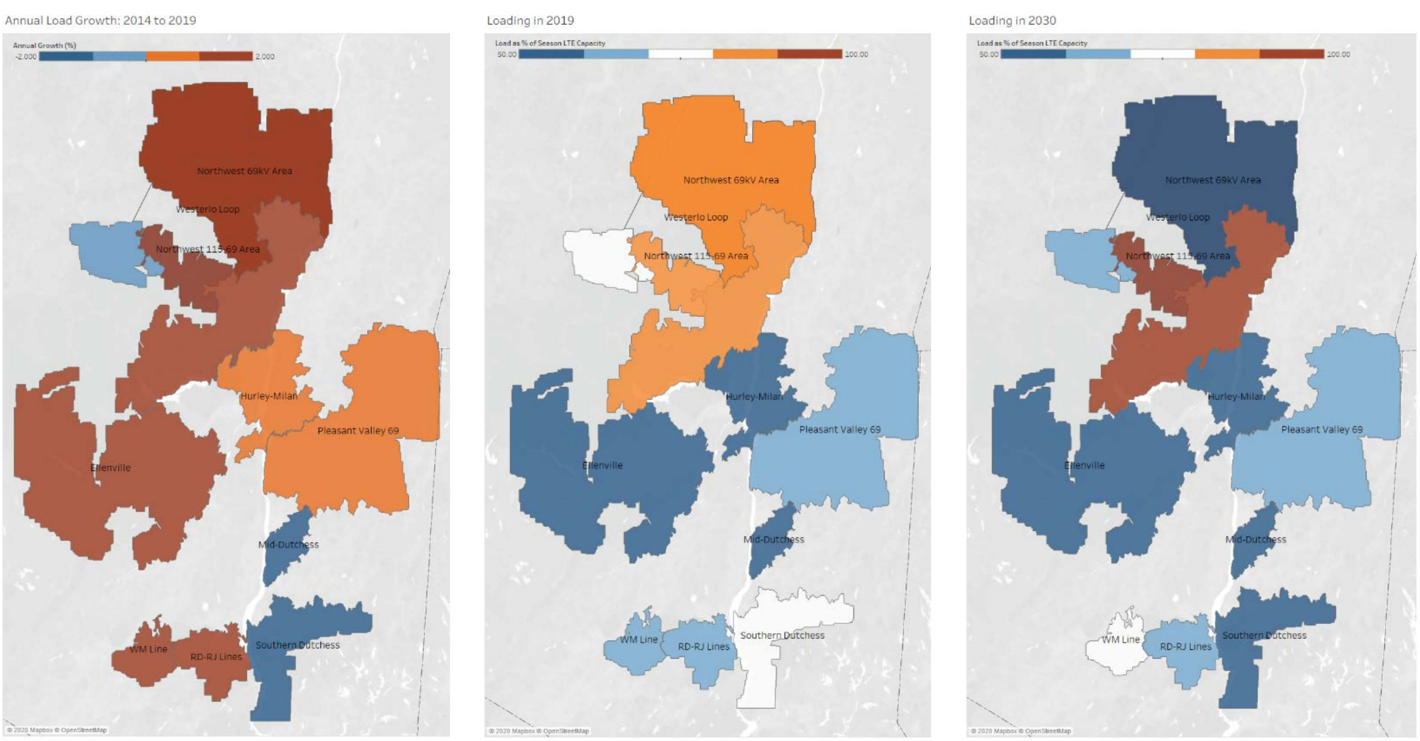


Table 1 summarizes the historical year by year growth for each transmission area, the growth trend, and the variability in the growth patterns, also known as the standard error of the forecast. They were estimated using econometric models designed to disentangle year by year growth rates from differences in weather patterns, day of week effects, and seasonality. For the most part, the year by year estimates of growth are relatively precise. The confidence bands around those estimates and the explanatory power of the models are summarized in Appendix A. 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 reflect 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.

For Table 2 and Table 5 below, note that the Westerlo Loop area is nested within the NW 69 Area and the NW 69 Area is nested within the NW 115-69 Area. Not all substations are located within a transmission area. For these two reasons, the sum of the transmission areas will not equal the total system load. Finally, the ratings shown correspond to 2019 ratings, including active Non-Wires Alternative project capacity.

Table 1: Transmission Area Historical Load Growth Estimates (2014-2019)

Transmission Area	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Ellenville	251.0	58.0	61.1	64.1	60.7	62.3	61.4	24.5%	1.3%	1.5%
Hurley-Milan	193.0	81.8	80.7	80.4	79.0	83.4	80.5	42.1%	0.4%	1.1%
Mid-Dutchess	230.0	118.8	117.0	113.5	113.0	110.6	108.1	51.1%	-1.3%	0.9%
NW 115-69 Area	149.6	126.7	119.4	125.7	127.4	132.2	128.6	82.5%	1.2%	1.3%
NW 69 Area	116.1	102.3	99.5	98.3	104.2	105.5	106.9	82.5%	1.8%	1.3%
Pleasant Valley 69	107.0	72.4	67.8	73.6	71.2	69.8	59.4	60.7%	0.2%	2.0%
RD-RJ Lines	144.0	87.2	88.5	89.0	89.7	89.5	92.8	60.3%	1.1%	1.4%
Southern Dutchess	211.0	146.8	145.3	141.2	137.6	139.3	139.2	70.3%	-1.6%	0.7%
WM Line	68.0	41.8	43.5	45.2	43.4	48.8	40.2	63.7%	1.7%	1.9%
Westerlo Loop	83.6	67.7	66.6	66.2	64.1	57.4	62.6	71.5%	-0.9%	1.3%

Table 2: Transmission Area Normalized Peak Load Estimates, Historical (2015-2019) and Forecast (2020-2025)

Transmission Area	Historical 1 in 2 Annual Peak (MVA)					Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Ellenville	58.4	59.1	59.9	60.7	61.5	61.7	62.5	63.4	64.2	65.1	65.9	251.0
Hurley-Milan	80.1	80.4	80.7	80.9	81.2	81.3	81.6	81.9	82.2	82.5	82.8	193.0
Mid-Dutchess	123.8	122.2	120.7	119.1	117.5	117.1	115.6	114.1	112.6	111.2	109.7	230.0
NW 115-69 Area	117.7	119.1	120.5	122.0	123.4	123.9	125.3	126.9	128.4	129.9	131.5	149.6
NW 69 Area	89.2	90.8	92.5	94.1	95.8	96.3	98.1	99.8	101.7	103.5	105.4	116.1
Pleasant Valley 69	64.7	64.8	64.8	64.9	65.0	65.0	65.1	65.2	65.3	65.5	65.6	107.0
RD-RJ Lines	83.2	84.1	85.0	86.0	86.9	87.2	88.1	89.1	90.1	91.1	92.1	144.0
Southern Dutchess	158.3	155.7	153.2	150.8	148.3	147.6	145.2	142.9	140.6	138.3	136.1	211.0
WM Line	40.6	41.3	41.9	42.6	43.3	43.5	44.2	45.0	45.7	46.5	47.2	68.0
Westerlo Loop	62.0	61.5	60.9	60.4	59.8	59.7	59.1	58.6	58.1	57.6	57.1	83.6
System	**995.5**	**1006.9**	**1019.8**	**1033.3**	**1046.4**	**1050.5**	**1064.9**	**1080.2**	**1094.1**	**1107.1**	**1121.4**	**N/A**

Before presenting the overload and investment trigger results, it is important to understand how ratings change over time, whether as a result of changes to transmission area infrastructure or as a result of changes to existing NWAs. Ratings are only expected to change over time for the Northwest 69kV and Northwest 115-69kV areas, as follows:

- **NWAs.** The Northwest 115-69kV area currently has a 10 MW NWA that is set to expire in 2029. Because the Northwest 69kV area is nested within the Northwest 115-69kV area, the Northwest 115-69kV NWA also serves the Northwest 69kV area. NWA capacity was assumed to be allocated relative to annual usage from 2017 to 2019. The NWA consists of both permanent non-dispatchable capacity (e.g. energy efficiency) and temporary dispatchable capacity (e.g. demand response) assumed to expire in 2029. Some non-dispatchable capacity was in place for the 2019 peak load season and was therefore reflected in the historical load data. Ratings were adjusted to reflect the NWA deployment and retirement schedule.

- **Generation retirement:** The Northwest 115-69kV area ratings were adjusted to reflect planned generation retirement effective starting in 2025. This corresponds to a summer LTE rating decrease of 13.1 MW / 13.2 MVA beginning in 2025.

- **Infrastructure upgrade:** The Northwest 69kV area ratings were adjusted for the transformer upgrade planned for 2025. There will be a combined net increase of 141 MVA in summer LTE for the Northwest 69kV area beginning in 2025 as a result of a generator retirement and the transformer upgrade.

Table 3 summarizes the peak season LTE rating for all ten transmission areas over time, including NWAs. The Northwest areas, highlighted in light blue, are the only locations where we expect the rating to change over time, based on the factors described above. The effect of these ratings changes is to reduce the risk for the Northwest 69kV area to zero but increase the risk of overloading and an investment being triggered for the Northwest 115-69kV area, which was already highly loaded in 2019.

Table 3: Transmission Area LTE Ratings by Year (MVA)

Transmission Area	Peak Season	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ellenville	Summer	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0
Hurley-Milan	Summer	193.0	193.0	193.0	193.0	193.0	193.0	193.0	193.0	193.0	193.0	193.0
Mid-Dutchess	Summer	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0
Northwest 115-69 Area[7]	Summer	149.7	149.8	149.8	149.8	149.8	136.7	136.7	136.7	136.7	136.7	128.3
Northwest 69kV Area[8]	Summer	116.2	116.3	116.3	116.3	116.3	257.3	257.3	257.3	257.3	257.3	250.5
Pleasant Valley 69	Summer	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0
RD-RJ Lines	Summer	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0
Southern Dutchess	Summer	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0
WM Line	Summer	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Westerlo Loop	Winter	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6

Figure 11 summarizes the mean load forecast for each transmission area from 2020 to 2032, expressed as a percentage of the transmission area's LTE rating so that the design rating equals 100. The Northwest 115-69kV area stands out for being the only location where the peak load exceeds the LTE rating during the forecast period. This is driven by the rating decreases in 2025 and 2029 described above combined with a positive expected load growth rate (1.2% per year). The Northwest 69kV area follows a similar trajectory as the Northwest 115-69kV area from 2020 to 2024, but in 2025 the rating more than doubles due to non-deferrable infrastructure upgrades, which results in a much lower loading for 2025 and beyond.

[7] Reflects 10 MW NWA capacity until stepdown at end of 2029.
[8] Reflects Northwest 69kV area portion (81%) of Northwest 115-69kV 10 MW NWA capacity until stepdown at end of 2029.

Figure 11: Expected Loading as Percentage of Transmission Area Rating, Including NWAs

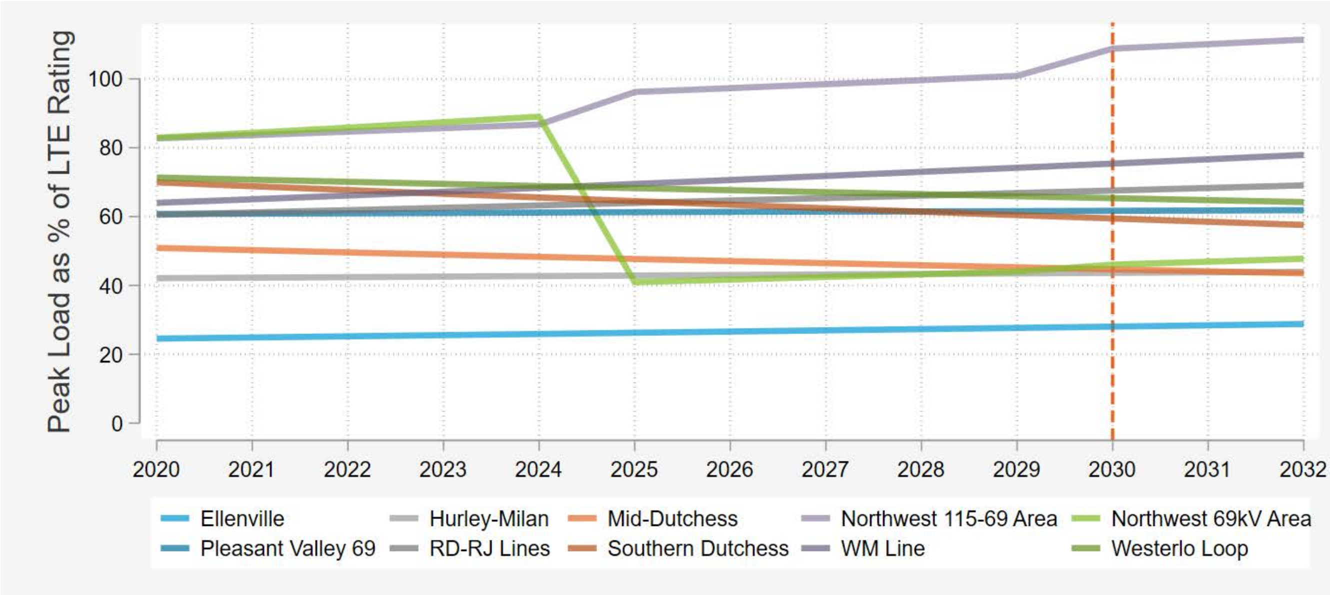


Figure 12 summarizes the likelihood that loads will exceed design ratings for each transmission area by year where the overload risk is at least 5%, which includes the Northwest 115-69kV area (all other locations have overload risk below 1%). Figure 13 summarizes the likelihood of triggering an infrastructure upgrade due to load growth, assuming two consecutive years where the long-term rating is exceeded (or a single year where the short term emergency rating is exceeded), assuming 1-in-2 weather conditions. Figure 13 is essentially the same as Figure 12, but shifted back by one year, which reflects the investment criteria of two consecutive years of overloads. The very low upgrade risk likelihood for all transmission areas except the Northwest 115-69kV area means there is no meaningful transmission avoided cost except for the Northwest 115-69kV area.

Figure 12: Probability of Forecast Load Exceeding Design Ratings: Transmission Areas

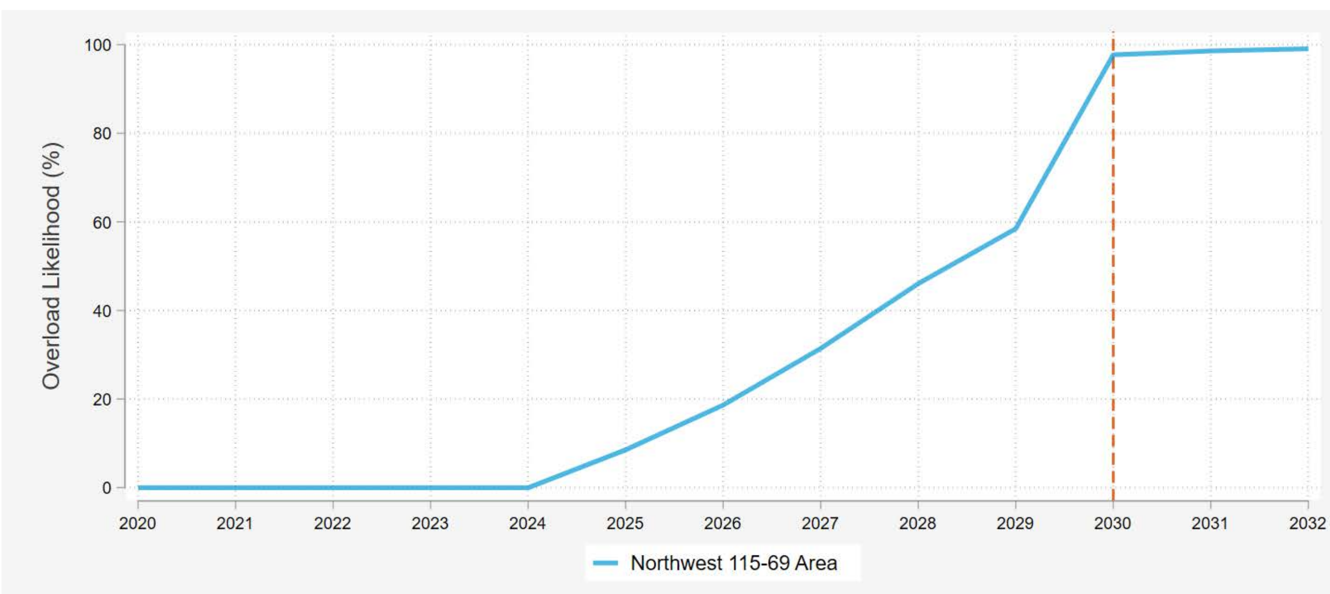
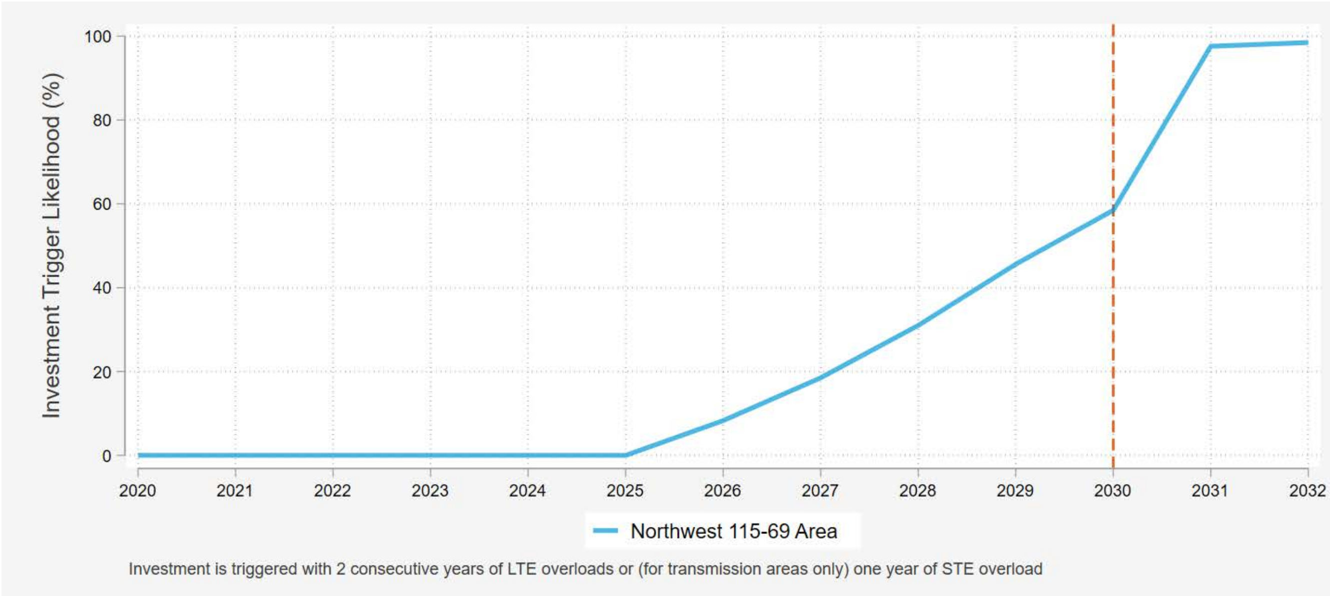
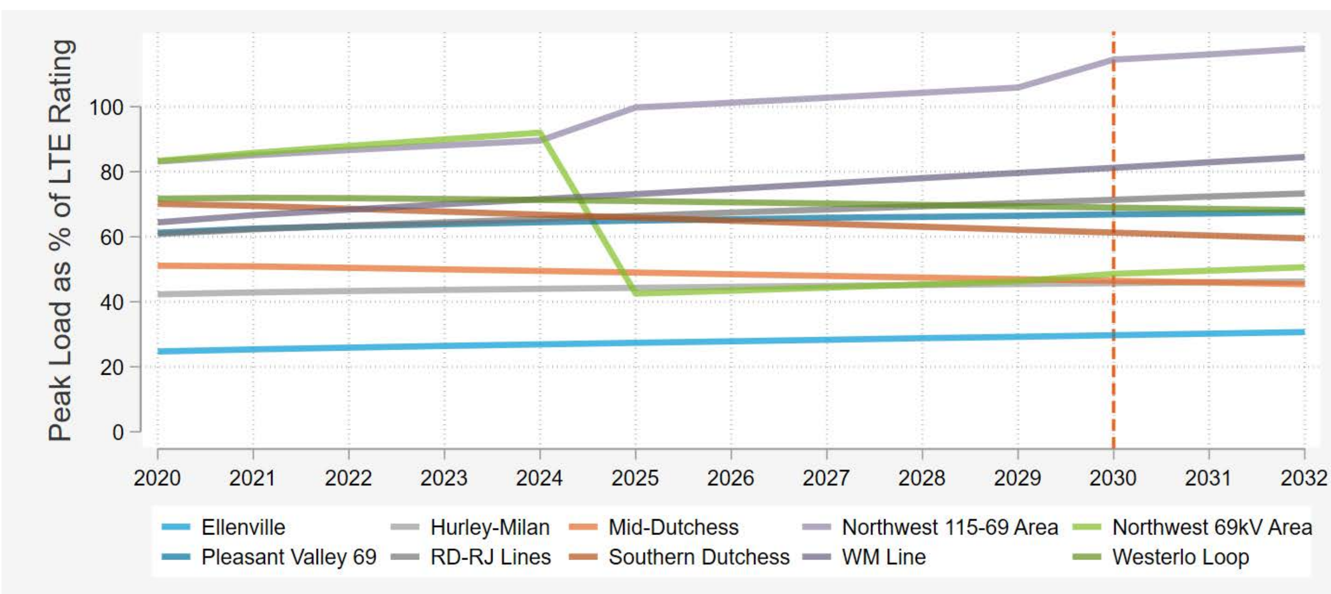


Figure 13: Probability of Growth Related Infrastructure Upgrade: Transmission Areas



To test this finding, we conducted an additional sensitivity test. While Figure 11 shows the expected (mean) transmission area load as a percentage of the rating across 5,000 growth simulations, we also looked at forecasted growth for the top 90th percentile of growth trajectories. Figure 14 shows these growth trajectories, again normalized by the local design rating so design rating = 100. As is the case for the expected value, only the Northwest 115-69kV area exceeds the design rating, with loads being flat or declining or else substantially below the design rating.

Figure 14: 90th Percentile Peak Load as Percentage of Transmission Area Rating, Including NWAs



3.2 DISTRIBUTION AREA LOAD GROWTH ESTIMATES

Figure 15 compares the annual load growth rate to the loading factor (weather-normalized peak divided by the location's design rating including NWAs) for each of Central Hudson's substations. The majority of substations are experiencing slowing growth or declining loads or have ample room for growth without having to upgrade them. Locations with a growth rate above 0% are experiencing growth, and locations where the loading factor is closer to 100% have less room for growth. Only the Woodstock and Shenandoah-Distribution substations area loaded above 80%, though other locations may have some probability of loads growing and approaching their design ratings. While loads at Woodstock can be easily transferred to neighboring substations, this is not possible for Shenandoah-Distribution, which also already has an NWA in place (the Fishkill-Shenandoah NWA), which we describe in more detail below.

Figure 15: Substation Growth Rates Versus Room for Growth

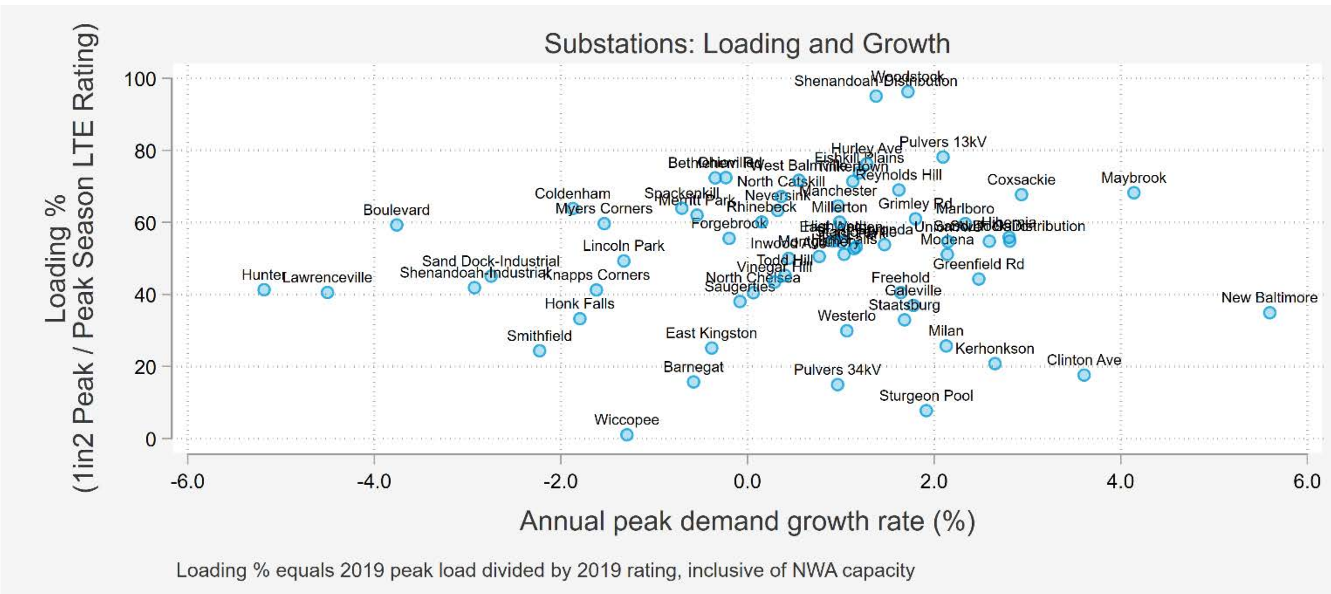
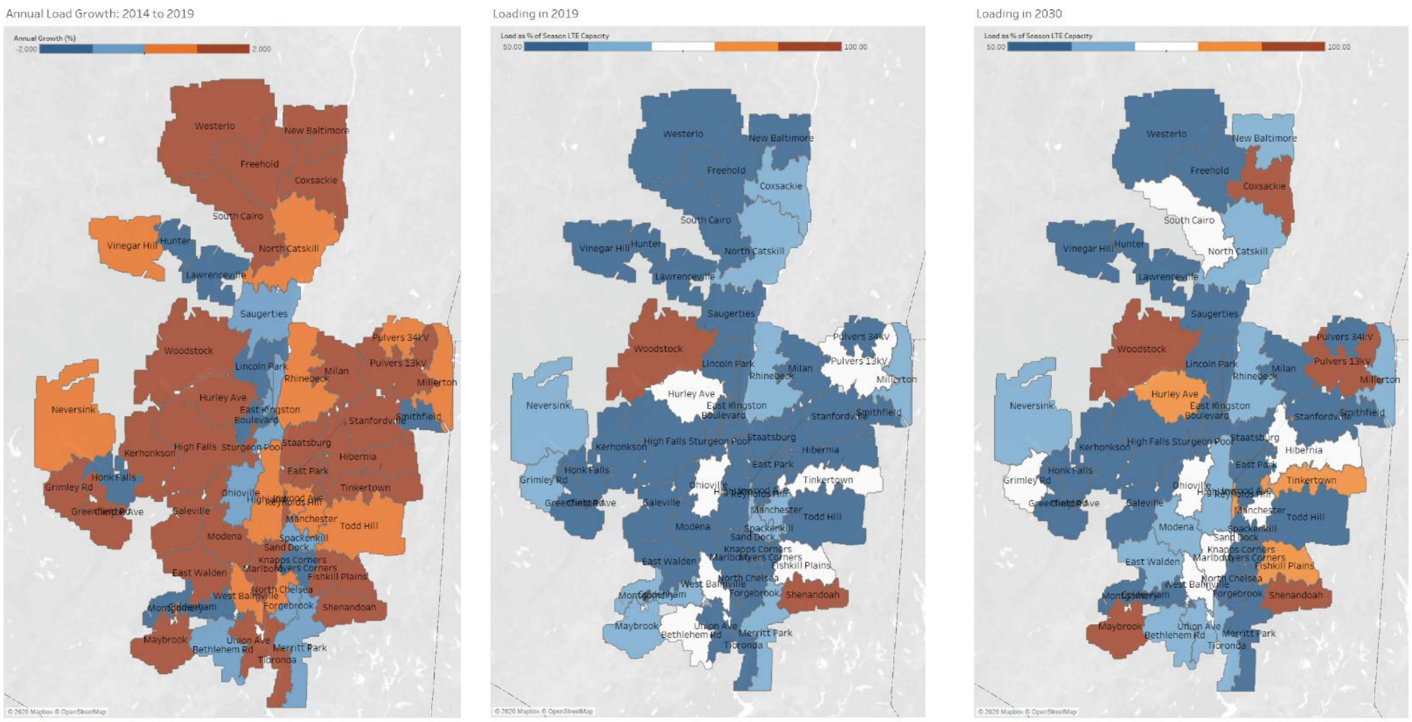


Figure 16 shows heat maps of the growth rate and the loading factor (peak / design rating) for each of Central Hudson's substations. Darker orange colors indicate higher growth rates and higher loading factors. Location with high loading factors typically do not have high growth rates (and vice-versa).

Figure 16: Heat Map of Substation Growth Rates and Loading Factors

Historical Growth Rates | Loading Factors 2019 | Loading Factors 2030



Three substations currently have NWAs that we added to ratings. Table 3 summarizes the peak season LTE rating (in MVA) plus NWA capacity for these three substations. As was the case in the transmission area capacity, the NWAs consist of both temporary dispatchable capacity (demand response) as well as permanent non-dispatchable capacity (energy efficiency); to prevent double counting energy efficiency that would show up in the 2019 load data, we added all dispatchable capacity but only incremental non-dispatchable capacity to the substation ratings. Because Fishkill Plains and Shenandoah-Distribution share an NWA, we allocated the NWA capacity between the two substations based on the ratio between the two locations' usage for 2017 to 2019. Shenandoah-Distribution comprised 25.9% of total usage, and was therefore allocated 25.9% of the NWA capacity.

Table 4: Substation Ratings By Year (MVA)[a]

Substation	Peak Season	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Fishkill Plains	Summer	50.2	51.3	51.3	51.3	51.3	51.3	48.2	48.2	48.2	48.2	48.2
Merritt Park	Summer	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	51.2	51.2	51.2
Shenandoah-Distribution	Summer	12.8	13.1	13.1	13.1	13.1	13.1	12.1	12.1	12.1	12.1	12.1

[a] The 5 MW Fishkill/Shenandoah NWA ramps up in 2020 and 2021 and sunsets at the end of 2025, and is split among Fishkill Plains and Shenandoah-Distribution based on the two substations' ratio of total usage from 2017 to 2019. The 1 MW Merritt Park NWA sunsets at the end of 2027.

Figure 17 summarizes the likelihood that loads will exceed long term design ratings by year for seven substations. Figure 18 summarizes the likelihood of triggering an infrastructure upgrade due to load growth, assuming two consecutive years where the long term rating is exceeded, assuming 1-in-2 weather conditions.

Based on the trajectory and variability in load growth, only four substations (Woodstock, Shenandoah-Distribution, Maybrook, and Pulvers 13kV) exhibit more than a 5% probability of triggering a growth related upgrade over the next 10 years, with Coxsackie, Fishkill Plains, and Hurley Ave having less than a 5% probability of triggering a growth related upgrade.

Among the locations with greater than a 5% probability of loads exceeding ratings, potential overloads can be addressed through low-cost load transfers to neighboring substations for three of the four locations (Woodstock, Maybrook, and Pulvers 13kV). For the Shenandoah-Distribution substation, this strategy not available. Therefore, at Shenandoah is there is an opportunity for beneficial DERs located at the Shenandoah-Distribution to avoid or defer investment that might otherwise be required to accommodate loads at the location.

Figure 17: Probability of Forecast Loads Exceeding Design Ratings

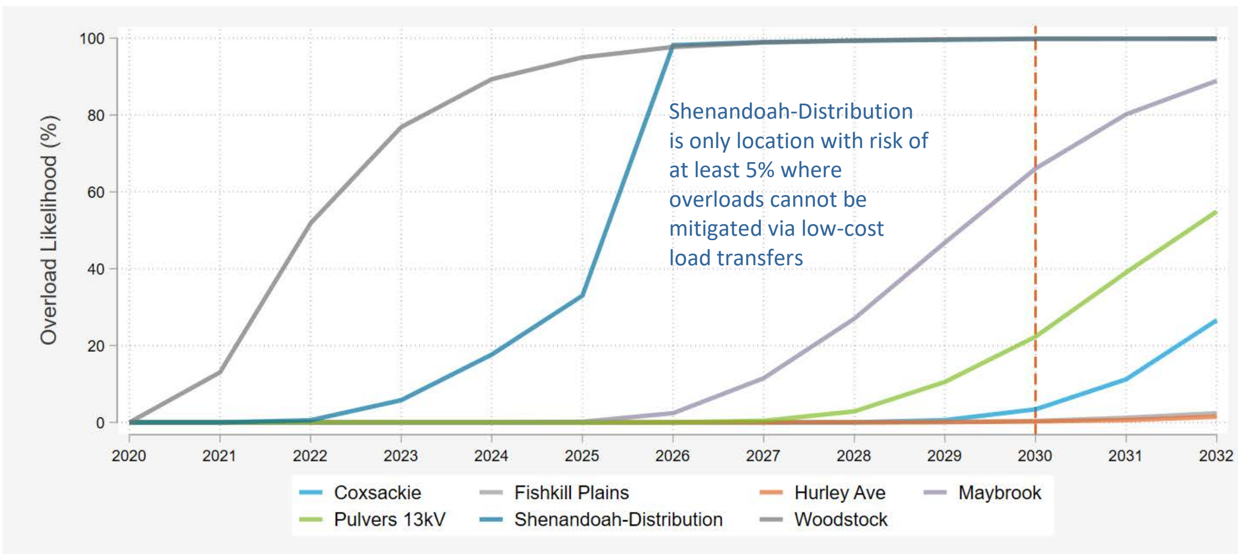


Figure 18: Probability of Growth Related Infrastructure Upgrade

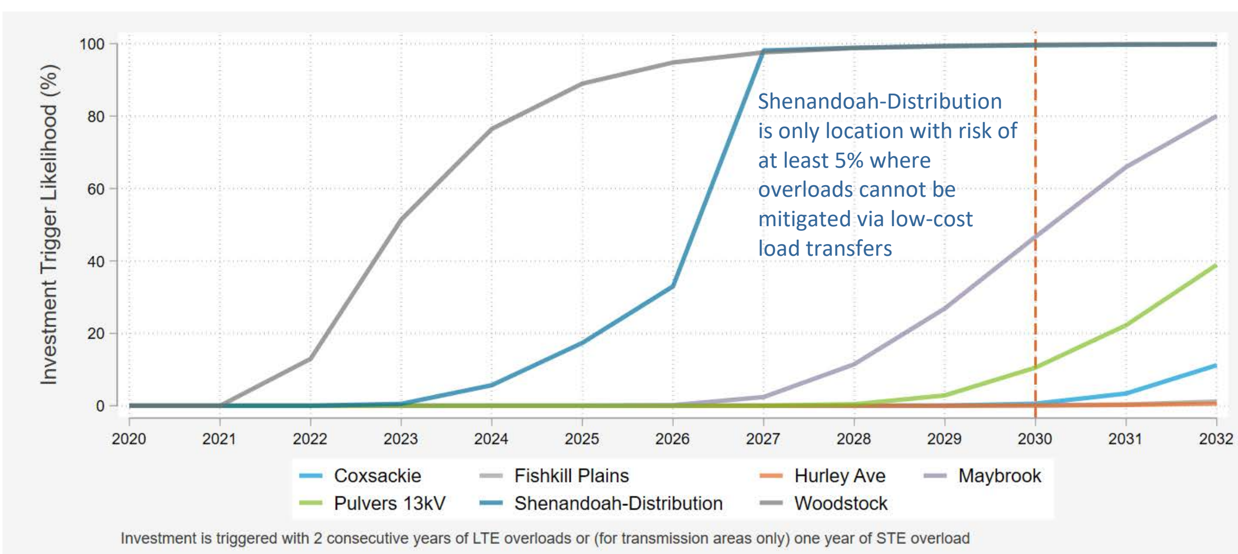


Table 5 through Table 12 summarize the results of the historical load growth analysis for each of the distribution load serving substations with at least three years of hourly data, grouped by load area.[9] Similar to the transmission areas, most of the substations have ample room to accommodate additional load growth. Table 13 shows historical and forecasted peak loads for all substations, normalized to 1 in 2 weather conditions. The five substations for which we used historic sales data rather than metered data are indicated with an asterisk (*).

Table 5: Ellenville Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Clinton Ave	7.7	1.4	1.4	1.4	1.4	1.5	1.6	17.6%	3.6%	1.2%
Greenfield Rd	15.4	6.6	6.5	6.9	6.8	7.5	7.2	44.3%	2.5%	1.3%
Grimley Rd	7.2	4.1	4.4	5.2	5.0	4.9	5.4	61.0%	1.8%	2.4%
High Falls	34.5	17.1	17.1	18.1	18.0	18.8	17.7	51.1%	1.0%	1.4%
Honk Falls	18.2	5.9	5.8	5.7	5.6	5.6	5.3	33.2%	-1.8%	1.2%
Kerhonkson	44.6	8.7	8.4	9.9	9.4	9.9	10.6	20.8%	2.7%	1.3%
Neversink	4.9	3.2	3.1	3.3	3.6	3.3	3.5	63.3%	0.3%	0.5%
Sturgeon Pool	29.7	2.2	2.2	2.2	2.4	2.6	2.7	7.7%	1.9%	1.5%
Overall	N/A	**45.8**	**46.2**	**50.7**	**47.6**	**52.5**	**50.5**	**0.5%**	**1.5%**	**1.1%**

Table 6: Fishkill Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Fishkill Plains	49.9	37.0	36.6	37.1	35.2	36.1	37.4	73.8%	1.2%	1.8%
Forgebrook	47.8	26.4	26.2	25.7	24.2	25.3	25.0	55.6%	-0.2%	1.3%
Knapps Corners	47.8	19.3	19.2	19.5	18.4	18.3	18.1	41.2%	-1.6%	1.4%
Merritt Park	52.2	30.8	32.0	31.9	31.2	32.6	30.7	62.0%	-0.5%	1.4%
Myers Corners	35.1	20.8	21.1	20.4	19.3	19.5	18.9	59.7%	-1.5%	1.1%
North Chelsea	48.3	19.0	19.5	19.3	19.4	19.3	18.0	40.5%	0.1%	1.7%
Sand Dock-D	8.0	4.3	4.4	4.8	4.6	5.4	4.9	54.8%	2.8%	1.7%
Shenandoah-D	12.7	11.0	11.3	11.1	10.9	13.3	12.3	95.0%	1.4%	1.6%
Tioronda	25.7	13.2	13.8	14.9	14.3	14.8	15.0	53.8%	1.5%	1.6%
Overall	N/A	**178.2**	**179.4**	**179.0**	**174.7**	**175.4**	**174.1**	**1.9%**	**-0.1%**	**1.3%**

[9] Central Hudson groups most substations in 10 distinct planning load areas. Load areas represent adjacent geographic regions, but, more importantly, nearly all load transfers between substations occur within planning load areas.

Table 7: Kingston-Saugerties Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Boulevard	35.0	20.5	20.6	19.8	18.4	20.1	18.9	59.3%	-3.8%	1.4%
East Kingston	48.0	12.0	12.1	12.2	11.7	11.4	11.4	25.1%	-0.4%	1.6%
Hurley Ave	23.1	17.6	17.0	17.3	16.8	18.4	18.2	76.2%	1.3%	1.6%
Lincoln Park	84.0	40.4	41.1	40.3	38.3	39.2	38.8	49.3%	-1.3%	1.0%
Saugerties	54.1	21.1	20.7	22.1	20.8	21.6	20.0	38.0%	-0.1%	1.5%
Woodstock	19.1	20.5	20.2	20.1	20.9	20.2	20.9	96.3%	1.7%	1.4%
Overall	N/A	**126.0**	**126.1**	**127.5**	**120.1**	**124.6**	**123.2**	**1.3%**	**-0.8%**	**1.1%**

Table 8: Modena Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Galeville	28.7	9.1	11.0	10.4	12.1	11.4	10.7	36.9%	1.8%	2.0%
Highland	32.9	17.1	17.1	18.1	18.0	18.8	17.7	54.8%	0.9%	1.4%
Modena	25.9	12.1	12.5	13.4	13.3	13.8	13.3	51.1%	2.1%	1.8%
Ohioville	29.7	24.2	22.9	20.1	22.0	24.4	21.9	72.4%	-0.2%	1.3%
Overall	N/A	**61.2**	**61.9**	**59.6**	**62.4**	**66.2**	**63.0**	**0.6%**	**1.2%**	**1.4%**

Table 9: Newburgh Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA) 2014	2015	2016	2017	2018	2019	Loading	Annual Growth	Std. Error
Bethlehem Rd	47.8	34.5	35.6	36.0	36.2	36.2	33.9	72.3%	-0.3%	1.3%
Coldenham	47.8	33.6	30.8	30.6	31.2	29.4	30.3	63.8%	-1.9%	1.5%
East Walden	26.2	14.1	14.7	14.1	13.7	15.1	14.7	54.6%	1.0%	2.1%
Marlboro	30.9	18.4	19.6	19.7	19.5	21.8	21.1	59.6%	2.3%	1.8%
Maybrook	24.0	14.6	17.8	18.9	18.6	20.5	18.2	68.2%	4.1%	2.8%
Montgomery	2.8	1.4	1.5	1.4	1.4	1.4	1.5	50.5%	0.8%	1.3%
Union Ave	94.5	53.1	53.4	54.2	53.6	56.3	60.7	54.6%	2.1%	1.6%
West Balmville	47.8	33.1	35.2	35.0	34.3	35.0	34.9	71.7%	0.6%	1.4%
Overall	N/A	**196.5**	**206.4**	**205.2**	**202.6**	**203.3**	**203.7**	**2.0%**	**0.8%**	**1.3%**

Table 10: Northeastern Dutchess Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
East Park	24.2	11.9	12.5	11.9	12.3	12.8	12.6	52.7%	1.1%	1.8%
Hibernia	17.8	10.5	10.6	10.0	10.8	12.1	12.4	55.9%	2.8%	2.7%
Milan	25.9	6.4	6.1	6.6	6.8	7.4	7.7	25.7%	2.1%	1.4%
Millerton	8.3	5.3	5.0	5.0	5.2	5.4	5.0	60.1%	1.0%	1.5%
Pulvers 13	5.8	4.5	4.4	4.7	4.9	4.9	5.0	78.1%	2.1%	1.5%
Pulvers 34	17.2	2.8	2.8	2.9	2.8	3.0	2.9	15.0%	1.0%	1.4%
Rhinebeck	47.8	28.4	28.0	28.7	26.5	28.5	29.9	60.1%	0.2%	1.3%
Smithfield	5.8	1.5	1.5	1.4	1.4	1.4	1.3	24.4%	-2.2%	1.3%
Staatsburg	26.5	8.6	8.0	8.7	8.3	9.2	9.1	32.9%	1.7%	1.7%
Stanfordville	6.3	3.1	3.0	3.4	3.9	3.5	3.5	53.1%	1.2%	2.3%
Tinkertown	19.1	13.1	13.1	14.8	13.6	14.4	13.7	71.4%	1.1%	1.9%
Overall	N/A	**93.1**	**92.0**	**93.3**	**91.6**	**97.8**	**98.4**	**1.0%**	**1.1%**	**1.2%**

Table 11: Northwest Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Coxsackie	16.4	11.8	11.9	11.8	12.4	13.3	11.4	67.7%	2.9%	1.7%
Freehold	15.7	6.4	6.3	6.3	6.5	7.5	6.9	40.5%	1.6%	1.6%
Hunter	19.5	14.2	13.4	14.7	11.1	10.1	10.7	41.3%	-5.2%	5.1%
Lawrenceville	22.1	17.2	15.1	16.9	13.2	13.3	12.5	40.5%	-4.5%	4.7%
New Baltimore	25.8	9.4	9.2	9.3	9.3	10.4	11.4	34.9%	5.6%	2.0%
North Catskill	35.1	23.8	23.1	24.1	22.7	24.2	23.0	67.2%	0.4%	1.3%
South Cairo	19.9	11.6	11.7	11.2	11.4	11.9	11.6	54.7%	2.6%	1.3%
Vinegar Hill	20.7	9.1	9.7	9.8	10.1	9.9	9.5	43.4%	0.3%	3.6%
Westerlo	27.0	8.6	8.2	8.9	8.2	8.0	8.1	29.9%	1.1%	2.4%
Overall	N/A	**99.6**	**94.4**	**97.5**	**100.2**	**94.3**	**92.9**	**0.9%**	**0.4%**	**1.6%**

Table 12: Poughkeepsie Load Area – Historical Load Growth Estimates (2014-2019)

Substation	Rating (MVA)	Historical Peak (MVA)						Loading	Annual Growth	Std. Error
		2014	2015	2016	2017	2018	2019			
Inwood Ave	47.8	25.3	24.6	26.3	26.2	24.9	24.4	50.0%	0.4%	2.0%
Manchester	47.8	29.2	28.8	33.7	32.9	32.4	31.4	64.6%	1.0%	1.4%
Reynolds Hill	47.8	34.6	32.8	35.6	34.1	36.1	36.0	69.0%	1.6%	1.0%
Spackenkill	47.8	31.4	31.3	31.1	30.5	29.8	30.8	63.9%	-0.7%	1.5%
Todd Hill	47.8	21.1	22.0	20.9	21.4	21.7	21.2	45.3%	0.4%	1.6%
Overall	N/A	**137.3**	**137.3**	**140.1**	**139.2**	**137.2**	**136.2**	**1.4%**	**0.5%**	**1.2%**

Table 13: Substation Normalized Peak Load Estimates, Historical (2015-2019) and Forecast (2020-2025)

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)					Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Ellenville	Clinton Ave	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.6	1.6	7.7
	Greenfield Rd*	6.2	6.3	6.5	6.7	6.8	6.9	7.0	7.2	7.4	7.6	7.8	15.4
	Grimley Rd	4.1	4.2	4.2	4.3	4.4	4.4	4.5	4.6	4.7	4.7	4.8	7.2
	High Falls	16.9	17.1	17.3	17.5	17.6	17.7	17.9	18.1	18.3	18.4	18.6	34.5
	Honk Falls	6.5	6.4	6.3	6.2	6.1	6.0	5.9	5.8	5.7	5.6	5.5	18.2
	Kerhonkson	8.4	8.6	8.8	9.0	9.3	9.3	9.6	9.8	10.1	10.4	10.7	44.6
	Neversink*	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.2	3.2	4.9
	Sturgeon Pool	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	29.7
	Total	**46.5**	**47.3**	**48.0**	**48.7**	**49.5**	**49.7**	**50.5**	**51.2**	**52.0**	**52.9**	**53.7**	**N/A**
Fishkill	Fishkill Plains	35.1	35.6	36.0	36.4	36.8	36.9	37.4	37.8	38.3	38.7	39.2	49.9
	Forgebrook	26.8	26.7	26.7	26.6	26.6	26.5	26.5	26.4	26.4	26.3	26.3	47.8
	Knapps Corners	21.0	20.7	20.4	20.0	19.7	19.6	19.3	19.0	18.7	18.4	18.1	47.8
	Merritt Park	33.1	32.9	32.7	32.5	32.4	32.3	32.1	32.0	31.8	31.6	31.5	52.2
	Myers Corners	22.3	21.9	21.6	21.3	20.9	20.8	20.5	20.2	19.9	19.6	19.3	35.1
	North Chelsea	19.5	19.5	19.5	19.5	19.5	19.6	19.6	19.6	19.6	19.6	19.6	48.3
	Sand Dock-D	3.9	4.0	4.1	4.3	4.4	4.4	4.5	4.7	4.8	4.9	5.1	8.0
	Shenandoah-D	11.5	11.6	11.8	11.9	12.1	12.1	12.3	12.5	12.6	12.8	13.0	12.7
	Tioronda	13.1	13.3	13.4	13.6	13.8	13.9	14.1	14.3	14.5	14.7	14.9	25.7
	Total	**186.3**	**186.1**	**185.8**	**185.7**	**185.4**	**185.4**	**185.2**	**185.0**	**184.8**	**184.6**	**184.4**	**N/A**
Kingston-Saugerties	Boulevard	24.2	23.3	22.4	21.6	20.7	20.5	19.7	19.0	18.3	17.6	17.0	35.0
	East Kingston	12.3	12.2	12.2	12.1	12.1	12.0	12.0	12.0	11.9	11.9	11.8	48.0
	Hurley Ave	16.7	17.0	17.2	17.4	17.6	17.7	17.9	18.1	18.4	18.6	18.9	23.1
	Lincoln Park	43.7	43.1	42.5	42.0	41.4	41.2	40.7	40.2	39.6	39.1	38.6	84.0
	Saugerties	20.6	20.6	20.6	20.6	20.6	20.6	20.5	20.5	20.5	20.5	20.5	54.1
	Woodstock	17.2	17.5	17.8	18.1	18.4	18.5	18.8	19.1	19.4	19.8	20.1	19.1
	Total	**133.1**	**131.9**	**130.9**	**129.8**	**128.7**	**128.4**	**127.4**	**126.3**	**125.3**	**124.3**	**123.2**	**N/A**
Modena	Galeville	9.9	10.1	10.2	10.4	10.6	10.7	10.8	11.0	11.2	11.4	11.6	28.7
	Highland	17.4	17.6	17.7	17.9	18.0	18.1	18.2	18.4	18.6	18.8	18.9	32.9
	Modena	12.2	12.4	12.7	12.9	13.2	13.3	13.6	13.9	14.2	14.5	14.8	25.9
	Ohioville	21.7	21.7	21.6	21.6	21.5	21.5	21.5	21.4	21.4	21.3	21.3	29.7
	Total	**59.2**	**59.9**	**60.6**	**61.3**	**62.0**	**62.2**	**62.9**	**63.6**	**64.3**	**65.1**	**65.8**	**N/A**
Newburgh	Bethlehem Rd	35.1	35.0	34.8	34.7	34.6	34.5	34.4	34.3	34.2	34.1	34.0	47.8
	Coldenham	32.9	32.3	31.7	31.1	30.5	30.3	29.8	29.2	28.7	28.1	27.6	47.8
	East Walden	13.8	13.9	14.0	14.2	14.3	14.3	14.5	14.6	14.8	14.9	15.1	26.2
	Marlboro	16.8	17.2	17.6	18.0	18.4	18.6	19.0	19.5	19.9	20.4	20.9	30.9
	Maybrook	13.9	14.5	15.1	15.7	16.4	16.6	17.3	18.0	18.8	19.5	20.3	24.0
	Montgomery*	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	2.8
	Union Ave	47.4	48.4	49.5	50.5	51.6	51.9	53.1	54.2	55.4	56.6	57.8	94.5
	West Balmville	33.5	33.7	33.9	34.1	34.3	34.3	34.5	34.7	34.9	35.1	35.3	47.8
	Total	**193.8**	**195.2**	**196.7**	**198.2**	**199.7**	**200.2**	**201.7**	**203.3**	**204.9**	**206.5**	**208.2**	**N/A**
Northeastern Dutchess	East Park	12.2	12.3	12.5	12.6	12.8	12.8	12.9	13.1	13.2	13.4	13.6	24.2
	Hibernia	8.9	9.2	9.4	9.7	9.9	10.0	10.3	10.6	10.9	11.2	11.5	17.8
	Milan	6.1	6.2	6.4	6.5	6.7	6.7	6.8	7.0	7.1	7.3	7.4	25.9
	Millerton	4.8	4.8	4.9	4.9	5.0	5.0	5.0	5.1	5.1	5.2	5.3	8.3
	Pulvers 13	4.2	4.3	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.8
	Pulvers 34	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	17.2
	Rhinebeck	28.6	28.6	28.6	28.7	28.7	28.7	28.8	28.8	28.9	28.9	29.0	47.8

Load Area	Substation	Historical 1 in 2 Annual Peak (MVA)					Forecasted 1 in 2 Annual Peak (MVA)						Rating (MVA)
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
	Smithfield	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	5.8
	Staatsburg	8.2	8.3	8.4	8.6	8.7	8.8	8.9	9.1	9.2	9.4	9.5	26.5
	Stanfordville	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.6	6.3
	Tinkertown	13.1	13.2	13.3	13.5	13.6	13.7	13.8	14.0	14.2	14.3	14.5	19.1
	Total	**92.2**	**93.2**	**94.2**	**95.2**	**96.2**	**96.5**	**97.5**	**98.6**	**99.6**	**100.7**	**101.8**	**N/A**
Northwest	Coxsackie*	9.9	10.2	10.5	10.8	11.1	11.2	11.5	11.9	12.2	12.6	13.0	16.4
	Freehold	6.0	6.1	6.2	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.9	15.7
	Hunter	10.0	9.5	9.0	8.5	8.1	7.9	7.5	7.1	6.8	6.4	6.1	19.5
	Lawrenceville	10.8	10.3	9.9	9.4	9.0	8.8	8.5	8.1	7.7	7.4	7.0	22.1
	New Baltimore	7.2	7.7	8.1	8.5	9.0	9.2	9.7	10.2	10.8	11.4	12.0	25.8
	North Catskill	23.2	23.3	23.4	23.5	23.6	23.6	23.7	23.8	23.9	23.9	24.0	35.1
	South Cairo*	9.8	10.1	10.4	10.6	10.9	11.0	11.3	11.6	11.9	12.2	12.5	19.9
	Vinegar Hill	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1	20.7
	Westerlo	7.8	7.8	7.9	8.0	8.1	8.1	8.2	8.3	8.4	8.4	8.5	27.0
	Total	**85.9**	**86.3**	**86.7**	**87.1**	**87.4**	**87.5**	**87.9**	**88.3**	**88.7**	**89.1**	**89.5**	**N/A**
Poughkeepsie	Inwood Ave	23.5	23.6	23.7	23.8	23.9	23.9	24.0	24.1	24.2	24.3	24.4	47.8
	Manchester	29.7	30.0	30.3	30.6	30.9	31.0	31.3	31.6	31.9	32.2	32.5	47.8
	Reynolds Hill	30.9	31.4	31.9	32.5	33.0	33.1	33.7	34.2	34.8	35.3	35.9	47.8
	Spackenkill	31.5	31.2	31.0	30.8	30.5	30.5	30.3	30.1	29.8	29.6	29.4	47.8
	Todd Hill	21.3	21.4	21.5	21.6	21.6	21.7	21.8	21.8	21.9	22.0	22.1	47.8
	Total	**133.3**	**134.0**	**134.6**	**135.3**	**135.9**	**136.1**	**136.8**	**137.5**	**138.2**	**138.9**	**139.5**	**N/A**

4 AVOIDED T&D COST AND LOAD RELIEF NEEDS

Avoided T&D cost studies now are able to produced location specific estimates and now utilize probabilistic methods, which quantify the risk mitigation value of managing demand. The estimates produced here are based on 5,000 simulations of potential load growth patterns for each substation and transmission area, respectively. For each simulation, we are thus able to 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 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. That is, the probabilistic method assigns T&D avoided costs when, for example, only 5% of potential growth trajectories leads to infrastructure upgrades.

This approach quantifies the risk mitigation value provided by resources that reduce demand at the right times at each location. The purpose of producing avoided T&D costs estimates is not necessarily to establish payments or incentives for DERs. The objective is to allow distributed energy resources to compete against each other and against traditional engineering solutions – wires, transformers, etc. – and thus increase competition and improve efficiency. The avoided cost estimates signal to DER providers not only where DERs are most beneficial but where they are most likely to be monetized. They also provide a reference point and allow comparison of DER costs to traditional engineering solutions. To deliver value, however, DERs needs to ramp up at the right time and the right place, for the right hours, with the right amount of availability, and the right level of certainty.

Avoided costs are tied to deferral of actual investments. Once sufficient NWA capacity has been contracted to defer a likely investment for a 10-year period, no value remains. As such, deferral value, though often expressed in dollars per kVA, really corresponds to deferral of a specific capacity magnitude for a specified length of time. Further, avoided T&D costs are classified into three mutually exclusive categories:

- Non-Wire Alternative (NWA) projects which provide contractual resources;
- Location Specific Relief Value (LSRV) which can be used to incentivize non-contracted resources in a specific location; and
- Distribution Relief Value (DRV) which represents can be used to incentivize non-contracted resources and assumes that resources will be located across the system and provide system wide load relief.

In general system-wide untargeted DRV values take into account the reductions would be broadly located throughout the system, providing system wide load reductions. The value is accordingly low due to the likelihood that reductions will be at a location where it might help defer or delay substation upgrades is relatively low, diluting any "system" avoided cost.

Because all transmission and distribution projects underlying the T&D avoided costs have been classified for NWA solutions, the LSRV and DRV transmission and distribution values are zero. If it is deemed feasible to use NWA resources to defer the projected investment needs, then contracted resources will be procured competitively. As such the locational avoided costs will not be included in this study.

4.1 AVOIDED TRANSMISSION COSTS

As discussed in the previous section, only the Northwest 115-69kV transmission area has non-zero avoided costs. All other transmission areas either have ample room for growth or declining loads.

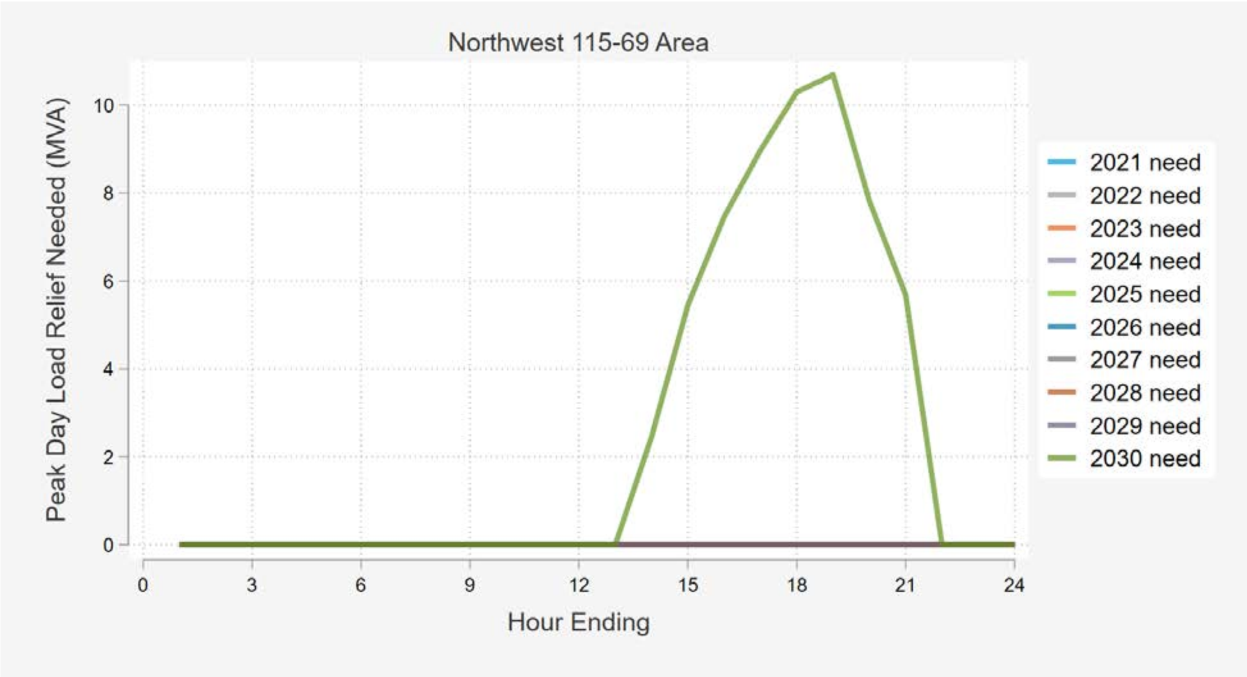
This study identified the Northwest 115-69 kV Area as a candidate for a Non-Wires Alternative project and is currently undergoing a review of feasibility. If it is deemed feasible to use non-wires resources to defer the projected investment need, then contracted resources will be procured competitively. As such the locational avoided costs will not be included in this study. Table 14 shows the peak load relief needed for the Northwest 115-69 kV Area in each year of the 10-year study period. Because the Northwest 115-69kV area is summer peaking, peak load relief is only needed in the summer and winter resources do not provide deferral value. This is discussed further in Section 5.

Table 14: Transmission Area Peak Load Relief Needed by Year (MVA)

Year	Northwest 115-69 Area
2021	0.0
2022	0.0
2023	0.0
2024	0.0
2025	0.0
2026	0.0
2027	0.0
2028	0.0
2029	0.0
2030	10.7

Although peak load relief is driven by the peak load in a location relative to the available capacity, load relief needs are not restricted to the single peak hour, rather load relief is required in all hours where load exceeds the available capacity. As such analyzing all hours where load relief is needed can reveal the concentration of need by hour of day and ultimately when (hour of day) and how long (peak window duration) load relief is needed. Understanding the concentration of need by hour in this manner is particularly critical for assessing the extent to which DER characteristics (load shape, duration, and dispatch constraints) improve or hinder the ability of a given resource to provide relief in the amount and timing needed. Figure 19 shows the hourly peak day load relief needs by year. Note that since the Northwest 115-69 kV area is summer peaking this value is concentrated in the summer hours.

Figure 19: Hourly Peak Day Load Relief Needed by Year – Northwest 115-69 kV Transmission Area



4.2 AVOIDED DISTRIBUTION SUBSTATION COST ESTIMATES

As discussed in the previous section, only the Shenandoah-Distribution substation has non-zero avoided costs. All other substations either have ample room for growth, declining loads, or can address ratings overloads via low-cost load transfers to neighboring substations.

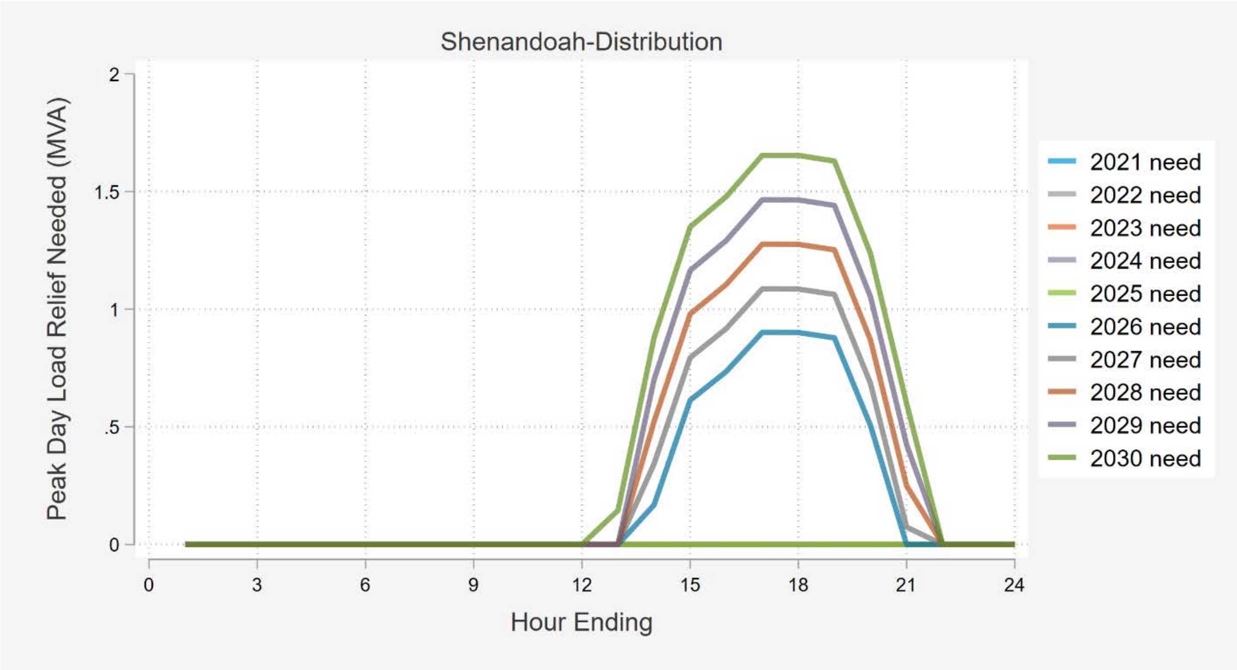
This study identified the Shenandoah Distribution substation as a candidate for a Non-Wires Alternative project and is currently undergoing a review of feasibility. If it is deemed feasible to use non-wires resources to defer the projected investment need, then contracted resources will be procured competitively. As such the locational avoided costs will not be included in this study. Table 14 shows the peak load relief needed for the Shenandoah Distribution substation in each year of the 10-year study period. Because the Shenandoah Distribution substation is summer peaking, peak load relief is only needed in the summer and winter resources do not provide deferral value. This is discussed further in Section 5.

Table 15: Substation Peak Load Relief Needed by Year (MVA)

Year	Shenandoah-Distribution
2021	0.0
2022	0.0
2023	0.0
2024	0.0
2025	0.0
2026	0.9
2027	1.1
2028	1.3
2029	1.5
2030	1.7

Although peak load relief is driven by the peak load in a location relative to the available capacity, load relief needs are not restricted to the single peak hour, rather load relief is required in all hours where load exceeds the available capacity. As such analyzing all hours where load relief is needed can reveal the concentration of need by hour of day and ultimately when (hour of day) and how long (peak window duration) load relief is needed. Understanding the concentration of need by hour in this manner is particularly critical for assessing the extent to which DER characteristics (load shape, duration, and dispatch constraints) improve or hinder the ability of a given resource to provide relief in the amount and timing needed. Figure 20 shows the hourly peak day load relief needs by year. Note that since the Shenandoah Distribution substation is summer peaking this value is concentrated in the summer hours.

Figure 20: Hourly Peak Day Load Relief Needed by Year – Shenandoah Distribution Substation



4.3 2020 VERSUS 2018 AVOIDED T&D COSTS STUDIES

In comparison to the 2018 study, the 2020 T&D avoided cost results differ along the following dimensions:

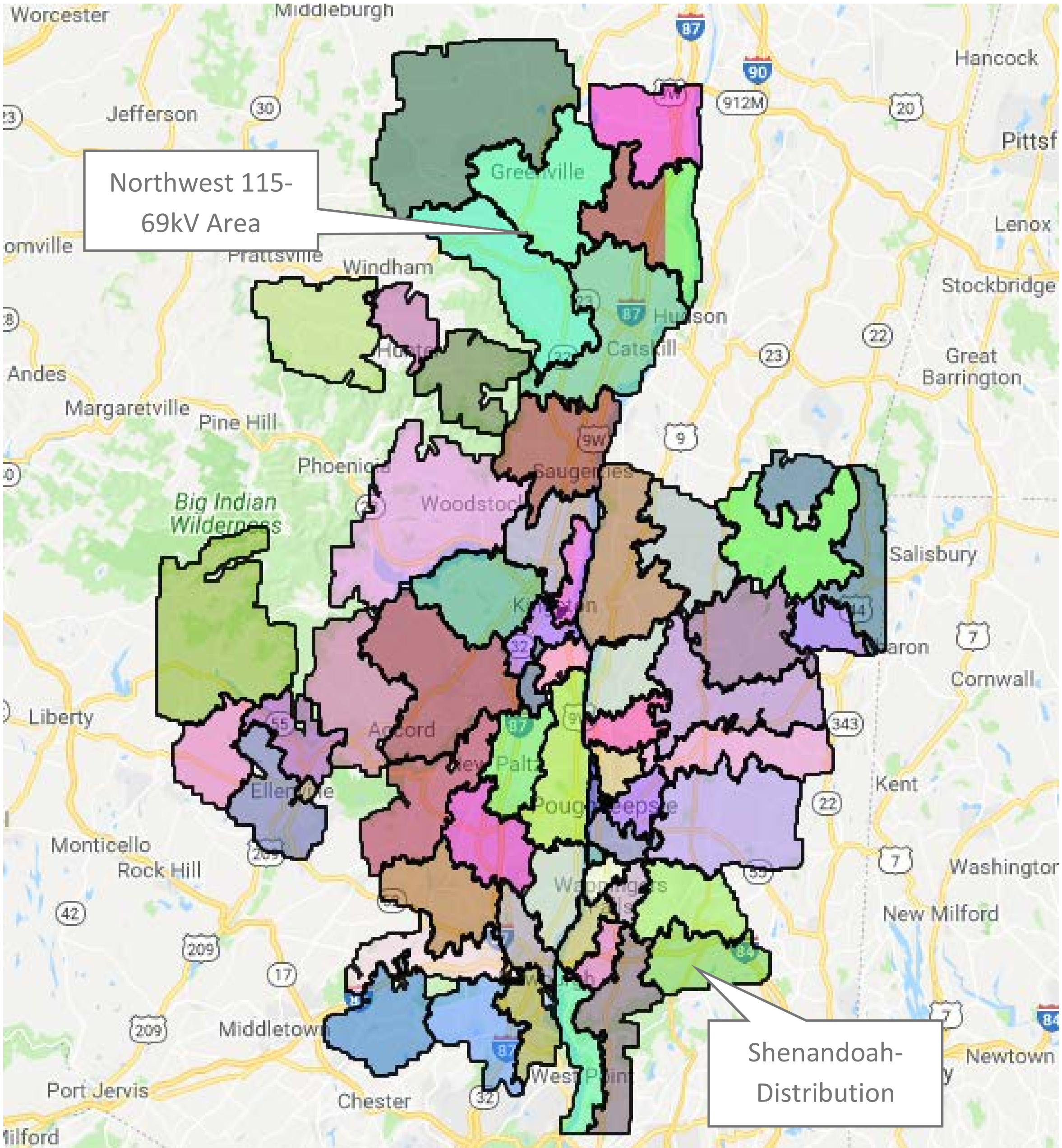
- The two locations with value in the 2018 study (Hunter and Lawrenceville substations) no longer trigger upgrades, due to load declines in the past two years and forecasted negative load growth;
- The two locations with value in the 2020 study (Northwest 115-69kV transmission area and Shenandoah Distribution substation) are both relatively highly loaded, have positive growth rates, and have ratings decrease expected in the study (due to NWA and generation load serving capability expirations), resulting in a high investment trigger likelihood (in the absence of further NWAs);
    - One key reason the 2018 study did not show risk for the Northwest 1115-69kV area was that it did not incorporate the 13.1 MW decrease to the rating at the end of 2025 attributable to generation retirement;
- Avoided costs are not included in the 2020 study because both beneficial locations identified are currently under feasibility review for Non-Wires Alternatives. Instead, the annual and hourly peak day need is shown for both locations. Notably, the need in both areas is in part driven by the retirement of current Non-Wires Alternatives resources;

5 BENEFICIAL LOCATIONS FOR DERS

Locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering an infrastructure investment by 2030 (10 years). In total, this includes one transmission area and four substations. While the locations can benefit from DERs, in some instances Central Hudson can provide temporary relief through distribution load transfers. This is specifically the case for three of the substations: Woodstock; Maybrook; and Pulvers 13kV.

For areas that lack load transfer options for deferring upgrades further, the right type of DERs with the right availability may allow for deferral of infrastructure investment. This is the case for the other two locations, the Northwest 115-69kV transmission area and the Shenandoah-Distribution substation. These are both summer peaking locations, meaning that peaks can be managed by Dynamic Load Management programs designed for the summer. Peaks in these locations typically occur in the later afternoon and early evening hours. Because deferral value is concentrated in these two locations, additional detail about them is included below.

Figure 21: Map of Beneficial Locations for DERs



5.1 NORTHWEST 115-69KV TRANSMISSION AREA

The Northwest 115-69kV transmission area is located at the northernmost part of the Central Hudson electric service territory. It currently has a summer long term emergency rating (LTE) of 140.8 MVA and a short term emergency (STE) rating of 157.6 MVA. In the winter, when cooler temperatures allow for higher loads, the LTE rating is higher, 179.2 MVA and a STE rating of 189.5 MVA. As discussed in section 3.1, the rating for the Northwest 115-69KV transmission area will decrease to 127.7 MVA in 2025. Additionally, the location currently has a 10 MW NWA set to sunset at the end of 2029.

Figure 22 shows the division of active accounts and 2019 electricity consumption in 2019 for Shenandoah-Distribution between residential and non-residential customers. Roughly 86% of the 19,000 accounts belonged to the residential customer class, and together they comprised 66% of total usage in 2019.

Figure 22: Northwest 115-69kV Transmission Area Accounts and Consumption

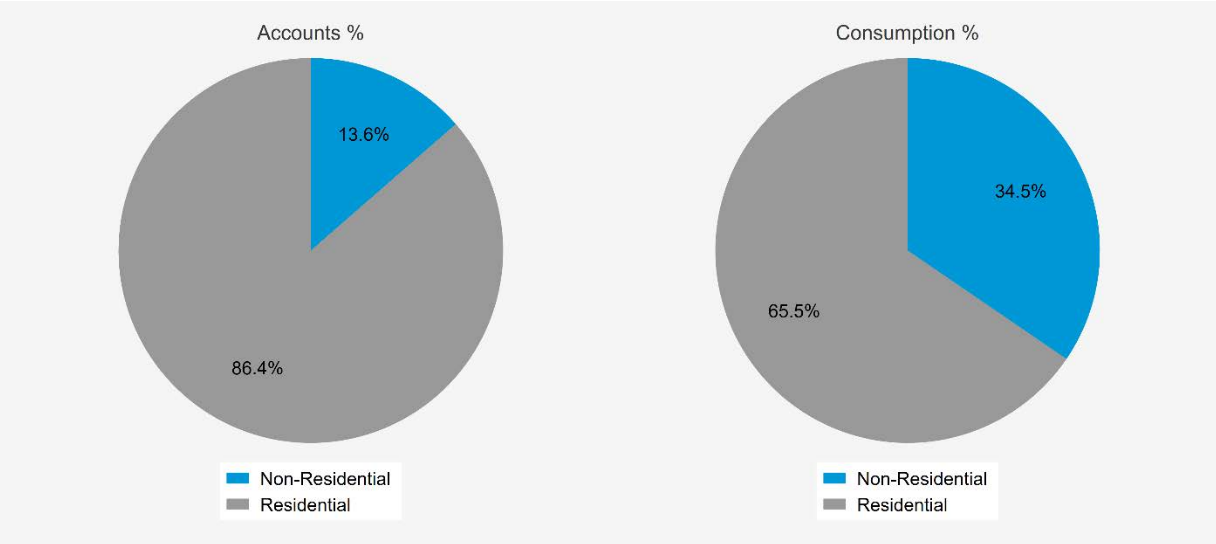
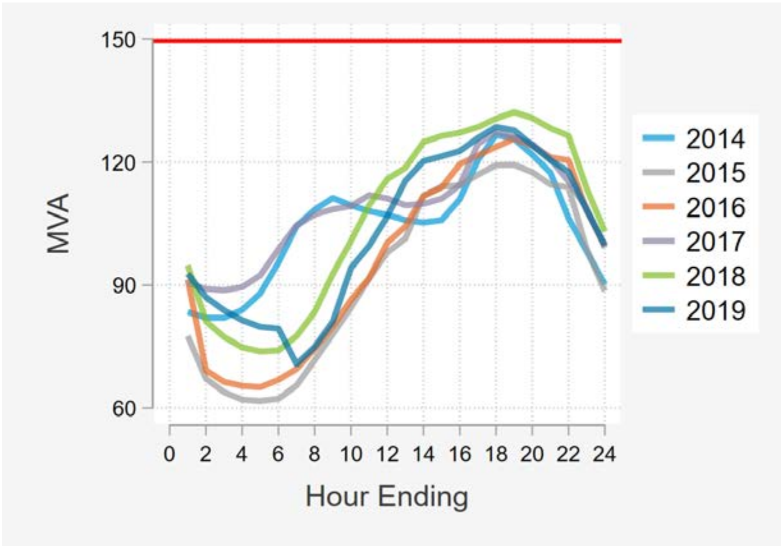


Figure 23 summarizes the peak day load for each year from 2014 to 2019 and includes details about the timing of the peak. Figure 24 summarizes the multi-year load duration curve over the same time frame and shows that peak demand is concentrated on a small share of hours. The weather sensitivity of load is illustrated in Figure 25, which shows the daily peak load as a function of different temperature ranges. Because the peak loads are driven by winter resort area visits and operation of snow related equipment, the peak loads are not as closely related to weather conditions and the timing of the peak is not as predictable as in other substations.

Figure 23: Northwest 115-69kV Transmission Area Historical Annual Peak Day Load Shapes



Date	Year	Hour	Load (MVA)	Day of Week
7-Jan-14	2014	18	126.7	Tuesday
29-Jul-15	2015	19	119.4	Wednesday
22-Jul-16	2016	19	125.7	Friday
28-Dec-17	2017	18	127.4	Thursday
2-Jul-18	2018	19	132.2	Monday
21-Jul-19	2019	18	128.6	Sunday

Figure 24: Northwest 115-69kV Multi-year Normalized Load Duration Curve, 2014-2019

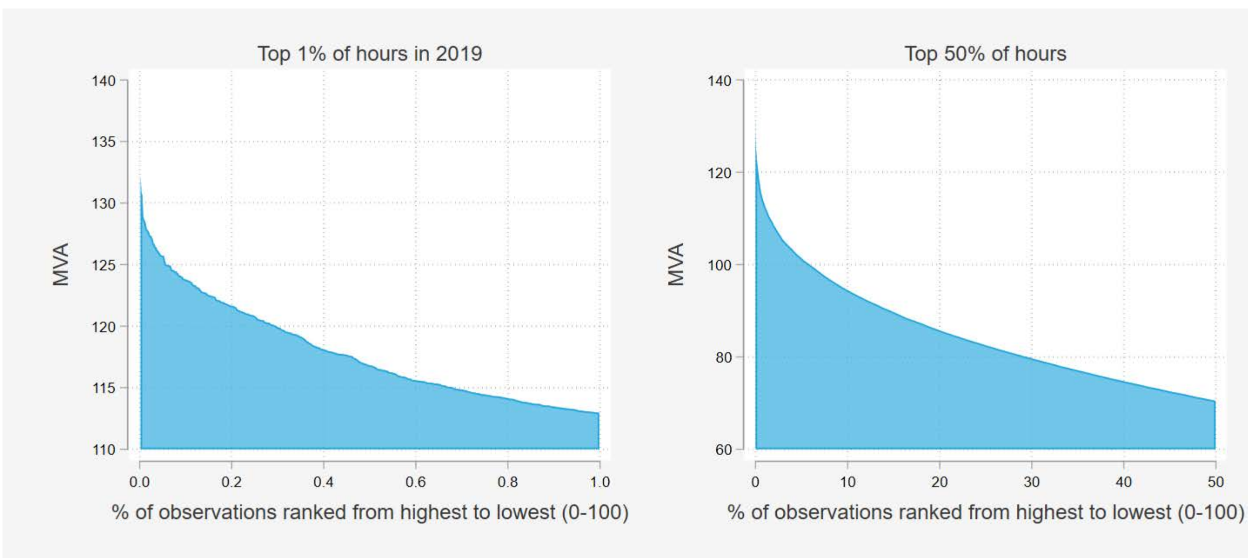
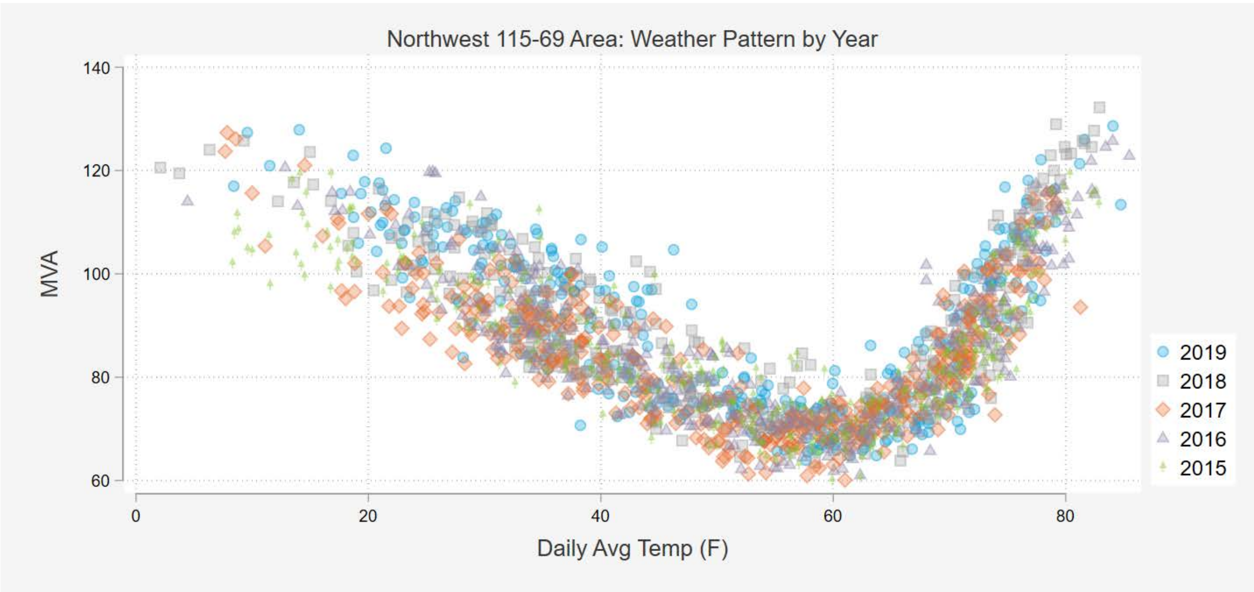


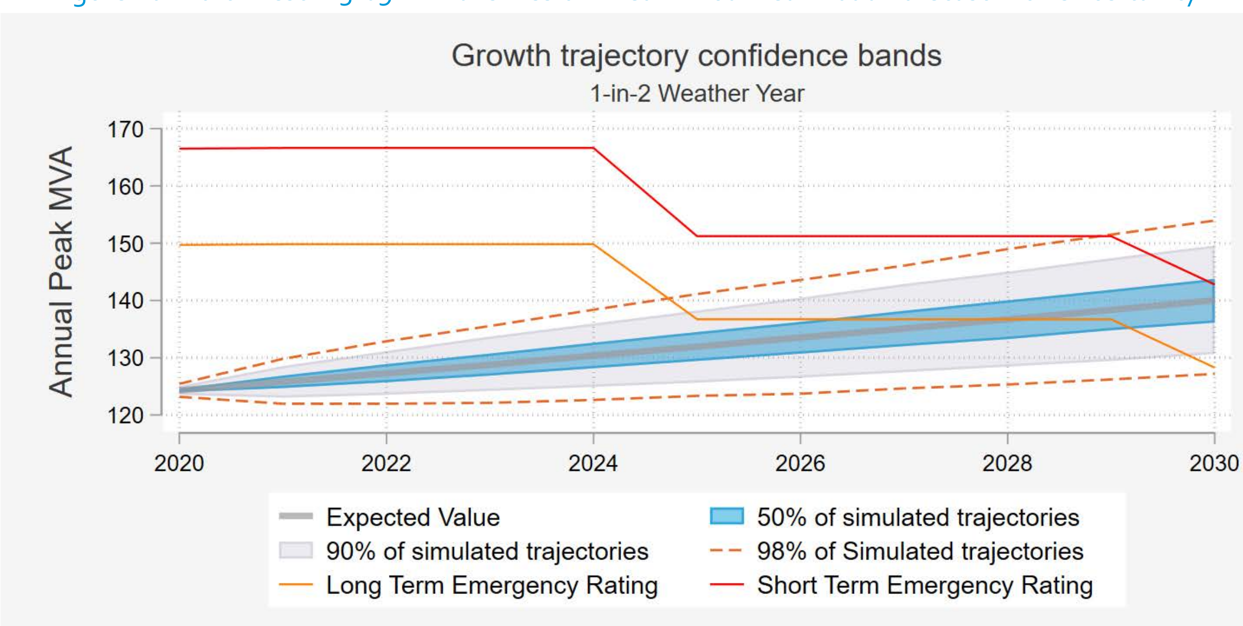
Figure 25: Northwest 115-69kV Transmission Area Daily Peak Load Weather Pattern by Year



Peak demand at the Northwest 115-69kV area has been growing at a rate of 1.2% per year since 2014. Load growth was modeled using probabilistic methods rather than straight-line forecasts.

Figure 26 shows the load growth forecast, assuming 1-in-2 weather year conditions. There is substantial uncertainty in the forecast, but there is a greater than 50% probability that loads will exceed LTE rating by 2028 and greater than a 90% probability loads will exceed the LTE rating by 2030 after the expiration of the current NWA.

Figure 26: Northwest 115-69kV Transmission Area Annual Peak Load Forecast with Uncertainty



5.2 SHENANDOAH-DISTRIBUTION SUBSTATION

The Shenandoah-Distribution substation is located in the southeastern part of the Central Hudson electric service territory. It is a summer peaking substation with a summer long term emergency rating (LTE) of 12 MVA and a short term emergency (STE) rating of 18 MVA. As discussed in section 3.1, the location currently has a 1.3 MVA summer capacity NWA set to sunset at the end of in 2025.

Figure 27 shows the division of active accounts and 2019 electricity consumption in 2019 for Shenandoah-Distribution between residential and non-residential customers. Roughly 90% of the 4,000 accounts belonged to the residential customer class, and together they comprised 73% of total electricity consumption in 2019.

Figure 27: Shenandoah-Distribution Substation Accounts and Consumption

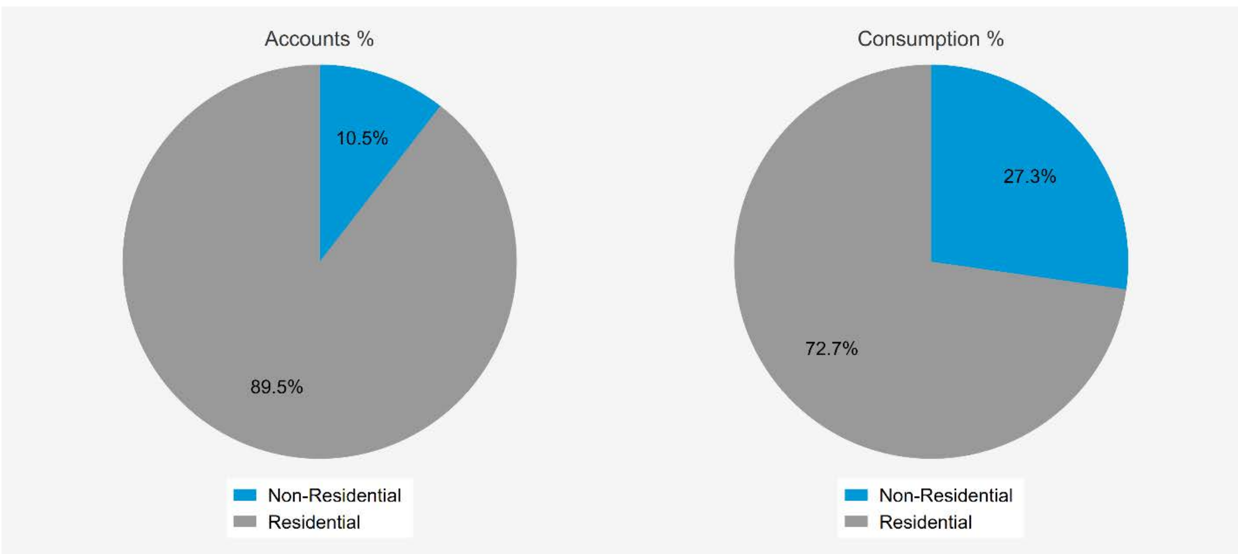
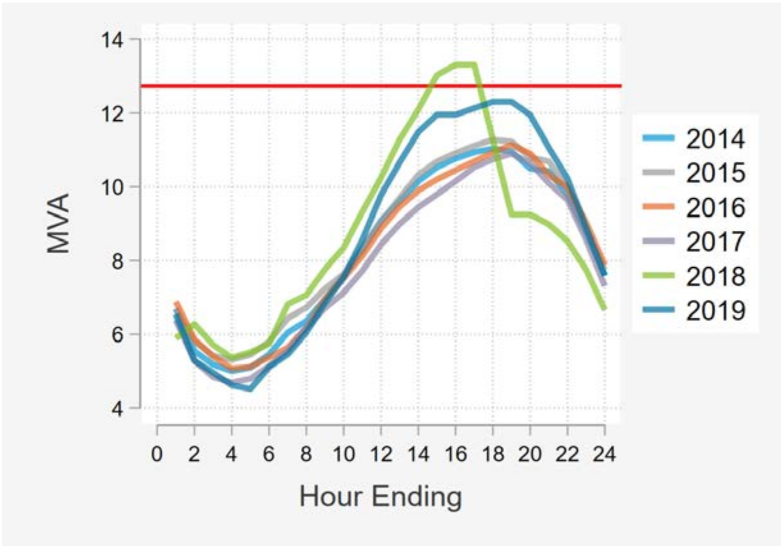


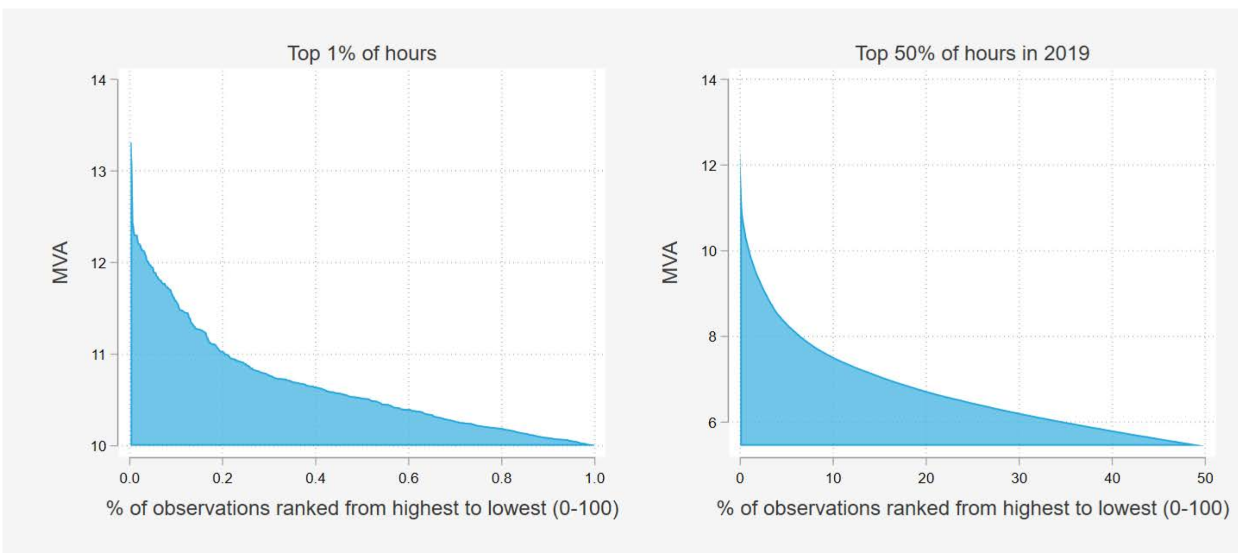
Figure 28 summarizes the peak day load for each year from 2014 to 2019 and includes details about the timing of the peak. Figure 29 summarizes the multi-year load duration curve over the same time frame and shows that peak demand is concentrated on a small share of hours. The weather sensitivity of Shenandoah-Distribution substation load is illustrated in Figure 30, which shows the daily peak load as a function of different temperature ranges. Peak demand in 2018 and 2019 was noticeably higher than in 2014 through 2017.

Figure 28: Shenandoah-Distribution Substation Historical Annual Peak Day Load Shapes[10]



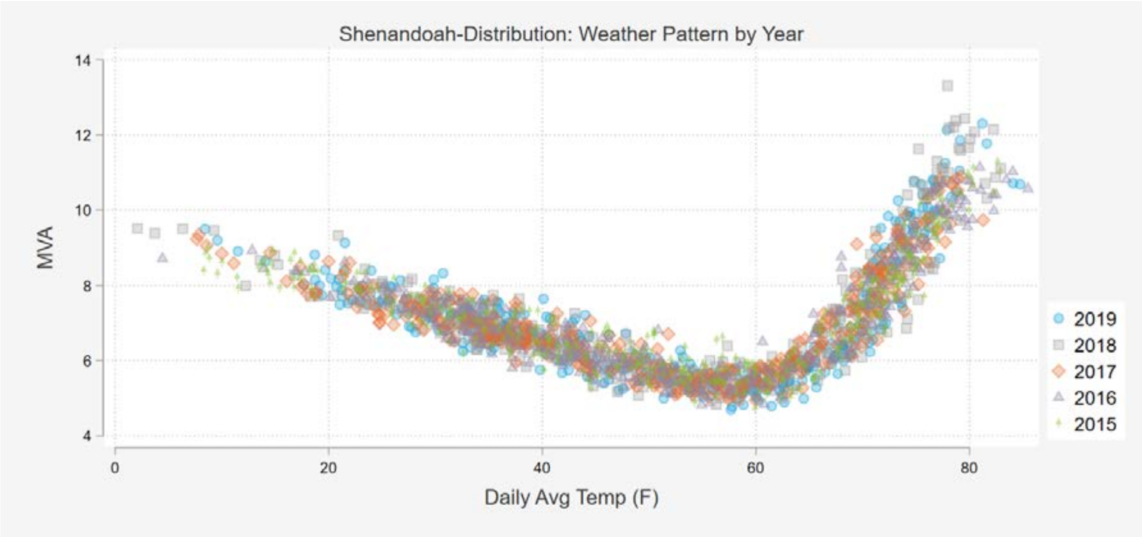
Date	Year	Hour	Load (MVA)	Day of Week
2-Sep-14	2014	18	11.0	Tuesday
8-Sep-15	2015	18	11.3	Tuesday
6-Jul-16	2016	19	11.1	Wednesday
12-Jun-17	2017	19	10.9	Monday
6-Sep-18	2018	16	13.3	Thursday
30-Jul-19	2019	18	12.3	Tuesday

Figure 29: Shenandoah-Distribution Substation Multi-year Normalized Load Duration Curve, 2014-2019



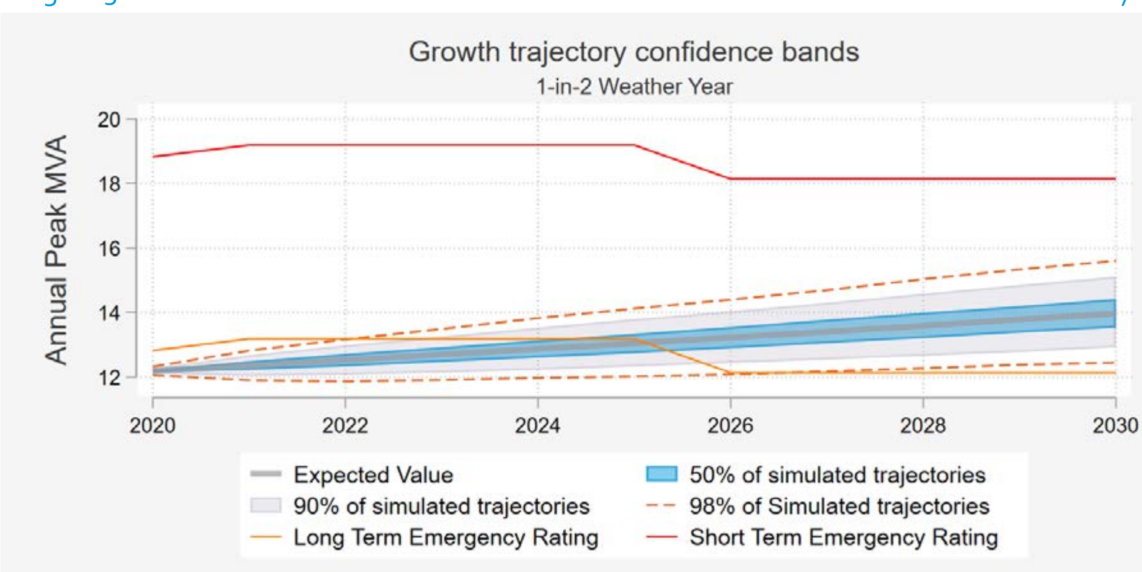
[10] The 2018 and 2019 historical peak day load shapes were adjusted upwards during event hours to account for a non-wires alternative events.

Figure 30: Shenandoah-Distribution Substation Daily Peak Load Weather Pattern by Year



Peak demand at Shenandoah-Distribution has been growing at a rate of 1.4% per year since 2014. Load growth and decline were modeled using probabilistic methods rather than straight-line forecasts. Figure 31 shows the load growth forecast, assuming 1-in-2 weather year conditions used for distribution planning. There is a relatively low but nonzero likelihood of the peak load exceeding the LTE rating until 2025 (the overload risk is roughly 30% in 2025), but the expiration of the Fishkill-Shenandoah NWA at the end of 2025 increases risk of overload in that year to over 90%. Unless loads remain below 2019 levels throughout the study period, the load will exceed the LTE starting in 2026 (though it is unlikely loads will exceed the STE).

Figure 31: Shenandoah-Distribution Substation Annual Peak Load Forecast with Uncertainty



6 KEY FINDINGS AND CONCLUSIONS

The key findings from the analysis are:

- The two locations with potential deferral value, the Northwest 115-69kV transmission area the Shenandoah-Distribution substation, are both summer peaking. As a result, only resources that deliver load relief in the summer provide value;
- Most substations and transmission areas are experiencing declining loads or have ample room for growth over the next 10 years;
- The expected avoided costs vary by location, year, season, and hour and are highly concentrated. Avoided costs are realized if additional resources are placed in the right locations and can deliver load relief at the right times. Without targeting, the value of distributed resources is diluted;
- For many distribution substations and transmission areas that have expected growth, the potential for avoided infrastructure upgrades through DER resources is minimal because there is already sufficient capacity built in the area to meet load growth;
- The avoided cost estimates reflect the uncertainty in the forecasts and the risk mitigation value of demand management. The two locations with value in this study have low risk (and avoided cost value) in initial years of the study but higher risk and value after 2025;
- In practice, all avoided T&D costs are location specific. For system-wide untargeted values, the estimates take into account the likelihood reductions would be in locations with value due to random chance. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low;
- Avoided T&D costs are classified into three mutually exclusive categories: projects for non-wire solutions which provide contractual resources, Location Specific Relief Value (LSRV) which can be used to incentivize non-contracted resources in a specific location, and Distribution Relief Value (DRV) which represents can be used to incentivize non-contracted resources and which incorporates the random chance that resources will be located where they will actually provide load relief. Because all projects underlying the T&D avoided costs have been classified for non-wire solutions, the LSRV and DRV T&D values are zero; and
- If it is deemed feasible to use non-wires resources to defer the projected investment needs, then contracted resources will be procured competitively. As such the locational avoided costs will not be included in this study;

The study demonstrates the value of developing T&D avoided cost estimates at a local level using probabilistic methods. Because the methodology is relatively novel, it may require future refinements and improvements. Future studies can be further bolstered by conducting sensitivity analyses and refinement of engineering rules, which trigger T&D infrastructure upgrades.

APPENDIX A: ECONOMETRIC MODELS USED TO ESTIMATE HISTORICAL GROWTH

The econometric models were purposefully designed to both estimate historical load growth in percentage terms and allow us to weather normalize loads for 1-in-2 weather peaking conditions.

The key to this process was to model the natural log of the daily peak loads as the dependent variable and include year-specific coefficients to estimate the percent change in loads, after controlling for other factors. By using the natural log as the dependent variable, all of the explanatory variables reflect the percent change in load associated with a unit change in the independent variable.

The regressions were estimated on the highest 150 local peak days for each year in the 2014 to 2019 timeframe for a total of up to 900 observations per location.[11] The goal was to include a sufficient number of days that reflected peaking conditions for each year. The number of observations by location varies slightly because of differences in the amount of data available and because peaks occurring on weekends or holidays were excluded. The model estimated daily peaks as a function of weather interacted with day of week, month, and historical year. Weather was included using a process that avoids assumptions about the type of relationship between weather and load. Rather than assume a constant linear relationship, the weather data is split into equally sized bins and a separate relationship is estimated for different temperature ranges—also known as a spline regression. All models were estimated using time series methods to take into account auto-correlation.[12]

Figure A-1 illustrates the model output for one location. A separate model was estimated for each substation and transmission area. The model explained 98.9% of the variation and, more importantly, produced estimates of the percent change in loads—the load growth—relative to 2019, after controlling for weather, day of week, and other factors. The coefficient on the year term represents annualized percent growth (in this case of 1.2%). The growth trend and the amount of year-to-year variation differ by location and are central to developing the probabilistic load forecasts. In addition, the confidence bands for the historical growth estimates are linked to the explanatory power of the models. When explanatory power is high, confidence bands are tight. When explanatory power is lower, confidence bands are broader.

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[11] For the Grimley Road, Hunter, and Lawrenceville substations, which have unique seasonal peaking behavior attributable to ski resort and summer camp loads, we added an additional minimum load requirement to include only seasonal driven peak loads.

[12] We relied on an iterative feasible GLS model with first order auto-correlation. Other time series options—such as ARIMA and the Newey-West model—do not handle gaps in the time series as easily. All options, however, produce consistent estimates.

The estimates of year-to-year historical load growth also were used to assess the degree to which growth patterns are related to each other—that is, the degree to which growth in the prior year predicts growth in the following year, technically known as auto-correlation. Each individual site had a limited number of individual year growth estimates—five years at most—so the estimate of auto-correlation was developed across all sites.

Figure A-1: Example Load Growth Econometric Model

```
Prais-Winsten AR(1) regression -- twostep estimates

Linear regression                               Number of obs     =        241
                                                F(12, 228)        =      73.58
                                                Prob > F          =     0.0000
                                                R-squared         =     0.9893
                                                Root MSE          =     .05178
```

lnload_gross	Coef.	Semirobust Std. Err.	t	P>|t|	[95% Conf.	Interval]
year	.0120939	.0025595	4.73	0.000	.0070506	.0171372
month						
7	.0543057	.0127421	4.26	0.000	.0291984	.079413
8	.0446781	.0127242	3.51	0.001	.0196061	.0697501
9	.0239124	.0173762	1.38	0.170	-.010326	.0581508
dow						
2	-.0095471	.0092772	-1.03	0.305	-.0278271	.0087329
3	-.0049196	.0114402	-0.43	0.668	-.0274617	.0176226
4	.0036314	.0114539	0.32	0.751	-.0189376	.0262005
5	-.0017852	.0116135	-0.15	0.878	-.0246687	.0210983
cdh60	.0042249	.0014206	2.97	0.003	.0014258	.007024
hdh60	0	(omitted)				
3.bins_cdd	-.1768186	.05521	-3.20	0.002	-.2856056	-.0680316
cdd60	.006798	.0048242	1.41	0.160	-.0027078	.0163038
bins_cdd#c.cdd60						
3	.0143631	.0048034	2.99	0.003	.0048985	.0238278
0.bins_hdd	0	(omitted)				
hdd60	0	(omitted)				
bins_hdd#c.hdd60						
0	0	(omitted)				
_cons	-20.02559	5.156308	-3.88	0.000	-30.1857	-9.865478
rho	.2534914					

```
Durbin-Watson statistic (original)    0.879187
Durbin-Watson statistic (transformed) 1.155407
```

E. Benefit Cost Analysis (BCA) Handbook

Central Hudson Gas & Electric

Benefit-Cost Analysis (BCA) Handbook

Version 3.0

June 30, 2020

Version History

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	Central Hudson BCA Handbook – v1.0	06/30/16	Central Hudson	First Issue
V1.1	Central Hudson BCA Handbook – v1.1	08/30/16	Central Hudson	Correction to Equation 4-3 and Equation 4-7
V2.0	Central Hudson BCA Handbook – v2.0	7/31/18	Central Hudson	Second Issue
V3.0	Central Hudson BCA Handbook – v3.0	6/30/20	Central Hudson	Third Issue

BACKGROUND

New York's Joint Utilities collaboratively developed a Standard BCA Handbook Template 2.0 in 2018 and have collaboratively worked to develop a revised 2020 Standard BCA Handbook Template 3.0 which reflects revisions to the 2018 filing. The purpose of the BCA Handbook Template 3.0 is to provide interested parties a consistent and transparent methodology to calculate the benefits and costs of potential projects and investments. The 2020 Standard BCA Template 3.0 serves as the common basis for each utility's individual BCA Handbook.

The 2020 BCA Handbooks include the key assumptions, scope, and approach for a BCA. They present applicable BCA methodologies and describe how to calculate individual benefits and costs as well as how to apply the necessary cost-effectiveness tests identified in the BCA Order. The BCA Handbooks also presents general BCA considerations and notable issues regarding data collection required for project and investment benefits assessments. Definitions and equations for each benefit and cost are provided along with key parameters and sources.

TABLE OF CONTENTS

ACRONYMS AND ABBREVIATIONS

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here at the front of the Handbook for ease of reference.

AC	Alternating Current
AGCC	Avoided Generation Capacity Costs
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost framework structure presented initially in the “Staff White Paper on Benefit-Cost Analysis” and finalized in the *BCA Order*.
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
C&I	Commercial and Industrial
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP Guidance Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
ICAP	Installed Capacity
JU or Joint Utilities	(Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation)
kV	Kilovolt
LBMP	Locational Based Marginal Prices
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt
MWh	Megawatt Hour
NPV	Net Present Value
NO_x	Nitrogen Oxides
NWA	Non-Wires Alternatives
NYC	New York City
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance

PV	Photovoltaic
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model (National Renewable Energy Laboratory)
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SENY	Southeast New York (Ancillary Services Pricing Region)
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	Utility Cost Test

1 INTRODUCTION

The State of New York Public Service Commission (NYPSC) directed the Joint Utilities (JU) to develop and file Benefit-Cost Analysis (BCA) Handbooks by June 30, 2016 as a requirement of the Order Establishing the Benefit-Cost Analysis Framework (*BCA Order)*.[1] The BCA Framework included in Appendix C of the *BCA Order* is incorporated into the BCA Handbooks. These handbooks are to be filed contemporaneously with each utility's initial Distributed System Implementation Plan (DSIP) filing and with each subsequent DSIP, scheduled to be filed every other year.[2] The 2020 BCA Handbooks are to be filed on June 30, 2020 with each utility's 2020 DSIP.

The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The *BCA Order* requires that a benefit-cost analysis be applied to the following four categories of utility expenditure:[3]

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection[4]
3. Procurement of DER through tariffs[5]
4. Energy efficiency programs

The BCA Handbook provides methods and assumptions that may be used to inform BCA for each of these four types of expenditure.

The *BCA Order* also includes key principles for the BCA Framework that are reflected in this 2020 BCA Handbook. Specifically, the Commission determined that the BCA framework should[6]:

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

1.1 Application of the BCA Handbook

The BCA Handbook provides a common methodology to be applied across investment projects and portfolios. The 2020 version of the BCA Handbook is meant to inform investments in DSP capabilities, the procurement of DERs through tariffs, the procurement of DERs through competitive solicitations (i.e. non-wire alternatives) and the procurement of energy efficiency programs. Common input assumptions and

[1] *BCA Order*: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

[2] DSIP Guidance Order, pg. 64: "shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018."

[3] *BCA Order*, pg. 1-2.

[4] Also known as non-wires alternatives (NWA).

[5] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).

[6] *BCA Order*, pg. 2.

sources that are applicable on a statewide basis (e.g., information publicly provided by the New York Independent System Operator (NYISO) or by Department of Public Service (DPS) Staff as required in the *BCA Order*) and utility-specific inputs (e.g., marginal costs) that may be commonly applicable to a variety of project-specific BCAs are provided within. Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

Table 1-1 lists the statewide values and respective sources to be used for BCA and referenced in this Handbook.

Table 1-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[7]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: 2018 ICAP Spreadsheet Model[8]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[9]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[10]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[11]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 1[12]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[13]

[7] The 2020 Load & Capacity Data report is available at: https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/. Supporting data can be found on the NYISO website in the Load & Capacity Data Report folder in the Planning Reports library section: https://www.nyiso.com/library.

[8] Per a letter of correspondence from DPS on August 29, 2019, the 2018 ICAP Spreadsheet Model is to be used, and not the 2019 ICAP Spreadsheet Model. The 2018 ICAP Spreadsheet Model, filed May 2, 2018, is found under Case 14-M-0101 at the Commission's website: http://documents.dps.ny.gov./public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search.

[9] The finalized annual and hourly zonal LBMPs from 2020 CARIS Phase 2 will be available by December 2020 on the NYISO website in the CARIS Study Outputs folder within the Economic Planning Studies folder. Until such time that the finalized 2020 CARIS 2 data is published, the utilities will employ the 2018 CARIS Phase 2 results, available at https://www.nyiso.com/documents/20142/1407490/2018-CARIS-2-Hourly-LBMP.zip/80fac5d5-c95f-5d92-4beb-9b3f23cd2c1f

[10] Historical ancillary service costs are available at: http://mis.nyiso.com/public/P-6Blist.htm. The values to apply are described in Section 4.1.5.

[11] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[12] Allowance price assumptions are to be used for the 2019 CARIS Phase 1 when available, at https://www.nyiso.com/planning. Until such time, the utilities will employ the 2017 CARIS Phase 1 results available at the same location.

[13] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year and post the results on DMM under case 14-M-0101.

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table 1-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table 1-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital in Cases 17-E-0459 and 17-G-0460	Order Approving Rate Plan issued and effective June 14, 2018
Losses	2019 Central Hudson Gas & Electric Corporation Analysis of System Losses
Marginal Avoided Transmission & Distribution Costs	Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods, 2016
Reliability Statistics	DPS: 2018 Electric Service Reliability Reports[14]

The New York general and utility-specific assumptions that are included in the 2020 BCA Handbook (as listed in Table 1-1 and Table 1-2) are typically values by zone or utility system averages.

The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.

1.2 BCA Handbook Version

This 2020 BCA Handbook provides techniques for quantifying the benefits and costs identified in the *BCA Order*. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

[14] The 2018 Annual Electric Service Reliability Report is available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/d82a200687d96d3985257687006f39ca/$FILE/Electric%20Reliability%202018%20DMM.pdf.

1.3 Structure of the Handbook

The four remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

Section 2. General Methodological Considerations describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.

Section 3. Relevant Cost-Effectiveness Tests defines each cost-effectiveness test included in the BCA Framework*.* These include the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure (RIM). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.

Section 4. Benefits and Costs Methodology provides detailed definitions, calculation methods, and general considerations for each benefit and cost.

Section 5. Characterization of DER profiles discusses which benefits and costs are likely to apply to different types of DER, and provides examples for a sample selection of DERs.

Appendix A. Utility-Specific Assumptions includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

2 GENERAL METHODOLOGICAL CONSIDERATIONS

This section describes key issues and challenges that that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in Section 4.

2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Doubling-counting can be avoided by 1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and 2) clearly defining and differentiating between the benefits and costs included in the analysis.

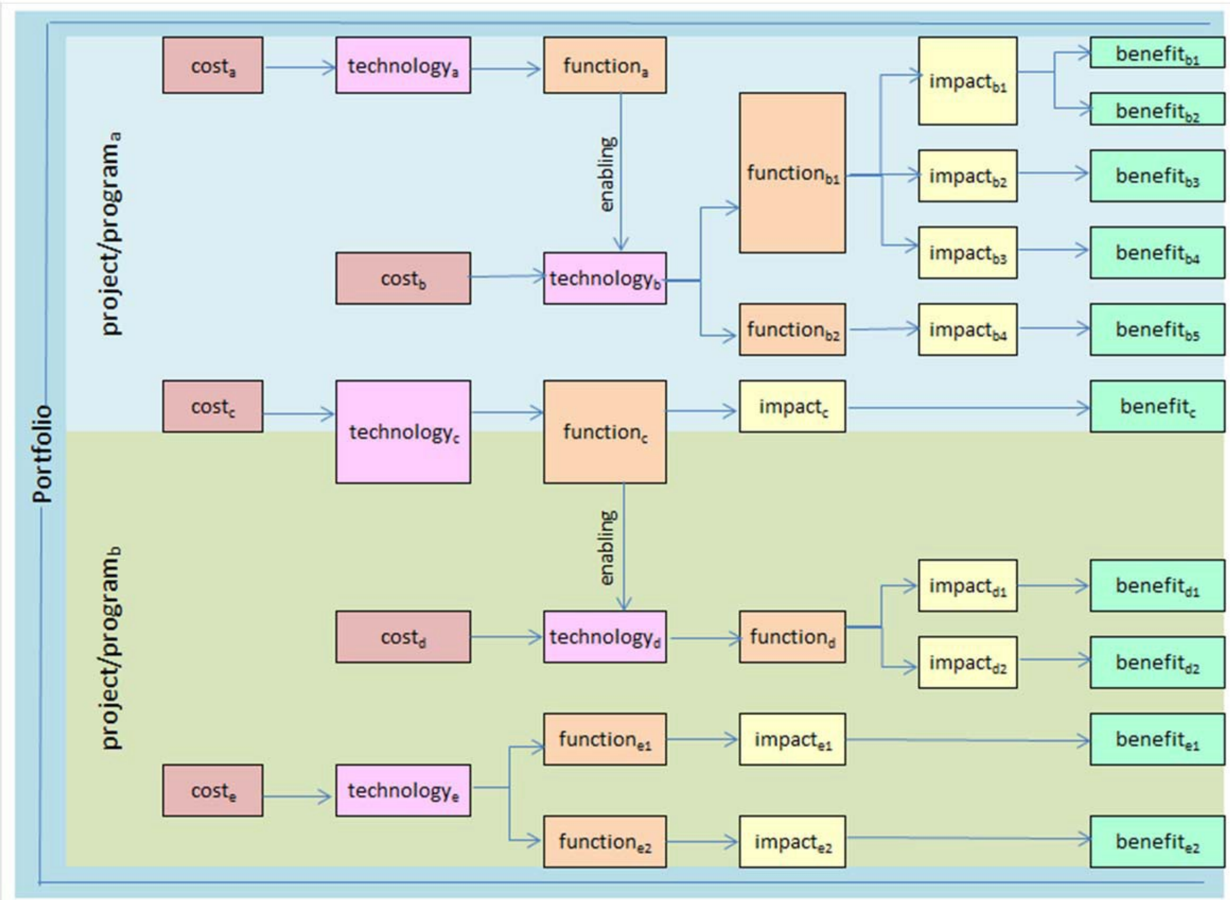
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

2.1.1 Accounting Across Multiple Value Streams of Benefits and Costs

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology provides one or more functions and that results in one or more quantified impacts, and are valued as monetized benefits.

Figure 2-1 is an illustrative example of value streams that may be associated with a portfolio of projects or programs.

Figure 2-1. Illustrative Example of Value Streams that May be Associated with a Portfolio of Projects or Programs



Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies (e.g. technology_b in Figure 2-1). Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function (e.g. technology_c in Figure 2-1). It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Benefits and costs should also be allocated properly across different projects within a portfolio. This may present challenges especially in the case of enabling technologies. For example, the investment in technology_c in Figure 2-1 is included as part of project/program_a. Some direct benefits from this technology are realized for project/program_a, however technology_c also enables technology_d that is included as part of project/program_b. In this example, the costs of technology_c and the directly resulting benefit should be accounted for in project/program_a, and the cost for technology_d and the resulting incremental benefits should be accounted for in project/program_b.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Over time, investments made as part of previous projects or portfolios may also enable or enhance new projects. The *BCA Order* states that utility BCA shall consider incremental T&D costs "to the extent that the characteristics of a project cause additional costs to be incurred."[15]

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility's distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, the impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. For example, if there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW- worth of capacity deferral credit for that feeder. As another example, the incremental improvement in reliability indices may diminish as more automated switching projects are in place.

Finally, the BCA should address situations where costs are incurred for a technology with a core function that benefits two programs as well as situations where costs are incurred for a technology with more than one core function, each potentially benefitting different programs.

2.1.2 Benefit Definitions and Differentiation

A key consideration when performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

As discussed in Section 3, the *BCA Order* identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section 4. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided LBMP, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided LBMP benefits should not be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Sections 2.1.2.1 and 2.1.2.2 below define the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided LBMP, and differentiate them from the impacts that should be counted as separate Avoided Transmission

[15] *BCA Order*, Appendix C pg. 18

Losses and Avoided Distribution Losses benefits. Sections 2.1.1.1 and 2.1.1.2 also provide differentiation between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

Table 2-1 provides a list of potentially overlapping AGCC, and Avoided LBMP benefits.

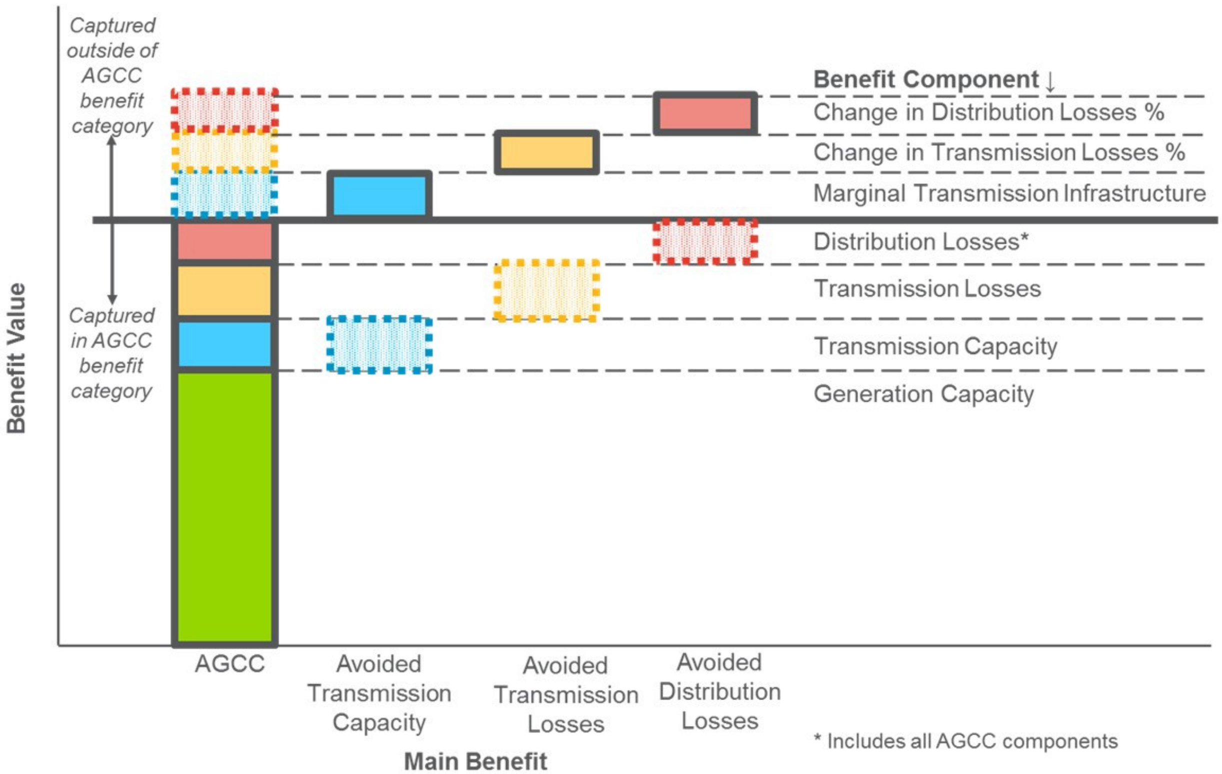
Table 2-1. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	• Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses
Avoided LBMP	• Net Avoided CO_2 • Net Avoided SO_2 and NO_x • Avoided Transmission Losses • Avoided Transmission Capacity • Avoided Distribution Losses

2.1.2.1 Benefits Overlapping with Avoided Generation Capacity Costs

Figure 2-2 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure 2-2. Benefits Potentially Overlapping with Avoided Generation Capacity Costs (Illustrative)



In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts not contained in the main benefit, but reflected in the calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission losses.[16] Additionally, a project's location on the system can affect distribution losses and the calculation of AGCC.[17] The AGCC calculation accounts for these distribution losses.

If a project changes the electrical topology and, therefore, the transmission loss percent, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

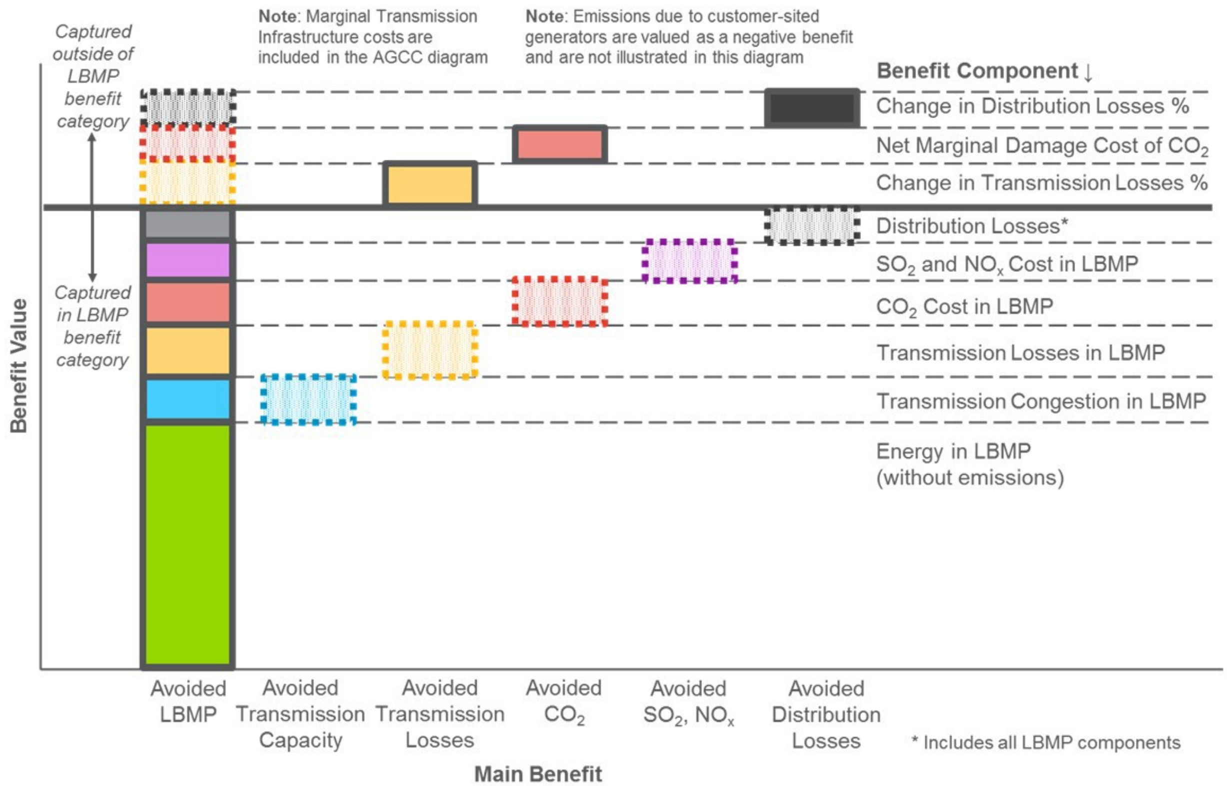
[16] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[17] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

2.1.2.2 Benefits Overlapping with Avoided LBMP

Figure 2-3 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

Figure 2-3. Benefits Potentially Overlapping with Avoided LBMP Benefit (Illustrative)



In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided LBMP benefit include costs for factors beyond just the energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided LBMP benefit:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the LBMP
- Transmission-level loss costs which are embedded in the LBMP
- Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the LBMP

Depending on a project's location on the system, distribution losses can also affect LBMP purchases, and this effect should be reflected in the calculation of LBMP benefits.[18] To the extent a project changes the electrical topology and changes the distribution loss percent itself, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[19] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from “loss percent”. The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section 4 follow the same notation to represent various locations on the system:

- “r” subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[20]
- “i” subscript represents the interface of the distribution and transmission systems.
- “b” subscript represents the bulk system which is the level at which the values for AGCC and LBMP are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{b\rightarrow r}$ would represent the loss percent between the bulk system (“b”) and the retail delivery or connection point (“r”). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

[18] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the LBMP purchases due to higher losses.

[19] In the BCA equations outlined in Section 4 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

[20] Transmission in this context refers to the distribution utility’s sub-transmission and internal transmission.

2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. The benefits of grid modernization projects accrue over many years; thus, baselines must be valid across the same time horizon. This introduces the following considerations:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO's CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may be made independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.
- **Normalizing baseline results**: Baseline data should be normalized to reflect average conditions over the course of a year. This is likely to involve adjustments for weather and average operational characteristics.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment and/or expected system performance. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions of the current baseline.

2.4 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[21]

2.5 Granularity of Data for Analysis

The most accurate assumptions to use for performing a BCA would leverage suitable locational or temporal information. When the more granular data is not available, an appropriate annual average or system average may be used to reflect the expected savings from use of DER.

While more granular locational or temporal assumptions are always preferred to more accurately capture the savings from use of a resource. The methodology included in the BCA Handbook would accommodate appropriate system averages in cases where data is not available.

2.6 Performing Sensitivity Analysis

The *BCA Order* indicates the BCA Handbook shall include a "description of the sensitivity analysis that will be applied to key assumptions.[22] As Section 4 indicates a sensitivity analysis may be performed on any of the benefits and costs by changing selected input parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided LBMP or AGCC.

For example, a sensitivity of LBMP, $/MWh, could be assessed by adjusting the LBMP by +/-10%.

In addition to adjusting the values of an individual parameter as a sensitivity, the applicability of certain benefits and costs would be considered as a sensitivity analysis of the cost-effectiveness tests. For example, inclusion of the Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.[23]

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[21] *BCA Order*, pg. 2

[22] *BCA Order*, Appendix C, pg. 31.

[23] *BCA Order*, pg. 25 ("The evaluation would then be conducted showing separately the impacts both with and without the wholesale market price effect.")

3 RELEVANT COST-EFFECTIVENESS TESTS

The *BCA Order* states that the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 3-1.

Table 3-1. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The *BCA Order* positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and ratepayers. Some projects may not provide benefits to the utility and ratepayers, even if it is beneficial to society as a whole. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that such impact is of a "magnitude that is unacceptable".[24]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 2 General Methodological Considerations.

[24] *BCA Order,* pg. 13.

Table 3-2 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test.

Table 3-2. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
Benefit				
4.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
4.1.2	Avoided LBMP‡	✓	✓	✓
4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
4.1.5	Avoided Ancillary Services*		✓	✓
4.1.6	Wholesale Market Price Impacts**		✓	✓
4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
4.2.2	Avoided O&M	✓	✓	✓
4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
4.3.1	Net Avoided Restoration Costs	✓	✓	✓
4.3.2	Net Avoided Outage Costs	✓		
4.4.1	Net Avoided CO_2‡	✓		
4.4.2	Net Avoided SO_2 and NO_x‡	✓		
4.4.3	Avoided Water Impacts	✓		
4.4.4	Avoided Land Impacts	✓		
4.4.5	Net Non-Energy Benefits***	✓	✓	✓
Cost				
4.5.1	Program Administration Costs	✓	✓	✓
4.5.2	Added Ancillary Service Costs*		✓	✓
4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
4.5.4	Participant DER Cost	✓		
4.5.5	Lost Utility Revenue			✓
4.5.6	Shareholder Incentives		✓	✓
4.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 2 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 2.1.2.1 for discussion of potential overlaps in accounting for these benefits.
** The amount of DER is not driver of the size of NYISO's Ancillary Services markets since a change in load will not result in a reduction in the NYISO requirements for Regulation and Reserves as the requirements for these services are set periodically by NYISO to maintain frequency and to cover the loss of the largest supply element(s) on the bulk power system. Therefore, there is no impact within the SCT as the overall Ancillary Services requirement remains unchanged.*
*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefit categories for each year of the analysis period (i.e., how much it will change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 4.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

Most of the benefits included in the *BCA Order* can be evaluated under the SCT because their impact applies to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants.

3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at the impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not considered in to the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not included in the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4 BENEFITS AND COSTS METHODOLOGY

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and a discussion of general considerations.

Four types of benefits are addressed in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

There are also four types of costs considered in the BCA Framework and addressed in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

The 2020 BCA Handbook 3.0 assumes that all energy, operational, and reliability-related benefits and cost,[25] occur in the same year. Thus, there is no time delay between benefit/cost impacts. However, for capacity and infrastructure benefits and costs,[26] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2020, the AGCC benefit would not be realized until 2021.

4.1 Bulk System Benefits

4.1.1 Avoided Generation Capacity Costs

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit

[25] Energy, operational, and reliability-related benefits and costs include: Avoided LBMP, the energy component of Avoided Transmission Losses, Avoided Ancillary Services, the energy portion of Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Net Avoided Restoration Costs, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO_2, Net Avoided SO_2 and NO_x, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, Shareholder Incentives, and Net Non-Energy Costs. .

[26] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity portion of the Wholesale Market Price Impact, Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[27] It is assumed that the benefit is realized in the year following the peak load reduction impact.

4.1.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2015 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

Equation 4-1. Avoided Generation Capacity Costs

$$\text{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{Z,Y,r}}{1\text{-Loss\%}_{Z,Y,b\rightarrow r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

The indices of the parameters in Equation 4-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\text{PeakLoad}_{Z,Y,r}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\text{Loss\%}_{Z,b\rightarrow r}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\text{SystemCoincidenceFactor}_{Z,Y}$ **(dimensionless)** captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\text{DeratingFactor}_{Z,Y}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$\text{AGCC}_{Z,Y,b}$ **($/MW-yr)** represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff and posted on DMM under case 14-M-0101 This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at

[27] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

4.1.1.2 General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast. The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[28] for more details on ICAP.

AGCC benefits are calculated using a static forecast of AGCC prices provided by Staff. Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section 4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (i.e. $\Delta \mathrm{PeakLoad}_{z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

4.1.2 Avoided LBMPs

Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP). The three components of the LBMP (i.e., energy, congestion, and losses) are all included in this benefit. See Section 2.1.2.1 for details on how the methodology avoids double counting between this benefit and others.

4.1.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-2 presents the benefit equation for Avoided LBMP:

[28] The NYISO Installed Capacity Manual is available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

Equation 4-2. Avoided LBMP

$$\mathrm{Benefit}_Y = \sum_Z \sum_P \frac{\Delta\mathrm{Energy}_{Z,P,Y,r}}{1 - \mathrm{Loss\%}_{Z,b\rightarrow r}} * \mathrm{LBMP}_{Z,P,Y,b}$$

The indices of the parameters in Equation 4-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\mathrm{Energy}_{Z,P,Y,r}$ (∆MWh) is the difference in energy purchased at the retail delivery or connection point ("r") as the result of project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $\mathrm{Loss\%}_{z,b\rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathrm{Loss\%}_{Z,b\rightarrow r}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\mathrm{LBMP}_{Z,P,Y,b}$ ($/MWh) is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

4.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section 4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that are valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the LBMP and the AGCC prices. Because static forecasts of LBMPs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

4.1.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation 4-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{Y+1} = \sum_{C} \frac{\Delta\mathrm{PeakLoad}_{Y,r}}{1 - \mathrm{Loss\%}_{Y,b\to r}} * \mathrm{TransCoincidentFactor}_{C,Y} * \mathrm{DeratingFactor}_{Y} * \mathrm{MarginalTransCost}_{C,Y,b}$$

The indices[29] of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system[30]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

[29] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[30] If system-wide marginal costs are used, this is not an applicable subscript.

$\Delta \text{PeakLoad}_{Y,r}$ **(∆MW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\text{Loss\%}_{Y,b\rightarrow r}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2.

$\textbf{TransCoincidentFactor}_{\textbf{C,Y}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $\text{DeratingFactor}_{Y}$). This input is project specific.

$\textbf{DeratingFactor}_{\textbf{Y}}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\textbf{MarginalTransCost}_{\textbf{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value reflects a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3.

4.1.3.2 General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study.

Some transmission capacity costs are already embedded in both LBMP and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in LBMP and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in

A significant over- or under-valuation of the benefits and/or costs and may result in no savings for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table A-3 include both capital and O&M, which cannot be split into two discrete benefits. Therefore, care should be taken to avoid double counting of any O&M values included in this benefit as part of the Avoided O&M benefit described in Section 4.2.2.

4.1.4 Avoided Transmission Losses

Avoided Transmission Losses are the benefits that are realized when a project changes the topology of the transmission system that results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided LBMP and Avoided Generation Capacity benefits as described above in Sections 4.1.2 and 4.1.1. While both the LBMP and AGCC will adjust to a change in system losses in future years, the static forecast used in this methodology does not capture these effects.

4.1.4.1 Benefit Equation, Variables, and Subscripts

Equation 4-4 presents the benefit equation for Avoided Transmission Losses:

Equation 4-4. Avoided Transmission Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i} = \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{post}}$$

The indices[31] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[32])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$SystemEnergy_{Z,Y+1,b}$ (MWh) is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b", ")includes both transmission and distribution losses. Total system energy is used for this input, rather than the project-specific energy, because this benefit is only included in the BCA when a change in system topology produces a change in the transmission loss percent, which affects all load in the relevant area.

$LBMP_{Z,Y+1,b}$ (\$/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$SystemDemand_{Z,Y,b}$ (MW) is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. System demand is used in this evaluation, rather than the project-specific demand, because this benefit is only quantified a change in the system topology is changed resulting in a change in the transmission losses percent, which affects all load in the relevant zone.

$AGCC_{Z,Y,b}$ (\$/MW-yr) represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data is posted on DMM in Case 14-M-0101 and can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level"[33] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\Delta Loss\%_{Z,Y,b \rightarrow i}$ (Δ%) is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

[31] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[32] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

[33] "Transmission level" represents the bulk system level ("b").

$\text{Loss\%}_{Z,Y,b\rightarrow i,\text{baseline}}$ **(%)** is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table A-2.

$\text{Loss\%}_{Z,Y,b\rightarrow i,\text{post}}$ **(%)** is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

4.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand, rather than project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to select DERs that qualify and are willing and are able to provide ancillary services to NYISO at a lower cost than conventional generators without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO. This value will be zero for nearly all cases and by exception would be a value included as part of the UCT and RIM.

DER causes a reduction in load but will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as the voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

4.1.5.1 Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of these benefits are project specific.

Frequency Regulation

Equation 4-5 presents the benefit equation for frequency regulation:

Equation 4-5. Frequency Regulation

$$Benefit_Y = Capacity_Y * n * (CapPrice_Y + MovePrice_Y * RMM_Y)$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$Capacity_Y$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project.

n (hr) is the number of hours in a year that the resource is expected to provide the service.

$CapPrice_Y$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$MovePrice_Y$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

RMM_Y **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 4-6 presents the benefit equation for spinning reserves:

Equation 4-6. Spinning Reserves

$$Benefit_Y = Capacity_Y * n * CapPrice_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$Capacity_Y$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project.

n (hr): is the number of hours in a year that the resource is expected to provide the service.

$CapPrice_Y$ **($/MW·hr)** is the average hourly spinning reserve capacity price. The default value uses the two- year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period.

The NYISO Ancillary Services Manual indicates that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ∆MW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.

4.1.6 Wholesale Market Price Impact

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., LBMP) and capacity (i.e., AGCC) due to a measure, project, or portfolio. LBMP impacts will be provided by Staff and are determined using the first year of the most recent CARIS database to calculate the static impact on wholesale LBMP of a 1% change in the level of load that must be met.[34] LBMP impacts will be calculated for each NYISO zone. AGCC price impacts are developed using Staff's ICAP Spreadsheet Model.

4.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

Equation 4-7. Wholesale Market Price Impact

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} (1 - \mathrm{Hedging\%} \ * (\Delta \mathrm{LBMP}_{Z,Y+1,b} * \ \mathrm{WholesaleEnergy}_{Z,Y+1,b} + \\ * \ \Delta \mathrm{AGCC}_{Z,Y,b} * \mathrm{ProjectedAvailableCapacity}_{Z,Y,b}$$

[34] *BCA Order*, Appendix C, pg. 8.

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K[35])
- Y = Year
- b = Bulk System

Hedging% **(%)** is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms in each year. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. The JU have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

$\mathbf{\Delta LBMPImpact_{Z,Y+1,b}}$ **(Δ$/MWh)** is the change in average annual LBMP at the bulk system ("b") before and after the project(s); requires wholesale market modeling to determine impact. This will be provided by DPS Staff.

$\mathbf{WholesaleEnergy_{Z,Y,b}}$ **(MWh)** is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This represents the energy at the LBMP.

$\mathbf{\Delta AGCC_{Z,Y,b}}$ **(Δ$/MW-yr)** is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[36] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\mathbf{ProjectedAvailableCapacity_{Z,Y,b}}$ **(MW)** is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

4.1.6.2 General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. LBMP market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS 2 database to calculate the static impact on LBMP of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT, but would be included in RIM and UCT as a sensitivity.

It is assumed that the capacity portion of Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand thereby reducing the benefit.[37] As noted previously, it is assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact.

[35] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

[36] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

[37] The one year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015.

4.2 Distribution System Benefits

4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

4.2.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation 4-8. Avoided Distribution Capacity Infrastructure

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{V}\sum_{\mathrm{C}} \frac{\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b \to r}}} * \mathrm{DistCoincidentFactor}_{\mathrm{C,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalDistCost}_{\mathrm{C,V,Y,b}}$$

The indices of the parameters in Equation 4-8 include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[38]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\mathrm{PeakLoad}_{\mathrm{Y,r}}$ (ΔMW) is the nameplate demand reduction of the project at the retail delivery or connection point (“r”). This input is project specific. A positive value represents a reduction in peak load.

[38] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

$\mathrm{Loss\%}_{Y,b\rightarrow r}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2. This parameter is used to adjust the $\Delta\mathrm{PeakLoad}_{Y,r}$ parameter to the bulk system level.

$\mathbf{DistCoincidentFactor_{C,V,Y}}$ **(dimensionless) is a project specific input that** captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system.

$\mathrm{DeratingFactor}_{Y}$ **(dimensionless) is a project specific input that** is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system.

$\mathbf{MarginalDistCost_{C,V,Y,b}}$ **($/MW-yr)** is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In limited circumstances the use of the system average marginal cost may be acceptable, for example, the evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3.

4.2.1.2 General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used wherever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure needs may result in significant over- or under-valuation of the benefits or costs. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DERs could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. These values are provided in Table A-3.

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the benefits should not be recognized from that point forward.

The marginal cost of distribution capacity values provided in Table A-3 include both capital and O&M; which cannot be split into two discrete benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and as part of the Avoided O&M benefit described in Section 4.2.2.

4.2.2 Avoided O&M

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. For example, this benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. However, at this time, it is expected that the value of this benefit for most DER projects will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

4.2.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-9 presents the benefit equation for Avoided O&M Costs:

Equation 4-9. Avoided O&M

$$\mathrm{Benefit}_{Y+1} = \sum_{AT} \Delta\mathrm{Expenses}_{AT,Y}$$

The indices of the parameters in Equation 4-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\Delta\mathbf{Expenses}_{AT,Y}$ (Δ\$): Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

4.2.2.2 General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, a benefit which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be trivial in most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely.

4.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project causes distribution system losses, to change which in turn results in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit is quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g. from 3% to 2.9%).

4.2.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-10 presents the benefit equation for Avoided Distribution Losses:

Equation 4-10. Avoided Distribution Losses

$$\text{Benefit}_{Y+1} = \sum_{Z} \text{SystemEnergy}_{Z,Y+1,b} * \text{LBMP}_{Z,Y+1,b} * \Delta\text{Loss\%}_{Z,Y+1,b\rightarrow i} + \text{SystemDemand}_{Z,Y,b} * \text{AGCC}_{Z,Y,b} * \Delta\text{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\text{Loss\%}_{Z,Y,i\rightarrow r} = \text{Loss\%}_{Z,Y,i\rightarrow r,\text{baseline}} - \text{Loss\%}_{Z,Y,i\rightarrow r,\text{post}}$$

The indices[39] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[40])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\text{SystemEnergy}_{Z,Y,b}$ (MWh) is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, rather than the project-specific energy, because this benefit is only quantified when the distribution loss percent value has changed, an event which affects all load in the relevant part of the distribution system.

$\text{LBMP}_{Z,Y,b}$ ($/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on using historical data to shape annual zonal averages by zone. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2

[39] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[40] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

modeling. It may be necessary; to assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh. If the LBMP forecast needs to extend beyond the CARIS planning period.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\mathrm{Loss\%_{Z,b \rightarrow r}}$ parameter. Note that the system demand is used in this evaluation, rather than the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent has changed, an event which affects all load in the relevant part of the distribution system.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system level ("b") based on forecast of capacity prices for the wholesale market provided by Staff and posted on DMM under Case 14-M-0101. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units to $/MW-yr, the summer and winter $/kW-mo values are multiplied by six months each added together, and then multiplied by 1,000.

$\mathbf{\Delta Loss\%_{Z,Y,i \rightarrow r}}$ **(Δ%)** is the change in the fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathrm{Loss\%_{Z,Y,i \rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathrm{Loss\%_{Z,Y,i \rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

4.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses from the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses.

Because losses data is usually available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with “Y” and “Y+1” subscripts to indicate the time delay of benefits relative to the impacts.

4.3 Reliability/Resiliency Benefits

4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, since utilities are required to fix the cause of an outage regardless of whether the DER allows the customer to operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of specific programs or specific projects are identified below. Use of either methodology depends on the type of investment/technology under analysis.

Equation 4-11 will generally apply to non-DER investments that allow the utility to save time and other expenses dispatching restoration crews. Equation 4-12 will generally apply to DER investments that are able to provide functionally equivalent reliability as an alternative to the traditional utility investment.

4.3.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-11 presents the benefit equation for Net Avoided Restoration Costs associated with non-DER invesments:

Equation 4-11. Net Avoided Restoration Costs

$$\text{Benefit}_Y = -\Delta\text{CrewTime}_Y * \text{CrewCost}_Y + \Delta\text{Expenses}_Y$$

Where,

$$\Delta\text{CrewTime}_Y = \#\text{Interruptions}_{\text{base},Y} * (\text{CAIDI}_{\text{base},Y} - \text{CAIDI}_{\text{post},Y} * (1 - \%\text{ChangeSAIFI}_Y))$$

$$\%\text{ChangeSAIFI}_Y = \frac{\text{SAIFI}_{\text{base},Y} - \text{SAIFI}_{\text{post},Y}}{\text{SAIFI}_{\text{base},Y}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for non-DER projects/programs that are applicable across a total system basis. More targeted & granular data should be utilized for localized and geographic specific projects that exhibit more localized impacts. Other reliability metrics will need to be developed to more suitably quantify reliability or resiliency benefits and costs associated with localized projects or programs. Once developed, the localized restoration cost metric will be applied and included in this handbook.

There is no subscript to represent the type of outage in Equation 4-11 because it assumes an average restoration crew cost that does not change based on the type of outage. The ability to reduce outages would be dependent on the outage type.

$\Delta CrewTime_Y$ **(Δhours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. This data is project and/or program specific. A positive value represents a reduction in crew time.

$CrewCost_Y$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration as provided in Table A-4.

$\Delta Expenses_Y$ **(Δ$)** are the average expenses (e.g. equipment replacement) associated with outage restoration.

$\#Interruptions_{base,Y}$ **(int/yr)** are the baseline (i.e., pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$CAIDI_{base,Y}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. However, in localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$CAIDI_{post,Y}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service. . Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\%ChangeSAIFI_Y$ **(Δ%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$SAIFI_{base,Y}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average. It is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$SAIFI_{post,Y}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

Equation 4-12. Net Avoided Restoration Costs

$$\text{Benefit}_{Y} = \text{MarginalDistCost}_{R,Y}$$

The indices of the parameters in Equation 4-12 are applicable to DER installations and include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\text{MarginalDistCost}_{R,Y}$ ($/yr): Marginal cost of the reliability investment. Because this value is project and location specific, a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent reliability as compared to the traditional distribution reliability investment that would have otherwise been installed/built; If the DER does not defer or avoid a traditional reliability investment, this benefit does not apply. When an individual or portfolio of DER is able to defer a distribution reliability investment, the value of the avoided restoration cost is already reflected in the Avoided Distribution Capacity Infrastructure benefit calculation.

4.3.1.2 General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline, rather than outside factors such as weather. The changes to these parameters should consider the appropriate context of the project including the types of outage events and how the project may or may not address each type of event to inform the magnitude of impact. For example, is the impact to one feeder or impact to a portion of the distribution system? The baseline values should match the portion of the system impacted.

In addition to being project-specific, the calculation of avoided restoration costs is dependent on projection of the impact of specific investments related to the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. However, as measurement capabilities and DER experience evolve, utilities may be able to develop comparative evaluations of the reliability benefits of DER and traditional utility investments. Application of this benefit would be considered only for investments with validated reliability results.

4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

4.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-13 presents the benefit equation for Net Avoided Outage Costs:

Equation 4-13. Net Avoided Outage Costs

$$\text{Benefit}_{\text{Y}} = \sum_{\text{C}} \text{ValueofService}_{C,Y,r} * \text{AverageDemand}_{C,Y,r} * \Delta\text{SAIDI}_{\text{Y}}$$

Where,

$$\Delta\text{SAIDI}_{\text{Y}} = \text{SAIFI}_{\text{base,Y}} * \text{CAIDI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}} * \text{CAIDI}_{\text{post,Y}}$$

The indices of the parameters in Equation 4-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{ValueOfService_{C,Y,r}}$ **($/kWh)** is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathbf{AvgDemand_{C,Y,r}}$ **(kW)** is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\Delta\text{SAIDI}_{\text{Y}}$ **(Δhr/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[41] Baseline system average reliability metrics can be found in Table A-4. A positive value represents a reduction in SAIDI.

$\text{SAIFI}_{\text{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case. Determining this parameter requires development of a distribution level model and a respective engineering study to quantify appropriately.

$\text{CAIDI}_{\text{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case. Determining this parameter requires the development of a distribution level model and a respective engineering study to quantify appropriately.

[41] SAIDI = SAIFI * CAIDI

$SAIFI_{base,Y}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$CAIDI_{base,Y}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

4.3.2.2 General Considerations

The value of the avoided outage cost benefit is customer-specific; the customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming that the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

Currently, the Standard Interconnection Requirements do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

4.4 External Benefits

4.4.1 Net Avoided CO2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[42] or the increase of CO_2 from onsite generation. To value the benefits associated with avoided CO2 emissions, utilities shall rely on the costs to comply with New York's Clean Energy Standard (CES),[43] valued as the resulting price per MWh of a Renewable Energy Certificate (REC) from the most recently completed NYSERDA RECs solicitation.

The net marginal damage cost of CO_2 may also be used to value CO_2 as a sensitivity to the BCA. The CARIS Phase 2 forecast of LBMP contains a cost of carbon based on the Regional Greenhouse Gas Initiative (RGGI). Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the LBMP. This adder is based on the United States Environmental Protection Agency damage cost estimates for a 3% real discount rate or the results of NYSERDA

[42] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

[43] Clean Energy Standard.

solicitations for renewable resource attributes. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs are the full marginal damage cost less the cost of carbon embedded in the LBMP.

4.4.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-14 presents the benefit equation for Net Avoided CO_2

Equation 4-14. Net Avoided CO_2

Using the cost to comply with New York's CES:

$$\text{Benefit}_{\text{Y}} = \text{CESCost} * \left(\frac{\Delta\text{Energy}_{\text{Y,r}}}{1 - \text{Loss\%}_{\text{Y,b}\rightarrow\text{r}}} + \Delta\text{Energy}_{\text{TransLosses,Y}} + \Delta\text{Energy}_{\text{DistLosses,Y}} \right)$$

Using the net marginal damage cost:

$$\text{Benefit}_Y = \text{CO2Cost}\Delta\text{LBMP}_Y - \text{CO2Cost}\Delta\text{OnsiteEmissions}_Y$$

Where,

$$\text{CO2Cost}\Delta\text{LBMP}_Y = \left(\frac{\Delta\text{Energy}_{Y,r}}{1 - \text{Loss\%}_{Y,b\to r}} + \Delta\text{Energy}_{\text{TransLosses},Y} + \Delta\text{Energy}_{\text{DistLosses},Y}\right) * \text{NetMarginalDamageCost}_Y$$

$$\Delta\text{Energy}_{\text{TransLosses},Y} = \text{SystemEnergy}_{Y,b} * \Delta\text{Loss\%}_{Y,b\to i}$$

$$\Delta\text{Energy}_{\text{DistLosses},Y} = \text{SystemEnergy}_{Y,b} * \Delta\text{Loss\%}_{Y,i\to r}$$

$$\Delta\text{Loss\%}_{Z,Y,b\to i} = \text{Loss\%}_{Z,Y,b\to i,\text{baseline}} - \text{Loss\%}_{Z,Y,b\to i,\text{post}}$$

$$\Delta\text{Loss\%}_{Z,Y,i\to r} = \text{Loss\%}_{Z,Y,i\to r,\text{baseline}} - \text{Loss\%}_{Z,Y,i\to r,\text{post}}$$

$$\text{CO2Cost}\Delta\text{OnsiteEmissions}_Y = \Delta\text{OnsiteEnergy}_Y * \text{CO2Intensity}_Y * \text{SocialCostCO2}_Y$$

The indices of the parameters in Equation 4-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\text{CO2Cost}\Delta\text{LBMP}_Y$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided LBMP benefit. The incremental value of CO_2 is captured in this benefit, and is valued at the net marginal cost of CO_2, as described below.

$\text{CO2Cost}\Delta\text{OnsiteEmissions}_Y$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\Delta\text{Energy}_{Y,r}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $\text{Loss\%}_{b\to r}$ parameter. A positive value represents a reduction in energy.

$\text{Loss\%}_{Y,b\to r}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table A-2.

$\Delta\text{Energy}_{\text{TransLosses},Y}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\Delta \mathrm{Energy}_{\mathrm{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section 4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathrm{NetMarginalDamageCost}_{\mathrm{Y}}$ **($/MWh)** is the “adder” Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of LBMP from CARIS Phase 2. The LBMP forecast from CARIS Phase 2 includes the cost of carbon based on the RGGI, fully reflect the SCC.

$\boldsymbol{\Delta \mathrm{Loss\%}_{\mathrm{Z,Y,b\to i}}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface of the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathrm{Loss\%}_{\mathrm{Z,Y,b\to i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface between the bulk system (“b”) and the interfaceofthe transmission and distribution systems (“i”). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\mathrm{Loss\%}_{\mathrm{Z,Y,b\to i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). Thus, this reflects the transmission loss percent post-project, which is found in Table A-2.

$\boldsymbol{\Delta \mathrm{Loss\%}_{\mathrm{Z,Y,i\to r}}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”) resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathrm{Loss\%}_{\mathrm{Z,Y,i\to r,baseline}}$ **(%)** is the baseline fixed and variable loss percent of the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathrm{Loss\%}_{\mathrm{Z,Y,i\to r,post}}$ **(%)** is the post-project fixed and variable loss percent of the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”). Thus, this reflects the distribution loss percent post-project, which is found in Table A-2.

$\Delta 0\mathrm{nsite}\mathbf{Energy}_{\mathrm{Y}}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathbf{CO2Intensity}_{\mathbf{Y}}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation. 1 metric ton is the equivalent of 1.10231 short tons.

$\mathrm{SocialCostC02}_{\mathrm{Y}}$ **($ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in carbon dioxide emissions. Annual values are provided by EPA. (using the 3% real discount rate) or derived from the results of NYSERDA solicitations for renewable resources attributes. EPA estimates of this cost (using a 3 percent discount rate) may be used in as part of any sensitivity analyses.

4.4.1.2 General Considerations

The equation above represents two sources of emissions based on: (1) a change in LBMP purchases, which is valued at the $/MWh adder (i.e., $\mathrm{NetMarginalDamageCost}_{Y}$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power [CHP]), based on the results of NYSERDA solicitations for renewable resources attributes.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided LBMP benefit. The LBMP impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in LBMP due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The *BCA Order* indicates “utilities shall rely on the costs to comply with New York’s Clean Energy Standard once those costs are known.”[44]

4.4.2 Net Avoided SO2 and NOx

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (i.e., SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

4.4.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation 4-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit}_{Y} = \sum_{P} \mathrm{OnsiteEmissionsFlag}_{C,Y,r} * \mathrm{OnsiteEnergy}_{Y,r} * \mathrm{PollutantIntensity}_{p,Y} * \mathrm{SocialCostPollutant}_{p,Y}$$

The indices of the parameters in Equation 4-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathrm{OnsiteEmissionsFlag}_{Y}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW will be included in the analysis as a result of the project.

$\mathrm{Onsite}\mathbf{Energy}_{Y,r}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

$\mathbf{PollutantIntensity_{p,Y}}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

[44] *BCA Order*, Appendix C, 16.

$SocialCostPollutant_{p,Y}$ ($/ton) is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2

CESCost ($/MWh) is the cost of compliance with New York's Clean Energy Standard (CES) valued as the resulting price per MWh of a Renewable Energy Certificate (REC) from the most recently completed NYSERDA RECs solicitation

4.4.2.2 General Considerations

LBMPs already include the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: "Annual NO_x" and "Ozone NO_x." Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

4.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

4.5 Costs Analysis

4.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

4.5.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-16 presents the cost equation for Program Administration Costs:

Equation 4-16. Program Administration Costs

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta\mathrm{ProgramAdminCost}_{\mathrm{M,Y}_{\mathrm{p,Y}}}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

$\mathbf{\Delta ProgramAdminCost_{M,Y}}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

4.5.1.2 General Considerations

Program Administration Costs are program- and project-specific. As a result, it is not possible to estimate in advance the Project Administration Cost in advance without a clear understanding of the program and project details. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

4.5.2 Added Ancillary Service Costs

Added Ancillary Service Costs occur when DER causes additional ancillary service costs on the system. These costs shall be considered and monetized in a similar manner to the method described in the 4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

4.5.3 Incremental Transmission & Distribution and DSP Costs

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional T&D infrastructure costs shall be considered and monetized in a similar manner to the method described in Section 4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. As a result, it is not possible to estimate the additional T&D infrastructure cost in advance without a clear understanding of this information.

Depending on the nature of a specific DER project the incremental costs could be borne by the interconnecting facility or utility customers. For instance, a utility may need to make further investment in their T&D infrastructure, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

4.5.4 Participant DER Cost

Participant DER Cost is money required to fund programs or measures that is not provided by the utility. It includes accounts for the equipment and participation costs assumed by DER providers or participants which need to be considered when evaluating the societal costs of a project or program. The Participant DER Cost is equal to the full DER Cost net of Program rebates, and incentives that are included as part of Program Administration.

The full DER Cost includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment as well as labor and materials for the installation. Operating costs include ongoing maintenance expenses. For projects where only a portion of the costs can be attributed to the establishment of a DER, only that portion of the total project cost should be considered as the Full DER Cost. This practice is generally appropriate for projects where the non-participation scenario carries some baseline cost, such as replacing an appliance with a high efficiency alternative at the time of failure. In such a scenario, only the incremental costs above the baseline appliance should be considered as the Full DER Cost.

This section provides four examples of DER technologies with illustrative cost information based on assumptions that will ultimately vary given the facts and circumstances specific to each DER application:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – reciprocating engine (100 kW)
- Demand Response (DR) – controllable thermostat
- Energy Efficiency (EE) – commercial lighting

All cost numbers presented herein should be considered illustrative estimates only. These represent the full costs of the DER and do not account for or net out any rebates or incentives. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from, each of which have different combinations of cost and efficiency.
- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the state
- **Available rebates and incentives:** include federal, state, and/or utility funding

The Commission noted in the February 2015 Track 1 Order that the approach employed to obtain DER will evolve over time, "The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach."[45]

Thus, the acquisition of most DER in the near term will be through competitive solicitations rather and standing tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation.[46] Company competitive solicitations for DER will require the disclosure of costs by the bidders, including but not limited to capital, installation, marketing, administrative, fixed and variable O&M, lost opportunity and/or behavioral incentive costs. The Company will use the submitted costs in the project/program/portfolio BCA evaluation. Additionally, the Company will employ this information to develop and update technology specific benchmark costs as they evolve over time.

For illustrative purposes, examples for a small subset of DER technologies are provided below.

4.5.4.1 Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table 4-1 for the intermittent solar PV example are derived based on information provided in the E3's NEM Study for New York ("E3 Report").[47] In this study, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in NY from 2003 to 2015. This is just one example of evaluating the potential cost of solar PV technology. For a project-specific cost analysis, actual estimated project costs would be used.

Table 4-1. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[48]	4,430
Fixed Operating Cost ($/kW)	**15**

Note: These costs would change as DER project-specific data is considered.

[45] Order Adopting Regulatory Policy Framework and Implementation Plan, Case 14-M-0101, pg. 33.

[46] BCA Order, Appendix C pg. 18.

[47] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

[48] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

1. **Capital and Installation Cost:** Based on E3's estimate for NYSERDA of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4 kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.
2. **Fixed Operating Cost:** E3's estimate for NYSERDA of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

4.5.4.2 CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. For this illustration, cost parameter values were obtained from the EPA's Catalog of CHP Technologies[49] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can affect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural-gas fired CHP system. All of these elements would need to be reviewed and incorporated to develop the Company's service territory technology specific benchmarks.

Table 4-2. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	**3,000**
Variable Operating Cost ($/kWh)	**0.025**

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [50]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[51]

4.5.4.3 DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell. The DR technology benchmarks will evolve as the company gains experience with development and implementation of a DR program portfolio.

[49] EPA CHP Report available at: https://www.epa.gov/chp/catalog-chp-technologies
[50] EPA CHP Report. pg. 2-15.
[51] EPA CHP Report. pg. 2-17.

Table 4-3. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$140

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature.
2. **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

4.5.4.4 EE Example

The energy efficient lighting used in this example is indoor installation of a LED lighting fixture in a commercial office setting. The Company would need to incorporate its service territory specific information when developing its DR technology benchmarks.

Table 4-4. EE Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/Unit)	$80

Note: This illustration would change as projects and locations are considered.

4.5.5 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue “losses” due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other ratepayers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

4.5.6 Shareholder Incentives

Shareholder Incentives include the annual costs to ratepayers of utility shareholder incentives that are tied to the projects or programs being evaluated.

Shareholder incentives should be project or program specific and should be evaluated as such.

4.5.7 Net Non-Energy Costs

A wide array of potential non-energy costs may be considered depending on the project type. As such, determination of suggested methodology to address a comprehensive listing of applicable elements is complex and will not be established in the Handbook.

However, methodology for one item; Suitable, Unused and Undedicated Land, has been addressed in this version of the Handbook. Suitable, Unused and Undedicated Land is defined as utility-owned property in reasonable proximity and electrically connected for possible use by non-wires opportunities projects providing load relief solutions. The formal appraised value of said land will be used in the BCA, should the bidder elect to proceed with lease or sale of the property along with costs incurred by the utility associated with securing property appraisals, environmental studies, and any other necessary documentation to support the sale or lease of Suitable, Unused and Undedicated Land.

5 CHARACTERIZATION OF DER PROFILES

This section discusses the characterization of DERs using several examples, and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are: *intermittent*, *baseload*, *dispatchable* and *load reduction*. There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table 5-1 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook.

Table 5-1. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies that have been selected as examples are shown in Table 5-2. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table 5-2.

Table 5-2. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER can enable a different set of benefits and incurs a different set of costs, as illustrated in Table 5-3.

Table 5-3. General applicability for each DER to contribute to each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided LBMP	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	●	●	●	●
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
Costs					
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Shareholder Incentives	●	●	●	●
23	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section 4, each quantifiable benefit typically has two types of parameters. The defined benefits established to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), however key parameters related to the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). In other words, the amount of the underlying value captured by the DER resource is driven by the key parameters. Table 5-4 identifies the parameters which are necessary to characterize DER benefits. As described in Section 4, benefits potentially applicable to DER require further investigation and project-specific information before their impacts can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table 5-4. Key parameter for quantifying how DER may contribute to each benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	**SystemCoincidenceFactor**
2	Avoided LBMP	**ΔEnergy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**ΔEnergy (annual)** **ΔAGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[52]
12	Net Avoided CO_2	**CO_2Intensity** (limited to CHP)
13	Net Avoided SO_2 and NO_x	**PollutantIntensity** (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

Table 5-5 further describes the key parameters identified in Table 5-4.

[52] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table 5-5. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[53] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[54]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
∆Energy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ∆Energy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the ∆Energy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[55]

[53] This parameter is also used to calculate the Wholesale Market Price Impact Benefit.

[54] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided LBMP and AGCC. This transmission coincidence factor is applicable for the Avoided Transmission Capacity Infrastructure and Related O&M benefit, which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs and Avoided LBMPs benefits.

[55] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit.

5.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

5.1.1 Bulk System

According to the NYISO, the bulk system peaks generally occur during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM. Table 5-6 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes, obtained from the 2020 Load and Capacity Data report.

Table 5-6. NYCA Peak Dates and Times

Year	Date of Peak	Time of Peak
2015	7/29/2015	Hour Ending 5 PM
2016	8/11/2016	Hour Ending 5 PM
2017	7/19/2017	Hour Ending 6 PM
2018	8/29/2018	Hour Ending 5 PM
2019	7/20/2019	Hour Ending 5 PM

5.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. In general, the benefits of a reduced transmission peak would be captured through the Avoided LBMP and AGCC benefits.

5.1.3 Distribution

The distribution peaks as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood. The distribution system peak may differ or coincide with the NYCA system peak and the transmission peak. System-wide averages have been historically acceptable to use for some investment portfolios such as Energy Efficiency where the programs are broad based, and system-wide averages are provided in the Technical Resource Manual

(TRM), which assumes a historical coincidence for the NYCA peak. Going forward, for investments that are more targeted in nature, a more localized coincidence factor is more appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be low or zero if no constrained element is relieved (e.g., no distribution investment is otherwise required in capacity in that location, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

5.2 Estimating Coincidence Factors

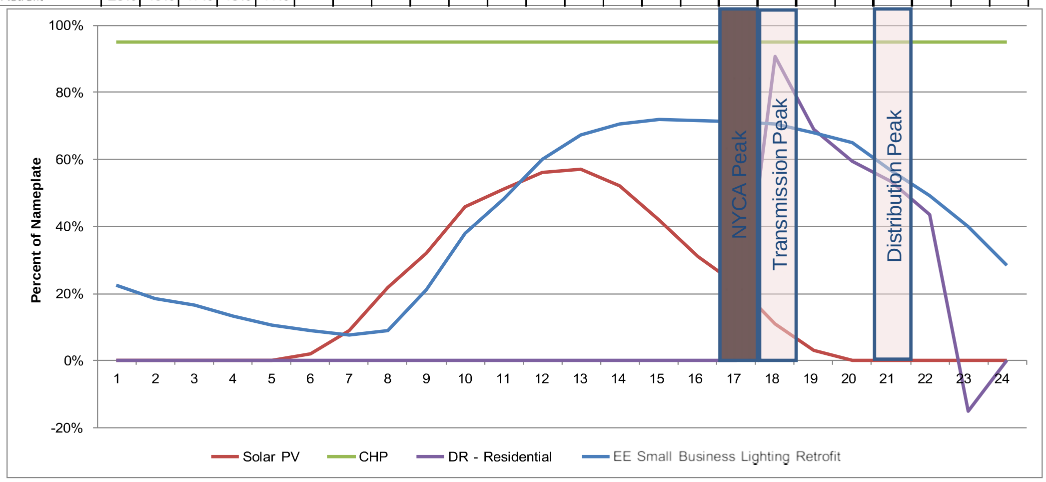
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable in some situations.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a ‘typical day’, or using a subset of hours that are appropriate that specific DER.

Figure 5-1 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource.

Figure 5-1. Illustrative Example of Coincidence Factors

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

The individual DER example technologies that have been selected are discussed below.[56]

The values for the DER examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in E3's NEM Study for New York ("E3 Report")[57] based on a simulation of a large number of solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

5.3 Solar PV Example

Solar PV is selected to depict an **intermittent** DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions, were obtained from the E3 Report.

[56] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DERs, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DERs and distribution system information is less generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWAs it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DERs, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, economic energy delivery. The BCA handbook incorporates derating factors in various benefit calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it was not included.

[57] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

The following examples include illustrative coincidence factors for several technologies. Actual locational estimates of coincidence with specific DER technologies are included in Appendix N of the DSIP.

5.3.1 Example System Description

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

5.3.2 Benefit Parameters

The benefit parameters in Table 5-7 for the intermittent solar PV example are based on information provided in the E3 Report.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted-averages based on electricity delivered by utility are provided in Table 5-7. These values are illustrative estimates that may be refined as more data becomes available. To determine project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (LBMP) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Table 5-7. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.36
TransCoincidenceFactor	0.08
DistCoincidenceFactor	0.07
∆Energy (time-differentiated)	Hourly

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-40% depending on system azimuth and tilt angle.[58] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section 4.1.1).
2. **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
3. **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[59] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
4. **∆Energy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly LBMPs.

5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

5.4.1 Example System Description

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance. The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[60]

5.4.2 Benefit Parameters

Benefit parameters for the baseload CHP example are a combination of assumptions on system use and system characteristics.

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, with the exception of down time for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to

[58] NYISO Installed Capacity Manual Version 6.47, page 55. Available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

[59] E3 Report, "Based on E3's NEM Ratepayer Impacts Evaluation in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed." PDF pg. 49.

[60] The Catalog on CHP Technologies is available here: https://www.epa.gov/chp/catalog-chp-technologies.

provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[61]
The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[62] "CHP Technology," "Fuel," "Unit Capacity" and "Operation" were the four inputs required. Based on the example, a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors.

Table 5-8. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
∆Energy (time-differentiated)	Annual average

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.1).
5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.2). There are no SO_2 emissions from burning natural gas.
6. **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

5.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

[61] EPA CHP Report. pg. 2-20.

[62] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.

5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it is reduces demand on request from the system operator or utility.[63] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g., <100 hrs). The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

The coincidence factors shown below do not account for load or device availability. Load availability is defined as the percentage of total potential capacity that can be shed from the load connected to the DR system at the time the DR event is called. Device availability is defined as the ability the DR system to accurately receive the DR signal and control the load. These factors, multiplied by the total potential capacity of the DR asset, would produce the average demand reduction for the asset. Average demand reduction multiplied by the coincidence factor is then defined as the average peak coincidence demand. These values are not presented here but are project- and technology-specific and will differ substantially among DR technologies and loads. As such, project-specific analyses would need to consider the load and system availability, as well as response rate (as described above) to accurately determine the appropriate coincidence factors.

This DR example is designed to reduce system peak (consistent with most existing DR programs), thus the system coincidence factor is 1.0 such that the DR resource is called to reduce the system peak load.[64] Given the small number of calls annually, the coincidence factor with the system peak is assumed to be 1, while the coincidence factors for the transmission and distribution peaks is assumed to be 0.5 which is consistent with the assumption that this particular DR example is not targeted to be coincident with those peaks.[65]

As an alternative approach, to calculate the coincidence factors for a specific DR resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system with the peak demand of the other systems. Comparing the coincidence of the top 50 hours of total system load and top 50 hours of each feeder's load would produce the distribution coincidence factor for a DR project that targets system peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the DR program. Coincidence factors for DR projects should use the most recently available data.

The value of reduced energy use attributable to the DR asset can be calculated using the average LBMP of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2 hour events, 4 hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

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[63] Some DR programs may be "dispatched" or scheduled by third-party aggregators.

[64] Note, the controllable load may not be operating at the time of peak.

[65] Specifically from the July 15 – 19, 2013 heat wave.

5.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above.

Table 5-9. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	0.5
DistCoincidenceFactor	0.5
∆Energy (time-differentiated)	Average of highest 100 hours

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is assumed to be 1.0, based on the assumption that the DR system is called upon at the time of system peak.
2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[66] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.
3. **DistCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak. Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above. If instead the DR asset were used to defer distribution capacity, the coincidence factor could be as high as 1 (though the system coincident factor could then be as low as zero, since if the peak periods were to occur at the same time, the project could only be dispatched for one program).
4. **∆Energy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings can be estimated based on the *average* demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time-differentiated LBMP.

5.6 Energy Efficiency Example

Energy efficient lighting depicts a **load-reducing** DER where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology. The parameter assumptions, and methodology used to develop those assumptions, developed using the NY TRM.[67]

[66] Con Edison Callable Load Study, Page 78, Submitted May 2008. https://uploads-ssl.webflow.com/5a08c6434056cc00011fd6f8/5a27177a5f89cb0001ea0c03_Schare%20Welch%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf

[67] New York State Technical Resource Manual (TRM): New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 7, Issue on April 15, 2019 and effective on January 1, 2020.– Lighting operating hour data is sourced from the 2008 California DEER Update study.

5.6.1 Example System Description

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting with an estimated utilization of 3,013 hours/year.[68] The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of an indoor, office-setting lighting system assumes that the coincidence factor is calculated during operational hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks.

5.6.2 Benefit Parameters

The benefit parameters described here were developed using guidance from the NY TRM.

Table 5-10. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	1.0
ΔEnergy (time-differentiated)	~7 am to ~7 pm weekdays

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 1.0 under the assumption that the system peak occurs while standard office lighting systems are operating.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 1.0 under the assumption that the transmission system peak occurs while standard office lighting system are operating.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 1.0 under the assumption that the distribution system peak occurs while standard office lighting systems are operating.
4. **ΔEnergy (time-differentiated):** This value is calculated using the lighting hours per year (3,013) as provided for General Office types in the NY TRM, divided by the total hours in a year (8,760). This time period is subject to building operation, which is roughly between 7 am and 7 pm, 5 days a week, 52 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

[68] Ibid.

5.7 Energy Storage Example

ES depicts an example of a dispatchable DER where the resource can be called upon to respond to peak demand. Furthermore, the storage will add load to the system during times of charge. This is the most flexible technology, with a wide variety of use cases.

5.7.1 Example Description

An exhaustive discussion of the types of storage configurations and potential use cases is beyond the scope of this handbook. ES requires understanding the specifics of how the project will be designed and operated to provide benefits to the system and/or customer. In this section, several of the most common considerations and examples are discussed, but this flexible resource must be considered on a case-by-case basis. Key system design parameters to consider include:

1. **Storage type:** There are many physical methods for storing energy such as thermal, chemical (electric battery), pumped hydro, compressed air, hydrogen, etc. All of these have their own benefits and constraints. In general, it is best to consider how the technical characteristics of the storage type may inhibit or facilitate electric load reduction or addition to the grid. For simplicity, the following examples consider electrochemical lithium ion battery storage only as this technology currently delivers desired services from ES at the least cost.
2. **Storage size:** Size is measured in both energy (kWh) and capacity (kW). The determination of energy and power are driven by the use case and what is needed to deliver services most cost-effectively.
3. **Ownership and Operation:** A wide variety of business models for storage ownership and operation exist today. Broadly, these can be characterized into two categories of utility and customer ownership. The ownership has implications for storage size, dispatch schedule, and location, which is why two different ownership scenarios are present in this example. For simplicity, we assume that the owner controls the storage dispatch and operates it to their benefit.
4. **Location:** ES may connect to the grid in front of the meter or behind the meter. The system configuration and isolation scheme determine whether the ES can be used to provide backup power during planned or unplanned outages. If multiple batteries are aggregated and dispatched simultaneously using a single control scheme, whether those batteries are all located on different parts of the system needs to be considered when calculating transmission and distribution deferral benefits.
5. **Dispatch Operation:** ES may be operated in a variety of ways, from completely automatic and optimized operation, to manual, to “standby” operation in which the storage stays charged until needed for backup power. Generally, it is presumed that storage is operated according to a set of priorities that establishes the primary reason for the storage investment as the top operational priority, then uses the remaining capacity and energy to capture the most economic value.
6. The two examples outlined below illustrate the interplay between these various system design parameters

Table 5-11. ES Example Characteristics for Utility and Customer Scale Systems

Storage Owner/Operator (Location)	Utility Scale (In Front of the Meter)[69]	Customer Scale (Behind the Meter)
Storage Type	Lithium Ion Battery	Lithium Ion Battery
Size (capacity/energy)[70]	1MW/5MWh	5kW/13.5kWh
Cycle Life	4,500 cycles (to 80% of rated energy)	2,800 cycles[71]
Efficiency	90%	90%[72]
Dispatch Operation Examples	Prioritized based on 1) distribution capacity 2) bulk system capacity, 3) ancillary service provision and 4) LBMP arbitrage	Prioritized based on 1) minimizing demand charges[73] 2) TOU rate arbitrage and 3) outage backup
Capital cost	Based on energy and capacity, decreasing annually at 8%/yr through 2022, then 4%/yr afterward[74]	
Fixed O&M	3% of capex per year, inflated annually	negligible
Variable O&M	$2/MWh	negligible
Degradation/ Augmentation Costs	Annual degradation should be calculated based upon number of cycles each year and degradation per cycle. For large batteries, augmentation can be conducted to counteract degradation each year. For smaller batteries, the battery will need to be replaced at the end of its useful life, which is typically determined in dispatch cycles rather than years.	

The use case of the battery determines the dispatch schedule and system design (size, location), which in turn determines the coincidence factors and hourly load/savings shape of storage. The battery needs to have a high enough duration (or be paired with other resources in a portfolio) to properly address the distribution peak period. There are numerous use cases, so the load impacts of each storage project need to be considered on an hourly basis. It is also possible that a customer may own a battery but provide the utility some control of the battery during certain times, in which case the storage operation would be similar to a DR event.

To calculate the coincidence factors for a specific storage resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system (e.g., distribution) with the peak demand of the other systems (e.g., transmission). Comparing the coincidence of the top X hours of each feeder’s load and top X hours of system load (where X is the storage duration at

[69] Unless otherwise noted, technical assumptions are sourced from a recent utility-scale storage for NWA analysis: Puget Sound Energy (PSE) Bainbridge Island Non-Wires Alternative Analysis, Appendix C: Energy Storage Analysis. July 9, 2019. https://oohpsebainbridgefall2019.blob.core.windows.net/media/Default/documents/Appendix%20D_Bainbridge%20Island%20Non-Wires%20Alternative%20Analysis_Navigant%20Consulting_July_9_2019.pdf

[70] These examples use round numbers for simplicity. If energy is 5 times the capacity, the battery is said to have 5 hours of dispatch duration.

[71] Based on Tesla Powerwall warranty which includes 37.8 MWh of aggregate throughput. At 13.5kWh per discharge, this equates to 2800 cycles. https://www.tesla.com/sites/default/files/pdfs/powerwall/powerwall_2_ac_warranty_us_1-4.pdf

[72] Based on Tesla Powerwall datasheet https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf

[73] Demand charges in New York would only apply to customers on commercial rates. In other parts of the US (Arizona for instance) residential customers are subject to demand charges.

[74] These costs reflect front-of-meter installed cost including a rough estimate of land lease costs for a large bulk system as well as interconnection. It is important to note that costs are changing in the energy storage industry and although there is a trend toward cost declines there is uncertainty about future costs. These cost declines may not apply to widely available consumer products. From PSE Ibid.

maximum discharge) would produce the system coincidence factor for a storage project that targets distribution peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the storage dispatch plan. Coincidence factors for storage projects should use the most recently available data.

Because storage projects often take advantage of the “value stack” of multiple benefits, it is important to avoid double counting of benefits. For example, the battery must be charged and ready to dispatch during distribution peak, thus may not be eligible for energy arbitrage or ancillary services benefits in the hours leading up to and following the distribution peak hours.

5.7.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above.

Table 5-12. ES Example Benefits Parameters – Utility Scale

Parameter	Value
SystemCoincidenceFactor	0.8
TransCoincidenceFactor	0.8
DistCoincidenceFactor	1.0
∆Energy (time-differentiated)	Hourly
ΔCapacity$_Y$ (ΔMW); n (hr)	Modeled from hourly dispatch analysis

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** Without specifically targeting the overall system peak, the coincidence factor is assumed to be 0.8, based on the assumption that the distribution system peak load is likely coincident with overall system peak load. However, this is not always the case. Location- and program-specific distribution coincidence factors should be calculated using hourly load data per the methodology described above.

2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but, similar to DR, would be greater if the storage is dispatched to target the transmission peak.[75] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.

3. **DistCoincidenceFactor:** In this example, the storage is used as a non-wires alternative and the top priority of dispatch operation is to reduce location-specific distribution peak capacity. Therefore, the distribution coincidence factor is 100%.

4. **∆Energy (time-differentiated):** The value of reduced energy use attributable to the storage project can be calculated using the hourly LBMP compared to the hourly charge and discharge

[75] Con Edison Callable Load Study, Page 78, Submitted May 2008. https://uploads-ssl.webflow.com/5a08c6434056cc00011fd6f8/5a27177a5f89cb0001ea0c03_Schare%20Welch%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

cycles of the storage project. Energy impacts should be adjusted for round-trip efficiency (battery losses).

5. **ΔCapacity$_Y$ (ΔMW); n (hr):** In this example, distribution capacity and system capacity take precedence over ancillary services in the storage dispatch operation. This dispatch schedule would need to be modeled on an hourly basis to determine the remaining capacity and hours (n) that the storage would be available for providing spinning reserves to NYISO. This could be a significant benefit if hours when spinning reserves are needed by NYISO are not coincident with distribution or system peak capacity needs.

Table 5-13. ES Example Benefits Parameters – Customer Scale

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	0.5
ΔEnergy (time-differentiated)	Hourly
ValueOfService$_{C,Y,r}$ ($/kWh) ; **$\Delta SAIDI_Y$ (Δhr/cust/yr)**	Retail rate of electricity (minimum) ; average energy stored compared to customer load

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** Assuming that customer TOU rates and demand charges align financial incentives toward peak load reduction, if the customer operates the battery to reduce energy costs the storage will have 100% coincidence with system peak.

2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5. Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.

3. **DistCoincidenceFactor:** Without targeting portions of the distribution system, the coincidence factor is assumed to be 0.5. Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.

4. **ΔEnergy (time-differentiated)**: The value of reduced energy use attributable to the storage project can be calculated using the hourly LBMP compared to the hourly charge and discharge cycles of the storage project. Energy impacts should be adjusted for round-trip efficiency (battery losses).

5. **ValueOfService$_{C,Y,r}$ ($/kWh)** ; **$\Delta SAIDI_Y$ (Δhr/cust/yr):** To determine Net Avoided Outage costs, the storage project needs to carry customer loads through an outage. The value of carrying a load through an outage should be at least the retail rate of electricity that would be used during that outage time. The change in SAIDI at the customer level can be calculated based on the average state of charge of the battery compared to the customer load to determine how long the battery could carry the load through an outage. For example, if the maximum energy in the battery is 10 kWh, and the annual average state of charge is 50%, then during a typical outage there will be 5 kWh available to carry the customer's load through the outage. If the customer uses 2 kW per hour on average, the storage can reduce the customer-level SAIDI by 2.5 hours on average.

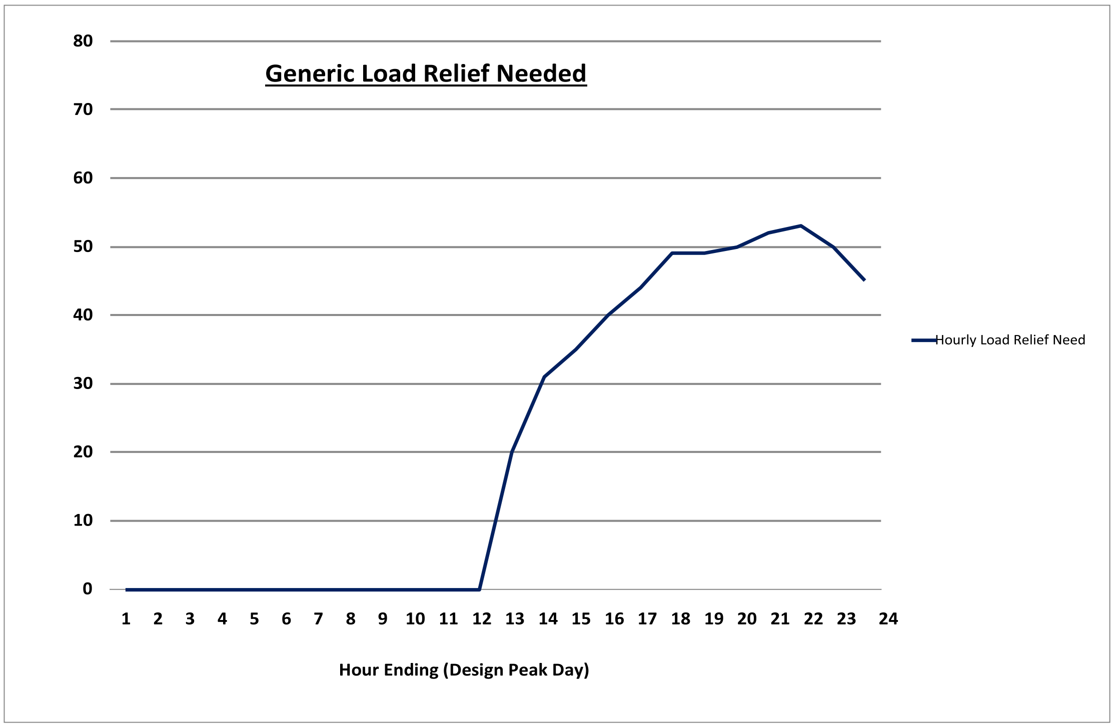
5.8 Portfolio Example

This example assumes that a segment of the distribution system needs locational load relief, illustrates how that relief might be provided through a portfolio approach, and examines some of the qualitative considerations impacting the development of the portfolio solution.

5.8.1 Example Description

The hourly locational load relief need is defined in Figure 5.2. This example is most likely representative of a locational need in a densely populated urban area and captures many of the considerations that go into the development of a portfolio of resources to provide a non-wires solution to the locational need.

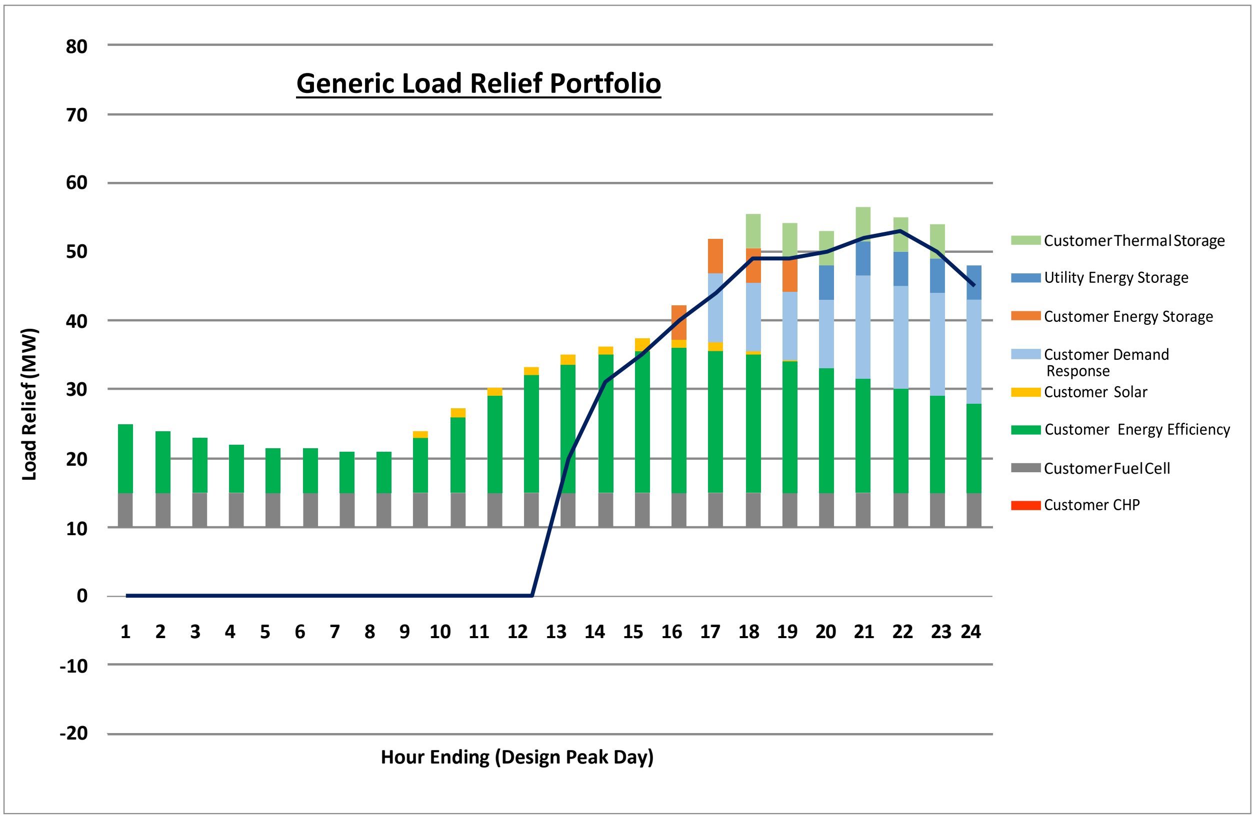
Figure 5.2. Location Load Relief Requirement



5.7.1 Example Solution

Unlike the specific examples considered previously in this section, the use of a portfolio approach to solve a need is a more complicated exercise as it will involve a solicitation for resources to address the load relief requirement. While many technologies in isolation have the potential to address portions of the load relief requirement by passing an individual benefit cost analysis for that technology, the utility must determine the most cost-effective combination of technologies that fully addresses the relief requirement through the application of a benefit cost analysis to portfolios of resources. Figure 5.3 provides an illustrative example of how the load relief requirement in Figure 5.2 might theoretically be solved.

Figure 5.3 – Theoretical Solution for Load Relief Need



BCA results are only one of many factors that go into the development of a load relief portfolio. The development of a portfolio solution requires consideration of a myriad of considerations which include but are not limited to:

1. Public Policy – The ability of respondent's proposal to address Commission public policy objectives.
2. Proposal Content – The quality of information in a proposal must permit a robust evaluation. Project costs, incentives, and the $/MW peak payment must be clearly defined.
3. Execution Risk - The expected ease of project implementation within the timeframe required for the solicitation (e.g., permitting, construction risks, and operating risks).
4. Qualifications - The relevant experience and past success of Respondents in providing proposed solutions to other locations, including as indicated by reference checks and documented results.

5. Functionality - The extent to which the proposed solution would meet the defined functional requirements and the ability to provide demand reduction during the peak time and area of need.
6. Timeliness - The ability to meet utility's schedule and project deployment requirements for the particular non-wires opportunity, reflecting that the detailed project schedule from contract execution to implementation and completion of projects is important for determination of feasibility.
7. Community Impacts - The positive or negative impact that the proposed solution may have on the community in the identified area (e.g., noise, pollution).
8. Customer Acquisition - The extent to which a respondent's proposed solution fits into the needs of the targeted network(s), the customer segment of the targeted network(s) and the customer acquisition strategy (Preliminary customer commitments from applicable customers are highly desirable.)
9. Availability and Reliability - The ability of the proposed solution to provide permanent or temporary load relief will be considered, along with the dependability and benefits that would be provided to the grid.
10. Innovation – Innovative solution that (i) targets customers and uses technologies that are currently not part of Con Edison's existing programs, (ii) targets generally underserved customer segments, and/or (iii) is based on the use of advanced technology that helps foster new DER markets and provides potential future learnings.

APPENDIX A. UTILITY-SPECIFIC ASSUMPTIONS

This section includes utility-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 4.

The discount rate is set by the utility cost of capital, which is included in Table A-1.

Table A-1. Utility Weighted Average Cost of Capital[76]

Year	For Use in SCT	For Use in UCT, RIM
2020	6.52%	8.06%
2021	6.54%	8.10%

System loss values may be affected by certain projects which alter the topography of the transmission and/or distribution systems. Central Hudson does not currently have disaggregated fixed and variable loss information available. Where loss values are applicable to calculations within the handbook, system average values should be used. System annual average loss data is shown in Table A-2.

Table A-2. Utility Loss Data[77]

System	Average Loss Percent (MWh)	Average Loss Percent (MW)
Transmission	1.87%	2.01%
Primary Substation	0.45%	0.46%
Primary Distribution	1.22%	2.26%
Secondary Distribution	1.84%	1.56%
Total System	5.39%	6.29%

[76] Source: Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, issued and effective June 14, 2018 in Cases 17-E-0459 and 17-G-0460. The 2021 values can be used for future years until superseded.
[77] Source: 2019 Central Hudson Gas & Electric Corporation Analysis of System Losses Appendix B Exhibit 1, produced by Management Applications Consulting, Inc. for Central Hudson.

Utility-specific system average marginal costs of service are found in Table A-3.

Table A-3. 10-Year Average Utility System Marginal Avoided T&D Costs[78]

Component	10 year Levelized Avoided Costs ($kW-year)
Distribution	$0.225
Transmission	$14.325
10-Year Levelized	$14.550

Note: The 2016 values are used based on guidance by the Department of Public Service to Central Hudson.

Average restoration costs are found in Table A-4.

Table A-4. Average Hourly Restoration Costs

Average Hourly Restoration Costs
Restoration Costs will be determined for each specific project as applicable
Source: Project Specific

Table A-5. Operation & Maintenance Costs

Average Hourly Restoration Costs
O&M Costs will be determined for each specific project as applicable
Source: Project Specific

[78] Source: Location Specific Transmission and Distribution Avoided Costs Utilizing Probabilistic Forecasting and Planning Methods report, 2016, produced by Nexant for Central Hudson. Central Hudson may update the avoided T&D costs to reflect the 2020 study results, upon approval by the Department of Public Service.