Central Hudson Initial Distributed System Implementation Plan

June 30, 2016

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Acronyms and Abbreviations

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

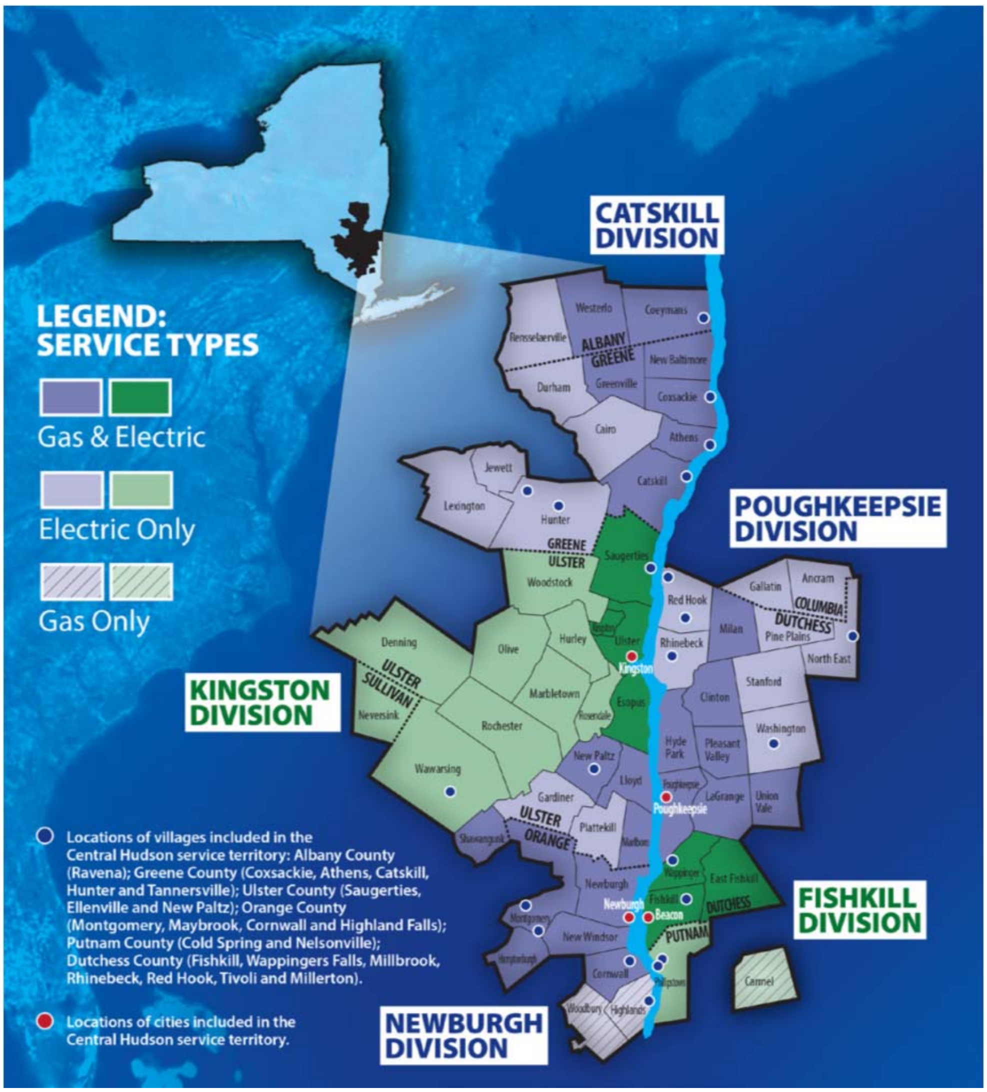
ACRONYM	DEFINITION
AICPA	Certified Public Accountants
ALT	Automatic Load Transfer
AMI	Advanced Metering Infrastructure
ASCR	Aluminum Conductor Steel-Reinforced Cable
BCA	Benefit Cost Analysis
CCA	Community Choice Aggregators
CDD	Cooling Degree Days
Central Hudson (or Company)	Central Hudson Gas and Electric Corporation
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CIS	customer information system
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
DSIP	Distributed System Implementation Plan
DSP	Distribution System Platform
EDI	Electronic Data Interchange
EE	Energy Efficiency
EMS	Energy Management System
ESCO	Energy Service Companies
EV	Electric Vehicle
FAT	Factory Acceptance Testing
FLISR	Fault Location, Isolation, and Service Restoration
GAPP	Generally Accepted Privacy Principles
GIS	Geographic Information System
HDD	Heating Degree Days

ACRONYM	DEFINITION
IED	Intelligent Electronic Device
ISM	Integrated System Model
ITWG	Interconnection Technical Working Group
JUNY	Joint Utilities of New York
LSC	Load Serving Capabilities
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 and Development Authority
O&M	operations and maintenance
OMS	Outage Management System
OTS	Operator Training Simulator
PCC	Primary Control Center
PDS	Program Development System
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
SIR	Standardized Interconnection Requirements
T&D	Transmission and Distribution
UBP	Uniform Business Practices
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 Hudson Valley of New York State. The Company provides electric and gas transmission and distribution (T&D) services to approximately 300,000 electric customers and 79,000 natural gas customers. Figure I-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 over 620 miles of transmission, 7,300 miles of overhead distribution and over 1,400 miles of underground distribution.

Figure I-1: Central Hudson Service Territory



The electric system set an all-time peak system demand in 2006 of 1,295 MW. As a result of slowdowns in the regional and state economy, energy efficiency (EE) programs and, to a much smaller extent, integration of primarily small-scale photovoltaic (PV) systems, the system peak has shown a steady decline. The actual system peak in 2015 was 1,059 MW and on a normalized basis was 1,085 MW. The peak forecast for 2021 is even lower, 1009 MW, continuing the declining trend.

As a result of this significant and persistent reduction in system demand growth, the majority of the Company's electric capital expenditures are focused on replacing existing infrastructure based on condition assessment. In addition to the infrastructure programs, the Company has embarked on implementing several projects which are 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 system and Energy Management System (EMS). These deployments were approved in the Company's prior rate case, began in 2015, and have the added benefit of being foundational to meet the future needs envisioned by the Public Service Commission (Commission) in its Reforming the Energy Vision (REV) efforts.

The Commission's 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 that includes improvements in system efficiency, resilience, and carbon emissions reductions. As the utility model transitions, the Commission defined a set of functions of the modern utility that are called the Distribution System Platform (DSP). The DSP functions combine planning and operations with the enabling of the markets. The process by which improved planning and operations would be defined and implemented is the DSIP.

Central Hudson has put significant effort into the development of this initial DSIP filing. In addition to establishing an internal team of subject matter experts to develop the filing the Company has worked collaboratively with various stakeholder groups as well as the state's jurisdictional electric utilities.

The filing is segregated into the following eleven sections:

- Section II Overview: This section provides a high level summary of the key drivers for policy changes in transitioning the utility model in New York including stated REV objectives, status of initiatives and proceedings and Central Hudson's commitment to this vision. Details of the process utilized for plan development are provided as well as our future vision of the DSP.

- Section III DSP Self-assessment & Near-term Initiatives: This section provides an overview of key DSP functions as well as assessment of our current capabilities in these functional areas and short-term improvement initiatives. Also described in this section are our plans to put in place an organization and the policies and procedures to operate and control the electric distribution system on a real-time basis.

- Section IV Foundational DSP Investments: Included in this section are details surrounding several core investments that Central Hudson has underway which while cost justified on their own also support REV objectives. These investments include our DA, DMS, Network Strategy, and electric geographic information system (GIS) project.

- Section V Demonstration Projects: The Company has launched an on-line portal called CenHub which provides residential and commercial customers the ability to be more engaged about their energy usage and energy savings options.
- Section VI Distribution System Planning: This section provides details on the planning criteria utilized by the Company, load forecasting of energy and demand, details of how forecasting changes are being made to incorporate Distributed Energy Resources (DERs) as well as discussions on interconnection processes and improvements, including hosting capacity.
- Section VII Delivery Infrastructure and Capital Investment Plans and Beneficial Locations: Details of the Company's capital investment plans specifically with regard to the electric T&D system are described as well as how DERs are playing a role and may play a role in the future in displacing traditional T&D infrastructure investment. We also define potential beneficial locations for DER deployment. In some cases these locations have already triggered Non-Wire Alternative (NWA) projects. Other locations will be evaluated based on what mitigation may be available or in place and the level of risk that we are willing to accept.
- Section VIII Distribution Grid Operations: In this section of the report we describe the anticipated near term impacts of DERs as penetration increases as well as policy changes and improvements in visibility of and communication with these resources.
- Section IX Distribution System Administration: In this section we describe the current status and future planned enhancements to sharing both system and customer data.
- Section X Advanced Meter Functionality: Central Hudson has completed comprehensive business case analyses for both full and partial advanced metering infrastructure (AMI) deployments. Neither of the business cases passes any of the benefit cost tests and as a result the Company is not pursuing any wide scale AMI deployments. Details are provided on how benefits can be realized without the need for these deployments.
- Section XI Cyber Security and Privacy: Cyber Security and Data Privacy are critical components of an engaged customer base. Details of the framework to maintain security and privacy are provided as well as summaries of the risk assessment.
- Section XII Costs & Cost Recovery: Throughout the report the Company provides details incremental resources, hardware and software and their costs that will be needed to meet the requirements of the DSP. Many of these items will likely be included in the Company's next rate filing; however, some may be required on a faster track. Proposed cost recovery mechanisms are also provided.

In summary, Central Hudson has put significant effort into this initial DSIP filing and is fully supportive of working with the stakeholders, the Commission, and the other utilities on improving transparency and data sharing and meeting the objectives of REV in a cost effective manner for all customers and with full transparency of all costs including both supply and delivery.

II. Overview

A. Introduction & Purpose

On April 25th 2014, the Commission issued its highly anticipated Order Instituting Proceeding in a new REV proceeding, accompanied by a Department of Public Service (DPS) Staff Report and Proposal. The proceeding was initiated as a result of the transition that was occurring in the energy industry. Technological innovation, increasing deployment of renewable energy resources, combined with continued capital needs to maintain the existing system, and make improvements to the security and resiliency of the system are key underpinnings that are driving significant changes in how electric energy is produced, managed, and consumed in the State.

1. Drivers for Change

To meet the challenges discussed above the Commission commenced the REV initiative to reform New York State's energy industry and regulatory practices. It is anticipated that this initiative will lead to regulatory changes that will promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, and wider deployment of DERs, such as micro grids, on-site power supplies, and storage. It will also promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. The changes are envisioned to ultimately empower customers by allowing them more choice in how they manage and consume electric energy.

2. State of the Assets/Systems

As described in greater detail throughout this report, Central Hudson is experiencing on a system wide basis a steady decline in system demand. With a system peak demand of 1295MW that occurred in 2006 actual demands and forecasts have declined ever since. The latest forecast projects that the system peak in 2021 will be 1009MW. With this significant and persistent decline in system wide load, there are relatively few areas of the system that are experiencing growth. As such the Company's capital plans have relatively few growth related projects. On a percentage basis the growth related projects represent less than 5% of the total electric program capital spend. The system, while well maintained and reliable, continues to age. Section VII of this report provides greater details on the drivers of our capital needs which are primarily infrastructure replacement initiatives. These expenditures are driven based on condition assessments of the major asset classes. As an example over 60% of our 115kV and 69kV transmission assets are over 50 years old. Even as the State transitions to increased utilization of renewable resources the transmission system will continue to play a critical role in ensuring a reliable grid and facilitating a robust and efficient market. Similar situations exist for other assets such as substation transformers and distribution poles.

In addition to these infrastructure replacement investments, the Company has been proactive in deploying new technologies and systems which provide net benefit to customers. These include the DA, DMS, and Network Communications Strategy programs. These foundational investments are described in greater detail in Section IV. Integration of these investments into the distribution system will greatly improve the Company's ability to meet its current responsibilities of maintaining a safe and reliable system as well as future requirements outlined in the REV proceedings as the DSP Provider (DSPP).

3. NY REV Objectives

The Commission has identified six core policy outcomes of REV. The details of these objectives are as follows:

- Enhanced information and tools to permit customers to manage their energy bills
- Market animation and leverage of ratepayer contributions
- Improved system-wide efficiency
- Fuel and resource diversity
- Improved system reliability and resilience
- Reduction of carbon emissions

4. Coincident Initiatives & Proceedings

Under the umbrella of REV are a significant number of interrelated proceedings that have been initiated by the PSC. The listing below provides additional filings required by the PSC jurisdictional utilities and related proceedings in which the Company continues to be actively engaged:

- Distribution Level Demand Response (DR) Tariffs
- Non Wires Alternative/ Targeted DR Programs
- Benefit Cost Analysis Handbook
- Net Energy Metering Filing
- Community Distributed Generation Tariff
- Supplemental DSIP Filing
- EE Transition Implementation Plan Filing
- Demonstration Projects
- Clean Energy Standard Proceeding
- REV Track 2 Order with seventeen (17) additional Compliance Filings

5. Commitment

The Company has dedicated significant resources committed to the Commissions REV and related initiatives. In addition to establishing an internal team of subject matter experts to address these many demands the Company has worked and continues to collaborate with various stakeholder groups as well as the state's jurisdictional utilities in working to achieve the objectives of REV in a cost effective manner for all customers and with full transparency of all the costs including those that impact both supply and delivery.

B. Plan Development

Central Hudson's approach for the development of this Initial DSIP was to provide as much information as possible about our current practices in the main three functional areas of the DSP, Distribution Planning, Distribution Grid Operations, and Distribution Markets. It was also to provide as much information as possible about the recent developments and changes to those practices related to the goals established in the REV proceedings, some of these changes being made for Central Hudson's own business purposes to advance the functionality of its systems and others made more in direct response to the REV proceedings and objectives. Finally, it was to report what steps are needed to close the gaps identified between the current state and the proposed future state of the DSP.

The Commission's Order Adopting DSIP Guidance issued on April 20, 2016 described the need to develop a more transactional, distributed electric grid that meets the demands of the modern economy that includes improvements in system efficiency, resilience, and carbon emissions reductions. As the utility model transitions, the Commission defined a set of functions of the modern utility that are called the DSP, which functions combine planning and operations with the enabling of the markets. The process by which improved planning and operations would be defined and implemented is the DSIP.

Central Hudson's approach to the plan development was to establish an internal team of subject matter experts with the assistance of consultants to develop the plan and filing. The Company's team was comprised of subject matter experts from groups throughout the Company including Distribution Engineering, Energy Transformation, System Operations, Cost and Rate, Electric Engineering, Information Technology, Drafting and GIS, Legal, and a special team for the development of the AMI business case, all lead by a DSIP Filing Leadership Team comprised of Officers and Managers from the Company. In addition to its own internal DSIP development, the Company has worked collaboratively with various stakeholder groups as well as the Commission's jurisdictional electric utilities to ensure that the Initial DSIP provided the information needed.

As described in the February 26, 2015 REV Order, the purposes of the DSIP are to serve as a source of public information regarding DSP plans and objectives, including specific system needs allowing market participants to identify opportunities, serve as the template for utilities to develop and articulate an integrated approach to planning, investment and operations, and enable the Commission to supervise the implementation of REV in the context of system operations.

The plan consists of the following major sections as described previously in the Executive Summary:

- DSP Self-assessment and Near Term Initiatives
- Foundational DSP Investments
- Demonstration Projects
- Distribution System Planning
    - Load and DER Forecasting
    - Interconnection and Hosting Capacity
- Capital Investment Plans & Beneficial Locations

- Distribution Grid Operations
- Distribution System Administration
- Advanced Metering Infrastructure (Smart Meters)
- CYBER Security and Privacy
- Costs & Cost Recovery

To ensure compliance with the Order, a Cross Reference Table, Table II-1, was developed to map the sections of the Order to Central Hudson's Initial DSIP Filing.

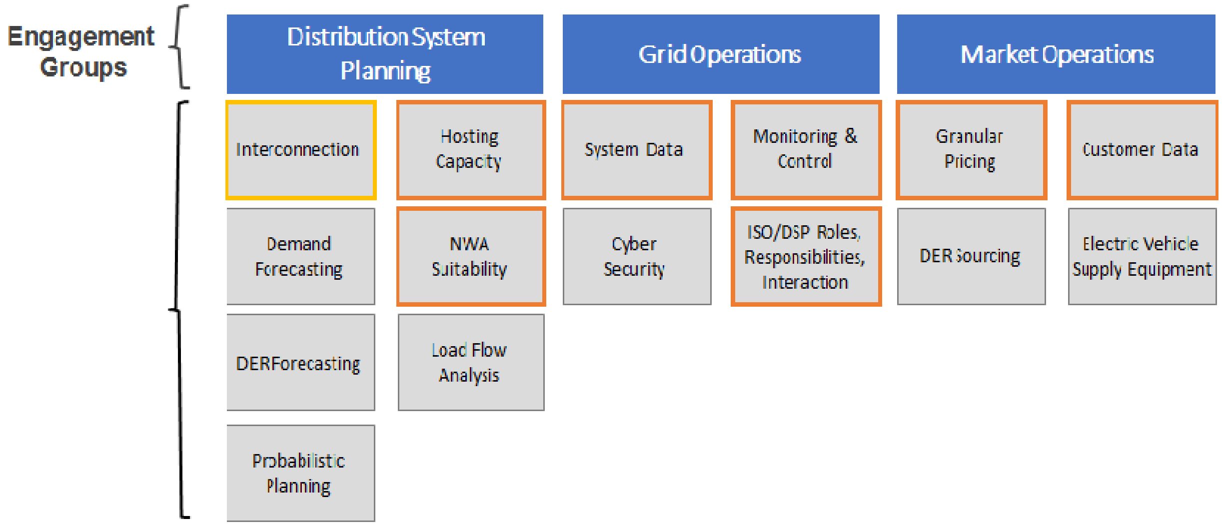
Table II-1: Initial DSIP Cross Reference Table

PSC April 20, 2016 Order Attachment 1	Central Hudson DSIP
C – Demonstration Projects	V
D.1.a.i – ii – Forecast and Data	VI.A,VI.B,VI.C
D.1.a.iii – Impact of DER on Forecast	VI.D
D.1.a.iv – v – Forecast Approach	VI.C
D.1.b.i – Increased DER	IV.A, VI.D, VI.F, VIII.A
D.1.c.i – Capital Plans	IV.A, V.B, VII.A
D.1.d.i – iii – Beneficial Locations	VII.B
D.1.e.i –iii – Hosting Capacity	VI.F
D.2.a.i – iv – System Operations	VIII.A
D.2.a.v –vii – Cyber Security	VIII.B, XI.A-D
D.2.b.i - iii – VVO	IV.A
D.2.c.i – iii – Interconnection Process	VI.E, VI.F
E .i – iii - AMI	X.A-F
F .ii–iii – Customer Data	IX.D, X.E, X.F

C. Issues Considered in Supplemental DSIP

The Joint Utilities have engaged the services of ICF International for support in developing the Supplemental DSIP filing and the associated stakeholder engagement. As part of this ongoing process, the Supplemental DSIP topics were broken down into three categories – Distribution System Planning, Grid Operations, and Market Operations. Each of these categories was further broken down into topic areas that were then prioritized for discussion, review, and stakeholder engagement sessions. The Figure II-1 below outlines the categories and topic area breakdown.

Figure II-1: Supplemental DSIP Topics



As seen above, within the Distribution System Planning Section, the following topics were identified for inclusion in the Supplemental filing: Improved Interconnection Process, Hosting Capacity Methodology, NWA Suitability, Demand Forecasting, DER Forecasting, Probabilistic Planning, and Load Flow Analysis. Improved Interconnection Process, Hosting Capacity Methodology, and NWA Suitability were given priority based on stakeholder and Commission staff input. To date, the Improved Interconnection Process topic area has been incorporated into the pre-existing Interconnections Technical Working Group purview. The NWA Suitability engagement group was kicked off on May 16 with sessions occurring/scheduled weekly since this time. The Hosting Capacity Methodology topic area has been advanced through ongoing Joint Utility work with EPRI. The engagement group for Hosting Capacity will kick off July 14th and proceed through August. The work to-date and any results of the efforts from these topic area work groups have been incorporated into the various applicable sections of this filing. The remaining Distribution System Planning topic areas (Demand Forecasting, DER Forecasting, Probabilistic Planning, and Load Flow) have been addressed as necessary with in this filing. The ongoing work effort of the Joint Utilities and ICF, including the stakeholder engagement process will continue to inform and evolve our thinking on these topics.

Within the Grid Operations Section, System Data, Monitoring and Control and ISO/DSP Roles, Responsibilities and Interaction and Cyber Security were identified for inclusion. To date, Stakeholder engagement has centered on System Data, identifying the types of information third parties find valuable and to gain an understanding of the third party needs and uses of this data. The Joint Utilities goal is to provide valuable system information rather than unfiltered/raw system data. The next phase of engagement in this area will be focusing on establishing guidelines for monitoring and control and seeking input on the development of standard communications protocols for these activities.

The third area, Market Operations will include DER sourcing, Customer Data issues, explore Electric Vehicle (EV) Supply Equipment.

In addition to the specific Engagement Group sessions mentioned above, the Supplemental DSIP will also be working with the New York Independent System Operator (NYISO) on both coordination of operations and markets as well as the development and assessment of more granular pricing on the wholesale market.

D. DSP Future Vision

As Central Hudson files this DSIP, it continues down its well established path of developing a smarter and more functional electric distribution system. A distribution system with the capability of using smart grid devices and functionality, two way communication and near real time monitoring, advanced system modeling and automated response to changing system conditions, and the ability to integrate customer-owned DER in such a way as not only to accommodate this 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 has, through this Initial DSIP process, outlined a number of the Foundational Investments that will allow for this functionality. One area that remains to be decided is how much of a liquid market can develop within the DSP as a result of this new functionality and the increased level of DER. A dominant factor in how this market may evolve is the "Value of D" or the value of DER to the distribution system and whether in a utility service territory where electric load growth meager this value 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 other Joint Utilities, Stakeholders, and the PSC to develop a common understanding and definition for the Value of D 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 meanwhile, 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.

III. DSP Self-assessments & Near-term Initiatives

The following provides a more detailed overview of the key DSP functions, self-assessment of current state in relation to those functions, and anticipated near term evolution.

A. Overview of Key DSP Functions

1. Distribution System Planning

The Electric Distribution System Planning function at Central Hudson has for several decades served our customers well by safely planning for a reliable electric system while moderating cost pressures. 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 system provide the backbone to the distribution system. Therefore, the planning process is not limited to the distribution system components.

Distribution system planning is accomplished by leveraging system knowledge and forecasting, 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, a primary output of the planning process is an Integrated System Plan and Capital Investment Forecast.

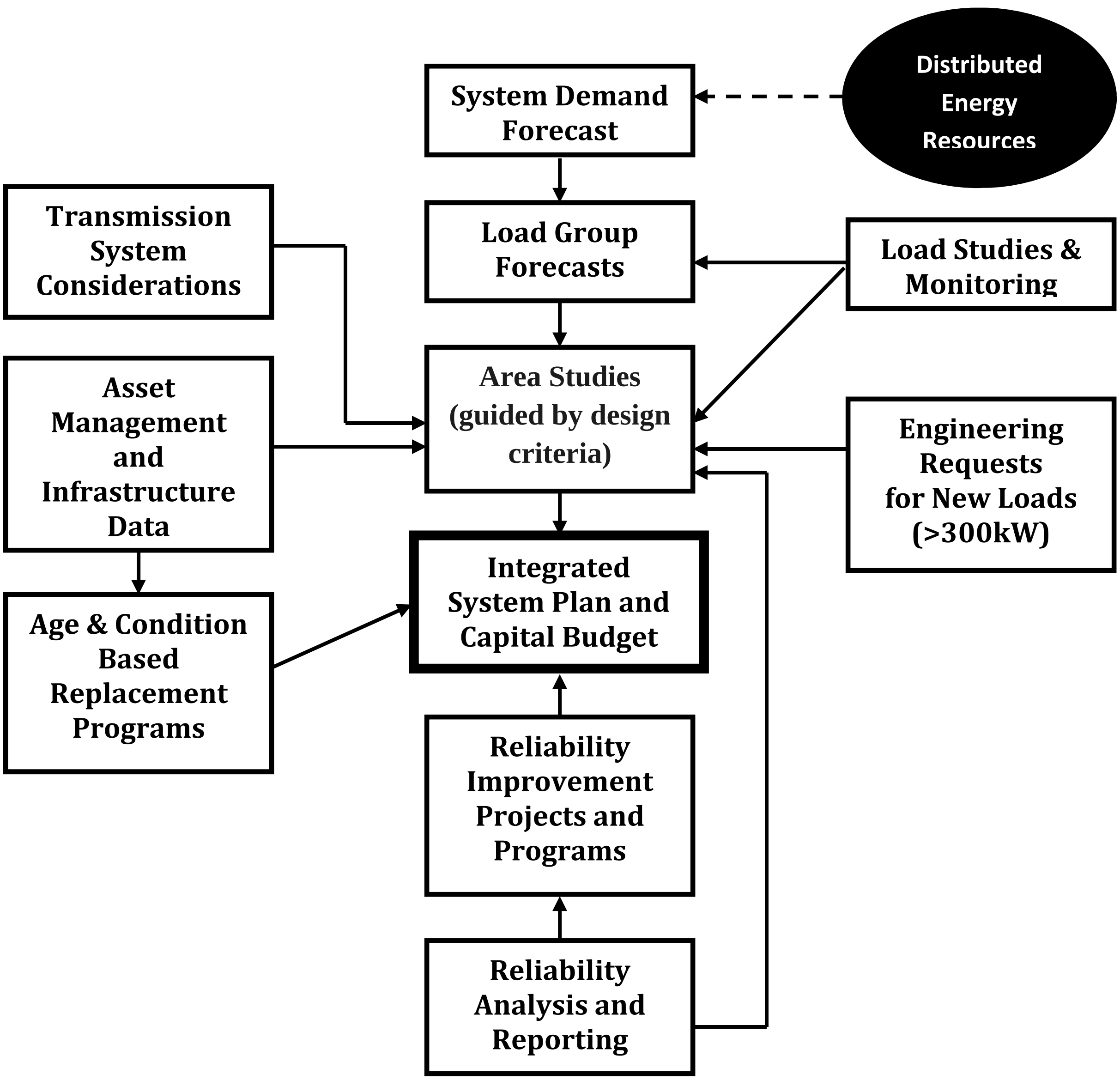
The following key tasks that are a part of the Distribution Planning function today are:

- Establish and maintain design and operating criteria to minimize risk and plan for a safe and reliable system.
- Perform analysis of reliability and power quality data and leverage the use of new technology to continuously improve our T&D systems.
- Develop an asset inspection, repair, and replacement program.
- Comply with all federal, state, and local codes, standards, and regulations.
- Maintain relationships with local developers and municipal officials to stay abreast of and support new residential and commercial economic development.
- Prepare, maintain, and analyze electric system models to ensure voltage, thermal, protection, and reliability standards.
- Forecast demand and energy growth at the system level and apportioning demand growth into more granular load growth areas.

- Complete area studies employing land based forecasting methodologies, age, and condition of infrastructure, and local system knowledge and experience to develop recommendations to maintain and improve reliability of service and support the capital budget plan.
- Evaluate DER applications and determine what system upgrades may be required to facilitate interconnection.

Figure III-1 illustrates the current components of the Integrated Distribution System Planning process at Central Hudson. More detail can be found in Central Hudson Gas & Electric's Electric Planning Guides, filed October 2013.

Figure III-1: Integrated Distribution System Planning Process



2. Distribution Grid Operations

Today the distribution system is operated in a decentralized basis. Each of the Company's five operating districts has operational responsibilities for each of their respective geographic based operating regions. The system, which includes some level of intelligent devices including Automatic Load Transfer (ALT) Switches, switched capacitors, voltage regulators, electronic reclosers, fault indicators, and voltage sensors, operates predominantly in an autonomous mode where the devices make decisions on their own or only communicate information in one direction.

As additional DERs have been integrated into the system there is limited visibility regarding the status of these resources. With an increasing level of DERs on the system, the continued operation of the distribution system in this decentralized approach will result in operating issues such as limiting the ability to integrate increasing levels of DER without significant system upgrades. While this mode of operation has allowed the system to operate safely and reliably for many years the requirements being placed on the system with bi-directional power flows and a desire to better utilize existing infrastructure requiring change.

3. Retail Market Facilitation

Today the retail market has many aspects designed to foster customer engagement, promote competitive markets, and encourage the development of DER. Whether through programs such as Customer Energy Choice, which provides electric and natural gas customers the opportunity to purchase their energy supply from independent marketers rather than through their utility, or Distributed Generation where customers may be eligible to install generating equipment and operate in parallel with Central Hudson's electric grid with net metering, Central Hudson customers have a host of possibilities to actively participate in the electric and gas markets to manage their accounts, choose their suppliers, choose green power, install solar generation, opt for Time-of-Use rates, make Energy Efficiency upgrades, and choose paperless billing.

While these choices exist today, it is Central Hudson's belief that there remains a lack of consumer engagement related to household energy use that is driven by the lack of awareness, information, convenience, understanding, and trust.

Central Hudson is also aware of the growing expectations of customers based on their interactions with other industries and businesses, for a higher quality of customer interaction with their utility provider. For these reasons we initiated the CenHub Demonstration Project detailed in section V.

DER developers also have a number of opportunities to become involved in the retail market. Again, through net metering they are able to take full financial advantage of their DER installations, not at the wholesale energy price, but at full retail delivery rate. In addition, Central Hudson now has in place two distribution based incentive programs, the recently filed Target DR program called Peak Perks and the Dynamic Load Management program. Both of these programs can reduce local or system peak deferring investment and reducing costs. Although these opportunities exist today, there exist many hurdles for DER developers to develop a market. The lack of visibility into our distribution system to be able to effectively market or site DER is one of those hurdles. The current number of DER applications (primarily net-metered PV) in the queue is another major hurdle. Finally, the limit of DER development on the system due to system constraints or interconnection costs is another major hurdle.

B. Short-term Improvement Initiatives

Recognizing the need for change to enhance customer engagement and improve the integration of DERs the Company has begun making changes to address these needs. Information provided in these next sections describe some of the Company's initiatives in these areas.

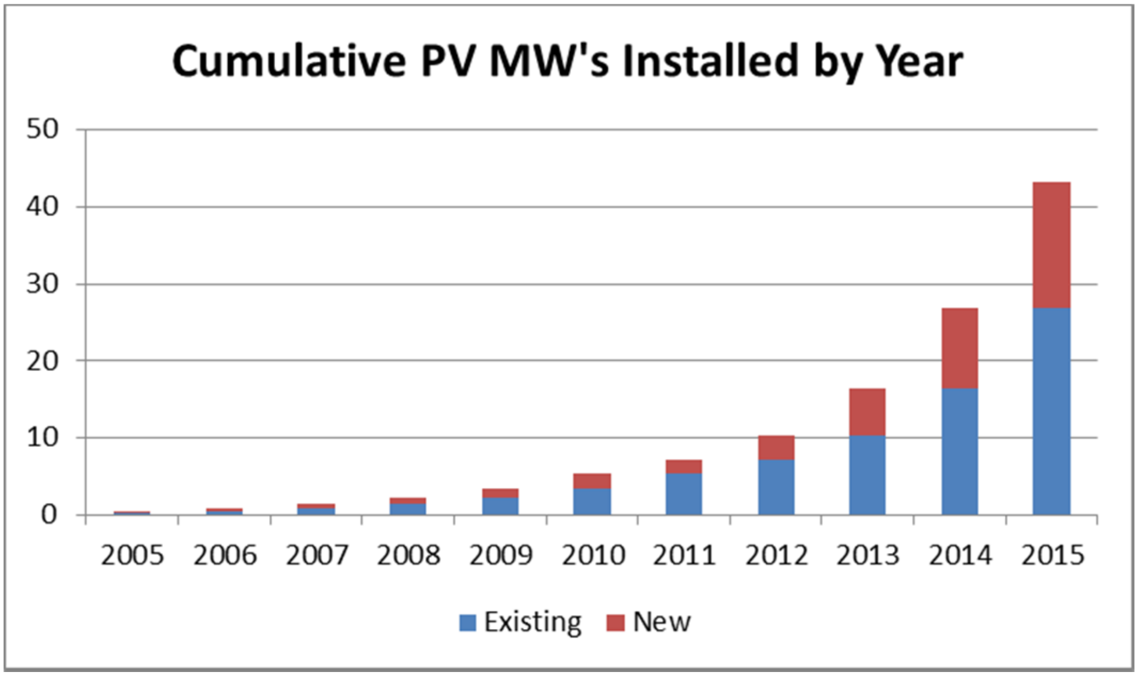
1. Distribution System Planning

While the core Distribution 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 customer owned assets, and alternatives to traditional utility investments, must be considered, and the requirements are described in more detail in Section VI. While Central Hudson has yet to measure the magnitude of this evolution, anecdotally, customers are expecting higher levels of reliability and resiliency, along with information transparency. They are also seeking to integrate DERs to the grid. Forecasting methodologies must evolve to an integrated approach that is probabilistic in nature. This is described further in Section VI.

Integration of Distributed Energy Resources

Over the past 10 years and particularly over the past five, Central Hudson has experienced exponential growth in the interconnection of customer sited DERs; most notably solar PVs. Figure III-2 illustrates this growth.

Figure III-2: Cumulative PV MWs Installed by Year



Central Hudson's Distribution Planning team has been proactive in determining how to accommodate solar PV on the distribution system, completing application approvals and detailed engineering reviews and system upgrades within the timeframes established within the New York State Standardized Interconnection Requirements (SIR)[1]. While solar PV is incorporated into our energy forecast, this process has been mostly segregated from the long range distribution system planning process as penetration remained low, correlation of solar output to peak load varied but was generally in the 15-20% range, and commercial modeling software focused primarily on peak load analysis.

Another widely utilized DER by Central Hudson customers is Energy Efficiency. While the EE Portfolio Standard scenarios are incorporated into our system wide energy forecast, they are not currently included in the Distribution System Planning process at the substation or feeder level.

Central Hudson has experienced virtually no application of other DERs, such as EV, wind, combined heat and power (CHP), and energy storage, by our customers to date. An NWA project utilizing DR is currently in-progress. As described throughout the document, Central Hudson will first integrate commonly utilized DERs into its demand and energy forecasts, incorporating additional items as appropriate. Forecasting methodologies and analysis are shifting to an integrated approach focused on hourly load shapes and efficiency.

Non-wire Alternatives

As described later in the document, if appropriate screening criteria are met, Central Hudson will solicit a NWA from third parties in order to defer a potential utility investment if certain criteria are met. The NWA will be pursued if it can meet the needs being fulfilled by the capital investment without compromising the safety or reliability of the utility system and is deemed cost effective pursuant to the Benefit Cost Analysis (BCA) handbook. The BCA handbook is included as Appendix K. Central Hudson is currently implementing several NWA projects as filed in the May 1, 2015 Rate Case Collaborative Status Report, with others in progress as described later in this document.

Distribution System Modeling

Until recently, Distribution Planning tools focused predominantly on modeling the electric system under peak conditions. In order to incorporate further automation to reduce customer energy usage, and to integrate DERs and NWAs, more detailed modeling is required. In 2011, Central Hudson commenced a partnership with a modeling vendor to transition towards an 8760 model that also integrates the transmission system. Several tools and proof of concepts were developed to analyze the impacts of solar PV on the distribution system, accounting for intermittency and correlation with load throughout all hours of the year. In addition, they tested the ability to defer transmission system capital investment by incorporating automation into the distribution system, reduce energy usage by applying Volt/VAr Optimization (VVO), and utilize Fault Location, Isolation, and Service Restoration (FLISR) to improve system reliability. From these pilot projects, a detailed Smart Grid strategy was developed into what would also provide foundational investments for REV. This is described in detail in Section IV.

[1] New York State PSC, "New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems", March 2016.

To facilitate implementation of the Smart Grid strategy, a detailed inventory of primary distribution conductor data, phasing, and significant distribution transformer information is underway and will be completed in 2017. Each area of the system must be modeled with precision to develop DA plans and integrate DERs while ensuring power quality standards are maintained.

2. Distribution 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 operate on a decentralized and autonomous basis and will need to have the ability to react to and manage to the changing conditions that will result from these DERs. Recognizing this, the Company embarked on the development of a Smart Grid Strategy which includes three major components; DA, DMS, and Network Communications Strategy. The deployment of these systems is currently underway and the details of these deployments are described in detail in Section IV. Also linked to these deployments are the changes that will be necessary to operate this system on a real time 24/7 basis as well as have greater visibility into the operation of the DERs. With regard to the changes that will be made to operate the system Central Hudson's plan is to centralize the operation of the distribution system with system engineers similar to how the transmission system is operated today. These engineers 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 included as Appendix C provides the Company's current vision of the major 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. These requirements are described in greater detail in Section VIII.

3. Retail Market Facilitation

Retail Market Facilitation goes far beyond the offerings of today through the Peak Perks program or the Distribution Load Management program. In order to facilitate the development of the retail market, customers need access to their electric usage data in order to be engaged, informed, and make the best choices for their situation. In addition, DER developers have indicated the need for more insight and transparency into our distribution system in order to enhance the development of DER.

In response to the April 20, 2016 Commission's DSIP Order and to the feedback we have received from DER developers and other Stakeholders, Central Hudson has taken steps in this filing and in the near term to provide data on its system to enhance the development of DER in its Service Territory.

Central Hudson is committed to providing valuable information that can help developers identify potential opportunities to offer solutions that could improve the efficiency of the system and add value to customers. Central Hudson has a history of being a leader in New York State in working with PV interconnections and supporting solar installations. Central Hudson is extending this same level of effort with all types of DER developers to facilitate information sharing and an open dialogue to further DER investment opportunities. Central Hudson held four DER engagement sessions to discuss the overall DSIP and stakeholder needs. These sessions included three stakeholder reviews with our most active DER providers and a general overview session open to a wider audience. All of these sessions helped identify the types of information that would be beneficial to stakeholders. The presentation material covered in these stakeholder sessions is included in Appendix A.

Central Hudson has developed and enhanced both its historic and forecasted load data to make this available for use by developers and other stakeholders. Central Hudson has developed a database containing historic hourly load data for each circuit. This historic load data was cleaned or corrected to identify and remove load transfers, outages, data gaps, and data recording errors. Synthetic hourly data was developed for missing or corrected data to ensure that 8760 historic load data was developed for all circuits. This data will be available for developers and other stakeholders upon request.

Central Hudson has also developed forecasts for each of its 54 distribution load serving substations where detailed metering data was available within its ten planning load areas (or clusters of substations). Some substations either lacked data or had lower quality data and, as a result, we were unable to estimate location specific forecasts for all substations. The substations substation lacking hourly data are generally smaller stations serving relatively few customers. The forecasting process was done in four main steps, cleaning or correcting the data to identify and remove load transfers, outages, data gaps, and data recording errors, estimate historical load growth for each year in 2010–2015 to assess the growth trend and the variability load growth patterns, weather adjust loads to reflect the 1-in-2 and 1-in-10 weather conditions, simulate potential load growth trajectories using probabilistic methods. This data will be available for developers and other stakeholders upon request. Based on the level of interest that stakeholders have in receiving this data, the Company may in the future consider developing a data portal to share this information.

In addition to the load forecast, Central Hudson developed DER penetration forecasts for the major DER expected in the service territory, EE end uses, PV, and EV. If data on the historical, locational distribution of a DER was available, that distribution was used for forecast years. If no such data was available, billing data was used to distribute penetration according to the population's annual usage. Finally, where forecasts were in annual MWh, penetration in each hour was estimated using end use specific load shapes, or demand, allocated to each of 8760 hours in a year on a percentage basis – a normalized load shape. Multiplying the load shapes on a percentage basis to annual MWh values ultimately yielded forecasts in kW on an hourly, weather year basis for each forecast year. This data will be available for developers and other stakeholders upon request.

Central Hudson has also developed or is in the process of developing several insightful system data sources to assist in the development of DER. The Company has developed and posted on its web page a System Indicator Map that provides insight to DER developers on locations that are not suitable for PV development based on circuit design. This is located at the following link:
http://centralhudson.com/dg/DERmap.aspx

Central Hudson has also developed maps for the Non Wire Alternative area and for Beneficial Locations for DER. These maps will provide insight to DER developers as to the locations where DER will have a positive impact on the distribution system.

Finally, as part of this DSIP – there are a number of other system data sources that we already publically provide or that we have included as part of this Initial DSIP filing is aligned with stakeholder needs. This information includes the following:

- Central Hudson's 2017-2021 Corporate Capital Forecast that identifies and provides details (cost, schedule, needs assessment) on our electric capital projects as well as details on gas and common programs (Appendix H).
- EPRI Hosting Capacity White Paper and road map outlining future efforts to both develop a common hosting capacity methodology with the Joint Utilities, Central Hudson's plans to develop and make available hosting capacity maps (Appendix E).
- Avoided T & D Cost study identifying areas of potential future need based on probabilistic forecasting methodologies (Appendix D).
- System and circuit reliability data provided annually through reliability reports that are filed with the Commission.

IV. Foundational DSP Investments—Summaries

A. Technology Platform Deployment Plan/ Status

Background

DA commenced at Central Hudson approximately fourteen years ago, with ALT switch teams that operate autonomously to transfer pockets of load to alternate feeds for loss of primary feed. Since that date, ALT switch operations have reduced the number of customers who experienced interruptions by over 422,000. DA expanded significantly over that time period beyond automated switches. In 2005, the program expanded to include switched capacitor banks to better optimize VAr flow and voltage levels. In 2008, Central Hudson added remote cellular communication, providing indication of status and other key information. In 2009, began a pilot that led to a system-wide replacement program of Type D hydraulic reclosers with electronic reclosers, which provide detailed fault data that reduces patrol time, enables troubleshooting, and enhances fuse saving, all while requiring minimal maintenance.

While the benefits of these programs to customers have been significant, Central Hudson recognized that they would soon plateau and not be as comprehensive without a centralized, integrated strategy. Along with the evolution of decentralized, automated devices, sophisticated modeling, GIS technology and DMS were beginning to commercialize and integrate, and rooftop solar was growing exponentially among our customer base. In addition, the Company was experiencing increasing levels of infrastructure that based on age and condition assessment required replacement and limited redundancy and operational flexibility, as well as reliance on communication systems provided by vendors whose core business models had shifted away from hard wired lines.

A centralized approach with sophisticated modeling will also improve system efficiency and defer capital investments by leveraging the distribution system for redundancy while 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 identified several gaps in its current approach.

Figure IV-1 shows the gaps identified, along with a desired future state:

Figure IV-1: Identified Gaps and Future State

Gaps Identified:		Future State:
Peak day system model with asset gaps	***Transition began in 2011 via Pilot Projects and Cross-***	Real time system model with detailed asset information
No remote control of distribution devices		Two-way communication with control via Operations Center
Decentralized communications with many platforms		Centralized communications through single strategy
Asset communications driven by vendor		Central Hudson led communications via vendor partnership
Does not integrate customer-owned devices		Integrates customer-owned DERs

In order to test a more integrated approach, Central Hudson partnered with a vendor along with NYSERDA to develop an Integrated System Model (ISM) focused on 8760 analysis and ability to defer transmission system investments by better leveraging the distribution system, and perform testing of conservation voltage reduction (CVR) as well as prototype a DMS for FLISR to avoid an outage to over 8,000 customers fed by a substation served by a radial transmission line through challenging terrain. 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 1.5-2.0% 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 our process in selecting a vendor for the DMS.

Centralized Strategy

With successful pilots in progress, Central Hudson fine-tuned and began implementing its integrated Smart Grid strategy. This program is developing a DMS to improve reliability, system safety, and system efficiency. We are creating detailed electric models in the ESRI GIS system to be used as the asset database. In addition, it will 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-builts between Engineering, Design, and Operating groups. Over 900 Intelligent Electronic Devices (IED; e.g. electronic reclosers, switched capacitors, and voltage regulating devices) and sensors are being installed through Smart Grid and other programs and that will provide real time data to the DMS so that it can become a centralized decision maker based on current system conditions rather than anticipated peak loads, as well as predicted conditions in future hours. Concurrently 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.

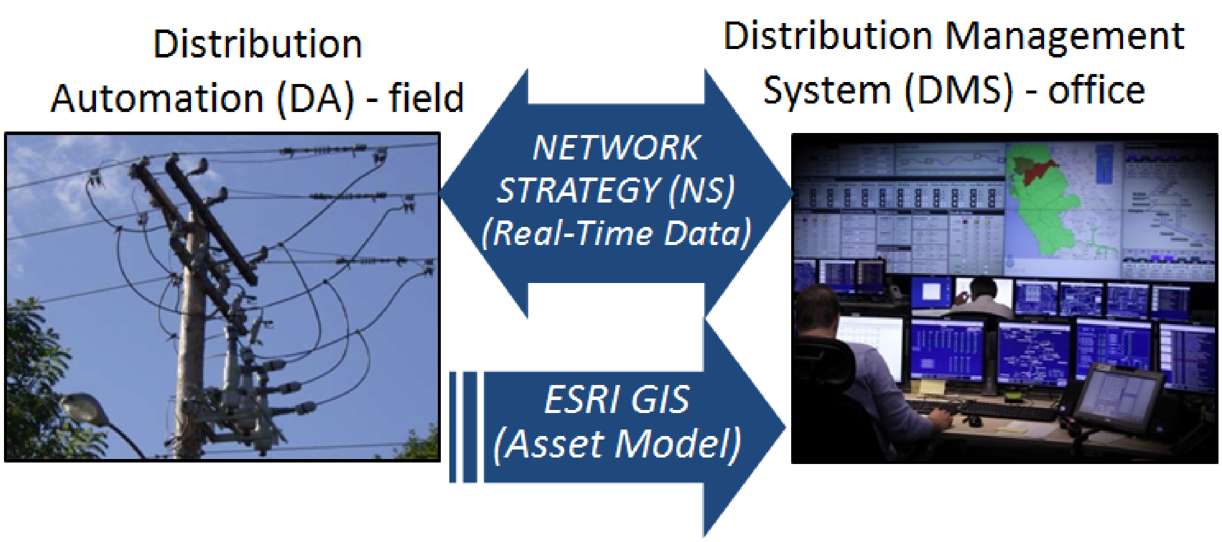
The Smart Grid Strategy is also foundational to REV. VVO and FLISR modules that will be included in the DMS are consistent with the REV policy goals of improving efficiency, reliability, and resiliency. Upon site acceptance testing, the system will consider the impact of DERs in switching and voltage 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 later add AMI, if justified, is being incorporated into the Network Communications Strategy.

Central Hudson's Smart Grid Strategy can be summarized as three major components that will be discussed in this section:

- Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)
- Distribution Management System (DMS) – the centralized software "brains"
- Network Communications Strategy – the two-way communication system between the DA devices and DMS

Figure IV-2 illustrates how these projects interact, along with the underpinning ESRI GIS Asset Model.

Figure IV-2: Smart Grid Projects



A roadmap has been developed to implement the Smart Grid strategy across our service territory (85-90%) by 2022. The business case for the project is financially net positive for our customers ($11.3 million 20 year net present value combined), primarily driven by energy reduction through VVO ($6.4 million/year at full implementation), deferral of transmission capital investment in providing a second transmission line to two radially fed substations ($36 million in capital investments deferred indefinitely), and elimination of leased communication lines. However, there are many qualitative benefits associated with reliability, power quality, and support of REV principles. Capital costs associated with the project are detailed in Distribution Planning Section regarding Delivery Infrastructure Investment Plans. The first three years of this plan were approved as detailed in the Order Approving Rate Plan, issued and effective June 17, 2015[2].

1. Distribution Automation Plan/ Status

The DA component of the Smart Grid strategy includes:

- Distribution system infrastructure upgrades
- Installation of IEDs and sensors

The distribution system infrastructure upgrades will be completed to develop ties between adjacent feeders, or upgrade exiting ties with larger wire. Coupled with IEDs and additional sensors, and the intelligence of the DMS, this will increase switching capabilities between load pockets, improving feeder management by flattening voltage profiles for further voltage reduction and reducing losses, as well as the frequency and duration of interruptions and ability to defer significant transmission system investments. Central Hudson also will be addressing two radial transmission feeders that will not meet our design criteria of 7 MVA of unreserved load. Rather than provide a redundant transmission feed, a DA solution is being completed. While the IEDs provide voltage and current data, additional sensors with even greater accuracy may be required to verify models at fringe points, as well as 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 and installation of IED, including VVO and FLISR. Additional functionality may be enhanced with the deployment of this technology as well. While the project is focused on DA, substation components will be upgraded where necessary to implement this functionality as well.

Voltage/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 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

[2] Case 14-E-0318, Order Approving Rate Plan, June 17, 2015, page 16.

overall voltage. As the voltage is reduced, the associated energy and carbon emission reduction occurs in a manner that is transparent to the customer.

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, switched capacitors, and substation load tap changers will need to be retrofitted with two-way communications and control. End of line voltage sensors must be connected, and communications must be added to verify the DMS model and ensure voltages are maintained within the ANSI 84.1 acceptable ranges. Operating the distribution system more efficiently will result in decreased line losses, reduced greenhouse gases, and decreased customer demand.

While Central Hudson complies with all existing CVR orders, sophisticated modeling with a DMS and two-way communications and control will enable us 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 impacts on switching and voltage implementation. In the longer term, should monitoring, control, and markets evolve in that direction, control of third party devices could be included with enhancements to the DMS.

Fault Location, Isolation, and Service Restoration

As noted in the Background section, Central Hudson has been utilizing ALT switches for approximately fourteen years. Autonomous teams are currently limited by the need for proximity and complexity due to the decentralized approach. With the installation of the DMS, the decisions can centrally consider a much wider geographic area. When a fault occurs, the IEDs will transmit information to the DMS to locate the section in which the fault occurred, isolate it by opening adjacent IEDs, and then closing 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.

Other Functionality

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

Schedule and Status

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 some Districts broken into 2 phases. 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, although an on-going evaluation of emerging products and technologies may always result in continuous improvement, particularly in the sensor area. Products such as solid state transformers that allow voltage control on the secondary side of a distribution transformer (i.e. 120V/240V, 208V etc.) will also continue to be monitored for economic applicability on Central Hudson's system to enable further feeder voltage reduction and/or mitigate impacts of solar PV installations.

Following three years of pilot projects, Central Hudson commenced full scale DA roll-out in July 2015. Table IV-1 illustrates the current status and schedule:

Table IV-1: Distribution Automation Roll-out

District	2015 Q3–Q4	2016 Q1–Q2	2016 Q3–Q4	2017	2018–2020	2020+
Fishkill Phase 1	P, D, C	C	C			
Fishkill Phase 2		P, D, C	D, C			
Newburgh Phase 1		P, D, C	P, D, C	D, C		
Newburgh Phase 2			P, D	D, C		
Poughkeepsie				P, D, C	P, D, C	
Kingston					P, D, C	D, C
Catskill					P, D, C	D, C

P = Planning

D = Design (field)

C = Construction

Project Costs

The DA portion of our foundational investments includes the installation electronic reclosers, switched capacitors, distribution regulators, voltage monitors, and mainline reinforcements. The total estimated cost of this work is $44 million of which $36 million is included in the current capital forecast.

2. Distribution Management System

Central Hudson is in the process of completing work that will lead to the installation of a DMS. The installation of the DMS was approved in the Order Approving Rate Plan issued by the New York State PSC on June 17, 2015. Central Hudson issued a request for proposals for the DMS in March 2015 to five vendors. Following a comprehensive review of the proposals, Central Hudson selected Schneider Electric as the approved vendor and ADMS Version 3.6 as the product in September 2015.

What is a DMS?

A DMS incorporates distribution level SCADA (Supervisory Control and Data Acquisition) with additional applications that allow for alerting, monitoring, and control of the electric and gas distribution networks. A DMS/DSCADA system will provide real time 24/7 remote visibility of the operations of our distribution system. The system also includes advanced system modeling and near real time load flow and contingency analysis capabilities.

Why is Central Hudson Installing a DMS?

Central Hudson is installing a DMS to implement applications including VVO and FLISR while providing an intelligent centralized control center to manage our 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 our electric and gas distribution systems and improve the overall efficiency of operations. In addition, as the DMS provides greater visibility and control of our distribution system, it will help facilitate and manage a greater penetration level of DERs.

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, 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 required 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 and are a replica of the PCC system hardware.

Quality Assurance System

The Quality Assurance System (QAS) supports development and testing of all components of the DMS. This system provides a platform for testing of system upgrades, system patches, network model updates, etc. The hardware and software in this system is closely modelled 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 it 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 the following:

- 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 allows for training personnel for operation of the DMS. The OTS provides introductory-level training as well as advanced instruction. The OTS provides 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.

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-base 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 base data all are stored in the two databases in various schemas.

The Electric Distribution GIS contains connected geometric model of all facilities from the substation breakers down to the customer transformers and service point. The data is stored in the standard Telvent/Schneider Electric ArcFM Distribution Data model. The geometry is stored in as geographically accurate a representation 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 base data set with streets, railroads, hydro features, political districts, operating districts, circuit map grid, etc. 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 to the Central Hudson's existing OMS. The DMS will receive outage information from the OMS and send device status to the OMS. The existing OMS is based on GE's PowerOn Version 4.2.3 and resides on the corporate network.

Energy Management System

The DMS 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 support Cyber Security applications including antivirus protections and security event logging as well as Disaster Recovery applications including backup and restore.

Central Hudson is in the process of developing internal cyber security 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 are being modified, as necessary, to more closely align with the Company's performance and business objectives. The DMS will be compliant with all relevant cyber security standards and requirements.

Project Schedule

The new DMS is being implemented in a phased approached, following the DA and Network Strategy projects, as these three projects are tightly intertwined. The Order Approving Rate Plan issued by the Commission on June 17, 2015 included the DMS project and included acceptance of the Final Joint Proposal that included a commitment by Central Hudson to file milestones developed for the project in collaboration with Commission Staff. The schedule for the DMS project will follow these agreed upon reporting milestones. In order to achieve success on the DMS, the objectives in Table IV-2 must be met within the designated time and budget allocations:

Table IV-2: Schedule Objectives

Objectives	Dates
PDS Environment set up. Hardware and software installed. System available for analysts and small subset of end users for testing and initial interface configuration.	March 15, 2016 – Complete
Commission Reporting Period - Milestone to demonstrate test system.	March 2016 - Complete
Functional and Design Specification Approval. Schneider to deliver installation and configuration guides, design documentation and documented configuration parameters. CH will review and approve documentation within 14 working days from the date of delivery.	May 6, 2016 - Complete
Active CIM-INT Link between DMS and GIS. Model Changes in ESRI confirmed in DMS and error reports available to analysis for review. 10 Substations and 25 feeders prior to FAT (Factory Acceptance Testing) and up to 75 feeders prior to SAT (System Acceptance Testing).	August 19, 2016
Active ICCP Link between DMS and EMS. SCADA points for SCADA devices will be created in ADMS database for 25% of the total network.	August 12, 2016
Active ICCP Link between DMS and OMS. DSCADA points for Lower Hudson DA devices will be created in OMS.	August 27, 2016
DMS Initial Analyst Training complete.	September 2, 2016
Commission Reporting Period – Milestone to Complete Link between GIS and DMS. Initial training of DMS Analyst to include Data Modeling and display support of the DMS consistent with need to support and build the system.	September 2016
FAT – Perform regression testing of the ADMS software at Vendor's site in Houston.	September 30, 2016
Ship System to CHG&E upon completion of FAT. Installation and configuration of the ADMS system on site. Includes PCC, BCC, QAS, DMZ and DTS environments.	December 8, 2016
SAT – Review by technical leadership team to certify that the system is ready for acceptance and Production rollout.	February 24, 2017

Objectives	Dates
Operator Training Completed	March 1, 2017
System GoLive/Cutover	March 20, 2017
VVO-ready device controlled through the DMS. Taps changed on regulator or capacitor opened/closed	March 31, 2017
DMS simulator runs FLISR in advisory mode. Devices reporting load current or voltage.	March 31, 2017
As fault is available within the reporting period, test FLISR capability with two or more field devices. When a fault occurs, a fault shall be isolated and customers outside of the isolated area shall be restored.	March 31, 2017
Commission Reporting Period – VVO ready device controlled through DMS, DMS simulator runs FLISR in advisory mode.	March 2017

The plan of implementation for the DMS will be staged to take advantage of opportunities at the several sections of the service territory. To achieve optimal benefits implementation will be focused initially in Lower Hudson following the DA and Network Strategy projects. Following work in the Lower Hudson, work will continue into the Mid-Hudson and finally the Upper Hudson sections of the service territory.

Control Room Redesign

Consistent with installation of the DMS will be the centralization of Distribution System Operating Authority. Distribution System Operating Authority currently exists within the five Operating Districts. Central Hudson will also be establishing the position of Distribution System Engineer, and with that a new Distribution System Operations area.

Central Hudson's PCC is located at its corporate headquarters in Poughkeepsie, NY. Building 810 was constructed in 1992 to house Transmission Operations. Centralized Distribution Dispatching was added in 2008. Central Hudson's plan is to modify Building 810 to accommodate the addition of Distribution System Engineers to Distribution Dispatch and Transmission Operations. In addition, Central Hudson also has plans to replace its current tile based transmission map board with a video wall based transmission map board.

The next steps in this part of the project will include selection of an architect, development of a detailed design and a request for proposal for construction services, and the selection of a construction contractor(s). It is planned that this work will be completed in late 2018 to early 2019.

Project Status

The DMS Project is currently on budget and on schedule. Major milestones completed to date include the completion of the installation of the PDS.

Central Hudson has received hardware procurement quotes for the full DMS system. Once hardware is ordered, it will be shipped to Schneider Electric in Houston, Texas in anticipation of Factory Acceptance Testing in fall of 2016.

Project Costs

The total estimated costs for the DMS portion of the project is $6.85 million. The majority of these expenditures will occur in 2016.

3. Network Strategy – Communications and IT Deployment Plan

Central Hudson is in the process of constructing an internal network for communication with its fixed assets. This project is referred to as the Network Strategy Project. The Network Strategy Project was approved in the Order Approving Rate Plan issued by the New York State PSC on June 17, 2015.

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. Applications such as SCADA, transmission line protection, security (video and card access), as well as general network traffic supporting internet traffic and Voice over Internet Protocol will use the network. 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 our most critical sites, including our most critical substations. 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 end points on the network.

Tier 1

As stated above, Tier 1 is the high bandwidth backbone connecting our most critical sites, including our most critical substations. 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 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 I000 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. With this, we are able to deploy Layer 2 Virtual Private LAN Service for certain critical applications such as SCADA and Layer 3 IP for certain less critical applications such as Voice over Internet Protocol.

Tier 2

As stated above, the 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 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 2400 – 2473 kHz and the range for the 5.8 GHz radio is 5150 – 5850 kHz. The current plan for the Tier 2 Network includes approximately 3000 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, the 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's plan is to establish an alternate NMS at the Alternate Control Center in Newburgh, NY by the end of 2018.

Cyber Security

Central Hudson is in the process of developing internal cyber security policies modeled after NERC CIP Version 5 Standards and Requirements for the DMS and Network Strategy projects. Applicable standards are being modified, as necessary, to more closely align with the Company's performance and business objectives. The Network Strategy Project will be compliant with all relevant cyber security 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 was placed in 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. Two different manufacturers were tested, as well as three different radio frequencies including both licensed and unlicensed frequencies. This work was completed during 2015.

In 2015, Central Hudson began construction of the Tier 1 Network. Six additional 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. Central Hudson plans to continue construction of the Tier 1 network over the next four years.

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 construction of the DA program. The construction plan for DA and Tier 2 will take place over the next five years with the Newburgh, Poughkeepsie, Kingston, and Catskill divisions following the completion of the Fishkill Division.

Milestone Testing

The Order Approving Rate Plan issued by the New York State PSC on June 17, 2015 included the Network Strategy project and included acceptance of the Final Joint Proposal that included a commitment by the Company to file milestones developed for the project in collaboration with Commission Staff. The schedule for the Network Strategy project will follow these agreed upon reporting milestones.

Project Costs

The Network Strategy Project was funded during Rate Year 1 (July 2015 through June 2016) at $4.3M. It is estimated that the cost of the Network Strategy Project will be $21M for the time period from 2015 to 2024.

V. Demonstration Projects

A. Overview

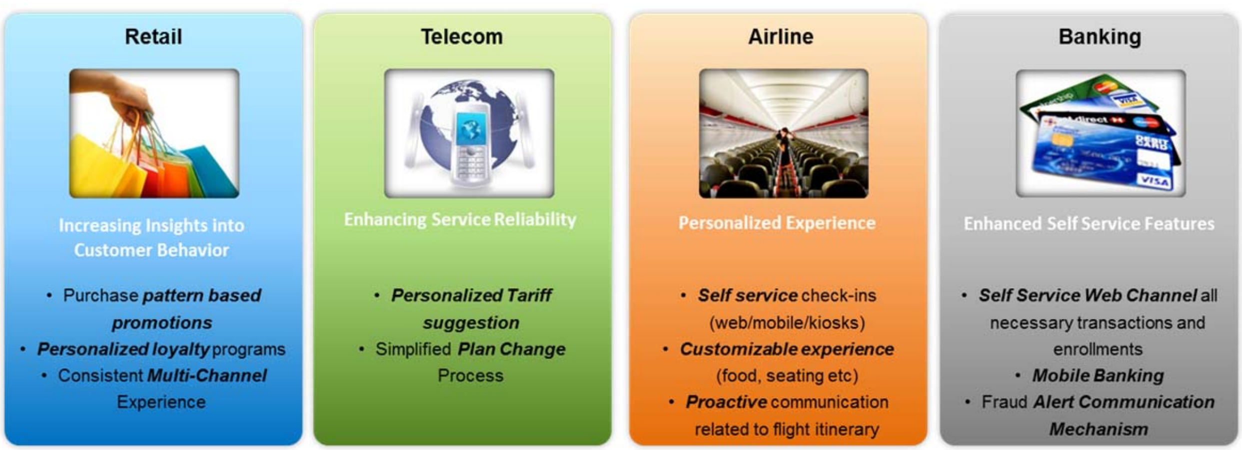
Central Hudson filed a proposal for the CenHub project on July 1, 2015 with the DPS Staff in compliance with Ordering Clause 4 of the Commission's Order Adopting Regulatory Policy Framework and Implementation Plan, issued and effective February 26, 2015.

It is Central Hudson's belief that lack of consumer engagement related to household energy use is driven by the lack of five primary factors:

- Awareness;
- Availability of information;
- Customer effort or lack of convenience;
- Understanding the value of products and services; and
- Trust in available solutions.

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 a solution that aligns with today's customer expectations, as illustrated in Figure V-1.

Figure V-1: Customer Experience Industry Trends



Taking all of this into consideration, CenHub is not only Central Hudson's response to the REV Track 1 order but also a leap forward in providing excellent service, choice and empowerment to all of its residential customers. By partnering with Simple Energy, CenHub extends the existing Central Hudson digital presence to increase customer self-service and insight while inspiring action. Within CenHub, customers are offered an extensive list of 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;
- Cross-promotion of programs that meet the specific needs of the individual customer; and
- A fun and engaging experience where customers are rewarded for interacting with CenHub through points, badges, leaderboards, discounts and gift cards.

For customers that want to engage further in the management of their energy portfolio, the Company is offering a value added monthly subscription so customers can receive more granular data and analytics. The offering will be reasonably priced and can be bundled with alternative TOU pricing or other offerings to incent additional savings and engagement.

CenHub ultimately strives to deliver the following benefits:

- Creation of a home energy advisory platform providing insight into energy usage for all residential customers;
- Introduction of new channels and cross promotion for customers to participate in energy and cost savings programs;
- Increased awareness and customer choice associated with program enrollment and the purchase of products and services;
- Customer convenience;
- Lower third party customer acquisition and transaction costs; and
- Evaluation of potential new revenue streams.

To date, Central Hudson has launched CenHub to its residential and commercial online communities. Mass marketing of the store began the last week of April. While the focus has been on residential customers Central Hudson has enabled access to the CenHub store to its commercial customers and customers outside of Central Hudson's territory in an attempt to increase sales and revenue.

Central Hudson has also integrated aspects of our NWA solutions and EE programs into the CenHub experience by offering customers the opportunity to enroll in the CenHub Peak Perks program and access instant rebates in the CenHub Store. Peak Perks is our overarching brand for DR program offerings with Comverge. Through the CenHub Store customers can select the CenHub thermostat, access an instant rebate, and proceed to enroll in our system-wide Dynamic Load Management program or see if they are eligible for additional incentives through enrolling in the Targeted DR program. If they are eligible and interested they can enroll online or use the contact information provided on the site to talk to someone about the program.

1. Measures of Success

In order to measure the success of CenHub, Central Hudson has defined five hypotheses to test throughout the life of the project. These hypotheses, depicted in Table V-1, are targeted at understanding Central Hudson's residential customers. They span the elements of customer engagement, customer behavior, and customer preference. Understanding the customer ensures alignment of business offerings and introduction of business models that benefit the customer through increased choice and control.

Table V-1: Test Statements

Test Statement	Hypothesis
Customers may be more engaged in their energy usage and energy management if they have: ▪ greater awareness of available products and services that are relevant to them ▪ the opportunity to interact with applicable tools through a fun, educational and engaging online experience.	If Central Hudson utilizes a Multi -Channel marketing campaign, specifically inclusive of email and social media to market CenHub to residential customers… then Central Hudson will increase the number of Digitally Engaged Residential Customers[3] to 60% of Central Hudson's residential customer base within 12 months of the April 1, 2016 Phase 1 Go Live Date. If Central Hudson utilizes gamification, reminders and relevant savings opportunities to encourage and prompt customers to complete the digital home energy profile… then 5% of the Digitally Engaged Residential Customers will complete the home energy profile within 12 months of the April 1, 2016 Phase 1 Go Live Date. If Central Hudson develops an engaging platform that informs customers about their energy use, provides actionable energy savings tips linked to available products and services, and reinforces behaviors through gamification and social interaction… then on average Digitally Engaged Residential Customers will become more energy efficient than their digitally unengaged counterparts
Customers may become engaged in the purchase of energy products and services they value through: ▪ An information driven, guided e-commerce experience. ▪ A social online experience that inspires competition and community action ▪ The availability of instant rebates and rewards programs	If Central Hudson provides CenHub users with energy usage information and targeted actionable savings tips linked to products and services available on CenHub … then we expect to achieve 8,000 product purchases within the first 12 months of the April 1, 2016 Phase 1 Go Live Date.

[3] Defined within Section B "Test Population" as customers that are currently My Account users and CenHub users following the Go Live Date

We believe Central Hudson will successfully implement a new business model leveraging our expertise and partnerships to create new revenue streams and that there are service providers willing to work with Central Hudson to deliver choice and value to our customers.	If Central Hudson provides CenHub users with energy usage information and actionable savings tips linked to products and services available on CenHub … then CenHub will generate approximately $40,000 of Platform Service Revenues for Central Hudson within the first 12 months of the April 1, 2016 Phase 1 Go Live Date.
Customers may be willing to pay for advanced data services.	If we offer an advanced data services package featuring an intuitive and engaging user experience and utilize multi-channel and targeted marketing… then 1,000 customers will subscribe to the advanced data services package within 12 months of the September 30, 2016 Phase 2 Go Live Date.
Advanced data services may influence customers' behavior.	If Central Hudson directly markets to Advanced Data Services subscribers and provides insights and tips regarding management of their energy usage and cross-promotes programs such as Targeted DR. then customers with Advanced Data Services subscriptions will make 10% more product purchases per customer than the 'Digitally Engaged Residential Customer' within the first 12 months of subscription enrollment (measured on a rolling 12 month avg. beginning 12 months after the September 30, 2016 Phase 2 Go Live Date.) 25% of Advanced Data Services subscribers will elect a non-standard rate offering such as our existing Time-of-Use rate within 2 years of the September 30, 2016 Phase 2 Go Live Date.

B. Future Demonstration Projects with High Level Cost Estimates

Central Hudson is currently looking for additional opportunities to provide incremental value to customers, explore new business models, and partner with third party service providers. The Company has received ideas from internal and external stakeholders and continues to evaluate potential new demonstration projects. At this time, Central Hudson has one potential demonstration project that is nearing the proposal stage. This potential project aims to accelerate the developing electrification of the transportation sector and the associated removal of greenhouse gasses. This project is still within the conceptual stage, but will target reducing "range anxiety" for EV drivers and initial expectations are that the budget would remain within the $10 million allowance for all demonstration projects authorized within the REV Track 1 order and Central Hudson's recent rate agreement.

VI. Distribution System Planning

Central Hudson's service territory includes a total of 70 distribution load serving substations, 62 of which are fed from the transmission system, and approximately 270 circuit feeders. For planning purposes, substations are grouped into 10 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 a total of 10 transmissions areas, or load pockets, where transmission lines and generators affect power flow.

One vital role of the electric utility is to ensure that electricity supply remains reliable by projecting future demand and reinforcing the local T&D networks so sufficient capacity is available to meet local needs as they grow over time.

A. Summary of Current Distribution Planning Criteria

1. Overview

Historically, electric grids were engineered to accommodate the flow of electricity from centralized generation to end users. Both generation and distribution infrastructure was sized to meet the aggregate demand of end users when it is forecasted to be at its highest (peak demand) while allowing for forced outages. At the system level, electricity supply needs to 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, is sized based on local peaks, which can be quite diverse, and often are not coincident with system peaks that drive generation infrastructure.

Central Hudson maintains reliability criteria for the planning and operation of our electric T&D systems. Based on level of regulatory oversight, system design and risk allowance, Central Hudson has differing criteria for the T&D systems. For our transmission system (voltages greater than 34.5kV), this criteria is 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; North American Electric Reliability Corporation (NERC) Standard TPL-001-4 – Transmission System Planning Performance Requirements.

Our distribution system reliability planning criteria is outlined within the Central Hudson Gas & Electric's Electric System Planning Guides, filed October 2013.

2. Transmission and Substation

The local transmission system, as well as urban substations, generally is developed with n-1 contingency planning. For local transmission networks, the LSC are developed by evaluating the maximum load level at which the load can be served reliably, while considering contingencies and without violating thermal or voltage limits.

For basic transmission loops with only two feeds, and urban substations (those containing greater than one transformer with a lowside bus tie breaker), the long-term emergency rating with the highest rated transmission line or substation transformer removed becomes the LSC (unless limited by another breaker, switch, fuse, cable/conductor, bus, other component, or voltage) or design rating. For rural substations (those that contain a single transformer or multiple transformers with no lowside bus tie), the summer normal rating of the transformer or other limiting element is applied.

Forecast loads in excess of the LSC or design ratings do not automatically trigger an infrastructure upgrade. With the exception of a rural substation or radial transmission line, forecast load in excess of the LSC does not result in overloading of equipment unless a contingency (e.g., the loss of a transmission line, transformer, or other component) occurs. The forecast load, therefore, is allowed to exceed the LSC, with the understanding of the low probability of a contingency occurring and that prolonged periods of overloaded lines and equipment lead to degradation of equipment.

Central Hudson has specified explicit risk tolerances, based on the total hours that forecast load can exceed design ratings, which vary by category and are summarized in Table VI-1. More risk is tolerated for less critical components of the system.

Table VI-1: Risk Tolerances

Category	Risk Tolerance
Transmission Network	2% of seasonal capability period (88 hours)
Transmission Loop	6% of seasonal capability period (263 hours)
Urban Substation	6% of seasonal capability period (263 hours)
Rural Substation	8% of seasonal capability period (350 hours) or 7 MVA unreserved

Modifiers to the risk at the substation level are made based upon load served, growth rates, and economic development, as demonstrated in Table VI-2, Table VI-3, and Table VI-4.

Table VI-2: Modifier Based on Load Served

% of System Load	<1	1 - 5	5 - 10	10 - 15	>15
% Adjustment to Base Risk Hours	+2	+1	0	-1	-2

Table VI-3: Modifier Based on Load Growth

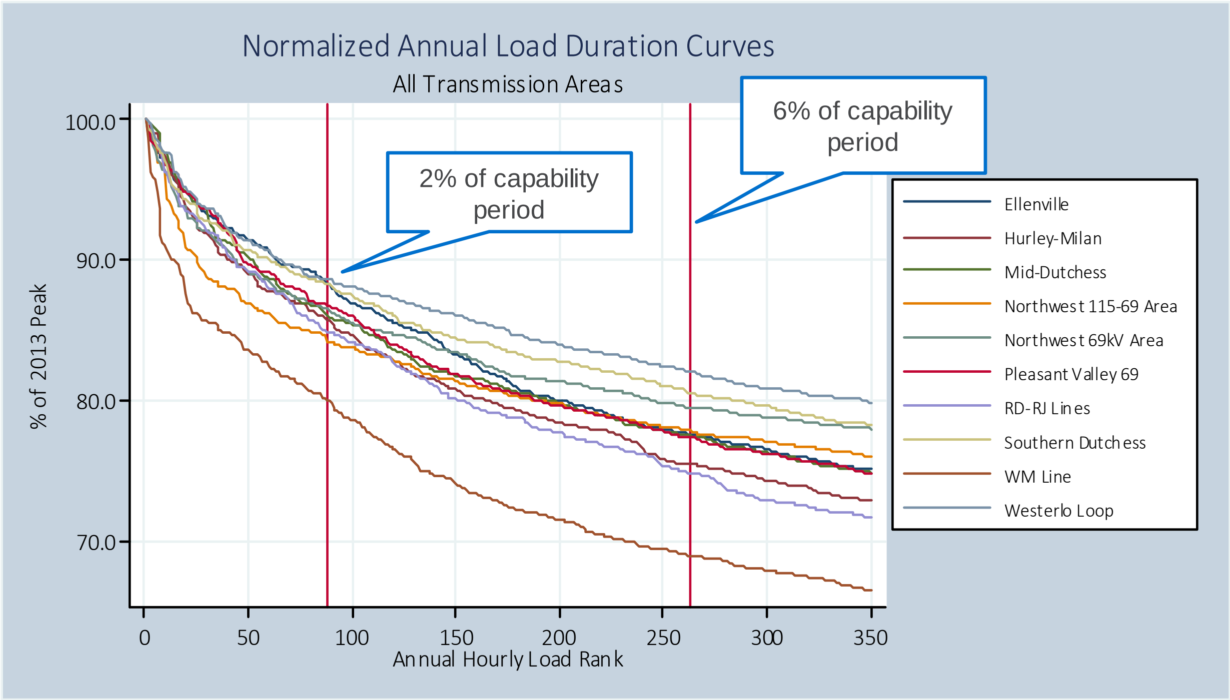
Area % annual load growth over 5-year period	<0	0 - 2	2 - 5	4 - 6	<6
% Adjustment to Risk Hours	+2	+1	0	-1	-2

Table VI-4: Modifier Based on Economic Development

Economic Development Potential	Active Marketing	No Potential
% Adjustment to Risk Hours	-1	0

Figure VI-1 illustrates the practical implications of the risk tolerance. The graph reflects the load duration curves for Central Hudson's 10 transmission areas, all of which have been normalized as the percent of the 2013 peak, which reflects 1-in-2 peak weather conditions. Because of inherent variation in load shapes, the amount by which the design rating can be exceeded, in MW's, varies for individual transmission areas and substations.

Figure VI-1: Normalized Annual Load Duration Curves



Central Hudson produces growth estimates for each of the 10 distinct load areas and applied those growth estimates to each individual substation within the load area. The growth rates are customized to these areas, but are not unique to each individual substation. This approach was adopted due to challenges in data quality of substation level data. Not all substations have hourly data and many of those that did included outages, data gaps, and both permanent and temporary or seasonal load transfers between substations. Unless identified and removed, load transfers can be confused with growth or decay in local peak loads. Because most load transfers occur between substations in a specific load area, load areas provided a stable unit of analysis for developing forecasts. In this DSIP, Central Hudson used data analytics to transition to substation level forecasts, identify and remove load transfers, data gaps, and outages from substation level data. This allowed Central Hudson to produce location specific, probabilistic forecasts. As penetration of DERs increases to the point of significantly changing a load curve at a substation, risk criteria may need to be reevaluated, particularly in the case of intermittent resources.

3. Distribution Feeders

The planning criteria for distribution feeders are a combination of thermal, economic, and reliability considerations, as well as engineering judgment, to provide a guiding foundation in developing or altering circuit configurations. The following criteria generally apply:

- Feeders operating at 13.2 kV have a 6 MVA normal / 9 MVA emergency design rating. This ensures load can be easily transferred from one distribution feeder via two circuit ties. In emergency situations, a feeder often can be fully restored through a second feeder (carrying nearly 12 MVA), if the feeder is not thermally or voltage limited along the circuit path.
- Feeders operating at 4 kV have a 1.5 MVA normal / 2 MVA emergency design rating.
- Several modern (30 MVA, 50 MVA or 100 MVA) substations contain feeders designed at higher ratings (9 MVA / 12MVA being most common). These are located in higher load density areas, or the feeder is bifurcated near the substation exit to mitigate reliability risk.
- Detailed circuit design considers reliability impacts by specifying number of customers in each zone of protection along with fusing and other protective device schemes. Central Hudson applies single phase reclosing and fusing, with lateral fuse saving where feasible.
- As the penetration of DERs increases, it will be important to separate base load from distributed generation, particularly intermittent resources such as solar PV. Planning criteria may have to be reevaluated in the future to better account for this.
- Particular analysis and care must be taken with DA to consider thermal and voltage limitations in the ability to transfer load. In addition, in high penetration DER scenarios, it will be important to separate base load from generation.

The dynamic nature of the distribution system and infinite scenarios and customer load group mixes may result in deviation from the stated criteria based upon load growth history and forecasts, or development of DER.

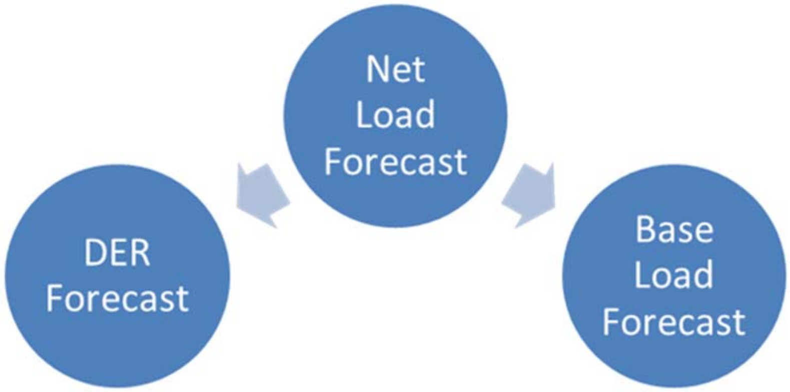
4. Distribution System Planning Roadmap

While the Distribution System Planning function to provide for the safety and reliability of the system described in Section III will remain, the tools applied and the complexity of the process is rapidly evolving. Currently, interconnection of DERs is evaluated separately from the long-term Distribution Planning process. With the increased intermittency associated with many DERs, application of a linear forecast, with Engineering knowledge and judgment, may be insufficient to recognize the range of potential generation and load scenarios. Additionally, the planning process will not end with the development of a Capital Forecast, but once acceptable criteria is developed, the capital plan will result in development of Beneficial Locations to install DERs, along with solicitations for NWA to defer or eliminate the need for some of the identified capital investments.

As discussed in the remainder of this section, Central Hudson is transitioning its Distribution System Planning process to incorporate probabilistic and more granular elements. The following section will describe the forecasting methodology applied across Central Hudson's system. While in the past, a net load forecast was sufficient for planning, the forecast going forward must separate the forecast into DERs and base load, as shown in Figure VI-2.

As an area of need is identified through traditional planning methodology, base load and DER forecasts should be developed with separate scenarios for each. DER forecasts should consider not only technical drivers of load shapes, but current and anticipated policy decisions and interconnection queues that will impact the penetration of DERs.

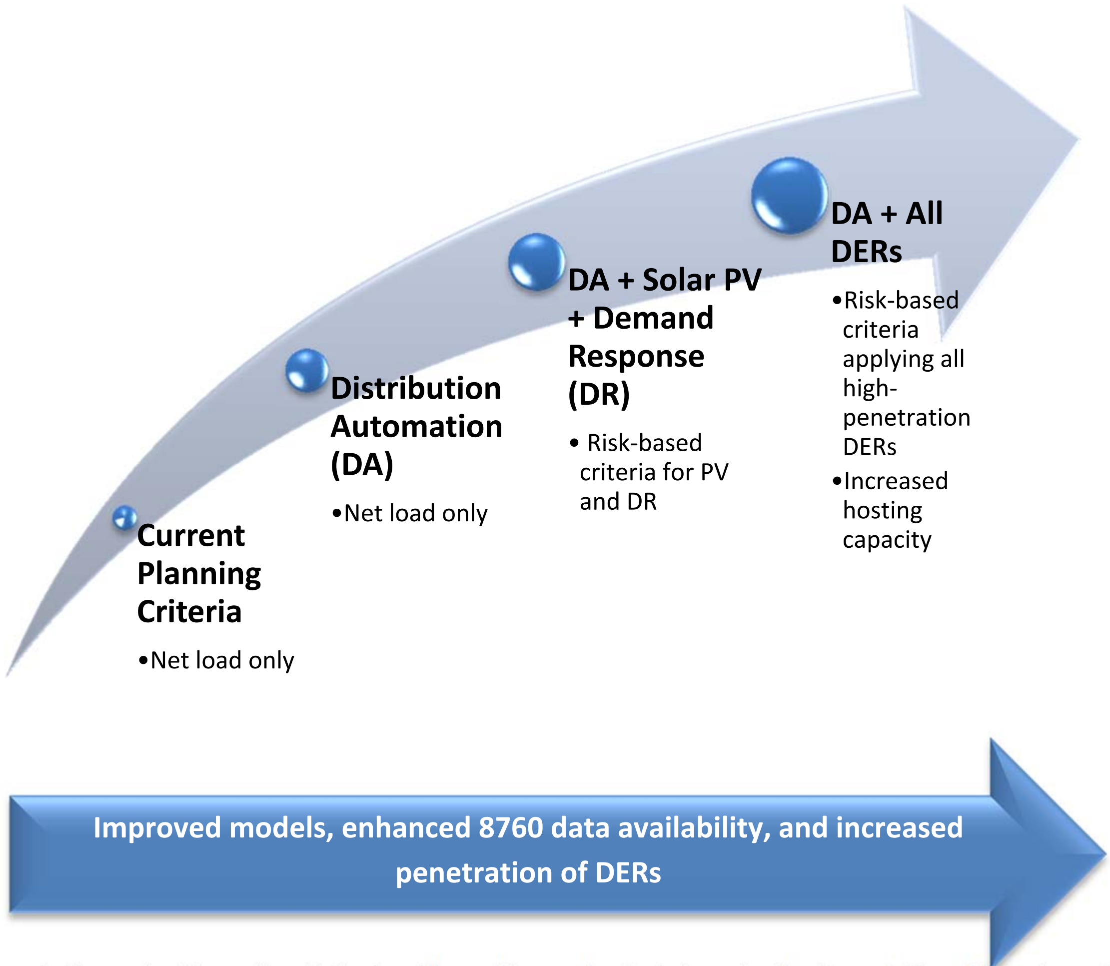
Figure VI-2: Future Forecasts Must Separate DERs and Base (Gross) Loads



This information should be applied to understand the system needs and develop alternatives and a final solution. Prior to applying the DER forecasts on a widespread basis, the T&D Design criteria against which needs are assessed will need to be updated.

Figure VI-3 provides a roadmap of this evolution.

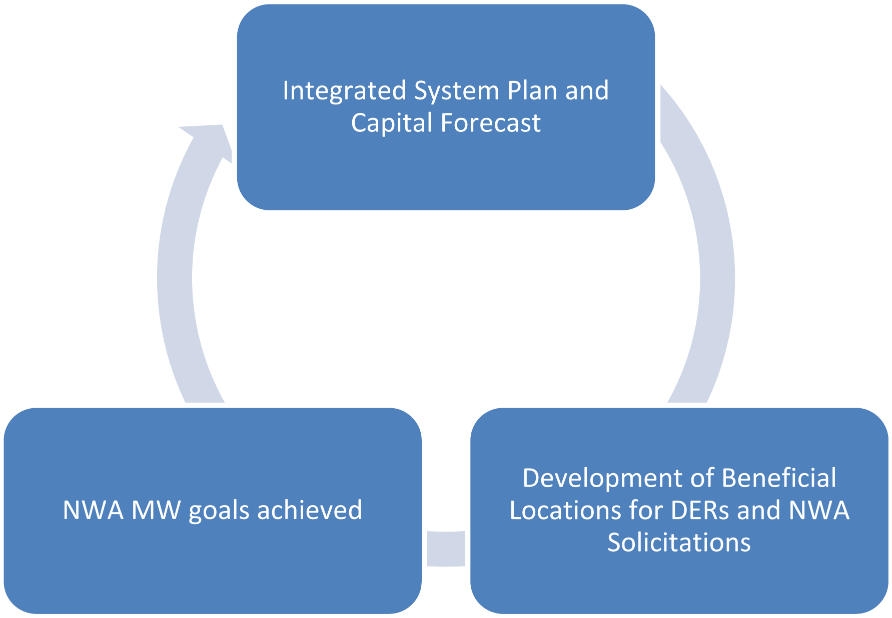
Figure VI-3: Evolution of Distribution Planning Criteria



On a similar note, Operating Criteria will need to evolve to integrate the Foundational Investments (i.e., DA and DMS) as well as DERs. This is discussed further in Section VIII.

Finally, as illustrated in Figure VI-4, the output of the Distribution Planning process will need to expand from the Integrated Capital Budget to include beneficial locations to install DERs. Note that this will not initially be presented in conjunction with hosting capacity maps, which will have its own roadmap described later in this section. Hosting capacity will identify areas where interconnection is easier, but will not necessarily coincide with beneficial locations to alleviate a system constraint.

Figure VI-4: Capital Forecast development with NWAs



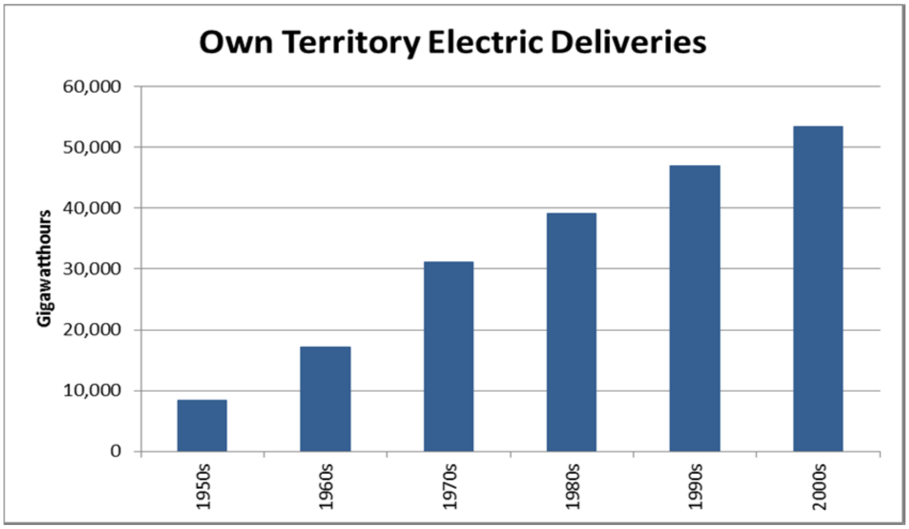
B. Forecast of Demand and Energy Growth—Methodologies

1. System-wide Historical Loads

Summary of Historical System Energy

Annual electricity usage in the Company's service territory increased dramatically from 1950 through 2009, although at a continuously slowing pace, fueled by population and economic growth and the expansion of electric-powered technologies. While annual growth in electricity deliveries during the 1950s and 1960s averaged six to eight percent, by the 1990s and 2000s average annual growth had slipped to less than one percent as a result of slowing population and economic growth and changes in technology, as demonstrated in Figure VI-5.

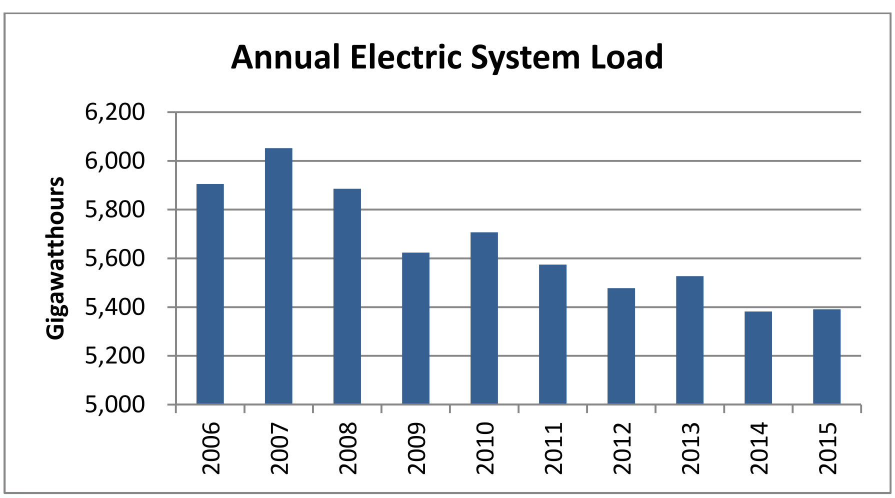
Figure VI-5: Annual Electricity Delivery Growth



More recently electric system load in the Company's service territory has been declining, with annual load for both 2014 and 2015 about 12% lower than the peak annual load of 6,097 GWh experienced in 2005, shown in Figure VI-6. While changes in weather conditions may help to explain a portion of the year-to-year variation in load, as illustrated by the impact of milder winter conditions during 2012 as compared to both 2011 and 2013 in the reduction of load, the overall recent trend of reduced load is the result of systemic changes in demographic, economic, technological, and regulatory factors.

Since 2010 the region's population growth has slowed dramatically, and more recently has exhibited an outright decline as every county in the mid-Hudson region, excluding Orange County, has experienced a decrease in population level. The recession of 2008-2009, and subsequent modest recovery, have also impacted demand for electricity. Finally, fundamental changes in electricity use, including improved EE from new appliance standards, EE programs, and installation of customer-sited DERs, all of which have been stimulated by regulatory policy, have moderated or reduced electric load growth.

Figure VI-6: Annual Electric System Load



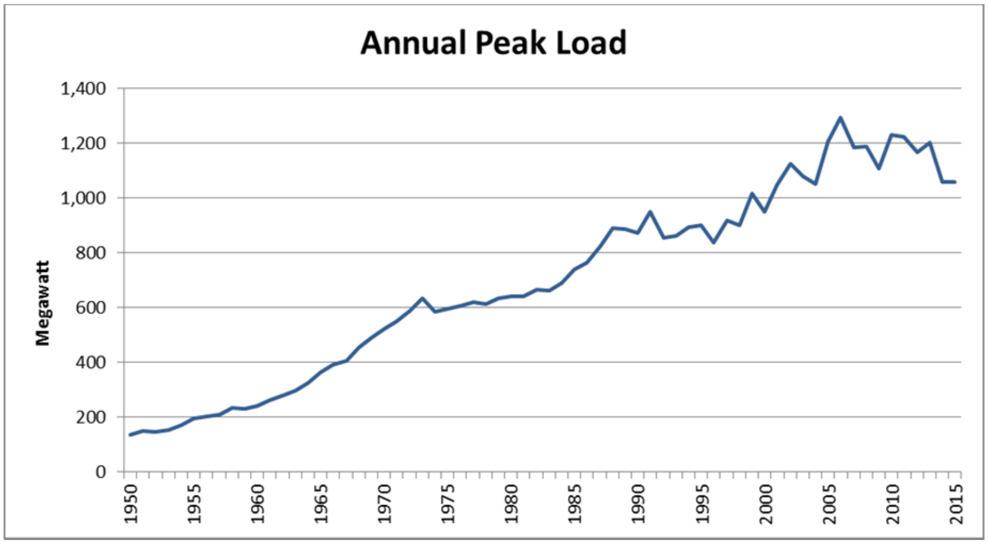
Summary of Historical System demand

In addition to looking at volume, measured as the annual electric system load, it is also important to consider the rate at which electricity is utilized, specifically the annual peak demand that measures the maximum amount of electricity required at a single point in time. The characteristic of peak demand as an insignificant portion of the annual system load with relatively infrequent occurrence belies its importance to the reliability of the system. Significant resources are dedicated to ensuring that peak requirements are safely and reliably met in order to avoid any interruption of service to customers.

Similar to the growth in annual electricity usage, peak hour load in the Company's service territory increased dramatically from 1950 through 2006, fueled by population and economic growth and the expansion of electric-powered technologies, which is demonstrated in Figure VI-7.

Expansion of electric appliances and electric heat helped spur growth in the 1950s and 1960s, while growth in the 1980s and 1990s reflected increased penetration of air conditioning. In fact, until the mid-1970s Central Hudson was a winter peaking utility.

Figure VI-7: Annual Peak Hour Load



More recently, system peak load in the Company's service territory has been declining, with annual load for both 2014 and 2015 about 18% lower than the system peak load of 1,295 MW experienced in 2006. As with the decline in annual electricity usage, the overall recent trend of reduced peak load is the result of the same systemic changes in the demographic, economic, technological, and regulatory factors discussed previously and demonstrated in Figure VI-8.

Figure VI-8: Peak vs. Average Load Trend

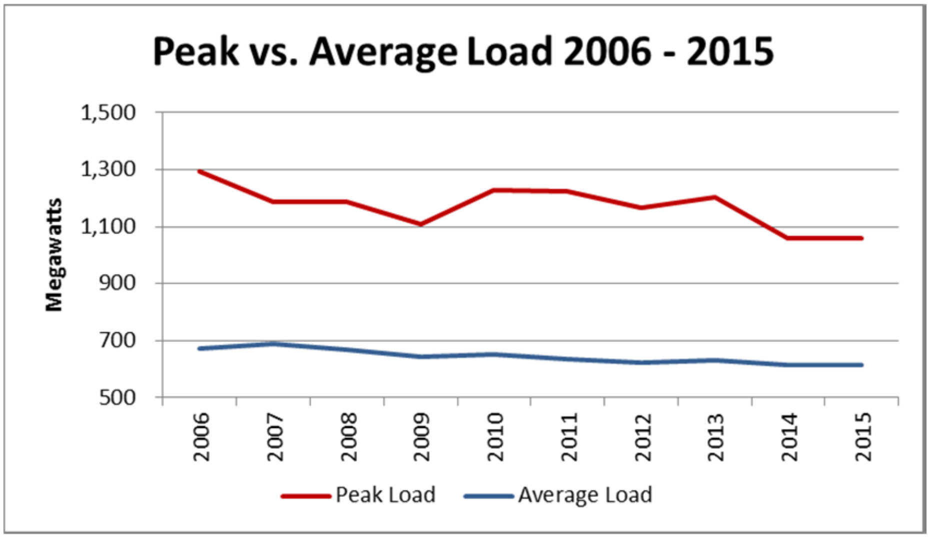
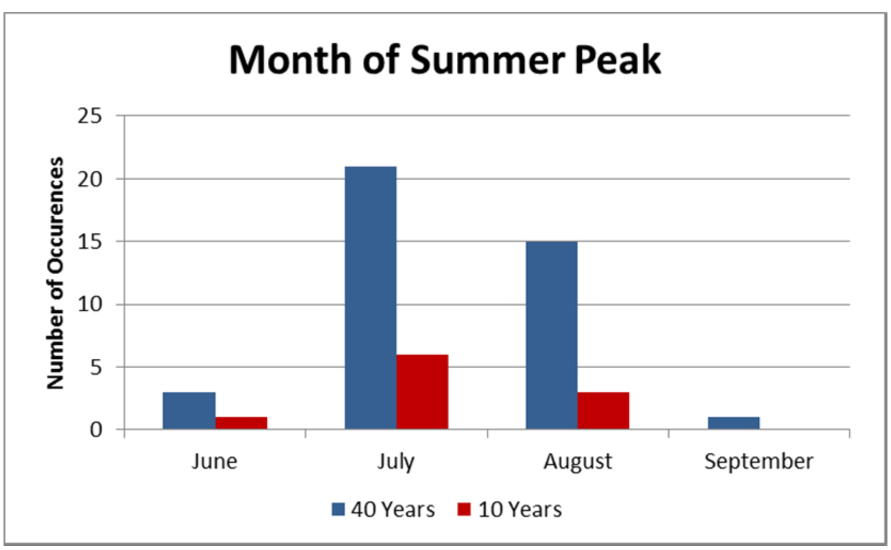


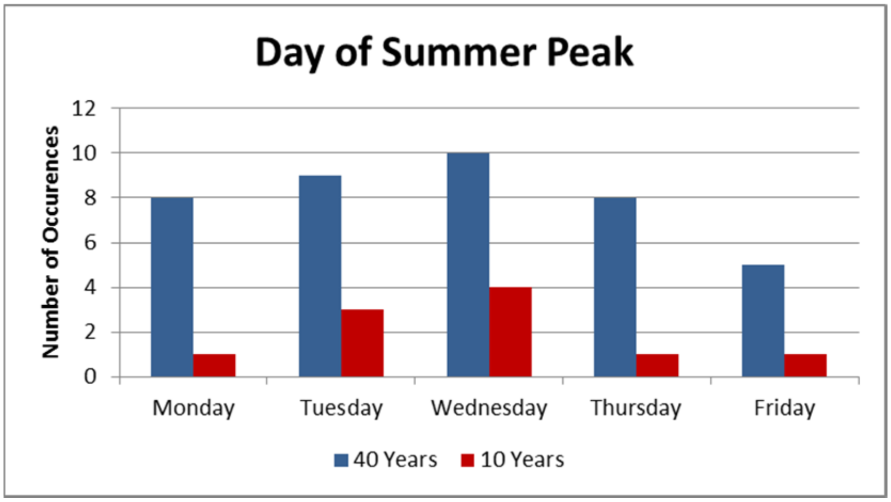
Figure VI-9 demonstrates that despite variation in the magnitude of the annual system peak, the timing of the system peak has been relatively consistent over the forty summer occurrences experienced since 1973 and the most recent ten occurrences:

- The peak generally occurs in July, or secondarily in August;
- The peak occurs on a weekday, generally Monday through Thursday; and,
- The peak generally occurs between 4 to 5 pm.

A compilation of the 24-hour load on each of the peak days over the past 10 years produces a fairly consistent load profile in terms of the hourly load as a percentage of the peak hour load, as shown in Figure VI-10.

Figure VI-9: System Peak Consistency





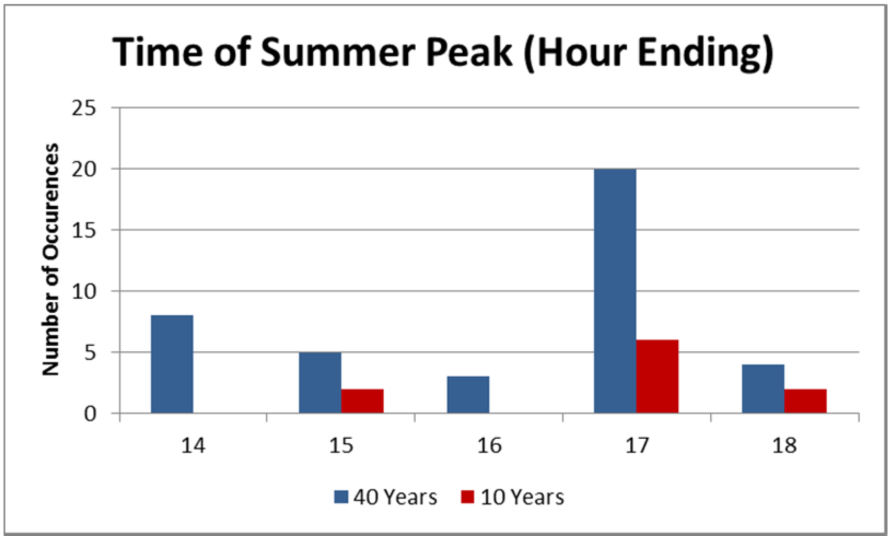
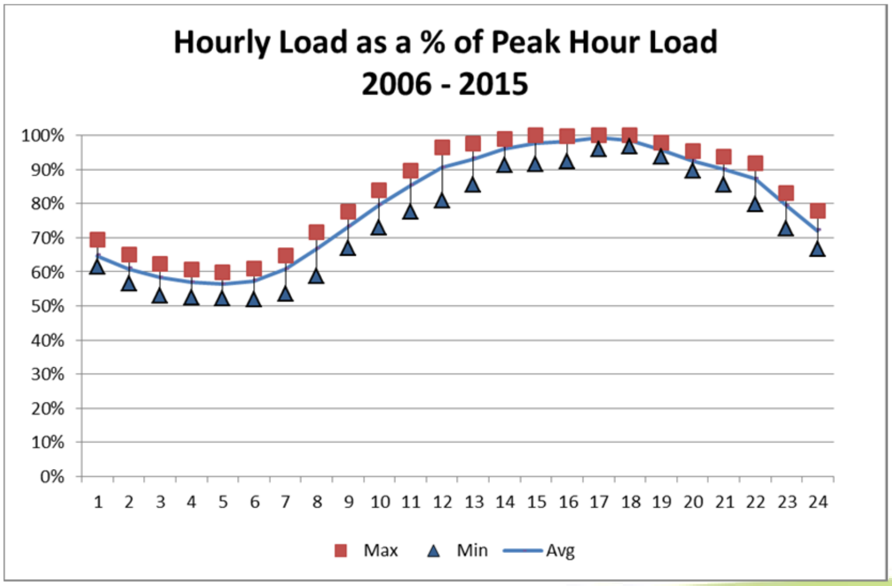


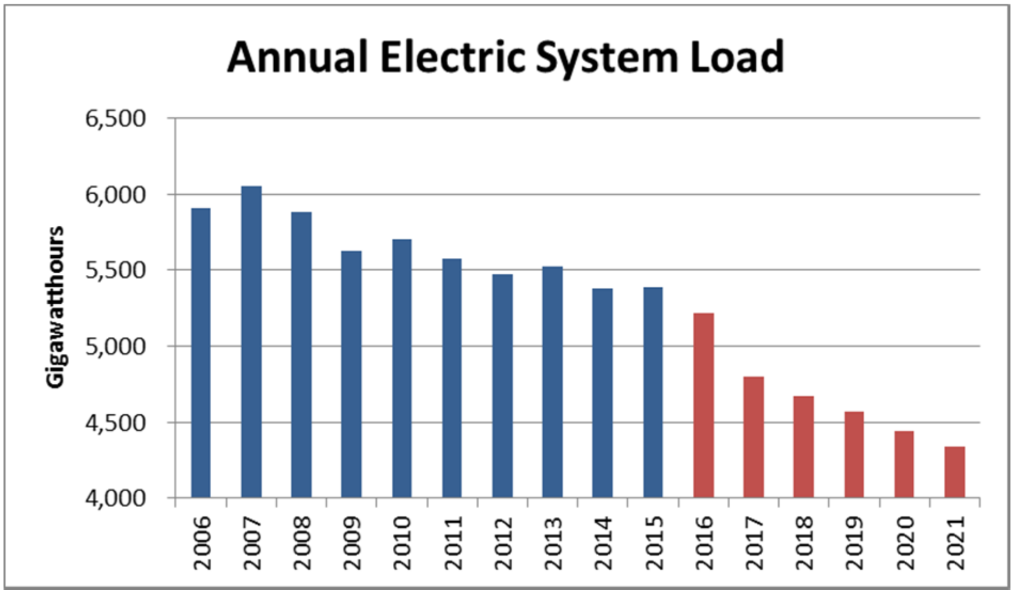
Figure VI-10: Load Profile Consistency



2. System-wide Forecast

The most recently completed sales forecast, included as Appendix M, indicates that widespread EE, both from new appliance standards and organized programs, as well as the continued installation of customer-sited DERs, will continue to dampen electric system load. In fact, as indicated in Figure VI-11, it is estimated that by 2021 annual system load will be about 28% lower than the peak annual load of 6,097 GWh experienced in 2005.

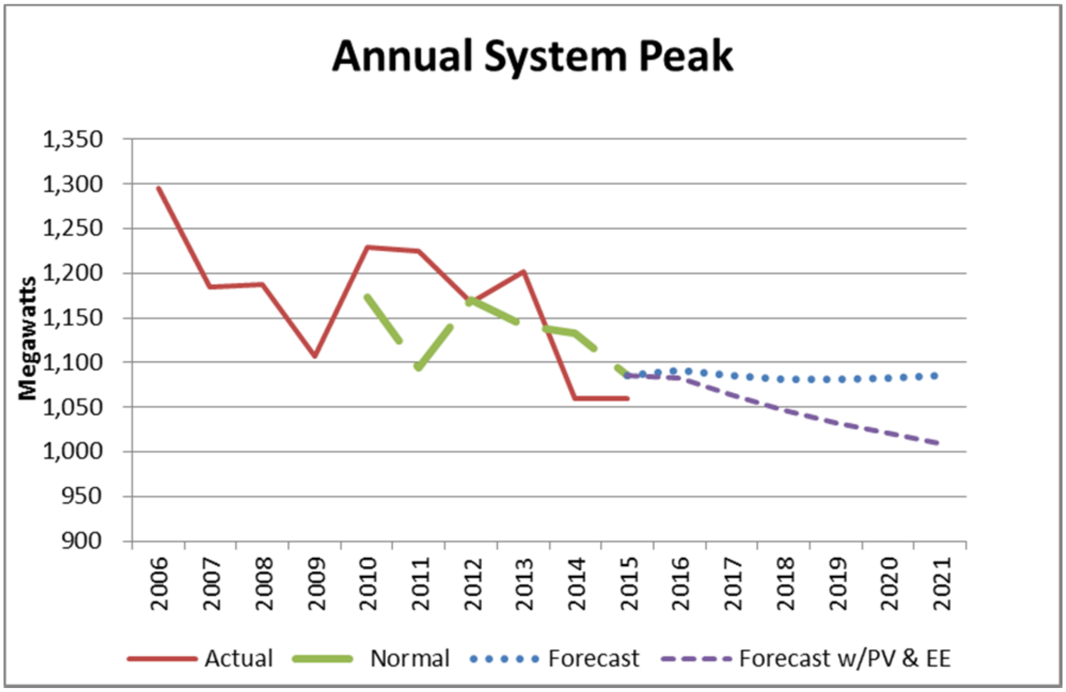
Figure VI-11: Actual and Forecast Annual Electric System Load



This reduction in annual system load may be moderated with increased penetration of EV as transformative technology increases the range between charges and makes the vehicles accessible to a larger portion of the population. Inclusion of the impacts of this technology in future forecasts will be critical as more sufficient data becomes available for assessing penetration and saturation.

Similar to annual system load, the most recent forecast of peak demand, included as Appendix L, indicates that EE and PV will continue to dampen peak demand. As indicated in Figure VI-12, it is estimated that by 2021 annual peak demand will be about 22% lower than the system peak load of 1,295 MW experienced in 2006.

Figure VI-12: Actual and Forecast Annual System Peak



This reduction in annual system load may be augmented by participation in the Company's various DR programs but may also be moderated with increased penetration of EV. Inclusion of the impacts of DR and EV charging in future forecasts will be critical as more sufficient data becomes available for assessing performance.

3. Location Specific 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. We first summarize actual historical peak demand levels and subsequently present weather normalized historical peaks and forecasts for each location.

Historical Local Peak Demand

Table VI4 summarizes the current design ratings, historical annual peaks, and growth rates for Central Hudson's transmission areas.

Table VI-5 summarizes similar information for Central Hudson's substations. The historical peak loads are not weather normalized and reflect year-to-year variation in weather. As discussed in Appendix D, the location specific growth trends were estimated using econometric models that control for differences in weather and the influence of day of week and season. Lastly, annual peaks are location specific and are not coincident and, thus, should not be summed up.

A careful examination reflects that most transmission areas and substation in Central Hudson's territory are experiencing declining loads or limited growth. Most locations that are growing have ample existing capacity to accommodate additional growth over the foreseeable future. For areas that are growing, the magnitude, timing, and cost of projected infrastructure upgrades directly influence the potential avoided cost. For some locations experiencing growth, the costs in the foreseeable future are minimal because loads can be transferred to neighboring areas. The most immediate needs are being addressed by non-wire projects, where additional DER capacity has been procured and is scheduled to come on line within the next few years. Since contracted DER resources provide additional room for growth, they are reflected by adding the contractual resources to the T&D design ratings as exhibited in Table VI-4 and Table VI-5.

Table VI-4: Transmission Area Historical Peaks, Design Ratings, and Growth Trends

Transmission Area	Design rating	Historical Annual Peak (MW)						Annual growth trend (%)[1]
		2010	2011	2012	2013	2014	2015	
Ellenville	251	64.1	64.3	61.3	63.9	57.3	60.7	-0.5%
Hurley-Milan	193	91.2	93.6	87.7	90.2	82.4	80.7	-0.8%
Mid-Dutchess	226	130.2	132.9	132.7	135.5	117.1	121.6	-0.9%
Northwest 115-69 kV Area	155	0.0	129.2	123.5	130.4	123.7	116.3	-0.4%
Northwest 69kV Area	140	106.1	102.0	97.0	102.0	100.4	95.0	-1.5%
Pleasant Valley 69	100	75.3	78.1	77.1	76.4	71.5	67.2	-1.0%
RD-RJ Lines	144	83.3	96.5	94.6	96.6	87.0	88.7	2.2%
Southern Dutchess	211	163.5	163.3	158.8	163.1	149.6	143.8	-1.1%
WM Line	68	45.9	40.4	42.1	48.2	40.0	41.8	0.8%
Westerlo Loop	91	66.2	63.8	68.9	67.2	70.2	66.4	0.1%

[1] The growth trend controls for differences in weather across years

Table VI-5: Substation and Planning Load Area Historical Peaks, Design Ratings, and Growth Trends

Load Area	Substation	Design rating	Historical Annual Peak (MW) 2010	2011	2012	2013	2014	2015	Annual growth trend (%)*
1 Northwest	Hunter	19.5	11.5	13.3	14.4	13.5	14.0	-	3.3%
	Lawrenceville	19.3	-	-	-	16.4	17.0	-	6.8%
	New Baltimore	25.8	11.0	10.1	9.2	10.0	9.2	9.2	-1.0%
	North Catskill	35.1	27.4	26.8	24.8	26.5	23.4	22.8	-0.5%
	Vinegar Hill	18.8	9.0	9.3	9.1	9.0	9.0	9.8	0.7%
	Westerlo	27.0	8.9	8.0	7.7	8.2	8.6	8.1	0.1%
	Total	**N/A**	**75.0**	**81.2**	**65.9**	**79.5**	**80.4**	**66.2**	**2.7%**
2 Kingston - Saugerties	Boulevard	30.6	23.6	24.3	22.4	26.6	20.5	20.6	-1.1%
	East Kingston	48.0	13.8	13.6	12.8	13.1	11.9	12.0	-1.0%
	Hurley Ave	23.1	19.9	20.5	18.7	20.2	17.6	17.0	-0.8%
	Lincoln Park	84.0	46.2	47.2	44.5	44.0	42.1	41.0	-1.7%
	Saugerties	50.0	-	-	-	24.2	21.0	20.6	-0.6%
	Woodstock	20.9	20.5	19.7	18.1	19.3	20.9	20.2	1.2%
	Total	**N/A**	**120.3**	**124.2**	**114.4**	**118.8**	**107.7**	**105.0**	**-0.9%**
3 Ellenville	Clinton Ave	7.7	1.2	1.3	1.2	1.4	1.6	1.4	1.2%
	Dashville	2.0	1.2	1.1	1.3	1.6	1.4	1.1	0.8%
	Grimley	7.2	-	-	1.1	5.0	4.1	4.4	3.6%
	High Falls	34.5	18.7	18.9	17.7	19.2	17.1	17.0	0.5%
	Honk Falls	18.2	6.1	6.1	6.3	6.1	5.9	5.8	0.8%
	Total	**N/A**	**26.8**	**26.6**	**26.1**	**26.4**	**24.7**	**24.5**	**1.0%**
4 Modena	Galeville	28.7	7.1	9.5	9.6	9.3	9.0	10.9	4.4%
	Highland	32.9	18.7	18.9	17.7	19.2	17.1	17.0	1.2%
	Modena	21.1	13.3	14.8	13.5	14.1	12.0	12.4	1.4%
	Ohioville	29.7	30.0	25.4	25.2	25.3	24.2	22.7	-2.9%
	Total	**N/A**	**61.5**	**65.8**	**63.9**	**65.7**	**60.7**	**61.4**	**1.4%**
5 Newburgh	Bethlehem	47.8	46.2	37.5	36.3	41.9	34.1	35.2	-0.6%
	Coldenham	47.8	31.9	35.3	33.0	39.0	33.5	30.7	1.5%
	East Walden	26.2	15.8	14.0	15.1	15.5	14.1	14.6	0.7%
	Marlboro	30.9	20.1	19.9	19.7	20.3	18.2	19.6	0.4%
	Maybrook	30.0	18.3	16.8	16.5	15.2	14.3	17.7	-0.1%
	Union Ave	94.5	-	61.9	59.9	56.7	53.1	55.6	-0.2%
	West Balmville	47.8	42.5	43.1	40.9	39.1	32.9	34.9	-2.4%
	Total	**N/A**	**211.5**	**206.9**	**215.8**	**224.0**	**194.1**	**203.9**	**0.9%**

Load Area	Substation	Design rating	Historical Annual Peak (MW)						Annual growth trend (%)*	
			2010	2011	2012	2013	2014	2015		
6 Northeastern Dutchess	EastPark	24.2	14.7	16.0	13.8	14.0	11.7	12.4	-1.9%	
	Hibernia	17.8	10.4	12.6	11.7	12.9	10.5	10.5	1.2%	
	Milan	25.9	4.8	5.4	4.6	6.0	5.4	5.1	2.4%	
	Millerton	8.3	5.5	5.3	4.9	4.9	5.3	5.0	-0.9%	
	Pulvers Corners 13 kV	5.8	5.1	4.9	4.6	4.4	3.9	4.4	-2.2%	
	Pulvers Corners 34 kV	17.2	4.0	4.0	4.3	3.7	2.8	2.7	-8.4%	
	Rhinebeck	47.8	32.2	32.4	30.3	31.8	28.3	27.7	-0.4%	
	Smithfield	5.8	1.4	1.5	1.4	1.4	1.5	1.4	-0.2%	
	Staatsburgh	27.2	9.8	9.9	8.9	10.8	8.5	8.0	-1.0%	
	Stanfordville	17.0	6.3	6.7	5.9	5.4	5.5	5.2	-1.8%	
	Tinkertown	19.1	15.2	19.6	14.2	15.2	13.0	13.0	-0.5%	
	Total	**N/A**	**108.2**	**110.7**	**102.0**	**97.7**	**88.4**	**92.8**	**-1.4%**	
7 Poughkeepsie	Inwood Ave	47.8	26.1	27.9	23.1	26.1	25.9	24.6	0.5%	
	Reynolds Hill	45.9	36.7	37.6	34.5	34.7	25.8	-	-2.7%	
	Spackenkill	47.8	-	-	34.1	36.0	31.2	32.0	-0.8%	
	Todd Hill	47.8	29.5	30.5	24.2	24.3	21.1	22.0	-4.4%	
	Total	**N/A**	**90.2**	**106.9**	**104.9**	**118.5**	**88.9**	**78.0**	**-3.0%**	
8 Fishkill	Fishkill Plains	52.8	44.6	46.5	43.0	43.8	36.5	38.7	-1.2%	
	Forgebrook	47.4	30.4	29.8	28.8	30.3	27.2	26.2	-1.0%	
	Knapps Corners	47.8	-	-	20.9	22.4	19.0	18.9	-2.3%	
	Merritt Park Industria	52.2	32.4	32.6	31.6	33.1	29.2	30.3	-0.3%	
	Myers Corners	35.1	30.5	28.0	28.5	28.1	20.8	21.0	-7.0%	
	North Chelsea	48.3	16.5	20.2	19.8	21.1	19.5	19.1	3.3%	
	Sand Dock	8.0	5.8	3.0	5.2	4.7	4.2	4.3	-2.1%	
	Shenandoah	18.0	9.8	9.8	9.5	11.7	8.4	9.2	-0.2%	
	Total	**N/A**	**228.8**	**215.1**	**190.9**	**206.5**	**158.9**	**179.0**	**-3.4%**	
9 Poughkeepsie Industrial	Barnegat Industrial	47.8	11.1	10.0	10.5	10.0	9.8	8.5	-1.1%	
	Sand Dock Industrial	51.0	24.4	25.6	25.3	24.3	23.1	23.4	-1.6%	
	Total	**N/A**	**33.6**	**35.3**	**35.8**	**34.2**	**32.5**	**31.7**	**-1.3%**	
10 Fishkill Industrial	Shenandoah Industria	147.1	71.2	70.7	71.4	72.1	68.6	65.2	-1.4%	
	Total	**N/A**	**71.4**	**70.9**	**71.4**	**72.1**	**68.7**	**65.2**	**-1.5%**	**-1.5%**

[1] The growth trends control for differences in weather across years
[2] Years were data is unavailable are left blank

4. Location Specific Load Forecasts

Table VI-6 and Table VI-7 summarize the weather normalized historical peaks and growth forecasts for each transmission area and substation. The tables only include the expected load growth and do not reflect uncertainty of the forecasts. For additional detail regarding the uncertainty bands of the forecasts, including tables summarizing the forecast uncertainty for each location, please refer to Appendix D.

Table VI-6: Transmission Historical and Forecast 1-in-2 Annual Peaks (MW)

Transmission Area	Historical 1-in-2 Annual Peaks [1]					Forecasted 1-in-2 Peaks (Expected value)						Design Rating
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Ellenville	65.6	62.4	63.8	63.3	65.5	65.4	65.1	64.8	64.5	64.2	63.8	251.0
Hurley-Milan	92.7	93.1	91.3	91.2	90.1	89.9	89.1	88.4	87.7	87.0	86.3	193.0
Mid-Dutchess	134.7	138.4	135.1	129.4	130.6	130.2	129.1	128.0	126.8	125.8	124.7	226.0
Northwest 115-69 kV	142.4	141.0	141.2	141.3	139.4	139.2	138.7	138.1	137.6	137.0	136.5	155.0
Northwest 69kV	108.0	106.4	107.3	107.7	106.1	105.5	104.0	102.4	101.0	99.5	98.1	140.0
Pleasant Valley 69	75.7	74.8	79.5	74.0	71.4	71.2	70.5	69.9	69.2	68.5	67.9	100.0
RD-RJ Lines	97.4	97.5	97.3	97.2	97.6	98.4	100.6	102.7	105.0	107.3	109.7	144.0
Southern Dutchess	162.4	164.7	162.4	158.9	156.9	156.3	154.6	152.9	151.2	149.6	148.0	211.0
Westerlo Loop	63.7	64.2	65.4	65.3	64.2	64.2	64.3	64.3	64.4	64.4	64.5	91.0

[1] Historical annual peaks were adjusted for 1-in-2 (2013) weather conditions via econometric models controlling for weather differences.

Table VI-7: Transmission Historical and Forecast 1-in-2 Annual Peaks (MW)

Load Area	Substation	Historical 1-in-2 Annual Peaks [1]					Forecasted 1-in-2 Peaks (Expected value)						Design Rating
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
1 Northwest	Hunter	7.8	8.0	8.8	8.3	7.8	7.8	8.1	8.4	8.7	9.0	9.3	19.5
	Lawrenceville	-	-	10.0	12.5	12.0	12.2	13.0	13.9	14.9	15.9	17.1	19.3
	New Baltimore	11.1	10.9	11.1	11.0	11.1	11.1	11.0	10.9	10.7	10.6	10.5	25.8
	North Catskill	26.8	26.7	27.0	26.6	26.6	26.6	26.5	26.3	26.2	26.1	25.9	35.1
	Vinegar Hill	8.0	8.1	8.4	8.4	8.5	8.5	8.5	8.6	8.6	8.7	8.8	18.8
	Westerlo	7.6	7.6	7.8	7.8	7.6	7.6	7.6	7.6	7.6	7.6	7.7	27.0
	Total	60.5	60.1	64.1	68.0	66.0	66.5	68.3	70.1	72.1	74.1	76.1	N/A
2 Kingston - Saugerties	Boulevard	23.1	23.2	23.5	22.7	22.2	22.1	21.9	21.7	21.5	21.2	21.0	30.6
	East Kingston	13.4	13.7	13.2	13.2	13.0	12.9	12.8	12.7	12.6	12.4	12.3	48.0
	Hurley Ave	19.7	19.6	20.2	20.0	19.6	19.5	19.4	19.2	19.1	19.0	18.8	23.1
	Lincoln Park	45.0	44.1	43.2	42.7	42.0	41.8	41.1	40.4	39.7	39.0	38.4	84.0
	Saugerties	-	-	23.6	23.7	23.4	23.3	23.2	23.0	22.9	22.7	22.6	50.0
	Woodstock	15.9	18.2	18.7	18.8	18.5	18.5	18.8	19.0	19.2	19.5	19.8	20.9
	Total	129.3	130.7	128.2	129.3	126.8	126.5	125.3	124.2	123.1	122.0	120.8	N/A
3 Ellenville	Clinton Ave	1.2	1.2	1.3	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.3	7.7
	Dashville	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	2.0
	Grimley Rd	-	5.0	5.9	6.2	6.2	6.3	6.5	6.8	7.0	7.3	7.5	7.2
	High Falls	18.1	18.2	18.8	18.6	18.6	18.6	18.7	18.8	18.9	19.0	19.1	34.5
	Honk Falls	5.8	6.1	6.1	6.2	6.2	6.2	6.3	6.3	6.4	6.4	6.5	18.2
	Total	29.4	30.4	31.1	31.5	31.0	31.1	31.4	31.8	32.1	32.4	32.7	N/A
4 Modena	Galeville	8.6	9.1	9.3	9.5	10.8	10.9	11.4	11.9	12.4	13.0	13.6	28.7
	Highland	18.6	18.9	19.4	19.6	19.6	19.6	19.8	20.1	20.3	20.6	20.8	32.9
	Modena	14.5	15.0	14.8	14.7	14.8	14.8	15.0	15.3	15.5	15.7	15.9	21.1
	Ohioville	26.4	25.6	25.9	25.9	23.9	23.8	23.1	22.4	21.7	21.1	20.5	29.7
	Total	66.8	67.5	68.2	68.8	68.0	68.2	69.2	70.2	71.1	72.2	73.2	N/A
5 Newburgh	Bethlehem Rd	37.9	35.1	36.0	37.7	36.9	36.8	36.6	36.4	36.1	35.9	35.7	47.8
	Coldenham	33.2	36.4	38.8	36.9	34.0	34.1	34.6	35.3	35.9	36.6	37.2	47.8
	East Walden	15.4	16.0	16.1	16.5	16.4	16.4	16.6	16.7	16.8	16.9	17.0	26.2
	Marlboro	20.2	21.0	20.7	20.0	21.2	21.2	21.3	21.3	21.4	21.5	21.6	30.9
	Maybrook	15.8	15.2	14.3	15.0	18.0	18.0	18.0	18.0	18.0	18.0	18.1	24.0
	Union Ave	58.8	61.1	59.7	58.4	59.4	59.4	59.2	59.1	59.0	58.8	58.7	94.5
	West Balmville	39.3	35.8	36.4	37.3	35.0	34.8	33.9	33.1	32.2	31.5	30.7	47.8
	Total	243.2	236.9	251.0	245.0	251.7	252.2	254.5	256.8	259.2	261.5	263.9	N/A

Load Area	Substation	Historical 1-in-2 Annual Peaks [1]					Forecasted 1-in-2 Peaks (Expected value)						Design Rating
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
6 Northeastern Dutchess	East Park	15.5	14.8	14.4	14.0	14.0	14.0	13.7	13.5	13.2	12.9	12.7	24.2
	Hibernia	11.0	11.0	11.3	11.3	11.1	11.1	11.2	11.3	11.5	11.6	11.8	17.8
	Milan	4.9	4.8	5.1	5.3	5.6	5.6	5.7	5.9	6.0	6.2	6.3	25.9
	Millerton	5.2	5.2	5.1	5.2	5.2	5.2	5.1	5.1	5.0	5.0	4.9	8.3
	Pulvers Corners 13 kV	4.8	5.0	4.6	4.5	4.9	4.9	4.8	4.7	4.6	4.5	4.4	5.8
	Pulvers Corners 34 kV	3.2	3.2	3.2	2.4	2.3	2.3	2.1	1.9	1.8	1.6	1.5	17.2
	Rhinebeck	31.6	32.0	31.9	31.7	31.4	31.4	31.3	31.1	31.0	30.9	30.8	47.8
	Smithfield	1.3	1.3	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2	5.8
	Staatsburg	9.7	9.8	10.0	9.6	9.5	9.4	9.3	9.3	9.2	9.1	9.0	27.2
	Stanfordville	6.7	6.8	6.6	6.3	6.2	6.1	6.0	5.9	5.8	5.7	5.6	6.3
	Tinkertown	14.9	15.3	15.4	15.4	15.1	15.0	15.0	14.9	14.8	14.7	14.7	19.1
	Total	130.3	130.8	126.1	123.7	125.2	124.8	123.1	121.5	119.8	118.1	116.4	N/A
7 Poughkeepsie	Inwood Ave	25.7	22.3	23.1	24.2	23.5	23.6	23.7	23.9	24.0	24.2	24.4	47.8
	Reynolds Hill	35.9	35.4	35.0	33.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.9
	Spackenkill	0.0	39.1	38.7	38.3	38.2	38.1	37.8	37.5	37.2	36.8	36.5	47.8
	Todd Hill	29.0	25.4	24.8	24.7	24.5	24.3	23.3	22.3	21.4	20.4	19.6	47.8
	Total	104.0	112.7	110.8	85.4	83.4	82.8	80.9	79.3	77.4	75.8	73.8	N/A
8 Fishkill	Fishkill Plains	46.1	46.9	45.5	44.1	44.1	44.0	43.4	42.9	42.4	41.9	41.4	52.8
	Forgebrook	29.4	30.1	29.7	29.4	29.0	28.9	28.6	28.3	28.1	27.8	27.5	47.4
	Knapps Corners	-	21.9	20.9	20.1	20.4	20.3	19.9	19.4	19.0	18.5	18.1	47.8
	Merritt Park	33.1	31.9	31.8	32.1	32.4	32.3	32.2	32.1	32.0	31.9	31.8	52.2
	Myers Corners	28.9	29.1	27.6	22.8	22.8	22.5	20.9	19.5	18.2	16.9	15.7	35.1
	North Chelsea	20.5	21.1	21.3	21.0	21.4	21.5	22.2	23.0	23.8	24.5	25.3	48.3
	Sand Dock	4.8	5.2	4.8	4.7	4.7	4.7	4.6	4.5	4.4	4.3	4.2	8.0
	Shenandoah	9.9	10.5	11.1	10.6	10.0	10.0	10.0	10.0	10.0	10.0	9.9	18.0
	Total	211.2	201.7	193.8	182.2	196.1	194.5	188.2	181.9	175.7	169.6	163.9	N/A
9 Poughkeepsie Industrial	Barnegat Industrial	10.0	10.4	10.0	9.6	8.6	8.6	8.6	8.5	8.4	8.3	8.3	47.8
	Sand Dock Industrial	25.7	24.9	23.6	23.1	23.3	23.2	22.8	22.5	22.1	21.7	21.4	51.0
	Total	36.5	36.1	34.3	33.3	32.6	32.5	32.1	31.7	31.3	30.9	30.5	N/A
10 Fishkill Industrial	Shenandoah Industrial	69.7	71.8	70.6	68.9	65.7	65.5	64.6	63.7	62.8	62.0	61.1	147.1
	Total	72.1	74.0	72.8	71.1	67.8	67.6	66.5	65.6	64.6	63.7	62.8	N/A

[1] Historical annual peaks were adjusted for 1-in-2 (2013) weather conditions via econometric models controlling for weather differences.

C. Forecasting Methodology

For this report, the system wide and location specific forecasts were developed independently. The bottom-up, location specific forecasts were crosschecked against the system wide forecasts to ensure any differences were within reason—either explained by line losses or explained by substations that were not included in the forecast due to sub-par or unavailable hourly data. Over the long run, synchronizing the bottom-up forecasts and using them produce system wide forecast would improve accuracy. A key barrier, however, is that not all feeders and substations have meters collection hourly or sub-hourly data. Once meters are installed, several years of data need to be collected to estimate local annual growth trends.

1. System-wide Forecasting Methodology

Energy sales projections are developed for multiple electric sectors, as detailed below, and aggregated with a projection of electric system losses to produce a forecast of net energy. This forecast of net energy is paired with a peak demand forecast to yield an annual system electric load forecast. While quantitative methods are utilized whenever possible in the forecasting process, judgment is an integral part in the development of any forecast.

Compile and Review Data

The first step in the system load forecasting process is the collection and verification of relevant actual energy sales and hourly energy load data. The sales forecast process primarily utilizes historic monthly billed customers, sales (kWh, or fixtures for lighting), and revenue levels obtained from Company records. Although the Commission previously approved the unbundling of commodity supply from delivery for Central Hudson, the resulting base delivery rates are the same for both full service sales and retail access customers. As a result, the sales forecasts reflect total full service and retail access deliveries. For forecast purposes this data is aggregated into the following sectors: residential, commercial, industrial, other public authority, lighting and interdepartmental. Peak demand forecasts utilize hourly system energy that is also obtained from Company records.

Once obtained, this data is reviewed for anomalies that are reviewed and resolved through either verification or adjustment. Examples of anomalies include, but are not limited to:

- Obvious data gaps that are remediated through either acquisition or estimation of the missing data;
- Unusually high or low singular values that are resolved through verification or adjustment, for example in the case of cancels and rebills of large customers that may skew monthly results;
- Data recording errors that are remediated through identification and acquisition; and,
- Process, structural or customer classification changes that are resolved through identification and adjustment if deemed appropriate, such as reclassification between demand and non-demand rates within the same sector or implementation of rate structure changes such as implementation of hourly pricing for customers exceeding a specific threshold size.

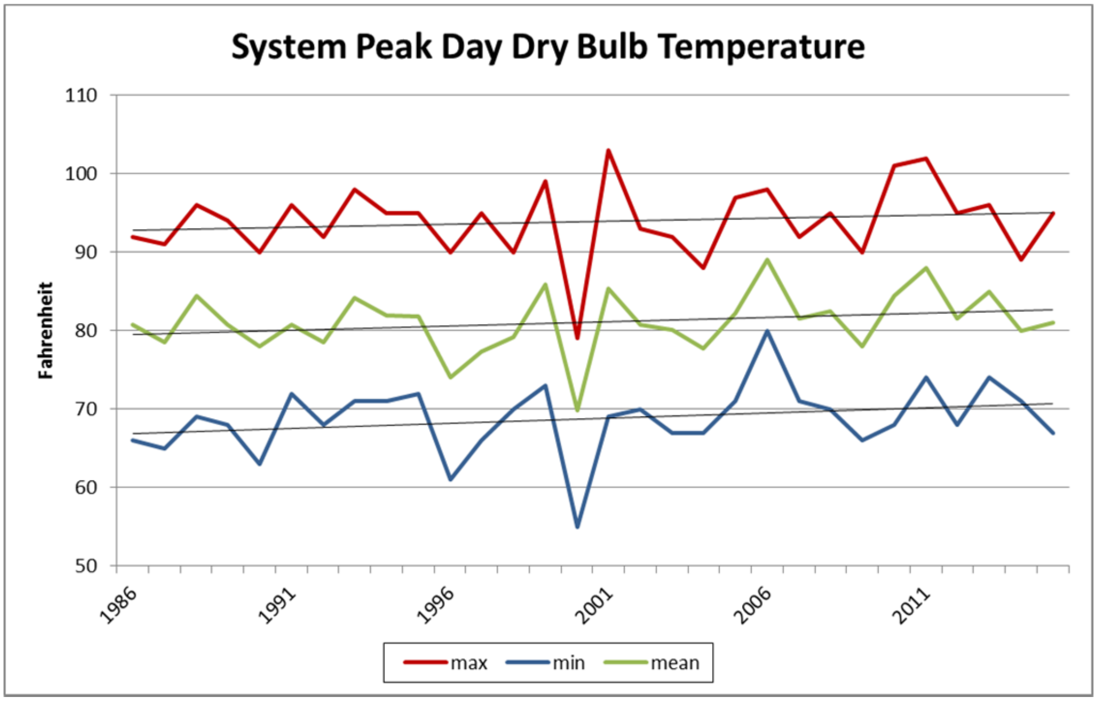
Data review and remediation, if necessary, provides assurance that the data is accurate and complete, and prevents artificial changes from being mistaken for actual growth or decline in loads or energy and being erroneously incorporated into forecasts.

Compile Data to be Utilized for Forecast Drivers

The majority of the sales projections and the peak demand projection are developed through econometric analysis, thus requiring exogenous data including weather, demographic, economic, price, and end-use saturation and efficiency data.

Weather data is compiled from hourly dry bulb temperature readings obtained from the Dutchess County Airport, and includes heating and cooling degree days (HDD and CDD, respectively) as utilized in various sales projections, as well as several temperature variants as determined during the peak model specification process. Electric HDD are defined as the amount by which 65 degrees Fahrenheit exceeds the average of the high and low temperatures for a given day as measured midnight to midnight. CDD are defined as the amount by which the average of the high and low temperatures for a given day, as measured midnight to midnight, exceed 65 degrees Fahrenheit. For sales forecasting purposes, monthly actual HDD and CDD are transformed into billed HDD and CDD to more closely correspond to the particular sales billing period. Further, the sales forecasts are based on normal weather conditions, where the normal weather is determined by a ten-year average of monthly HDD or CDD through the most recently completed calendar year at the time a forecast is prepared, as applicable and pursuant to the Commission’s June 22, 2009 Order in Case 08-E-0887. The system peak normal demand projections are based on an estimated normal peak day defined as the upper 95% mean of the selected temperature variable(s) over 30 years. Utilizing the upper 95% mean provides confidence that the mean will not be understated particularly since the mean daily temperature has been increasing due primarily to an increase in the minimum daily temperature as shown in Figure VI-13.

Figure VI-13: System Peak Day Temperatures



Demographic and economic variables, both historic and forecast including population, households, household income, GDP, Consumer Price Index, and various employment indicators, are based on actual and forecast data provided by Moody's Analytics. Composite variables for the Central Hudson region are constructed from four regions included in the forecast: Albany, Catskills, Dutchess County, and Orange County. The composite variables are calculated as a weighted sum of the regional forecasts, where the weights reflect actual average residential and non-residential electric deliveries (kWh) in the Company's service territory over the most recently completed three calendar years at the time a forecast is prepared.

The historic price series utilized for each class in the sales forecast is determined as a function of the total bundled revenue (including delivery and supply) billed to full service customers divided by sales to full service customers in each class. Monthly forecast prices for each class include applicable base delivery charges inclusive of projected increases or decreases. The supply price is forecasted using monthly regression equations to estimate supply price as a function of the on-peak price forecast for NYISO Zone G during the development of the forecast as obtained from SNL.com. The price variable is indexed against the Consumer Price Index and expressed as a 12-month moving average on a 1-month lag.

Residential appliance and commercial end-use saturation and efficiency trends are based on Energy Information Administration estimates for the Middle Atlantic Census Region as compiled by Itron, Inc. Where possible, electric estimates are calibrated to Central Hudson's service territory based on results from the Company's Residential Appliance Saturation and/or Energy Management surveys.

Identify Data or Processes Requiring Alternative Treatment

EE and DERs are increasingly positioned to become significant resources to meet customer needs. On a practical basis, the impacts of these resources must be integrated into energy and demand forecasts in order to produce more realistic estimates of load levels to ensure that customer needs are adequately met. As both EE and DER, in terms of PV in the Company's service territory, have been growing at increasing rates, the Company has identified these two processes as requiring alternative treatment in order to reduce the likelihood that the impacts of these processes will be misstated in the forecasts.

For sales forecasting purposes, both EE and DER, more specifically net-metered PV, are addressed external to the sales modeling process. This prevents the sales regression models from assuming that the historical EE and PV growth pattern will continue in the future, allowing the growth patterns to be altered. This is accomplished by first adjusting historic data to add back the EE savings and PV output estimated to actually have been achieved in the historic period in order to avoid double counting these savings. Estimated actual EE savings reflect information filed by the Company and the New York State Energy Research and Development Authority (NYSERDA) in Case 07-M-0548. Historic PV output is based on an estimate of the production of the actual kilowatt (kW) capacity of installed PV systems. The forecast of electric sales reductions attributable to EE is developed by allocating annual reductions identified in various Orders issued by the Commission (100% of Company EE Transition Implementation Plan program savings targets as ordered in Case 15-M-0252 and a portion of Clean Energy Fund minimum 10 year EE goals for NYSERDA in Case 14-M-0094 based on an estimate of savings expected to be acquired, which reflects historic realized savings) across applicable customer classes and months based on the pre-adjustment forecast of sales. The forecast of sales reductions attributable to PV penetration is based on a forecast of net-metered PV kW installed developed by applying a polynomial regression to the monthly cumulative kW installed. The resulting monthly kW is converted to energy output based on historic realized savings and allocated across applicable customer classes. These reductions are then applied as post forecast adjustments to arrive at the final sales forecast. It is important to note that customer-initiated EE or EE due to codes and standards (naturally-occurring) is reflected in the regression models either through residential appliance and commercial end-use saturation and efficiency trends or as embedded in historic sales.

For peak demand forecasting purposes, EE and DER (more specifically net-metered PV) are also addressed external to the forecast by reducing forecast years by the difference between the individual EE and DER forecasts and the estimated realized amount in the last year of the estimation period.

Determine Forecast Methodology and Specify Models

For sales forecasting purposes, the previously identified customer sectors are further delineated into 13 individual forecasting classes, distinguishing between either heat and non-heat or demand and non-demand. Customer forecasts are developed for each of the thirteen classes. For a number of these classes, sales volume forecasts are developed on a sales per customer basis, with total sales specified as a function of sales per customer and customer count. Sales forecasts for the remaining classes are developed on a total class basis. Generally, this approach was applied to the classes with relatively large numbers of customers. Separating total consumption into customer and sales per customer components recognizes that each component is influenced by different factors and provides the opportunity to incorporate more structure into the analysis of total consumption.

Forecasts of customers and sales are developed utilizing various econometric or time series models, or trend projections. The models developed to produce the forecasts are estimated using actual monthly billed customer and sales data with estimation periods varying somewhat for the different classes in order to recognize structural changes to the billing process and data quality issues that can sometimes limit data availability. For example, revisions to billing cycles, in terms of customer composition, and recording of customers' end-use category (residential, commercial, industrial, etc.) can cause shifts in data requiring different estimation periods.

Econometric models are generally constructed to forecast sales for all electric classes, excluding: large industrial, the three lighting classes, and interdepartmental. Further, the sales forecasts developed for the electric residential and commercial classes generally utilize Statistically Adjusted End-Use models, which integrate structural changes in end-use saturation and efficiency trends, as well as address the interaction of economic variables through the construction of end-use variables: heating, cooling and other (base use). These end-use variables include weather, price, economic drivers and end-use saturation and efficiency trends. Additionally, the electric end-use variables generally constructed for the residential classes reflect changes in housing square footage and thermal shell integrity.

The large industrial class includes customers who require service at transmission voltage or who have provided all the necessary equipment to take service directly from a substation. The sales forecast for this class has generally been developed based on discussions with these customers who provide the Company with either written or verbal general forecasts/indications of future electric consumption. In the absence of customer provided forecasts/indications, the Company considers historical customer-specific information including, but not limited to, usage, demand, and load factor data in order to develop customer-specific forecasts.

Street and area lighting sales are commonly projected by extrapolating inventory trends for existing fixtures, including the switch to more efficient lighting. Traffic signal sales recognize the contraction due to the closing of the specific tariff effective November 1, 2001, and resulting inclusion of transfers in the commercial class. Based on the extremely small volume of interdepartmental sales (electric sales to the gas department), projections are generally based on an analysis of several years of actual sales data.

The total monthly sales forecast is developed by aggregating the individual sector forecasts and applying any post forecast adjustments. A system loss factor is projected based on an analysis of several years of actual data and applied to sales along with a sales to energy allocation algorithm to convert sales into system energy requirements.

Based on the results of the analysis presented in Figure VI-9, which indicates that 90 percent of annual peaks occur in the months of July or August and all annual peaks occur on weekdays, the annual peak projection is based on actual daily weekday peak load for the months of July and August. An econometric model is generally constructed to forecast annual peak demand as a function of system energy requirements, economic variable(s), and several temperature variants as determined during the peak model specification process. The applicable forecast driver(s) and design weather conditions over the forecast period are incorporated into the resulting equation and post forecast adjustments are applied in order to determine the peak demand forecast.

Calibrate Load Estimates for Extreme Peak Conditions

The system extreme peak projections are based on the normalization methodology utilized for Central Hudson's submission of weather normalized peak to the NYISO Load Forecasting Task Force, which utilizes a composite temperature humidity index variable and employs a third-degree polynomial model to address intra-year sensitivity, which results in a lower (or flatter) response per temperature unit at higher values of the temperature variable.

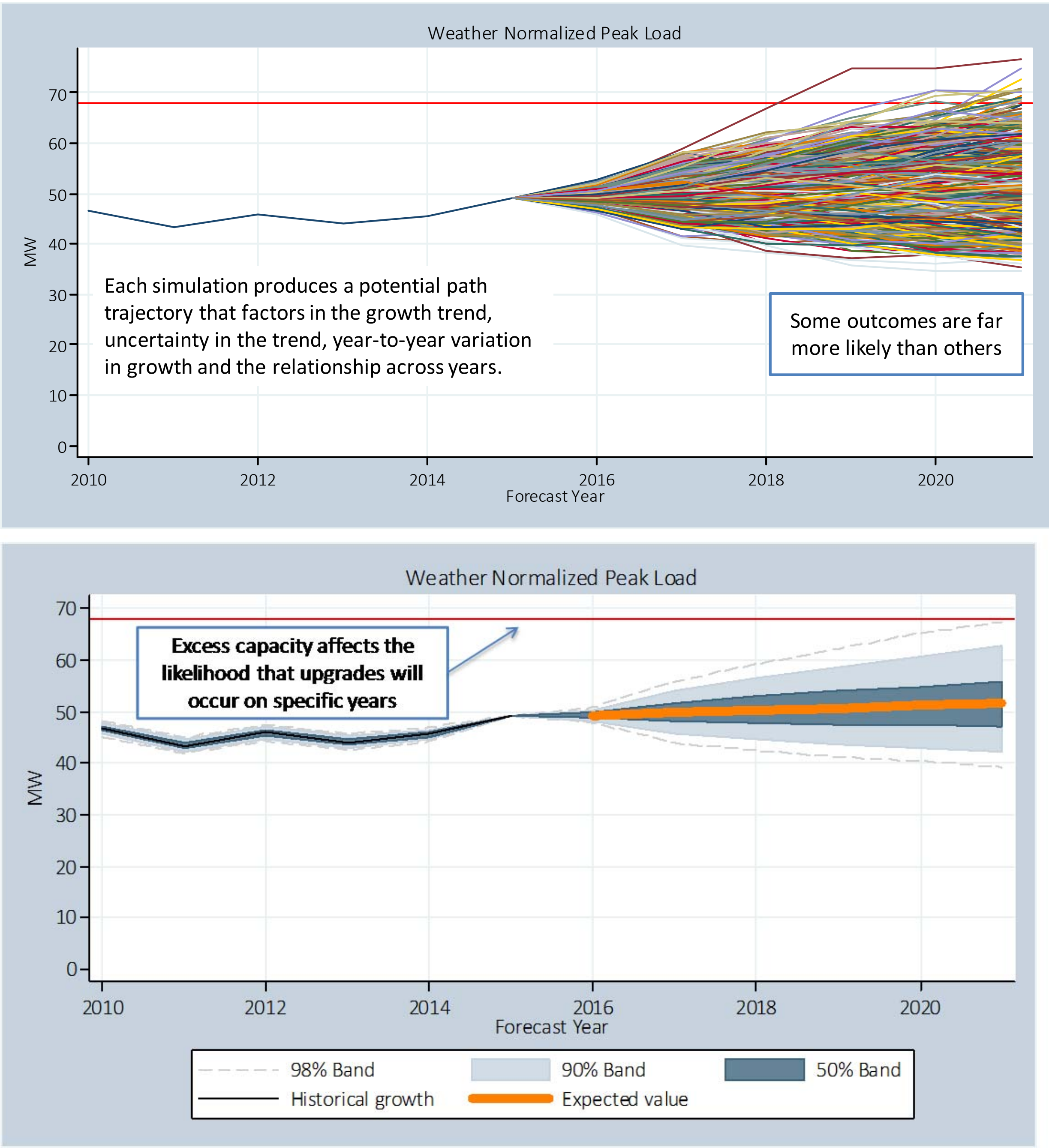
2. Location Specific Forecasting Methodology

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 forecast for each broader areas within Central Hudson's territory and apply them to the specific peak loads for substations and transmission areas. Central Hudson has been evolving its planning method to produce more granular, location specific, probabilistic forecasts.

Figure VI-14 illustrates the critical role of probabilistic, location-specific forecasts. Forecasts inherently include uncertainty and grow more uncertain further into the future. In practice, actual growth trajectories are rarely linear and growth patterns relate to each other across time and location

Probabilistic distribution forecasting requires estimating historical load growth patterns and variability and simulating load growth trajectories. The process produces several thousand potential trajectories for each location, each of which reflects the non-linear nature of growth and has its own path. However, some outcomes are far more likely than others. These are summarized into probabilistic bands that identify the likelihood of load growth falling within specific confidence bands.

Figure VI-14: Illustration of Location Specific Simulations and Probabilistic Forecasts



Central Hudson developed forecasts for 10 distinct transmission areas, ten planning load areas (or clusters of substations), and 54 of distribution load serving substations where detailed metering data was available. Some substations either lacked data or had lower quality data and, as a result, we were unable to estimate location specific forecasts for all substations. The substations lacking hourly data are generally smaller stations serving relatively few customers. The forecasting process can be summarized in four main steps.

1. Clean the data. Historically data quality for substations granular locations have been a barrier to their use for load forecasting. 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.
2. Estimate historical load growth trends and noise. The objective was to estimate historical load growth for each year in 2010–2015 in percentage terms. The year-to-year growth patterns were then used to assess the growth trend and the variability 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 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 variables 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 and 1-in-10 conditions. Based on historical patterns, the 2013 and 2010, 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. It simulates the reality that the near term forecast has less uncertainty than forecasts 10 years out. A total of 10,000 simulations were implemented for each transmission area and 2,000 simulations were implemented for each load 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.

Central Hudson also has produced separate granular 8760 forecasts for a number of EE end use load shapes, solar, and EV resources. Forecasts for incremental load shaping DERs were not incorporated into the granular, location specific T&D forecasts.

3. Incorporating DERs into System and Granular, Location Specific Forecasts

How to incorporate DER into location specific forecasts is a challenging issue. Not including them may not reflect the reality that customers are installing solar PV, purchasing EVs, and installing EE on their own. However, incorporating into forecasts DERs that have not yet been built or installed can dilute the location value signal and potentially slow down their adoption. For each DER type, Central Hudson considered three different approaches for incorporating DERs into the forecasts—summarized in Table VI-8 and distinguished between existing and forecasted DERs.

Figure VI-15 illustrates how a forecasting process could work. A prerequisite for such an approach is accurate tracking of DERs and dispatch events so that both the gross and net loads can be estimated. Net loads are simply gross loads minus load shaping DERs. A key limitation to such an approach is the inability to track all DERs. Many types of DERs—e.g., naturally occurring EE and EVs—are not administered by a utility and do not require an interconnection. Another consideration is forecast uncertainty. Forecasting DERs early in the adoption process such as battery storage and EVs is highly uncertain and, at the same time, difficult to quantify.

One of the most important considerations is how to accurately reflect the location value of incremental resources. As discussed in Appendix D, the locational value is closely tied to probabilistic forecasting. This creates a paradox: including yet to be built DERs into forecasts, lower load forecasts, and dilutes the locational value of DER resources. Central Hudson took the additional step of quantifying and time differentiating the location specific avoided T&D costs. It is for this reason, that only existing DERs were incorporated into the forecasts.

Figure VI-15: Illustrative Process for Incorporating DERs into Forecasting

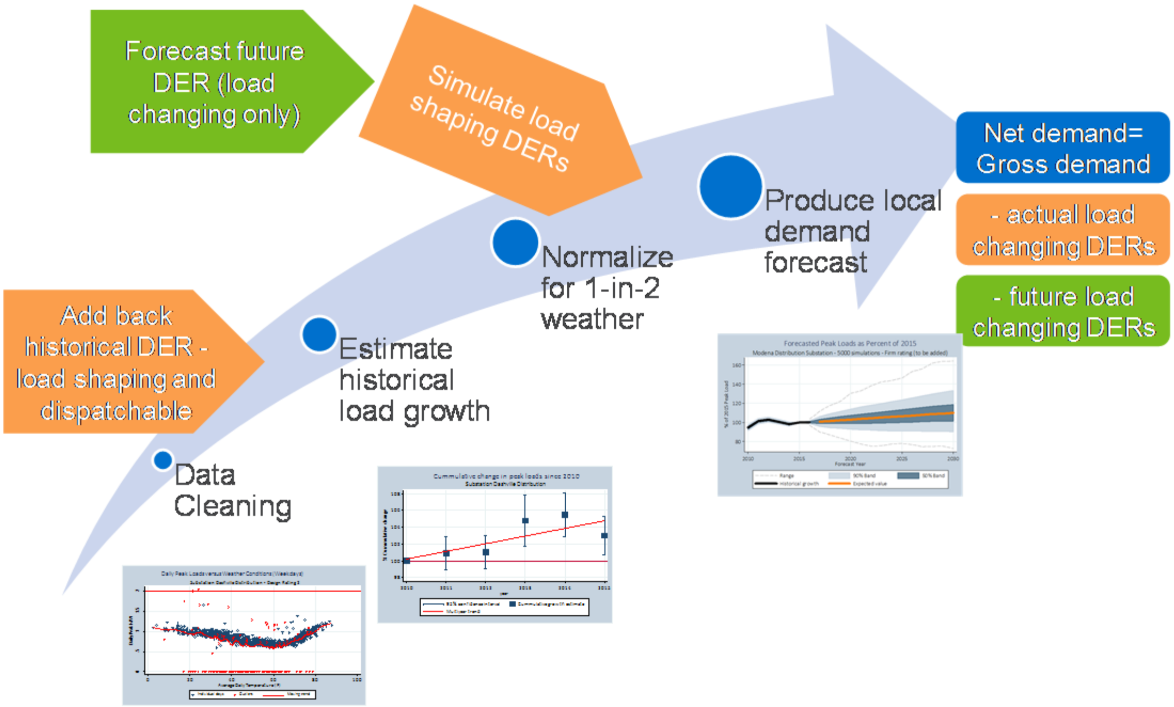


Table VI-8: Approaches for Integrating DERs into Forecasting

#	Approach	Description	Considerations
1	**Embedded**	DERs that shape loads – solar and EE – and are adopted by customers are embedded into loads observed by utilities. Additional load shaping DERs bend the growth trajectory and are reflected in granular forecasting. Resources that are dispatched such as batteries and DR would be added back to historical loads and can be reflected as additional local capacity.	▪ The change in growth is a lagging indicator and the growth trajectory may not reflect the most recent information about deployments and load shapes ▪ An embedded approach only work for load shaping DERs. It does not work for dispatchable resources such as DR, batteries, and small distributed generators. ▪ Locational value of additional DERs is <u>not</u> diluted by including DERs that have not yet been built or installed.
2	**Model actual deployments into the future**	This requires accurate tracking of DER installations and dispatches, which must added back to observed loads to produce a gross load forecast. The most recent information about installations is used to develop the aggregate DER load shape which is subtracted from the gross load forecasts to produce a net load forecast. Only existing DERs are included. Resources that are dispatched such as batteries and DR would be added back to historical loads and can be reflected as additional local capacity.	▪ Requires detailed tracking of DER installation and dispatches at a locational level, including those that are adopted by customers without incentives. ▪ Not all DERs can be tracked since many types of DERs are not administered by a utility and do not require an interconnection ▪ Locational value of additional DERs is <u>not</u> diluted by including DERs that have not yet been built or installed.
3	**Forecast incremental DER and include in the forecast**	This requires accurate tracking of DER installations and dispatches, which must added back to observed loads to produce a gross load forecast. A forecast of incremental DER resources is then produced. *Both historical and forecasted* DER installations are subtracted from the gross load forecasts to produce a net load forecast. Resources that are dispatched such as batteries and DR would be added back to historical loads and can be reflected as additional local capacity.	▪ Requires detailed tracking of DER installation and dispatches at a locational level, including those that are adopted by customers without incentives. ▪ Not all DERs can be tracked since many types of DERs are not administered by a utility and do not require an interconnection. ▪ The DER forecasts are highly uncertain and it is difficult to quantify the magnitude of the uncertainty. ▪ Historical value <u>is</u> diluted by including DERs that have not yet been built or installed.

4. Ensuring Accuracy as DER Penetration Levels Increase

There a few steps that can be undertaken to ensure 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 process to track when and where DER resources were dispatched (e.g., battery storage or DR) and magnitude of the resources dispatched.
- Produce standard 8760 load shapes for different types of DERs that reflect both historical weather condition and 1-in-2 and 1-in-10 conditions.
- Forecast DER penetration and 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
- 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 locational value reflects the full range of potential growth patterns.

D. Available Resources (DER Forecasts)

1. DER Penetration Forecast Methodology

DER penetration forecasts were produced for EE end uses, PV, and EV. Although the details of each analysis, which can be found in Appendix N differed for each DER, the methodology was guided by common principles and was broadly similar across DERs.

Where possible, existing forecasts were used to estimate future annual penetration, and otherwise, historical trends were analyzed and extrapolated. If data on the historical, locational distribution of a DER was available, that distribution was used for forecast years. If no such data was available, billing data was used to distribute penetration according to the population's annual usage. Finally, where forecasts were in annual MWh, penetration in each hour was estimated using end use specific load shapes, or demand, allocated to each of 8760 hours in a year on a percentage basis – a normalized load shape. Multiplying the load shapes on a percentage basis to annual MWh values ultimately yielded forecasts in kW on an hourly, weather year basis for each forecast year.

Unlike the demand forecasts, DER forecasts are not probabilistic. Instead, they reflect explicit goals for EE and solar PV. They also were not fully integrated into the system peak forecast. Future iterations will need to focus on coordinating the integration of DER forecasts into location specific and system peak forecasts. Additional refinements will be needed in the future to transition DER forecasts to a probabilistic forecast of intermittent resources. DERs have risk associated with them both in terms of how common they will become, their aggregate magnitude as a resource, and their performance (especially for intermittent resources).

Table VI-9 shows the primary data source and forecast approach for each DER; however, DR was not forecast as it is fully managed by the utility.[4] Battery storage was not included due to lack of data; no public data source was available on either historical or forecast penetration of behind-the-meter batteries or customer adoption rates.

Table VI-9 Primary Data Source and Forecast Approach for DERs

DER	Historical Data Input	Forecast Input	Local Allocation	Allocation of Load shapes
EE	Commission Scorecard	ETIP	Customer/Circuit Level of Total Local MWh Consumption	By End Use and Segment
PV	Interconnections Database	NYISO Load and Capacity Data	Customer/Circuit Level	Applied to Installed Capacity
EV	EV Registrations	Tesla Pre-Orders	Proportion of Residential Customers	Applied to Number of EVs
DR	NA	NA	NA	NA
Storage	NA	NA	NA	NA

2. Initial DER Penetration Forecast

The process to identify each DER resource's specific expected contribution to peak load, energy reduction and load shape in the next five years was facilitated by DER penetration forecasts at the hourly level. Any assumptions made in generating those forecasts are documented in Appendix N.

The steps to identify peak contribution from the forecasts were the following:

1. Using 8760 load for each area, identify peak hour and day for 1-in-2 (2013) and 1-in-10 (2010) weather year; and
2. Look up contribution in the corresponding local peak for each DER.

Table VI-10 shows the 2017 forecast peak contribution (MW) by transmission area and Central Hudson's system for 1-in-2 year weather conditions. Table VI-11 shows the 2017 forecast peak contribution by substation under 1-in-2 year weather conditions. The contributions to local peaks vary by location because of the diversity of local peaking patterns. For the local peak hour, the table shows the contribution to the peak of each DER. Some DERs are broken out by sector, residential or commercial. Appendix L contains all tables showing forecast peak contribution for forecast years 2016 through 2021 for 1-in-2 and 1-in-10 weather conditions, and the forecast peak contribution for each substation.

[4] Existing TDM was included in the beneficial location analysis so a forecast of DR penetration would be redundant.

Table VI-10: 2021 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Area	Peak Month	Peak Day Type	Peak Hour	Residential Energy Efficiency				Commercial Energy Efficiency				Other DERs			Total
				HVAC	Lighting	Other	Home Energy Reports	HVAC	Lighting	Other	General	EV	PV	DG	
Ellenville	July	Weekday	19	0.83	0.45	0.00	2.04	0.00	0.37	0.00	0.18	0.00	0.80	0.06	4.74
Hurley-Milan	July	Weekday	16	1.63	0.43	0.01	1.97	0.00	1.59	0.01	0.16	0.00	4.29	0.09	10.18
Mid-Dutchess	July	Weekday	15	1.37	0.47	0.01	2.14	0.00	1.68	0.01	0.16	0.00	3.37	0.14	9.33
Northwest 115-69 Area	July	Weekday	17	1.28	1.02	0.01	4.57	0.00	1.17	0.03	0.45	0.00	4.80	0.13	13.44
Northwest 69kV Area	July	Weekday	18	1.13	0.79	0.01	4.07	0.00	0.79	0.01	0.33	0.00	2.65	0.10	9.88
Pleasant Valley 69	May	Weekday	18	0.82	0.61	0.00	1.69	0.00	0.53	0.00	0.21	0.00	2.21	0.08	6.15
RD-RJ Lines	July	Weekday	16	0.72	0.47	0.00	2.00	0.00	1.76	0.01	0.20	0.00	5.15	0.10	10.41
Southern Dutchess	July	Weekday	15	0.93	0.48	0.01	2.21	0.00	0.98	0.01	0.21	0.00	2.67	0.16	7.66
WM Line	December	Weekday	18	0.00	0.14	0.00	0.07	0.00	0.32	0.00	0.02	0.00	0.00	0.05	0.60
Westerlo Loop	January	Weekday	18	0.01	0.55	0.00	0.28	0.00	0.53	0.00	0.29	0.00	0.00	0.07	1.73
CH System	July	Weekday	17	12.87	6.38	0.06	28.64	0.00	12.58	0.12	2.63	0.00	38.54	1.06	102.88

Table VI-11: 2021 Forecast Peak Contribution (MW) by Substation and Central Hudson's System for 1-in-2 Year Weather

Substation Name	Peak Month	Peak Day Type	Peak Hour	Residential Energy Efficiency				Commercial Energy Efficiency				Other DERs			Total
				HVAC	Lighting	Other	Home Energy Reports	HVAC	Lighting	Other	General	EV	PV	DG	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.05	0.16	0.00	0.65	0.00	0.34	0.00	0.03	0.00	1.97	0.04	3.25
Boulevard	July	Weekday	14	0.07	0.13	0.00	0.35	0.00	0.20	0.01	0.05	0.00	0.70	0.03	1.53
Clinton Ave	February	Weekday	12	0.00	0.01	0.00	0.00	0.00	0.11	0.00	0.01	0.00	0.02	0.00	0.15
Coldenham	July	Weekday	15	0.06	0.14	0.00	0.62	0.00	1.75	0.01	0.05	0.00	2.66	0.04	5.35
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	December	Weekday	8	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
East Kingston	July	Weekday	17	1.02	0.09	0.00	0.42	0.00	0.35	0.00	0.03	0.00	0.45	0.01	2.38
East Park	July	Weekday	18	0.34	0.10	0.00	0.42	0.00	0.09	0.00	0.03	0.00	0.15	0.01	1.15
East Walden	July	Weekday	16	0.22	0.12	0.00	0.53	0.00	0.10	0.00	0.04	0.00	1.25	0.02	2.28
Fishkill Plains	July	Weekday	17	0.51	0.32	0.00	1.45	0.00	0.21	0.00	0.07	0.00	1.84	0.04	4.45
Forgebrook	July	Weekday	17	0.58	0.13	0.00	0.58	0.00	0.32	0.01	0.07	0.00	0.71	0.03	2.43
Galeville	July	Weekday	11	0.09	0.10	0.00	0.24	0.00	0.06	0.00	0.02	0.00	1.61	0.01	2.12
Grimley Rd	July	Weekday	19	0.00	0.01	0.00	0.04	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.08
Hibernia	July	Weekday	16	0.08	0.09	0.00	0.43	0.00	0.17	0.00	0.05	0.00	2.25	0.01	3.09
High Falls	July	Weekday	16	0.51	0.16	0.00	0.71	0.00	0.22	0.00	0.06	0.00	1.12	0.02	2.79
Highland	July	Weekday	16	0.61	0.14	0.00	0.65	0.00	0.33	0.00	0.06	0.00	2.12	0.02	3.93
Honk Falls	July	Weekday	13	0.06	0.03	0.00	0.10	0.00	0.04	0.00	0.02	0.00	0.10	0.01	0.36
Hunter	December	Weekday	21	0.00	0.04	0.00	0.02	0.00	0.03	0.00	0.02	0.00	0.00	0.01	0.12
Hurley Ave	July	Weekday	17	0.13	0.13	0.00	0.52	0.00	0.30	0.00	0.06	0.00	0.67	0.02	1.83
Inwood Ave	July	Weekday	16	0.01	0.12	0.00	0.52	0.00	0.29	0.00	0.06	0.00	0.22	0.03	1.25
Knapps Corners	July	Weekday	17	0.00	0.10	0.00	0.13	0.00	0.17	0.00	0.02	0.00	0.84	0.02	1.28
Lawrenceville	December	Weekday	21	0.00	0.06	0.00	0.03	0.00	0.01	0.00	0.03	0.00	0.00	0.02	0.14
Lincoln Park	July	Weekday	19	0.02	0.17	0.00	0.18	0.00	0.16	0.00	0.04	0.00	0.85	0.04	1.46
Marlboro	July	Weekday	17	0.15	0.14	0.00	0.65	0.00	0.22	0.01	0.05	0.00	1.13	0.02	2.37
Maybrook	July	Weekday	18	0.06	0.09	0.00	0.37	0.00	0.29	0.00	0.02	0.00	0.35	0.02	1.21
Merritt Park	July	Weekday	16	0.08	0.14	0.00	0.60	0.00	0.36	0.00	0.05	0.00	0.31	0.03	1.58
Milan	July	Weekday	10	0.07	0.07	0.00	0.10	0.00	0.08	0.00	0.02	0.00	0.29	0.01	0.62
Millerton	January	Weekday	18	0.00	0.04	0.00	0.02	0.00	0.05	0.00	0.03	0.00	0.00	0.00	0.15
Modena	July	Weekday	17	0.13	0.12	0.00	0.47	0.00	0.07	0.01	0.04	0.00	0.94	0.01	1.78

Substation Name	Peak Month	Peak Day Type	Peak Hour	Residential Energy Efficiency				Commercial Energy Efficiency				Other DERs			Total
				HVAC	Lighting	Other	Home Energy Reports	HVAC	Lighting	Other	General	EV	PV	DG	
Myers Corners	July	Weekday	18	0.00	0.12	0.00	0.62	0.00	0.16	0.00	0.04	0.00	0.29	0.03	1.26
New Baltimore	July	Weekday	18	0.04	0.08	0.00	0.37	0.00	0.07	0.00	0.03	0.00	0.30	0.01	0.91
North Catskill	July	Weekday	16	0.24	0.18	0.00	0.83	0.00	0.22	0.02	0.09	0.00	0.81	0.03	2.42
North Chelsea	July	Weekday	17	0.90	0.12	0.00	0.51	0.00	0.16	0.00	0.07	0.00	0.34	0.02	2.12
Ohioville	July	Weekday	15	0.61	0.12	0.00	0.55	0.00	0.40	0.00	0.07	0.00	1.55	0.03	3.32
Pulvers Corners	January	Weekday	18	0.00	0.05	0.00	0.03	0.00	0.04	0.00	0.03	0.00	0.00	0.01	0.16
Reynolds Hill	July	Weekday	14	0.70	0.12	0.00	0.43	0.00	0.95	0.00	0.08	0.00	0.54	0.03	2.86
Rhinebeck	July	Weekday	18	0.43	0.18	0.00	0.81	0.00	0.47	0.01	0.08	0.00	0.99	0.03	3.01
Sand Dock	July	Weekday	13	0.01	0.03	0.00	0.10	0.00	0.11	0.00	0.00	0.00	0.13	0.03	0.41
Saugerties	July	Weekday	17	0.33	0.16	0.00	0.70	0.00	0.18	0.00	0.06	0.00	0.98	0.02	2.43
Shenandoah	July	Weekday	15	0.10	0.11	0.00	0.51	0.00	0.07	0.00	0.03	0.00	0.48	0.08	1.38
Smithfield	December	Weekday	8	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	July	Weekday	18	1.29	0.19	0.00	0.86	0.00	0.38	0.00	0.04	0.00	0.37	0.04	3.17
Staatsburg	July	Weekday	18	0.15	0.08	0.00	0.37	0.00	0.04	0.00	0.02	0.00	0.24	0.01	0.92
Stanfordville	December	Weekday	18	0.01	0.07	0.00	0.03	0.00	0.03	0.00	0.01	0.00	0.00	0.01	0.16
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	0.38	0.11	0.00	0.45	0.00	0.17	0.00	0.06	0.00	0.39	0.02	1.58
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	0.30	0.19	0.00	0.87	0.00	0.24	0.01	0.05	0.00	1.15	0.02	2.83
Union Ave	September	Weekday	16	0.52	0.36	0.00	1.05	0.00	1.41	0.01	0.12	0.00	2.61	0.06	6.14
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.00	0.05	0.00	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.11
West Balmville	July	Weekday	16	0.01	0.17	0.00	0.73	0.00	0.23	0.00	0.05	0.00	1.09	0.04	2.32
Westerlo	July	Weekday	15	0.05	0.07	0.00	0.32	0.00	0.10	0.00	0.03	0.00	0.68	0.01	1.26
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	0.42	0.17	0.00	0.88	0.00	0.14	0.01	0.07	0.00	0.54	0.02	2.26
Total System	July	Weekday	17	12.87	6.38	0.06	28.64	0.00	12.58	0.12	2.63	0.00	38.54	1.06	102.88

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, we calculated conversion factor to enable conversion of potential DERs into local peak contribution. The interpretation of each conversion factor differs with the type of resource. Table VI-12 shows the interpretation and methodology used to calculate each conversion factor.

Table VI-12: Methodology for Applying Conversion Factors for Potential DERS

DER	Calculating Peak Contribution	Interpretation
EE and load control	MW = conversion factor x (total annual MWh / 8760 hours)	Percent of average annual hourly demand). Essentially this is a peak coincidence factor for annual average hourly savings for segment specific end uses
PV	MW = conversion factor x nameplate capacity	Percent of capacity. Simply apply the peak contribution factor to nameplate capacity to estimate forecast local peak contribution. The conversion factor incorporates the performance of solar, which falls short of the optimal performance to due positioning, roof angle, shade, failed inverters, and other factors. The single hour contribution for an intermittent resource such as solar is not typically used for planning because resources need to be available over multiple hours and days.
EV	MW = conversion factor x number of EV's	Expected peak contribution of a single EV (incorporating charging behavior and a variety of EV sizes. Note that the mix of short and longer range EVs and PHEVs may change over the forecast period. The analysis assumes future EV's and PHEV's will be similar to the recent past.
Storage	MW = Capacity installation	Assuming appropriate charging schedule, batteries can deliver 100% of capacity as coincident peak load for the single peak hour.

Table VI-13 and Table VI-14 show conversion factors by transmission area and substation, respectively. Both of these can be used to estimate the contribution to the single peak hour at each location. For the local peak hour, the table shows the conversion factor of each DER. Some DERs are broken out by sector, residential or commercial.

Table VI-15 and Table VI-16 show conversion factors by transmission area and substation weighted for the top 100 hours at each location. This value is more appropriate for estimating contribution to peak because resources are needed for more than a single hour to shave the load duration curve and avoid overloads. Appendix L contains all tables showing forecast peak contribution for 1-in-2 and 1-in-10 weather conditions for each forecast year and location.

Table VI-13: Single Peak Hour Conversion Factors by Transmission Area for 1-in-2 Year Weather

Transmission Area	Peak Month	Peak Day Type	Peak Hour	Residential Energy Efficiency				Commercial Energy Efficiency				Other DERs			Total
				HVAC	Lighting	Other	Home Energy Reports	HVAC	Lighting	Other	General	EV	PV	DG	
Ellenville	July	Weekday	19	10.90	1.01	1.00	4.28	2.85	1.02	2.54	1.18	2.14	0.07	1.00	NA
Hurley-Milan	July	Weekday	16	12.60	1.04	1.00	4.44	3.59	2.00	2.59	1.24	2.14	0.35	1.00	NA
Mid-Dutchess	July	Weekday	15	12.35	1.02	1.00	4.34	3.55	2.14	2.59	1.30	2.14	0.41	1.00	NA
Northwest 115-69 Area	July	Weekday	17	11.35	1.02	1.00	4.28	3.48	1.63	2.65	1.25	2.14	0.28	1.00	NA
Northwest 69kV Area	July	Weekday	18	12.14	0.96	1.00	4.61	3.22	1.31	2.62	1.16	2.14	0.18	1.00	NA
Pleasant Valley 69	May	Weekday	18	7.51	1.13	1.00	2.92	2.85	1.34	2.18	1.10	2.14	0.17	1.00	NA
RD-RJ Lines	July	Weekday	16	11.49	1.01	1.00	4.07	3.32	1.92	2.52	1.42	2.14	0.35	1.00	NA
Southern Dutchess	July	Weekday	15	12.32	1.02	1.00	4.34	3.55	2.09	2.59	1.30	2.14	0.41	1.00	NA
WM Line	December	Weekday	18	0.50	1.16	1.00	0.56	1.47	1.43	3.49	0.62	2.14	0.00	1.00	NA
Westerlo Loop	January	Weekday	18	0.43	1.12	1.00	0.53	1.22	1.37	0.00	1.68	2.14	0.00	1.00	NA
CH System	July	Weekday	17	11.84	1.02	1.00	4.28	3.48	1.63	2.60	1.25	2.14	0.28	1.00	NA

Table VI-14: Single Peak Hour Conversion Factors by Substation for 1-in-2 Year Weather

Substation Name	Peak Month	Peak Day Type	Peak Hour	Residential Energy Effiency				Commercial Energy Efficiency				Other DERs		
				HVAC	Lighting	Other	Home energy reports	HVAC	Lighting	Other	General	EV	PV	DG
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	10.56	1.02	0.67	5.82	3.25	1.61	2.57	1.35	2.14	0.27	1.00
Boulevard	July	Weekday	14	7.86	1.18	0.67	4.55	3.09	2.17	2.32	1.19	2.14	0.44	1.00
Clinton Ave	February	Weekday	12	0.00	1.53	0.00	0.74	1.26	2.21	0.00	1.43	2.14	0.09	1.00
Coldenham	July	Weekday	15	10.74	0.99	0.67	5.91	3.34	2.09	2.56	1.38	2.14	0.40	1.00
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	December	Weekday	8	0.39	0.83	0.67	0.74	0.76	1.09	0.00	0.59	2.14	0.00	1.00
East Kingston	July	Weekday	17	12.23	1.02	0.67	6.38	3.48	1.67	2.58	1.25	2.14	0.28	1.00
East Park	July	Weekday	18	10.27	0.95	0.67	5.47	2.87	1.36	0.00	1.12	2.14	0.17	1.00
East Walden	July	Weekday	16	11.11	1.01	0.67	6.07	3.32	1.82	0.00	1.42	2.14	0.35	1.00
Fishkill Plains	July	Weekday	17	11.94	1.02	0.67	6.38	3.48	1.62	0.00	1.25	2.14	0.28	1.00
Forgebrook	July	Weekday	17	12.26	1.02	0.67	6.38	3.48	1.62	2.58	1.25	2.14	0.28	1.00
Galeville	July	Weekday	11	7.73	1.31	0.67	4.42	3.13	1.94	0.00	1.28	2.14	0.35	1.00
Grimley Rd	July	Weekday	19	8.70	1.01	0.67	5.38	0.00	0.00	0.00	0.98	2.14	0.07	1.00
Hibernia	July	Weekday	16	12.60	1.04	0.67	6.62	3.59	1.88	0.00	1.24	2.14	0.35	1.00
High Falls	July	Weekday	16	11.81	1.04	0.67	6.62	3.59	2.01	0.00	1.24	2.14	0.35	1.00
Highland	July	Weekday	16	12.26	1.04	0.67	6.62	3.59	2.01	2.59	1.24	2.14	0.35	1.00
Honk Falls	July	Weekday	13	9.00	1.17	0.67	5.08	3.16	1.69	0.00	1.32	2.14	0.42	1.00
Hunter	December	Weekday	21	0.38	1.60	0.67	1.27	1.13	0.64	0.00	1.68	2.14	0.00	1.00
Hurley Ave	July	Weekday	17	10.24	1.02	0.67	5.82	3.25	1.66	0.00	1.35	2.14	0.27	1.00
Inwood Ave	July	Weekday	16	10.51	1.01	0.67	6.07	3.32	1.93	0.00	1.42	2.14	0.35	1.00
Knapps Corners	July	Weekday	17	0.00	1.21	0.67	2.23	2.00	0.89	0.00	0.94	2.14	0.25	1.00
Lawrenceville	December	Weekday	21	0.33	1.60	0.67	1.27	1.13	0.66	0.00	1.68	2.14	0.00	1.00
Lincoln Park	July	Weekday	19	2.78	1.18	0.67	1.80	1.69	0.67	0.00	0.89	2.14	0.18	1.00
Marlboro	July	Weekday	17	11.83	1.02	0.67	6.38	3.48	1.74	2.59	1.25	2.14	0.28	1.00
Maybrook	July	Weekday	18	9.49	0.95	0.67	5.47	2.87	1.41	2.46	1.12	2.14	0.17	1.00
Merritt Park	July	Weekday	16	10.99	1.01	0.67	6.07	3.32	2.00	0.00	1.42	2.14	0.35	1.00
Milan	July	Weekday	10	3.77	1.12	0.67	2.36	2.41	1.93	0.00	0.89	2.14	0.28	1.00
Millerton	January	Weekday	18	0.28	1.12	0.67	0.79	1.22	1.42	2.06	1.68	2.14	0.00	1.00

Substation Name	Peak Month	Peak Day Type	Peak Hour	Residential Energy Effiency				Commercial Energy Efficiency				Other DERs		
				HVAC	Lighting	Other	Home energy reports	HVAC	Lighting	Other	General	EV	PV	DG
Modena	July	Weekday	17	10.62	1.02	0.67	5.82	3.25	1.73	2.51	1.35	2.14	0.27	1.00
Myers Corners	July	Weekday	18	11.87	0.96	0.67	6.88	3.22	1.24	0.00	1.16	2.14	0.18	1.00
New Baltimore	July	Weekday	18	11.15	0.98	0.67	6.24	2.94	1.33	0.00	1.22	2.14	0.17	1.00
North Catskill	July	Weekday	16	12.05	1.04	0.67	6.62	3.59	1.84	2.81	1.24	2.14	0.35	1.00
North Chelsea	July	Weekday	17	11.29	1.02	0.67	5.82	3.25	1.72	2.57	1.35	2.14	0.27	1.00
Ohioville	July	Weekday	15	11.67	1.02	0.67	6.48	3.55	2.01	0.00	1.30	2.14	0.41	1.00
Pulvers Corners	January	Weekday	18	0.35	1.16	0.00	0.80	1.40	1.38	0.00	1.66	2.14	0.00	1.00
Reynolds Hill	July	Weekday	14	11.51	1.18	0.67	5.95	3.52	2.20	0.00	1.26	2.14	0.43	1.00
Rhinebeck	July	Weekday	18	11.25	0.98	0.67	6.24	2.94	1.35	2.57	1.22	2.14	0.17	1.00
Sand Dock	July	Weekday	13	9.49	1.20	0.67	5.52	3.41	2.16	0.00	1.29	2.14	0.43	1.00
Saugerties	July	Weekday	17	11.22	1.02	0.67	6.38	3.48	1.75	0.00	1.25	2.14	0.28	1.00
Shenandoah	July	Weekday	15	11.75	1.02	0.67	6.48	3.55	2.16	0.00	1.30	2.14	0.41	1.00
Smithfield	December	Weekday	8	0.00	0.83	0.00	0.74	0.00	0.00	0.00	0.59	2.14	0.00	1.00
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	July	Weekday	18	11.75	0.98	0.67	6.24	2.94	1.42	0.00	1.22	2.14	0.17	1.00
Staatsburg	July	Weekday	18	11.90	0.98	0.67	6.24	2.94	1.38	0.00	1.22	2.14	0.17	1.00
Stanfordville	December	Weekday	18	0.51	1.15	0.67	0.79	1.43	0.82	0.00	0.59	2.14	0.00	1.00
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	10.80	1.02	0.67	5.82	3.25	1.66	0.00	1.35	2.14	0.27	1.00
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	11.79	1.02	0.67	6.38	3.48	1.59	2.58	1.25	2.14	0.28	1.00
Union Ave	September	Weekday	16	8.97	1.19	0.67	4.84	3.76	2.00	2.53	1.04	2.14	0.35	1.00
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.63	1.58	0.00	1.25	1.34	0.44	0.00	1.92	2.14	0.00	1.00
West Balmville	July	Weekday	16	10.51	1.01	0.67	6.07	3.32	2.01	0.00	1.42	2.14	0.35	1.00
Westerlo	July	Weekday	15	10.20	0.99	0.67	5.91	3.34	1.91	0.00	1.38	2.14	0.40	1.00
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	12.27	0.96	0.67	6.88	3.22	1.34	2.62	1.16	2.14	0.18	1.00
Total System	July	Weekday	17	11.84	1.02	0.67	6.38	3.48	1.63	2.60	1.25	2.14	0.28	1.00

Table VI-15: Top 100 Hour Weighted Conversion Factors by Transmission Area for 1-in-2 Year Weather

Transmission Area	Peak Month	Peak Day Type	Peak Hour	Residential Energy Efficiency				Commercial Energy Efficiency				Other DERs		
				HVAC	Lighting	Other	Home Energy Reports	HVAC	Lighting	Other	General	EV	PV	DG
Ellenville	July	Weekday	19	8.85	1.08	1.00	3.45	2.93	1.39	2.39	1.11	2.14	0.24	1.00
Hurley-Milan	July	Weekday	16	9.86	1.06	1.00	3.57	3.08	1.72	2.44	1.16	2.14	0.30	1.00
Mid-Dutchess	July	Weekday	15	9.85	1.04	1.00	3.56	3.08	1.76	2.45	1.16	2.14	0.29	1.00
Northwest 115-69 Area	July	Weekday	17	6.74	1.13	1.00	2.75	2.51	1.48	2.54	1.35	2.14	0.18	1.00
Northwest 69kV Area	July	Weekday	18	4.58	1.20	1.00	2.03	2.07	1.37	2.77	1.55	2.14	0.12	1.00
Pleasant Valley 69	May	Weekday	18	7.57	1.09	1.00	2.86	2.77	1.67	2.28	1.16	2.14	0.23	1.00
RD-RJ Lines	July	Weekday	16	9.74	1.05	1.00	3.54	3.09	1.69	2.44	1.16	2.14	0.29	1.00
Southern Dutchess	July	Weekday	15	9.94	1.06	1.00	3.59	3.09	1.67	2.45	1.16	2.14	0.29	1.00
WM Line	December	Weekday	18	2.87	1.28	1.00	1.46	1.75	1.20	2.92	0.84	2.14	0.06	1.00
Westerlo Loop	January	Weekday	18	0.52	1.33	1.00	0.66	1.26	1.16	0.00	2.33	2.14	0.01	1.00
CH System	July	Weekday	17	9.83	1.04	1.00	3.62	3.03	1.60	2.44	1.17	2.14	0.27	1.00

Table VI-16: Top 100 Hour Weighted Conversion Factors by Substation for 1-in-2 Year Weather

Substation Name	Peak Month	Peak Day Type	Peak Hour	Residential Energy Efficiency				Commercial Energy Efficiency				Other DERs		
				HVAC	Lighting	Other	Home Energy Reports	HVAC	Lighting	Other	General	EV	PV	DG
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	9.23	1.05	1.00	3.50	2.92	1.50	2.38	1.17	2.14	0.26	1.00
Boulevard	July	Weekday	14	8.21	1.10	1.00	3.18	3.11	1.85	2.37	1.14	2.14	0.32	1.00
Clinton Ave	February	Weekday	12	0.00	1.35	0.00	0.54	1.23	1.86	0.00	1.53	2.14	0.14	1.00
Coldenham	July	Weekday	15	9.24	1.05	1.00	3.49	3.12	1.81	2.44	1.16	2.14	0.31	1.00
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	December	Weekday	8	4.25	1.05	1.00	1.76	1.79	1.23	0.00	0.75	2.14	0.15	1.00
East Kingston	July	Weekday	17	9.68	1.05	1.00	3.46	3.01	1.66	2.42	1.16	2.14	0.27	1.00
East Park	July	Weekday	18	9.69	1.03	1.00	3.46	2.90	1.40	0.00	1.10	2.14	0.24	1.00
East Walden	July	Weekday	16	9.55	1.04	1.00	3.61	2.99	1.47	0.00	1.15	2.14	0.25	1.00
Fishkill Plains	July	Weekday	17	10.06	1.05	1.00	3.67	2.97	1.43	0.00	1.13	2.14	0.26	1.00
Forgebrook	July	Weekday	17	10.10	1.05	1.00	3.58	3.06	1.66	2.45	1.17	2.14	0.28	1.00
Galeville	July	Weekday	11	7.72	1.08	1.00	3.00	2.80	1.61	0.00	1.02	2.14	0.26	1.00
Grimley Rd	July	Weekday	19	8.90	1.06	1.00	3.56	0.00	0.00	0.00	1.09	2.14	0.23	1.00
Hibernia	July	Weekday	16	9.91	1.07	1.00	3.57	3.05	1.60	0.00	1.16	2.14	0.32	1.00
High Falls	July	Weekday	16	9.35	1.05	1.00	3.64	2.93	1.44	0.00	1.13	2.14	0.25	1.00
Highland	July	Weekday	16	9.72	1.05	1.00	3.64	2.93	1.44	2.44	1.13	2.14	0.25	1.00
Honk Falls	July	Weekday	13	9.08	1.08	1.00	3.47	3.01	1.40	0.00	1.16	2.14	0.31	1.00
Hunter	December	Weekday	21	0.65	0.98	1.00	0.60	0.86	0.61	0.00	1.89	2.14	0.00	1.00
Hurley Ave	July	Weekday	17	8.77	1.06	1.00	3.43	2.98	1.64	0.00	1.13	2.14	0.28	1.00
Inwood Ave	July	Weekday	16	8.23	1.06	1.00	3.28	3.00	1.84	0.00	1.14	2.14	0.32	1.00
Knapps Corners	July	Weekday	17	0.00	1.08	1.00	2.83	2.63	1.44	0.00	1.06	2.14	0.26	1.00
Lawrenceville	December	Weekday	21	0.50	1.09	1.00	0.61	0.96	0.77	0.00	1.96	2.14	0.01	1.00
Lincoln Park	July	Weekday	19	6.18	0.87	1.00	2.42	2.02	0.86	0.00	1.05	2.14	0.12	1.00
Marlboro	July	Weekday	17	9.68	1.04	1.00	3.58	3.04	1.64	2.42	1.14	2.14	0.26	1.00
Maybrook	July	Weekday	18	8.86	1.02	1.00	3.45	2.94	1.56	2.39	1.14	2.14	0.24	1.00
Merritt Park	July	Weekday	16	9.24	1.05	1.00	3.51	3.06	1.71	0.00	1.16	2.14	0.30	1.00
Milan	July	Weekday	10	8.54	1.03	1.00	3.27	2.74	1.27	0.00	1.08	2.14	0.22	1.00
Millerton	January	Weekday	18	0.31	1.29	1.00	0.58	1.28	1.31	2.95	1.76	2.14	0.03	1.00
Modena	July	Weekday	17	9.72	1.03	1.00	3.66	2.93	1.44	2.09	1.13	2.14	0.23	1.00

Substation Name	Peak Month	Peak Day Type	Peak Hour	Residential Energy Efficiency				Commercial Energy Efficiency				Other DERs		
				HVAC	Lighting	Other	Home Energy Reports	HVAC	Lighting	Other	General	EV	PV	DG
Myers Corners	July	Weekday	18	9.00	1.02	1.00	3.59	3.01	1.64	0.00	1.14	2.14	0.25	1.00
New Baltimore	July	Weekday	18	8.98	1.03	1.00	3.46	2.89	1.47	0.00	1.15	2.14	0.23	1.00
North Catskill	July	Weekday	16	9.30	1.05	1.00	3.54	3.01	1.61	2.42	1.17	2.14	0.28	1.00
North Chelsea	July	Weekday	17	10.22	1.03	1.00	3.62	2.92	1.45	2.43	1.14	2.14	0.23	1.00
Ohioville	July	Weekday	15	8.86	1.07	1.00	3.40	3.10	1.75	0.00	1.14	2.14	0.30	1.00
Pulvers Corners	January	Weekday	18	0.57	1.27	0.00	0.64	1.26	1.19	0.00	1.62	2.14	0.08	1.00
Reynolds Hill	July	Weekday	14	9.41	1.09	1.00	3.32	3.12	1.94	0.00	1.17	2.14	0.34	1.00
Rhinebeck	July	Weekday	18	9.64	1.07	1.00	3.63	2.99	1.47	2.46	1.14	2.14	0.27	1.00
Sand Dock	July	Weekday	13	8.25	1.08	1.00	3.27	3.09	1.97	0.00	1.18	2.14	0.34	1.00
Saugerties	July	Weekday	17	9.19	1.04	1.00	3.61	2.99	1.63	0.00	1.16	2.14	0.26	1.00
Shenandoah	July	Weekday	15	9.21	1.09	1.00	3.49	3.14	1.76	0.00	1.15	2.14	0.30	1.00
Smithfield	December	Weekday	8	0.41	1.11	0.00	0.61	0.00	0.00	0.00	0.72	2.14	0.14	1.00
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	July	Weekday	18	9.82	1.00	1.00	3.57	2.84	1.39	0.00	1.13	2.14	0.20	1.00
Staatsburg	July	Weekday	18	10.29	1.04	1.00	3.67	2.89	1.43	0.00	1.16	2.14	0.24	1.00
Stanfordville	December	Weekday	18	0.75	1.33	1.00	0.77	1.34	0.94	0.00	1.84	2.14	0.00	1.00
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	9.97	1.05	1.00	3.66	2.98	1.46	0.00	1.15	2.14	0.26	1.00
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	9.79	1.05	1.00	3.63	2.95	1.39	2.44	1.12	2.14	0.25	1.00
Union Ave	September	Weekday	16	9.13	1.08	1.00	3.32	3.11	1.77	2.40	1.09	2.14	0.31	1.00
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.63	1.29	0.00	0.67	1.19	0.87	0.00	2.73	2.14	0.08	1.00
West Balmville	July	Weekday	16	8.97	1.05	1.00	3.56	3.09	1.74	0.00	1.17	2.14	0.29	1.00
Westerlo	July	Weekday	15	6.79	1.10	1.00	2.80	2.58	1.44	0.00	1.37	2.14	0.20	1.00
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	4.92	1.20	1.00	2.14	2.10	1.28	2.86	1.89	2.14	0.12	1.00
Total System	July	Weekday	17	9.83	1.04	1.00	3.62	3.03	1.60	2.44	1.17	2.14	0.27	1.00

E. Current Interconnection Process

1. Current Status

Central Hudson processes all interconnection applications within the required timelines specified in the New York State SIR. As shown in Figure III-2, the growth in cumulative MW of solar PV installed in Central Hudson's service territory has been exponential. The number of applications received per year has grown even more quickly, increasing over 10 fold between 2011 and 2015, as shown in Figure VI-16. While growth of rooftop solar has been significant for several years, Central Hudson has experienced a tremendous surge in large solar PV applications (nameplate ratings >300kW) in 2016 due to the launch of the Community DG program in New York State. From 2011–2015, only 64 applications were received for large solar PV interconnections; 413 applications were received in the first 5 months of 2016 alone. This is illustrated in Figure VI-17.

Figure VI-16: Solar PV Interconnection Applications Received

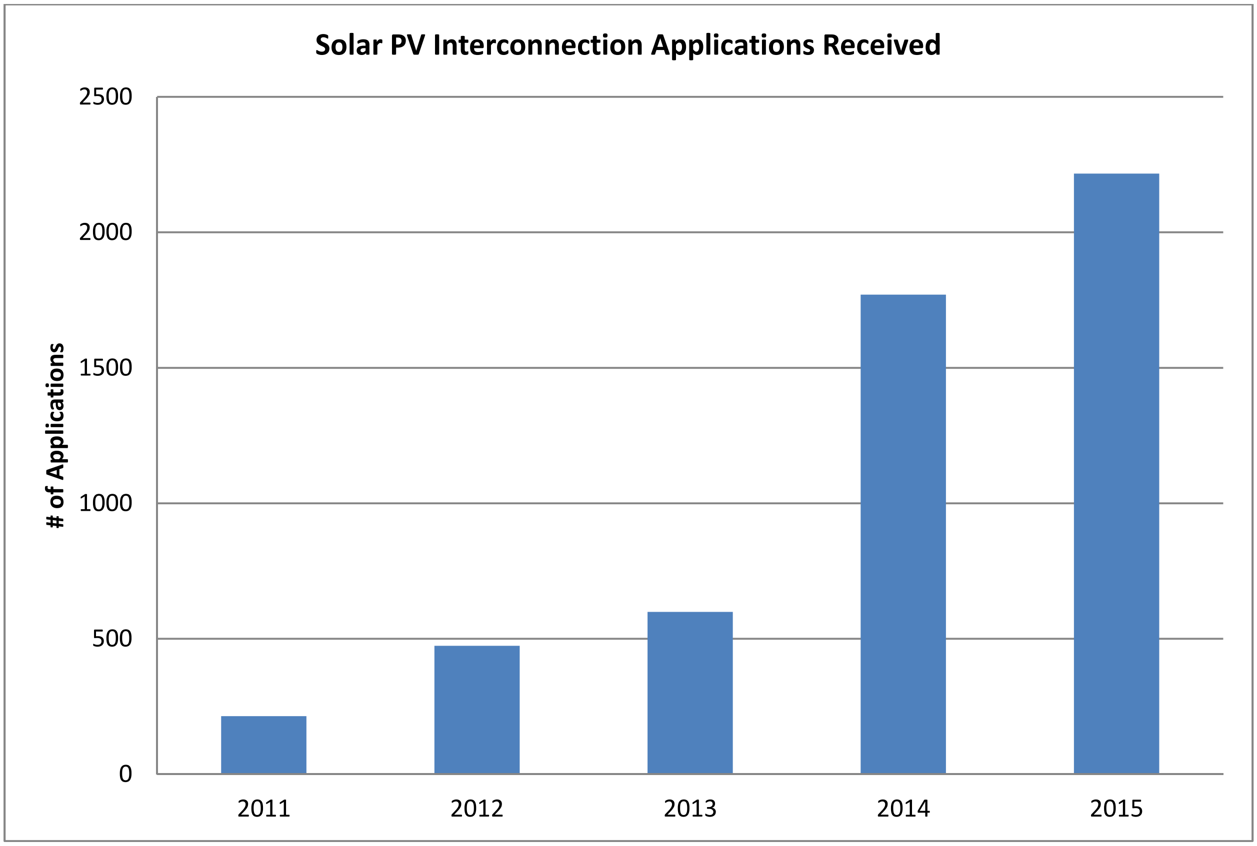
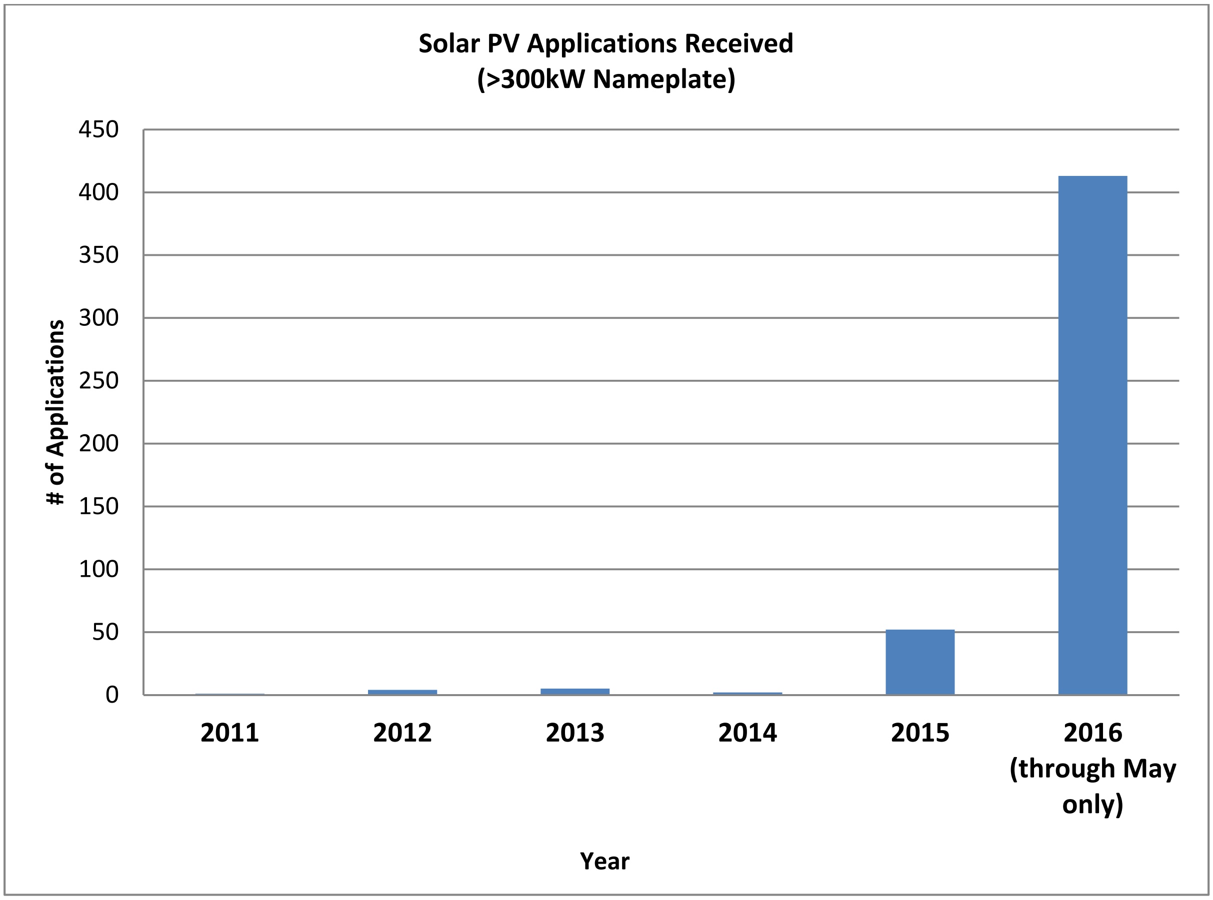


Figure VI-17: Solar PV Applications Received



As a result, the Company hired additional employees and shifted internal resources in order to process these applications within the NYSSIR timelines. A second external consultant was also hired to handle the expected in-rush of applications. The department is currently staffed by four full-time equivalents who complete work associated with interconnection processes and technical reviews and two (2) external consultants who are utilized to perform CESIRs.

2. Existing Best Practices

Where manual processes for many components of the application processing were sufficient in the past, more automation has become necessary with the increase in volume to continue to meet the goals established within the SIR. In 2009, an online portal was developed based on our CIS mainframe system to accept customer applications, as well as provide developers and customers with current status for all DG applications following the SIR regardless of whether they are submitted through the portal. The Company continuously provides status and approval updates to customers/contractors via their existing web portal as well as through e-mail correspondence. Separately, Central Hudson tracks and reports interconnection data by utilizing Microsoft Access and Excel.

Through its internal Bridge-to-Excellence process improvement program, Central Hudson established a team to identify and implement improvements to further streamline the interconnection process, automating and consolidating components. Central Hudson has worked to improve procedures over time in order to make processing timelines, reporting, and workload tracking more efficient. This includes making customized updates to the internal Microsoft Access database to enable approval letters to automatically pull in customer data. For the online portal, Central Hudson also provides developers with a contractor number so when entered into the application submission form, the developer's contact information is auto-filled. To reduce the number of deficient application submissions, the Company also ensured specific fields are required so the applicant cannot submit the application with crucial information missing.

Central Hudson also established a central phone number and e-mail address for inquiries regarding Distribution Generation, which are continuously monitored by multiple employees to insure a prompt response. On an annual basis, the Company hosts a Solar Summit for developers and energy professionals. This event sees a successful turn out each year and provides developers and professionals with industry updates and technical guidance, as well as feedback on ways to reduce application errors and streamline submissions.

For larger application reviews, the Company worked to link their existing internal Microsoft Access database to existing load-flow software in order to automatically pull in existing and proposed DG systems as part of the preliminary analysis. To streamline the CESIR process, the Company has been working to cluster applications located on the same feeder and submitted by the same developer as well as trained one of the external CESIR contractors to extract system modeling data, in order to free up internal resources and more quickly review CESIR results and process applications.

The Company is also working diligently through the Ombudsman and stakeholder engagement process to remove projects from queues that are unlikely to be constructed. Prior to the influx of Community DG applications, approximately 6% of applications were abandoned. Central Hudson anticipates this rate to be much higher for Community DG applications.

3. Interconnection Portal

As mentioned earlier, Central Hudson currently has a web portal available for customers to electronically submit interconnection applications online. The web portal was developed in-house in 2009 and meets the requirements within the SIR. As described in further detail within EPRI's *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*[5], customers/developers can create a login to view the current status of their interconnection request. The portal indicates whether or not next steps for the application are dependent upon the utility or the customer and provides comments to indicate when documents may be missing or deficient. The portal also lists the dates in which successful documentation was received as well as the dates the customer was given for preliminary and/or final

[5] "Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment", Electric Power Research Institute, September 2015.

approval. Customers can also view whether or not a meter change is required as part of their application, along with information regarding the CESIR.

F. Changes to Methodology to Incorporate High Penetration of DERs

1. Interconnection Portal

Central Hudson's current web portal meets the SIR requirements and the Company continuously works to improve the portal and automate internal processes. However, Central Hudson recognizes that there is potential to further streamline some of the administrative components of the process and develop a more modern, efficient experience for the customer and developer. To allow for a quicker, more transparent and user friendly customer experience, Central Hudson intends to pursue an interconnection software that can be tied to existing internal systems and allows all interconnection data to be housed in one location. To the extent possible, Central Hudson is awaiting further insight through on-going REV-related processes, such as the Interconnection Technical Working Group (ITWG) and completion of additional phases of the EPRI Utility Readiness Assessment.

The software capabilities the Company sees as a current priority due to existing gaps are:

- Payment for application, CESIR, and construction fees online at the time of submission;
- Issuance of automated e-mails when an application has moved to the next stage of review or is approved;
- Submittal of all application components via the web portal, such as final and pre-application documents, as well as enabling the user to update existing application information when changes occur;
- Automated, real-time data reporting by the utility for internal and external use;
- Mobile applications;
- Auto-fill and auto-calculations to reduce human error;
- Customer/developer view of initial documentation submitted, such as the design of the initial project submitted in order to determine if updated documents are needed for final approval;
- Status updates to the customer/developer for any upgrades required;
- Auto population of customer information from internal systems to eliminate inaccuracies with the customer name and/or site address; and
- Customer/developer satisfaction surveys.

Focusing on improving the process from an administrative perspective is a near-term initiative that will improve the experience for customers/developers, while resolution on technical issues are completed through the ITWG, stakeholder engagement occurs following the Initial DSIP, and primary system modeling is completed through our DA program (see Sections III and IV). Please note that even with completion of primary system modeling, the secondary system may need to be modeled prior to automation of some of the technical screens or components of the SIR. Secondary modeling is not currently included in our 5 year capital plan and would need to be evaluated in light of a roadmap to automate technical components of the process.

2. Hosting Capacity

Definition

The Joint Utilities of New York (JUNY) engaged the Electric Power Research Institute to develop a whitepaper outlining a proposed roadmap for Hosting Capacity in New York State. Prepared with input from all of the Joint Utilities, the goal is to present stakeholders with a uniform definition and approach along with the foundational requirements to evolve through the stages. As stated in the whitepaper, "Hosting capacity is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades.[6]" While a wide array of technical factors are considered in the evaluation, the range of values determined will change over time. Initial efforts will focus on solar PV. The whitepaper is attached as Appendix E.

Roadmap

Due to the challenges associated with the broad and dynamic array of information and modeling required, a roadmap for hosting capacity was developed. This is described in further detail in the whitepaper. Figure VI-18 and Table VI-17 illustrate the four phases.

[6] Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State. EPRI, Palo Alto, CA: 2016. 3002008848, pg. 1.

Figure VI-18: Four Phases of the Roadmap

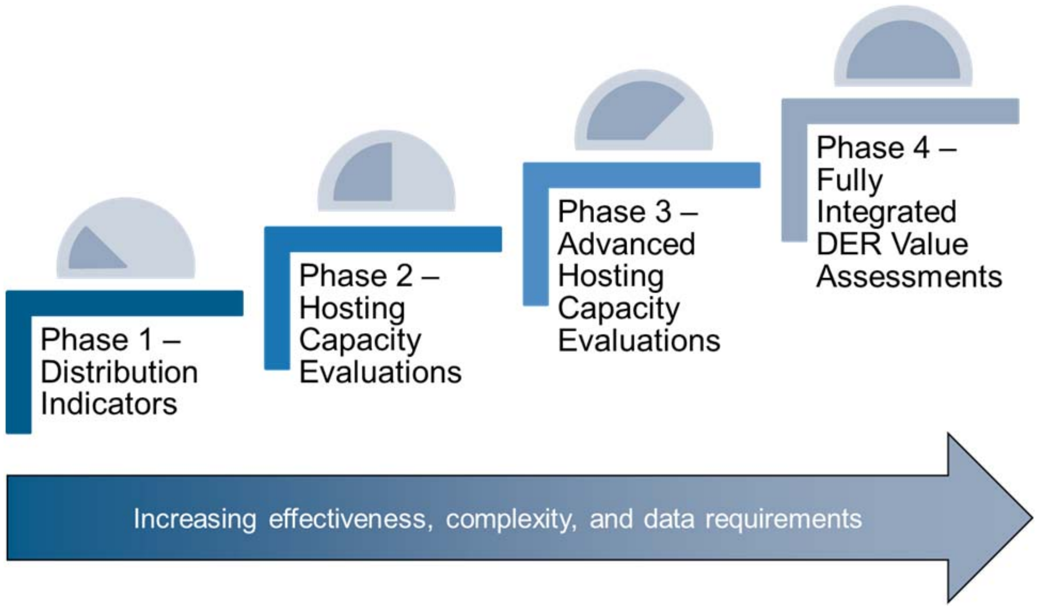


Table VI-17: Hosting Capacity Roadmap

Phase 1 **Distribution Indicators**	Recognizes specific indicators that contribute to hosting capacity based on available data, but does not represent a complete hosting capacity evaluation.
Phase 2 **Hosting Capacity Evaluations**	Evaluation of hosting capacity on a feeder-level basis considering the key components of DER impacts.
Phase 3 **Advanced Hosting Capacity Evaluations**	Evaluation of the hosting capacity on the more granular (node) level including considerations for operational flexibility and transmission constraints.
Phase 4 **Fully Integrated DER Value Assessments**	Hosting capacity assessment combined with DER value assessments that identifies potential benefits including improved efficiency, reliability, and capacity deferral. Means for increasing hosting capacity through use of smart inverters and storage.[7]

In a parallel path, the Central Hudson will evaluate methods to increase hosting capacity through infrastructure investments as well as energy storage, smart inverters, and other emerging technologies.

Completed Work

Central Hudson has completed work on Phase 1 Distribution Indicators. The DER System Indicator map can be found at: http://centralhudson.com/dg/DERmap.aspx

Central Hudson Gas & Electric's interactive DER System Indicator Map illustrates the areas/circuits across the system where DERs have a greater likelihood of not being easily accommodated on the distribution system. This can be used to aid customers and developers on locations to avoid for large (greater than

[7] *Ibid*, pg. 5.

300kW) DER systems due to the potential for high integration costs. The locations highlighted fall into four categories based upon the current queue:

- Low voltage circuitry (5kV class);
- Single phase circuitry;
- Feeders where minimum load is anticipated to be significantly exceeded; and
- Feeders emanating from a substation transformer that is anticipated to experience significant backfeed.

The two latter bullets indicate feeders with over 4 MW of solar PV in queue on the feeder, or an average of 4 MW per feeder in queue emanating from a particular substation bus. It is anticipated that this methodology will continue to evolve as Central Hudson participates with DPS Staff, NYSERDA, and the Joint Utilities through the DG Ombudsman group.

This map ***does not*** indicate circuit hosting capacity and ***does not*** restrict applications from being submitted within these locations, but rather is a tool to notify applicants that DER interconnections in these locations have a higher likelihood of requiring significant system upgrades at the customer's cost. Central Hudson intends to update this map on a quarterly basis.

Central Hudson is also a participant in an EPRI project entitled Distribution Planning with DER: System-Wide Assessment. EPRI is currently analyzing 15 Central Hudson representative feeders utilizing the detailed analysis that was summarized in the whitepaper developed for the Joint Utilities. While final results are not anticipated until the second half of 2016, the process has enabled Central Hudson to learn about the detailed modeling efforts required to develop hosting capacity, and the wide range of values that may impact results. Some examples are as follows:

- Minor deviations in voltage regulating device settings could create voltage violations;
- Feeders with many zones of protection will have pockets that require protective device upgrades to support solar PV or quickly introduce a risk of islanding in that small zone; and
- Hosting capacity values vary significantly for small, distributed DER vs. large, centralized units.

Plans to share information with stakeholders

As mentioned above, Phase 1 indicator maps are available. All DG developers with active projects in Central Hudson's service territory were notified via email and provided a link to the website. As additional information is available, developers will be notified in a similar manner. In addition, Central Hudson hosted Stakeholder Engagement sessions with solar PV developers regarding system data with high participation rates in Central Hudson's service territory on May 16, 17, and 31, and with a more general audience regarding the Initial DSIP as a whole on June 21. The presentations shared at these sessions is included as Appendix A.

Central Hudson will participate with the Joint Utilities in Supplemental DSIP stakeholder engagement sessions to shape the continued development of hosting capacity methodology and work products. These sessions will be covered as a part of the Supplemental DSIP process and is anticipated to commence on July 14.

3. Integration of Battery Storage in Planning

Battery storage technologies are highly flexible. They can be located on substation pads or behind the meter; they can be used alone or to complement other distributed resources. They not only can help defer or avoid T&D infrastructure upgrades but can help increase hosting capacity for other DER's. Because of their speed, they can deliver multiple grid value streams, including peaking capacity, system ancillary services, and distribution ancillary services. For customers, it can help manage bills, improve power quality and avoid outage costs. Because of its multiple applications, sometimes those needs compete against each other, thus, while the capability is there, the commitments to deliver T&D capacity and grid services need to be in place. Pricing for battery storage is also changing rapidly and batteries are becoming increasingly competitive.

The specific characteristics of battery storage, local peak patterns, and the availability of other DER's is critical in deciding where and when batteries deliver cost-effective value. While batteries are high flexible, they often have limits on how much power can be stored, the maximum output (limited by the inverter), and the duration it can sustain production. Most batteries to date, can sustain maximum output for two or four hours at a time, but not longer. For example, Tesla's Powerwall can deliver up to 6.4 kWh per unit with a maximum output of 3.3 kW. The maximum output cannot be relied on when resources are needed for six or more consecutive hours. From a planning standpoint, the potential to exhaust battery storage needs to be considered and factored into how it is rated and used.

On its own, battery storage is suitable for very sharp peaks. For prolonged peaks, however, battery storage may need to pair with other DER's. The flexibility of batteries makes it well suited to fill gaps from DERs that may not be as flexible. In the right combination, the combination of DERs plus battery storage can deliver more value as a whole solution than as stand-alone components and can be the lowest cost resource.

Battery storage will be assessed a part of competitive solicitations open to all DER's. Central Hudson will work to standardize the process so the locational needs are clearly defined and DER vendors can submit cost and DER characteristics in a standardized manner. Central Hudson will work to standardize the process for rating resources and identifying the remaining need. The combination of technologies that can meet needs at the lowest costs will be deployed. This likely will be a combination of DER technologies, including battery storage, and/or T&D infrastructure upgrades if they are more cost-effective. There may exceptions in demonstration projects due to the benefits of testing how battery storage can be incorporated into distribution planning and operations.

VII. Delivery Infrastructure Capital Investment Plans and Beneficial Locations

A. Delivery Infrastructure Capital Investment Plans

1. Five-Year Capital Forecast Development

Central Hudson prepares a comprehensive five-year capital investment plan for its electric transmission and distribution and gas transmission and distribution businesses and common areas (facilities, IT, Transportation etc.) on an annual basis. The integrated plan is divided into Electric, Gas and Common Sections. The focus of this portion of DSIP is the Electric Section and components of the Common Section of the plan as they relate to Central Hudson's role as the DSP. The 2017 – 2021 is included as Appendix H.

The electric capital forecast is developed for each of the budget categories—Production, Transmission, Substation, New Business, Distribution, and Meters—and integrated into a comprehensive and coordinated plan. Projects identified with in the electric forecast are developed meeting system planning based on current load forecasts, equipment inspection and diagnostic trending, tariff mandated expenditures, non-discretionary daily operations expenditures and compliance related programs. The most recent planning studies, econometric forecast, corporate demand forecast, and other industry changes (i.e. forthcoming compliance mandates) are utilized as inputs.

As part of the budgeting process, core functions including asset management, planning area studies, project identification and review, and project scoping are performed on a continual basis. Capital forecasts and expenditures within Central Hudson are defined in three major summary categories to analyze spending trends and clarify the levels of historic and forecasted capital expenditures. These categories are Non-Discretionary, Maintain System Standards, and System Enhancement. A detailed description of each of each of these categories and examples of projects that fit into these categories are included in our Capital Prioritization Process Guidelines that is included as Appendix G to this filing.

In addition to the Summary Categories described above, projects are independently characterized by their Investment Categories to differentiate the main project drivers. These Investment Categories are growth, compliance, day-to-day business management, new business, and infrastructure replacement. The following are guidelines and examples regarding the application of each investment category:

- Growth (Study-Based) – Projects where the needed is system reinforcement to due to organic system growth is the primary driver of the project. The Electric System Planning Guides describe how reinforcement projects and alternatives are evaluated. The alternatives are evaluated as a part of the system planning process, and then the selected project(s) are included in the capital budget. For some future projects, the Capital Forecast may include a placeholder capital project while the wires and NWAs are being analyzed.
- Infrastructure - The Electric System Planning Guides describe how inspection-based priorities on the Transmission and Distribution Systems are identified. The output is then documented in the Long Range Electric System Plan. Infrastructure projects are primarily based upon the following:

- ✓ Inspection Based Replacements
- ✓ Diagnostic Testing Based Replacements
- ✓ Reliability Based Replacement (For equipment issues identified)
- ✓ Planned replacements (End of life or obsolescence)

- Compliance – These are projects required to fulfill regulatory needs, such as:
  - ✓ Highway Relocation Projects
  - ✓ Regulatory Requirement Related projects (i.e., NERC)
- New Business – These projects are budgeted separately from other growth-related infrastructure projects and include projects related to:
  - ✓ New Commercial and Industrial customers
  - ✓ New Residential developments and single home additions
  - ✓ Upgrades for existing customer additions
  - ✓ Installation of street/area lights
- Daily Operations – These are generally unplanned projects following a disturbance to the system, or other day-to-day projects such as:
  - ✓ Equipment Failures
  - ✓ Storm-related replacements
  - ✓ Third party damage

The overall capital budgeting and prioritization processes are outlined in greater detail within our Capital Prioritization Process Guidelines. As noted, this document is included as Appendix G.

2. Five-Year Capital Forecast

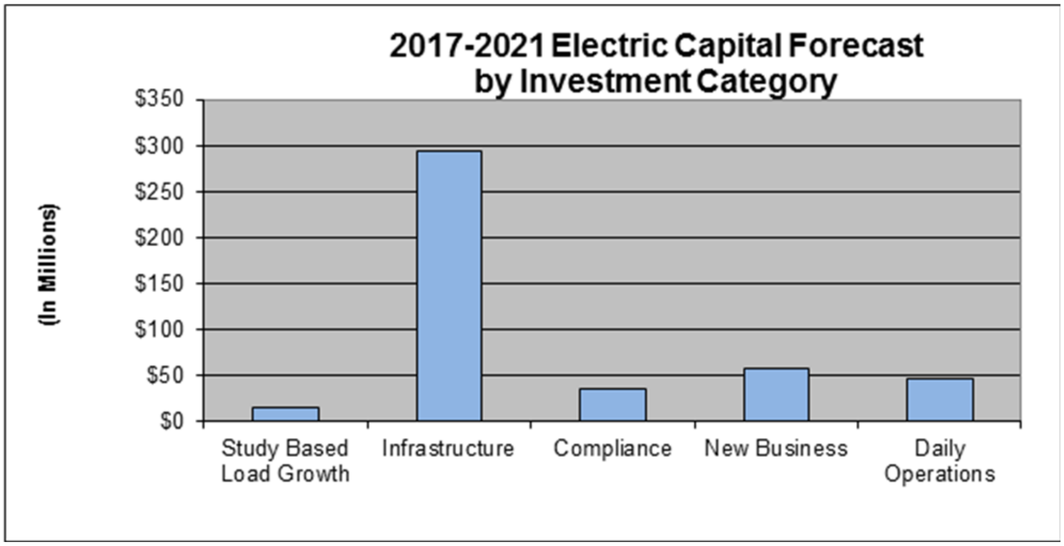
Table VII-1 below summarizes the latest five-year capital construction forecast for delivery infrastructure as developed based on criteria outlined above.

Table VII-1: 2017- 2021 Capital Construction Forecast ($000's)

	INSTALLATION W/ AFUDC (with inflation & OH adjustment)					
	2017 Proposed Budget	2018 Proposed Budget	2019 Proposed Budget	2020 Proposed Budget	2021 Proposed Budget	2017-2021 Proposed Budget Total
Transmission	18,920	17,006	19,771	22,096	21,494	99,287
Substations	23,142	21,613	15,306	19,720	16,984	96,765
Dist. Improvements	30,166	34,380	42,895	38,764	33,085	179,290
Subtotal	72,228	73,000	77,972	80,580	71,563	375,342

As described in the Five-Year Capital Forecast Development section, the projects within these areas are categorized by Investment Category as follows: growth, compliance, day-to-day business management, and infrastructure replacement. The graph below, Figure VII-1 shows the breakdown of the projects in our current five-year forecast by these Investment Categories. Following the graph is a description of the major projects/drivers of the construction forecast broken down into electric transmission and electric substation and distribution sections.

Figure VII-1: 2017-2021 Electric Capital Forecast by Investment Category



Electric Transmission

The significant Electric Transmission projects in the 5-year forecast are: rebuild of the 69kV WH line; rebuild of the northern portion of the 69kV G line; P/MK line structure replacements; rebuild of the 69kV KM/TV lines (note this project remains under study); rebuild of the Hurley Ave—Saugerties SB line for 115kV; rebuild of the Saugerties—North Catskill H line for 115kV; rebuild of the 115kV EF Line; and rebuild of the 69kV CL Line. A project that appeared in our previous 5-year forecast, the Northwest Reinforcement Project (that adds a 345 kV interconnection to the Catskill District 115kV system), has been deferred due to the Targeted DR Program; this DR program is expected to delay the NW Reinforcement in service date until at least 2029.

All of the projects identified above are driven by infrastructure conditions. Included in the list above is the WH Line reconductoring project associated with the aluminum conductor steel-reinforced cable (ACSR) conductor replacement program. The WH Line was originally constructed in 1932. The rebuild project is predicated on conductor failures and subsequent testing of the line conductor. Test results have shown that the existing ACSR conductor requires replacement. This replacement addresses infrastructure issues, while improving reliability and load serving capability to customers. The previously completed A and C line rebuild also was driven by ACSR condition assessment. The expected cost to complete the WH replacements is $6.94M. To a lesser degree, the FV Line has indications that it will require reconductoring in the future. This line will be reevaluated within the next few years.

As listed above, rebuilding portions of the 69kV G-Line are identified in the five-year forecast. The G line, originally constructed in the 1920s, is one of Central Hudson's oldest wood pole transmission lines and inspections have identified more than 60% of the structures would need to be replaced. This has initiated a review of the line to develop the most economical alternative to rebuild the line, improve reliability, and (if possible) improve load-serving capability in the mid Dutchess County area. The project has been split into two parts: the northern section and the southern section. The northern section will remain at 69kV and provide reserve for the Tinkertown substation by rebuilding from the Todd Hill Substation north and installing a 115/69 kV transformer at Todd Hill. This northern section of the project is expected to be constructed from 2016 through 2017 at a total cost of $12.3M. The southern section will be retired.

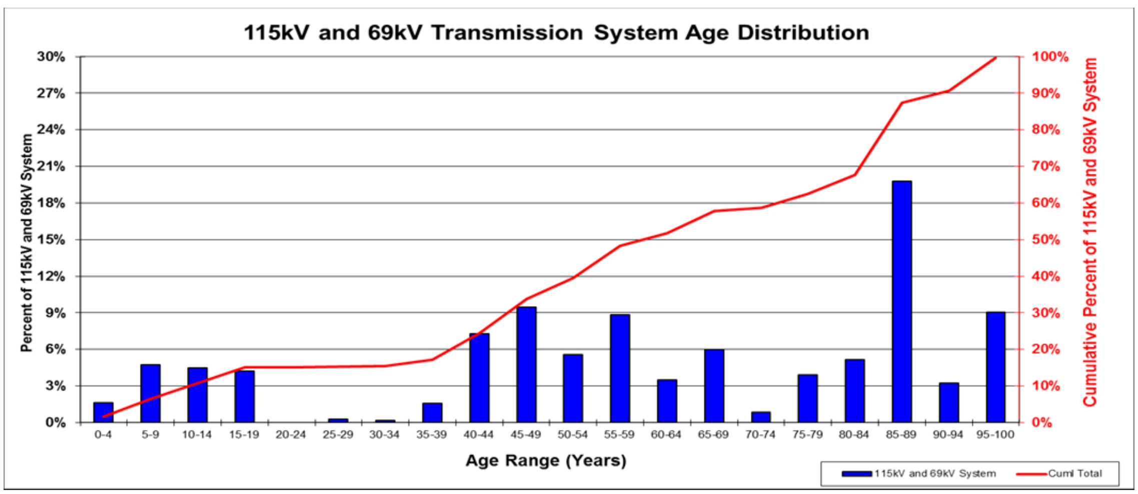
Additionally, rebuilding the KM & TV lines is identified in the 5 year forecast. Inspections have identified 58% and 53%, respectively, of the lines' wood pole structures needing replacement**.** These lines originally were constructed in the 1920's and 1930's. In addition to addressing known infrastructure issues, potential benefits of the KM/TV rebuild include an increase of the transmission supply to the Myers Corners substation. Concerns impacting the rebuild include both numerous right-of-way issues and the proximity to the Dutchess County Airport.

The 69kV P and MK lines were built and placed in service in 1991. The need to replace 125 structures on the lines resulted from subsequent review have led to the discovery that many of the structures on these lines are undersized for current code required structure loading requirements. The updated LiDAR/PLS-CADD data on the lines is being re-analyzed, and an exact plan for the structure replacements on the 69kV P/FK/HK/MG/GK/MK Lines (the original P and MK Lines since have been split into these six lines) is being studied. The previous plan for mitigation was to replace the structures with taller poles and larger class sizes capable of holding the increased loads, similar in scope to the recently completed transmission SAG and NERC Mitigation programs. According to that plan, the replacements would occur over the 2018, 2019, and 2020 forecast years at an estimated total cost of $6M.

Rebuilding the 69kV H & SB line also is identified in the 5 year forecast. This transmission path is another of Central Hudson's oldest (c. 1919) but of steel lattice construction. Inspections have shown 32% of structures needing replacement with another 36% in need of significant repair. These findings have initiated a review of the line to develop the most economical alternative to rebuild the line, improve reliability, and (if possible) improve load-serving capability for the Northwest Area. Each line will be rebuilt for 115kV but continue to be operated at 69kV for the foreseeable future. This project is expected to be constructed from 2020 through 2022 at a total cost of approximately $35M.

In addition to the above capital expenditures, there are several programs in Electric Transmission designed to reduce risk and improve infrastructure. The High Priority Replacement Program under the Electric Transmission Budget provides funding to respond to results of the inspections completed each year. High Priority Replacement projects address infrastructure issues that will reduce the risk of system failure, contact incidents, or loss of reliability. Figure VII-2 indicates the approximate Transmission System Age Distribution. The replacement work is prioritized based upon whether 345 kV or underlying system and whether radial or loop feed. When an inspection severity of 4 or 5 has been indicated, structures, insulators, and other capital items are replaced according to a specified timeline. Based on the number and severity findings for the EF Line and CL Line during inspections, more comprehensive rebuilds will be completed in lieu of individual repairs (note that these projects remain under study).

Figure VII-2: Transmission System Age Distribution



Electric Substation & Distribution

Due to the projected low to declining load forecast in the majority of our planning areas, there are a very limited number of growth driven major substation and distribution projects that have been identified through the planning process in this 5-year forecast. Based on the age and the continuing condition assessment of our major substation and distribution infrastructure, there are a number of projects and programs to proactively replace equipment prior to the development of age/condition related operating issues. Currently, the Maybrook Substation upgrade is the only major substation project in our five-year forecast due primarily to load serving capability/growth. The addition of a new substation in the Beekman/Phillips Road area of our service territory due to load growth and transmission/substation upgrades to reinforce and increase the load serving capability in the Northwest Area of our system have been deferred outside of our five-year forecast (from 2018 until 2022) due to NWA solutions.

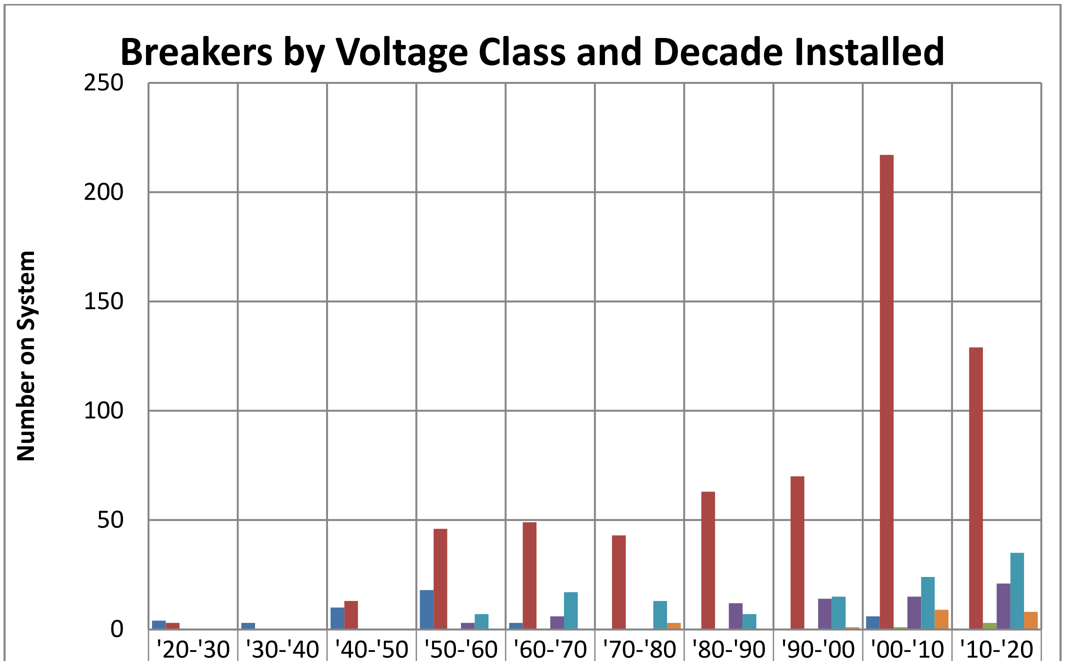
A total of $85.8M is allocated to infrastructure-related substation programs and projects within the five-year forecast. Major substation rebuilds or partial rebuilds due to infrastructure considerations include work/upgrades at the following substations: Sturgeon Pool, Union Avenue, Knapps Corners, Greenfield Road, Montgomery, Modena, and Woodstock. Additional major substation projects include the Danskammer storm hardening rebuild due to risk reduction and the addition of a second transformer for reliability and operational flexibility at the New Baltimore Substation.

A major substation infrastructure program included in the five-year forecast is the continuation of our Breaker Replacement Program. This program was initiated to improve infrastructure and maintain system reliability through a planned prioritized equipment replacement program. The assessment process for the selection and prioritization of the breakers included in the replacement program is as follows:

- Breaker Duty: All power circuit breakers with breaker duties greater than 85 % with highest priority given for breakers with duties greater that 100%.
- Condition: All of the power circuit breakers identified based upon the recommendations from our Operations Services Division. These recommendations are based upon reports of failures or reports of poor testing results.
- Obsolescence: Several of the circuit breakers on our system still 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: Other power circuit breakers on our system meet the above breaker duty or condition selection criteria, but they have not been selected for this replacement program because they will be replaced with new breakers as part of new substation construction projects.

For reference, Figure VII-3 shows the decade of installation for our system circuit breakers broken down by voltage class.

Figure VII-3: Breaker Age (As of 06/01/16)



	'20-'30	'30-'40	'40-'50	'50-'60	'60-'70	'70-'80	'80-'90	'90-'00	'00-'10	'10-'20
5kV	4	3	10	18	3	0	0	0	6	0
15kV	3	0	13	46	49	43	63	70	217	129
34.5kV	0	0	0	0	0	0	0	0	1	3
69kV	0	0	0	3	6	0	12	14	15	21
115kV	0	0	0	7	17	13	7	15	24	35
345kV	0	0	0	0	0	3	0	1	9	8

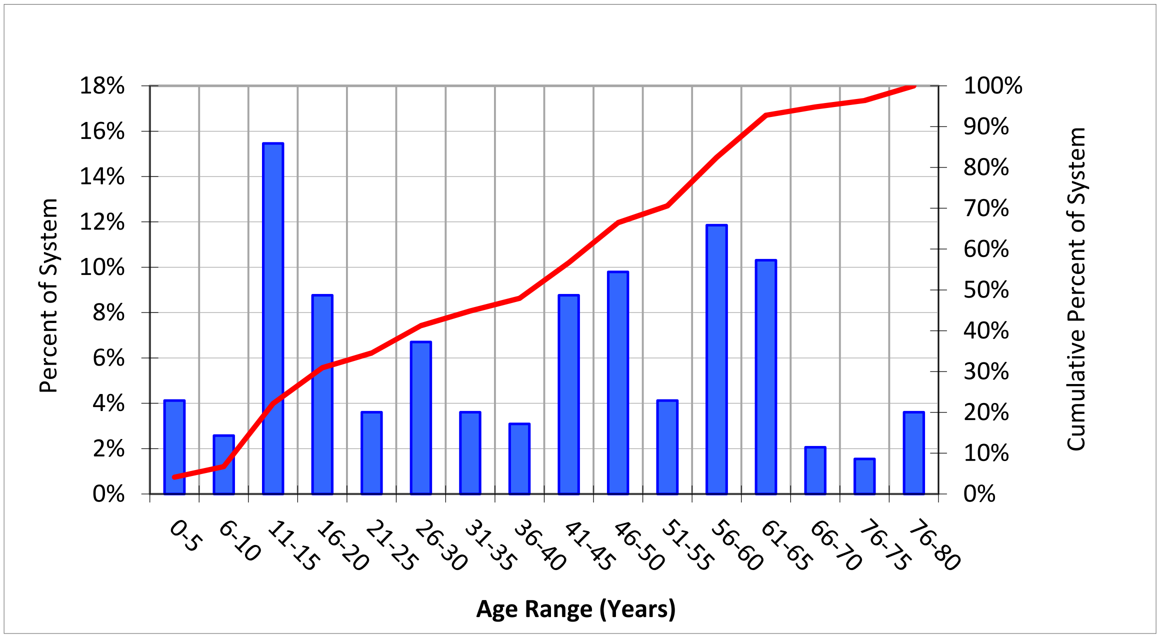
The Breaker Replacement Program has been in place since 2009, and, to date, 180 of the originally identified 196 breakers have been replaced. By the end of 2016, 35 additional breakers are scheduled to be replaced as part of this program. As a continuation of this program, 96 breakers have been identified for planned replacement in the 5-year forecast horizon, with $7.65M included in the 5 year forecast.

Additional major infrastructure replacement programs associated with substation equipment are the continued replacement of protective relaying equipment and Substation Power Transformers. Additionally, circuit switchers, disconnect switches, and motor-operated switch replacement programs have commenced based on feedback and maintenance trends from substation operations.

There is $13M for a comprehensive relay and metering modernization and integration program included in the 5-year forecast to enable replacements of outdated meters, relays, and communications infrastructure. In addition, first generation microprocessor relays were manufactured in a time when technology was changing rapidly; this relay technology quickly was surpassed and is obsolete in many cases. Many of these relays are unsupported by the manufacturers and have limited parts available. The replacement program of these first generation microprocessor relays is nearing completion with $1M in the 5-year forecast to conclude this program.

With regard to the Substation Power Transformers, the condition of the power transformers varies and the ability to maintain them is tied closely to their age. The average age of our substation transformers is approximately 40 years old with some transformers more than 80 years old. Figure VII-4 below shows the age distribution of our Substation Power Transformers. The transformers are monitored using: dissolved gas analysis; oil screen/testing; and Doble power factor testing at an interval based on voltage level and equipment criticality. Transformers are replaced based on this testing, condition, and the ability to maintain the equipment. There are seven substation projects in the 5-year forecast associated with the condition based replacement of aging transformers totaling $17.6M. These projects include transformer replacements at the following substations: the Boulevard Substation in Kingston; the Coxsackie Substation in Green County; the Reynolds Hill Substation in the City of Poughkeepsie; the Montgomery Street Substation in Newburgh; the Stanfordville Substation in Eastern Dutchess County; the North Chelsea Substation in Southern Dutchess County (the need for this replacement is tied to the KM/TV Line analysis); and the installation of 115/69 kV transformers at the Kerhonkson Substation following the retirement of the Modena 115/69kV transformer and upgrade of the P and MK Lines to 115kV operation. Also, the Ohioville 115/69 kV transformer will be retired following installation of a 115/69 kV transformer at Sturgeon Pool.

Figure VII-4: Transformer Age Distribution

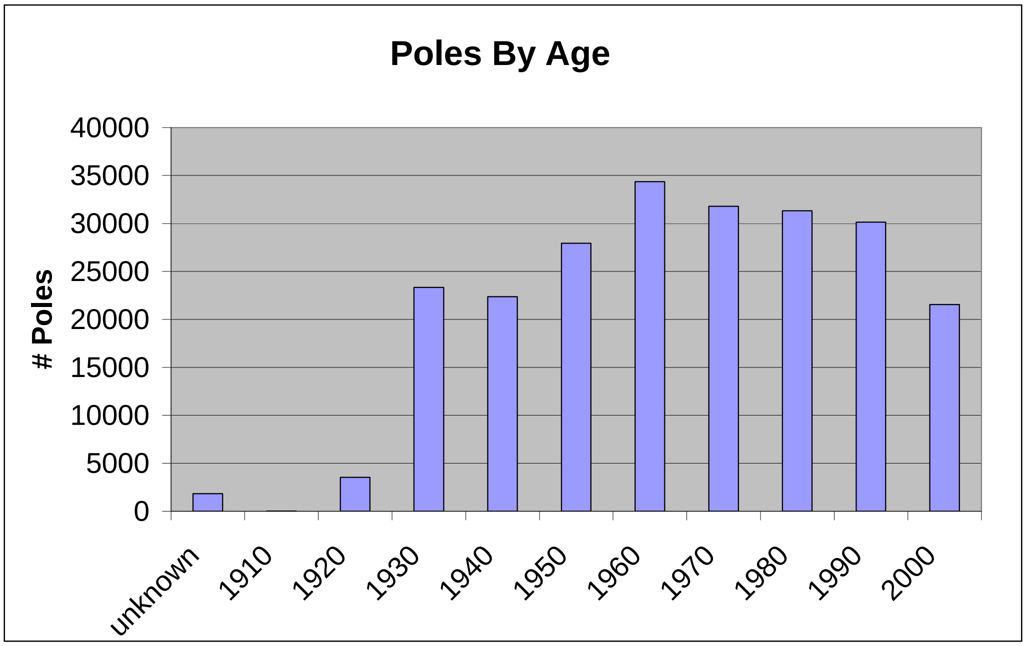


Similar to the breaker replacement program, programs have been created to address concerns with the remaining life of substation circuit switchers, disconnect switches, and motor operated switches. Replacement programs have been created to replace proactively these devices subject to potential failure. Recent problems have been identified with certain style switches, and there are limited to no replacement parts available. There is $6M in the 5 year forecast allotted to these replacements.

The Distribution projects are identified as thermal or growth related projects (approximately $12M of growth related projects in the five-year forecast), voltage improvement projects, reliability improvement projects justified on a cost per outage avoided basis, and operating improvements allowing flexibility in restoration. In addition to these projects, there are several Distribution Improvement programs or initiatives that are related to infrastructure or extreme reliability issues that are in the capital forecast. These major programs include the 10X program (areas experiencing more than 10 outages per year), the secondary network replacement program, the 5 kV cable replacement program, the overhead secondary replacement program, the 4800V conversion program, the copper wire replacement program, the oil switch replacement program, and the URD replacement program.

With regard to the Distribution infrastructure, there are ongoing programs designed to replace proactively aging or failing equipment. The replacement of porcelain cutouts, prone to failure, is another ongoing capital program. . The replacement of distribution poles identified through the inspection program is one of those programs. Figure VII-5 below depicts our distribution level pole age distribution.

Figure VII-5: Age Distribution of Poles



The DA Program is a major initiative that has been included in the five-year forecast. Central Hudson will continue with the ALT switch and recloser replacement programs. Incremental in the five-year forecast is advanced DA. This program will develop a DMS to improve reliability, system safety, and system efficiency, enhancing the capability of ALTs to include more complex FLISR, while providing for VVO. There also is a large infrastructure improvement aspect of this project that will dramatically alter the design of the electric distribution system by creating robust mainline feeders that can be looped through switching to restore customer after an outage or optimize and balance feeders during normal operations.

To accomplish this, there also will be an increased number of ALT switching schemes, switched capacitors, electronic reclosers, and voltage regulators, all of which will be tied back to the DMS to optimize system operation as well as improve reliability and power quality. The cost of this program within the five-year forecast, including the additional ALTs, reclosers, capacitors and DMS/DSCADA system is approximately $36 million and is estimated to have a positive cost/benefit ratio primarily due to the reduced energy usage (supply savings) and capital deferral. Much of the costs are related to the rebuilding and reconductoring of electric distribution mainline, some of which would need to be replaced as part of the normal asset replacement program. Additional benefits will include reduced system losses, improved switching safety, and improved restoration times through the use of manual switching when an ALT is not available. Since a portion of these costs are related to the replacement of aging infrastructure, these costs would be required to maintain system standards and are not included as system enhancement projects. The DA program and the complimentary Smart-Grid initiative programs are discussed in both the Smart Grid Initiative section below and within the Foundational DSP Investments section of this filing.

The current electric five-year capital forecast as detailed above is included with additional supporting documentation in our 2017-2021 Corporate Capital Forecast. The 2017-2021 Corporate Capital Forecast is included as Appendix H to this filing.

The Electric Section of the 2017-2021 Corporate Capital Forecast includes the five-year capital forecast broken down into the distinct budget categories identified above. Included within each budget category section of the Capital Budget Book are the five-year construction forecasts broken down by individual project with detailed project listings for each category, similar to those provided in annual filings and rate cases. For the Transmission, Substations, and Distribution categories, the five-year forecast (adjusted for inflation) does not show any large budgetary changes from historical spending trends.

For reference, Appendix H, outlines the historical spending amounts over the previous five years for the following Transmission, Substations, and Distribution Electric Categories.

Smart-Grid Initiative

Included within our five-year capital forecast is funding allocated for our Smart-Grid initiatives; this funding is based on implementation of Central Hudson's Smart-Grid road map for the enhancement of our distribution operations. The road map includes several inter-related components—the development of an Electric GIS model as the underlying data source of distribution assets, the roll-out of DA throughout our service territory, the roll-out of a tiered network strategies plan, which includes provisions to provide communications with our distribution assets and the installation and implementation of a DMS. These programs are foundational and include monitoring, communications, and information technology systems to support our role as the DSP. The installation of low-cost, high resolution sensors that enhance system visibility and smart devises with FLISR capabilities are included within our DA program, whose expenditures are included within the distribution category of our Electric Forecast (discussed above). The GIS, DMS, and Network Strategy expenditures are included within the Common Section of our Capital Forecast. Greater details on these programs including the five-year forecasted budgets and our progress to date are covered in the Foundational DSP Investments (Section IV) of this document. For reference, Appendix H, outlines the historical spending amounts over the previous five years for the Information Technologies, Communications, and Shared Services from the Common Section of our five-year forecast.

3. Distributed Energy Resources – Planning and Budgeting Process

The integration of DERs into the planning and budget process has been evolving at a relatively rapid pace with the evaluation of DERs as alternatives to reliability projects ongoing for a number of years.

In 2015, as part of a NWA solicitation, Central Hudson identified areas within our service territory that were experiencing sufficient load growth to warrant capital projects to meet the areas' load serving needs within the planning timeframe. These projects included a substation project (the installation of a new substation in the Philips Road area of our service territory), a distribution project (a distribution circuit upgrade in the Southern Dutchess/ Merritt Park area) and a transmission reinforcement project in the Northwest area of our service territory. A NWA solicitation was initiated to evaluate potential solutions to defer the need for the capital re-enforcements in these areas. The proposed solutions were evaluated including a comparison with the traditional utility solutions. A portfolio approach was selected and the NWA solution currently is being implemented as a cost effective solution to address the needs in these areas. These areas will be reevaluated on an ongoing basis to determine the effectiveness of the NWA solution, track load growth and update demand forecasts. As part of this process, the continuation/modification of the NWA solution will be evaluated versus both area needs and effectiveness of the existing NWA solution.

In addition, our current demand forecast incorporates the effects of both EE programs and the net effect of behind the meter generation (i.e., PV installations). This forecast is utilized as an input to our planning scenarios. These types of forecasts are adequate for the current penetration levels of DERs. As part of our initial DSIP filing, Central Hudson is implementing more granular and more sophisticated DER forecasting and is evaluating probabilistic forecasting methods to better incorporate DER resources moving forward. This work is outlined in the forecasting section of this document.

4. Distributed Energy Resources – Transmission and Distribution Project Needs Assessment

As indicated in the Capital Prioritization Process Guidelines (Appendix G), Central Hudson capital projects are characterized by their Summary Categories (Non-discretionary, Maintain System Standards and System Enhancements) and more granularly by their Investment Categories to help identify the main project drivers. These Investment Categories are growth, compliance, day-to-day business management, and infrastructure replacement. DER has the greatest potential to impact project needs in the Growth category, however, only for projects where organic system growth is the primary driver (as compared to a project to supply large new customer(s) lumped loads) of the needed system reinforcement. The Growth based projects are identified in Central Hudson's 2017-2021 Corporate Capital Forecast.

Based on the most current load forecasts, there are a very limited number of projects within our five-year forecast within the Growth category. Specifically, the Maybrook Substation upgrade and the Coldenham Distribution Circuit upgrade fall within the Growth investment category. The Maybrook Substation project currently is in the permitting and design phase and will need to move forward regardless of any local DER deployment. This project primarily is driven by the proposed addition of lumped loads within this area. The timing of the need (Dec 2018 in service date) will preclude pursuing a NWA. Although the Maybrook upgrade will provide capacity relief to the Coldenham Substation, a Coldenham distribution circuit upgrade project is planned to alleviate forecasted constraints on one of the substation feeders. The Coldenham Distribution Circuit upgrade currently is in the evaluation phase and a NWA solution will be solicited as a potential alternative to the traditional T & D solution.

Finally, DERs (specifically microgrids) has the potential to impact project needs for a smaller subset of reliability based distribution projects. A microgrid solution can be evaluated as part of the needs assessment to determine the least cost solution to meet area reliability concerns. .

B. Beneficial Locations for DER Deployment

Central Hudson has been proactive in identifying location beneficial for DERs and implementing NWA projects. In 2015, as part of the planning process, Central Hudson identified several areas (one Substation, one Distribution Circuit, and one Transmission Area) that were experiencing sufficient load growth to warrant capital projects to meet the areas load serving needs within the planning time frame. An additional area (Coldenham Distribution Circuit) has been identified as part of current planning process.

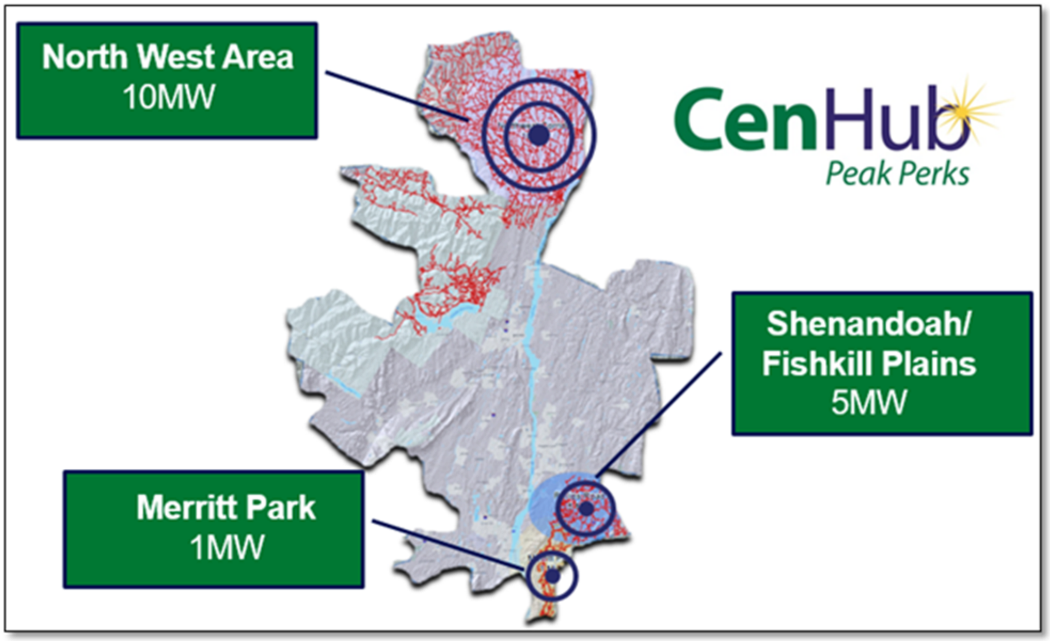
1. Update on NWA Pilots

Central Hudson is currently implementing its first NWA, the Targeted DR Program. The program launched on April 4, 2016. The program structure was selected as the highest value option among several other solutions.

Program Summary

The Targeted DR Program is available to specific commercial and residential customers located in three distinct regions (shown in Figure VII-6) where there is a previously identified growth-based distribution or transmission need. Approximately 61,000 customers are eligible for this program, based on geography. Load relief in this program will be acquired through controllable central air conditioning thermostats, as well as direct control switches for central air conditioning, electric water heaters, and pool pumps. Site specific measures will also be employed to achieve load reductions in the large commercial & industrial sectors. The target load reduction for the entire program is 16 MW by 2019. Comverge is providing turnkey program services, including marketing/sales, equipment installation, call center, rebate processing, & the IntelliSOURCE DR management system. A system map of the Target Program locations is included as Appendix J.

Figure VII-6: Targeted Demand Response Program Areas



Incentives

Customers will be offered attractive incentives to participate in the Targeted DR Program, as shown in Table VII-2. Enrollment reward will be paid to customers following the commissioning of a direct load control device, as well as annual rewards for continued participation. Customers can elect to receive their rewards in the form of check or as a credit applied to their Central Hudson bill. In addition to cash rewards, the program also provides residential and small commercial customers the thermostat(s) or direct load device(s), including installation, free of charge.

Table VII-2: Targeted DR Program Incentives

	Residential Incentives		Commercial Incentives	
	Enrollment	Annual	Enrollment	Annual
Central Air	$85	$50	$125	$75
Water Heater	$25	$24	$40	$36
Pool Pump	$85	$50	$125	$75

Marketing Update

Central Hudson has adopted the program name "CenHub Peak Perks" for the Targeted DR program marketing campaign. Marketing efforts have strategically targeted areas in which the distribution need is most timely, with consideration for efficient deployment of installation teams. Approximately 12,000 eligible customers have received introductory direct mail packages detailing the program offering, as well as the overall benefit of this program. Each customer will receive a second introductory package to improve response rates. To supplement the direct mail, there is also an active outbound call campaign within the same geographic areas. Door to door campaigns may also be utilized to further boost participation. All 61,000 eligible customers will be informed of the program offering throughout 2016.

Program Operations

The program's call center is fully operational and handling customer questions and enrollments. The program's website, CenHubPeakPerks.com, is live. The web page provides detailed program information, and allows customers to verify eligibility, self-enroll, and choose an installation appointment. As of June 21, 2016, 348 customers are currently enrolled in the program. A team of technicians is supporting ongoing device installations throughout neighborhoods which have been strategically targeted with marketing efforts.

2. NWA Suitability Criteria

The design and implementation of NWA sourcing processes will continue to evolve as experience is gained from demonstration projects and as utilities begin to incorporate NWAs as a routine aspect of distribution system planning. A major component of this evolution is the development of suitability criteria that can help utilities identify NWAs with the best chance of success in a competitive procurement process. These criteria represent the initial high level principles that will serve as the starting point for the development of proposed NWA suitability criteria to be included in the JU's forthcoming Supplemental DSIP filing.

The application of suitability criteria for NWAs can help utilities identify projects where DER solutions have the greatest chance of successfully deferring or eliminating the need for traditional grid infrastructure. To the extent the criteria target those projects where NWAs have the greatest chance of providing comparable value and being chosen in a competitive solicitation, they can help make the NWA procurement process more efficient and cost-effective for utilities and market participants. Additionally, the criteria would provide DER developers with greater clarity, certainty, and long-term visibility to the market and help avoid misallocation of time and resources for both developers and utilities. As these criteria are incorporated into planning processes, they will provide a means by which NWA procurement can become a routine aspect of system planning.

In designing the NWA suitability criteria, it is important that they not be overly restrictive, such that the criteria eliminate potentially valuable projects. Also, the criteria should be sufficiently adaptive to allow utilities to incorporate experienced gained with NWA procurement and respond to changing cost structures and market conditions. Additionally, the criteria should reflect stakeholder input and experience. To that end, the JUNY have launched a stakeholder engagement process in conjunction with the preparation of their Supplemental DSIP filing that will solicit input from stakeholders on the NWA suitability criteria concepts described below.

NWA suitability criteria captures the various dimensions of project characteristics that influence the ability of the project to defer or avoid traditional utility infrastructure. These include (1) the type of work and category of project, (2) the lead time of the project relative to the need date on the system, and (3) the cost structure of the project.

Type of Work

The type of work places the project into broad categories of utility projects that can help bound their overall suitability. For example, to the extent that capacity concerns (thermal load, voltage, power quality) represent a large share of projects with high potential for NWA solicitation, projects in this category would have a relatively high project applicability. Reliability work to put in place system enhancements to mitigate interruption risk might be difficult to displace, but reliability projects that mitigate outage impacts could be well suited to NWAs. New business might be a great opportunity for DERs to work with customers directly prior to issuance of their load letter rather than addressing capacity issues through a NWA solicitation. Therefore, in the context of NWA suitability, the project applicability for new business projects might be relatively low despite fruitful opportunities for DERs to participate in other avenues.

In some cases, the type of work does not lend itself to procurement of NWAs. In the case of planned repairs or replacements of existing infrastructure, the ability of NWAs to displace the utility solution must include the repair or replacement of the asset or otherwise obviate the need for the asset altogether. To the extent that asset condition upgrades are needed to maintain safety and reliability of the system, this type of work will likely need to meet a very high standard of availability and performance and, therefore, might have a relatively low project applicability with respect to NWAs. The same could be said for damage failure repairs that must be addressed under extremely short timeframes, as well as non-T&D infrastructure such as telecommunications, tools, and systems.

Lead Time Required

For the NWA to be suitable from a timing perspective, the NWA must be able to be procured and implemented prior to when a solution is needed on the system. The time needed to design and implement a competitive solicitation will depend on the scale and complexity of the project. This includes the time needed to produce the RFP, collect proposals, review bids, undertake purchasing processes, secure board approval, and contract with the winning bidder(s). The NWA solicitation time is typically 10 to 20 months based on recent NWA experience. The timeframe for the implementation of the solution is also a function of scale and complexity, and is typically in the range of 20 to 40 months. Therefore, based on recent experience, the minimum amount of lead time required is typically 30 to 60 months in advance of when it is needed on the system. Experience conducting competitive solicitations for NWAs and implementing DER solutions can help achieve greater efficiencies; therefore, the lead time criteria should be updated regularly to reflect current experience.

Cost Structure

Finally, the cost of the utility project will also have an impact on its suitability for a NWA solicitation. In some cases, a utility solution might be available at such a low cost that it would not be efficient or cost effective to carry out a competitive solicitation for NWAs to meet the need. The cost used as a threshold should be set so that it does not overly restrict project suitability for NWA consideration and could perhaps be implemented as a guidance criteria in parallel with the type of work considerations described above as opposed to a bright line test.

The specific design and implementation of these criteria will continue to evolve and the input provided by the stakeholder engagement groups will help to inform the JUNY's development of these concepts.

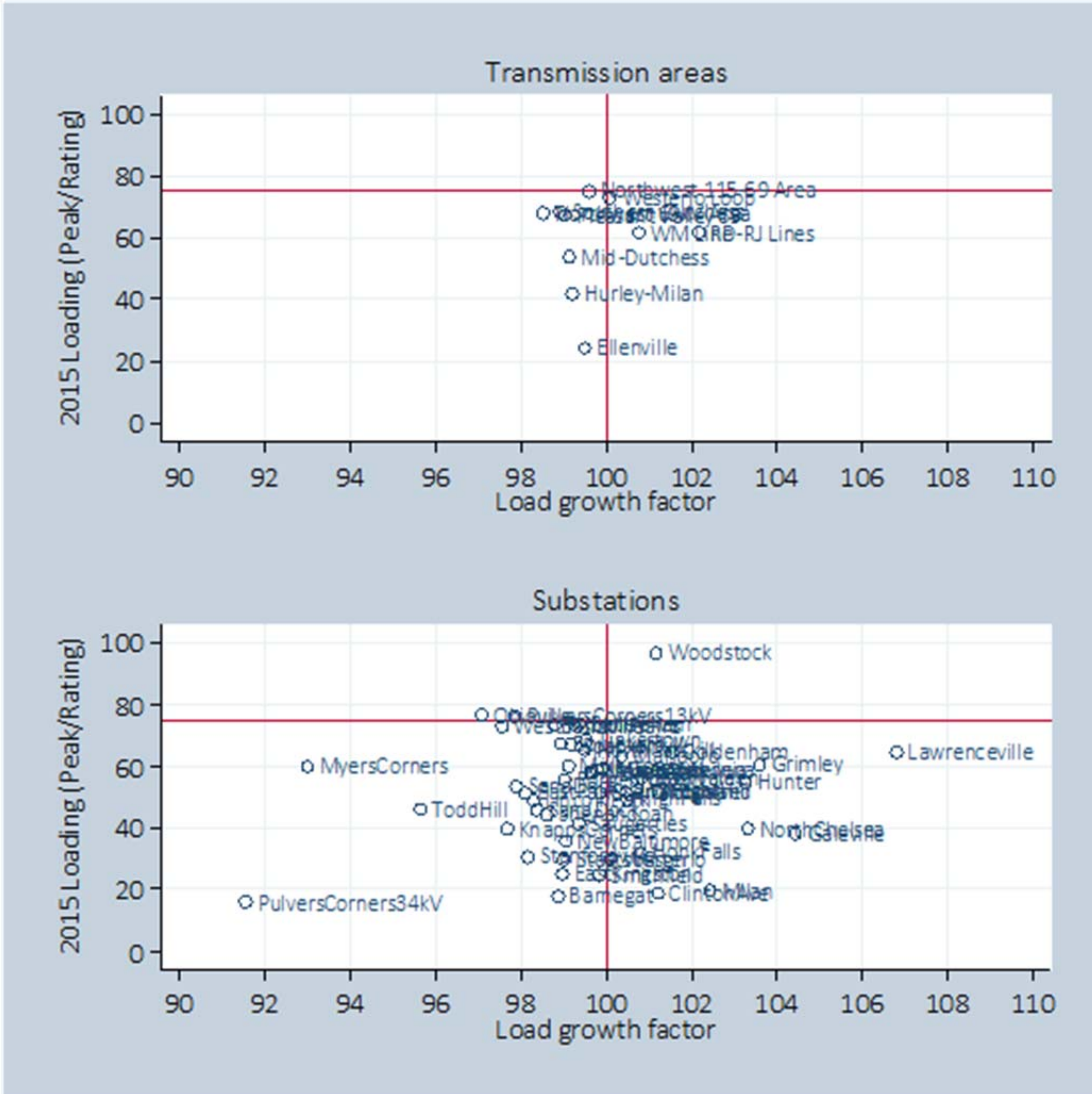
3. Beneficial Locations

Central Hudson has performed Avoided T&D Cost study in conjunction with our normal capital planning and budgeting process to help identify forecasted system requirements that would be amenable to the potential for DER to resolve or mitigate the identified needs. The study is included as Appendix D.

To avoid or defer infrastructure upgrades DERs need to ramp up at the right time and right place. In addition, the DER resources 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, location may not 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.

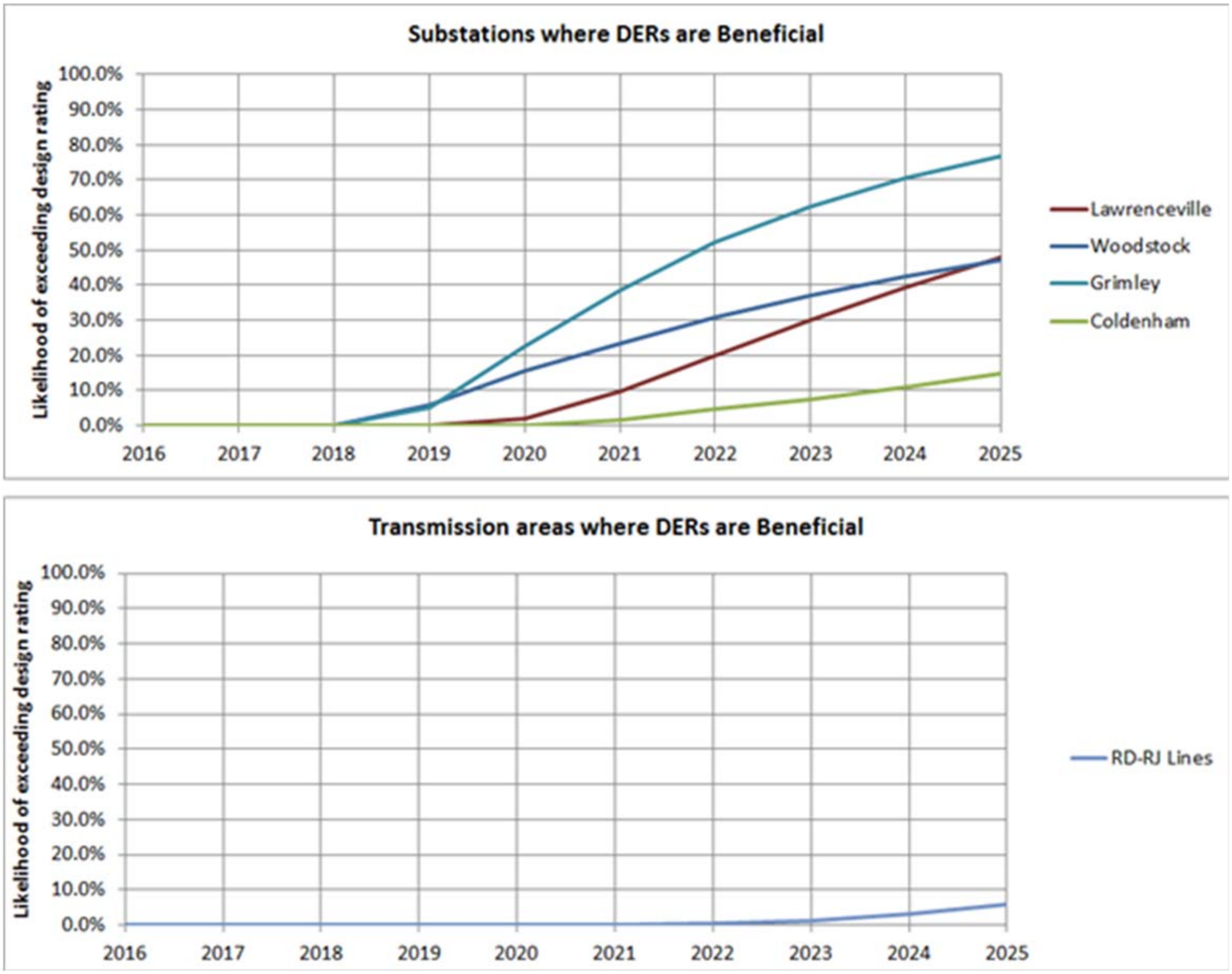
Because beneficial locations are areas where loads are growing but there is limited room to accommodate growth, one approach to identifying beneficial location is to plot growth factors against the peak loading. Figure VII- illustrates this approach for transmission areas and substations. With a few 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 were the 2015 loading (peak demand /load serving capability) is closer to 100% have less room for growth. This approach, however, is overly simplistic. It does not reflect that, all other things 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.

Figure VII-7: Beneficial Location Exhibit Growth When There is Limited Room for Growth Compared to Facility Rating



To identify beneficial locations, Central Hudson relied on the probabilistic analysis described in the discussion regarding forecasting methodology (Section VI.C.2) and detailed further in Appendix B. Locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering and infrastructure investment by 2025 (10 years). In total, this includes one transmission area – the RD RJ Lines– and four substations – Coldenham, Lawrenceville, Grimley Road, and Woodstock. Two of the substations, Lawrenceville and Woodstock, are winter peaking. A system map indicating these Beneficial Locations is included as Appendix I. Figure VII-8 shows the likelihood of an infrastructure upgrade by year. While the locations can benefit from DERs, in some instances Central Hudson can provide temporary relief through load transfer or other low cost steps. For example, roughly 10.6 MW can be transferred from the RD-RJ Line to neighboring areas, if needed, at a relatively low cost. This may postpone the timing of the upgrades and their inclusion as NWA projects. Appendix B provides additional detail regarding the characteristics of each beneficial location.

Figure VII-8: Beneficial Locations and Likelihood of Exceeding Load Serving Capability by Year



4. Evaluation Criteria for Non-wire-alternative Bids

Central Hudson's goal is to establish transparent, objective evaluation criteria that incorporate both objective measures—such as cost and ability to meet the locational need—and qualitative criteria. The proposal evaluation needs to not only take into consideration costs, but also needs to weight the viability of different DERs proposed, consider both energy and non-energy benefits, and the implications for grid reliability of the different options proposed.

Considerations

The key challenge is ensuring the criteria do not inadvertently favor one technology or vendor over others. The process is complicated by several factors:

- DER resources include a wide range of technologies each with different operational characteristics and constraints. Based on the Commission's definition, DERs include EE, load management, electricity storage, solar panels, small generators, CHP plants, etc. This makes it difficult to directly compare nameplate capacity and cost without a process for rating resources based on their characteristics. For some locations, specific constraints are material, in others they are inconsequential

- The value of DR also depends very much on the characteristics of the distribution system in question and how well delivery of each DR resource coincides with local needs. To provide value, DER resources need to target the right locations, at the right time, for the right hours, with the right amount of availability, and the right level of certainty. However, depending on the location, the same DER resource can have different value based on how well its characteristics align with the need.
- DERs are not designed exclusively to manage local peaks and can include other benefits and costs. The additional benefit due factor in the decision, but, for distribution planning, the core question is whether the DER resource will resolve the local T&D capacity constraints and do so reliably. The emerging but not yet standard practice is to value other concrete benefits and calculate net cost per incremental load serving capability.
- NWA solution is inherently an iterative optimization problem. DERs are not a simple commodity and the best solution is not always made up of the cheapest parts or the same parts. The overall value of each individual DER depends on the quantity and type of DERs already selected and the remaining need. To use an analogy, if one is building a single car, one needs the right type and quantity of parts that can be combined into a whole car. A car without wheels is not useful, nor is having two engines.
- Some resources cannot be added to each other. Many types of DER rely on recruiting customers to install technology or reduce peak loads and different bid are based recruiting from the same customer pool. To illustrate, if an aggregator projects they can recruit 5 MW of residential air conditioner load control in a local area and another aggregator also projects 5 MW, those values should not be added since both aggregators are basing their estimate on the same recruitment pool.
- Qualitative factors play a role in the decision making. There are several additional questions, besides cost, that must be addressed in selection process, particularly as Central Hudson gains experience with projects. Is the implementation plan well thought out and feasible? Has the bidder demonstrated the ability to attain the level of DER penetration proposed? How well does the proposal promote other REV goals such as customer engagement? Is the company financially viable over the multi-year course of the project? What is the level of responsibility if the bidder fails to deliver sufficient DER resources on time? These qualitative components are used to screen bids and determine which resources are included in the portfolio optimization.

Rating Resources

One of the central aspects of assessing DER bids is the process for rating resources based on their characteristics and how well those characteristics align with project area's peaking patterns. In specific, this includes:

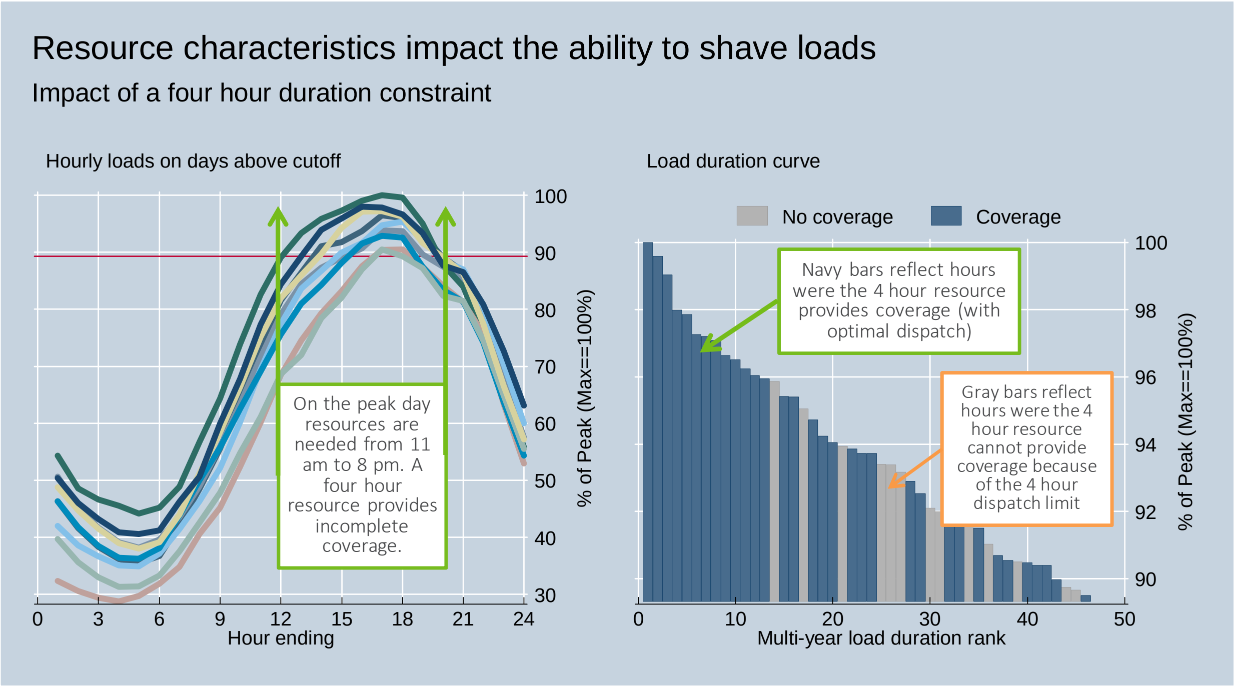
- Nameplate capacity (if applicable);
- Alignment of underlying load shape with local peaking patterns (if applicable);
- Availability windows;
- Ability to dispatch at different start and end hours;
- Maximum duration of continuous DER output;
- Limitations on the total number of dispatch hours in a year or month;

- Ability to control the resources ,including ability ramp the output up or down;
- Speed of response; and
- Historical realization or performance rates (if available).

To develop this rating, known as effective load carrying capacity, Central Hudson simulates the DER resource—including loads shapes, flexibility, and operating constraints—on five years of historical data for the location in question. If one had been trying to cut loads by, say, 5 MW, when, how often, for how long, and how much of the DER resource would have been needed? Would the DER resource been able to meet the needs given its operating characteristics and nameplate capacity? The resource is rated based on fraction of the hour.

Figure VII-9 illustrates how constraints—in this case, the inability to sustain production (or reductions) for more than four hours—can limit the value of a DER. The left hand panel shows the hourly peak patterns during days when capacity relief is needed most. During the highest load day, resources are needed from 11 am to 7 pm. A resource with a four-hour dispatch duration limit cannot, on its own, sustain loads below the target threshold during the highest load day. The right hand panel shows the loads above the target threshold in the form of a load duration curve. Each bar represents a specific hour when resources are needed to maintain loads below the target threshold. The gray bars are specific hours when reductions are needed, but the specific DER cannot deliver because the resource has already reached the four-hour constraints on a given day.

Figure VII-9: Illustration of Resource Constraints on Ability to Manage Loads



5. Procurement Process for NWA

Central Hudson's procurement process for NWA solutions will be highly dependent on the specific need & technology solutions that are available to meet that need. Initially, a system need will be determined via engineering analyses of various data on various performance metrics of the electrical system, such as load monitoring, population growth, and capacity of existing equipment. A key aspect of the analysis will be a forecast of the timeline at which the need must be met. Although different types of needs will call for different procurement approaches, The Company will utilize the following guidelines:

- Utilize RFPs to procure a solution. In some cases RFIs and or RFOs will precede the RFP to gain an understanding of the market offerings;
- The company plans to utilize an independent consultant to evaluate the ability of each solution to meet the identified need. This evaluation will take into account detailed aspects of each proposed solution such as availability, coincidence with bulk system, transmission, & distribution peak, reliability, and intermittency.
- The cost effectiveness of each solution will be evaluated using the procedure prescribed in the BCA Handbook included in Appendix K.

6. M&V Process for NWA

The Company recognizes the importance of implementing robust measurement & verification (M&V) protocols to demonstrate the effectiveness of NWA solutions. This is particularly critical when considering that future NWAs are likely include emerging technologies that have not traditionally been a part of utility infrastructure projects or business case analysis. Recognizing the possibility for a variety of innovative solutions to be utilized as NWAs, the M&V process will not be a "one size fits all" solution. For example, evaluation of a battery storage solution will vary greatly from direct load control. The M&V process will follow key principles while allowing flexibility to tailor the protocols for each technology.

Data Collection

Project data & tracking requirements, to the extent possible, will be stated in the request for proposal. Vendors will be required to design & implement solutions in such a way that key information is collected, and proper data collection techniques are used. This may include data loggers, device telemetry, metering, or other methods depending on the technology to be measured. Publically available information such as weather station data may also be used. Central Hudson may already have access to certain data points such as monthly billing, or interval metering for large commercial & industrial customers. In these cases, relevant data collected from Central Hudson may be provided to the vendor, so long as the vendor's systems incorporate adequate data security.

Experimental Design & Analysis

For each NWA, Central Hudson will design and implement a methodology to reliably prove statistically significant results, in accordance with industry standards. The M&V protocols will be uniquely designed to fit the proposed technology or solution. Through the solicitation process, vendors may be required to develop appropriate protocols to evaluate their proposed solution, particularly for proprietary or emerging technologies. In this case, M&V plans will be evaluated in consideration of industry standards, utility experience, guidance from independent trade associations, or third party consultants.

Targeted Demand Response Program M&V Plan Summary

Detailed below is a summary of the M&V plan for the existing Targeted DR Program.

Objective

- Measure the impact of the direct load control devices by monitoring the collected use of pool pumps, water heaters, central A/Cs, runtime information from the entire install population;
- Calculate overall DR reduction for the Residential/Small Commercial population based on the measured load reduction on the actual events and analyzing kW measurements; and
- Calculate individual & overall DR reduction for the large C&I population based on interval metering.

Data Sources and Uses

The M&V performance evaluation methodology for direct load control depends on two key data items: runtime of the device and the connected load of the device. In the case of thermostats, the device records and report the time during which the thermostat is “calling” for cooling from the HVAC system. Switches perform this function similarly for water heaters and pool pumps. This total accumulated runtime is recorded in the thermostat in integer minutes. IntelliSOURCE calculates the difference in runtime between successive five- minute data transmissions. This information can be used to determine energy used by multiplying the five-minute runtime value by a connected load measurement. The connected load values will be estimated from nameplate information of the equipment recorded by the field technician.

Hourly Weather Data

U.S. Government NOAA forecast weather data is utilized for official temperature information. Recorded temperature will be considered at KPOU station (Poughkeepsie, Dutchess County Airport) for Merritt Park and Fishkill/Shenandoah, and KALB station (Albany International Airport) for Northwest Corridor.

Interval Meter Data

15-minute interval data is utilized for load reduction results for all participants in the large C&I sector.

Evaluation Algorithm

The final load impact estimates are the result obtained from a baseline methodology defined in *NYISO Emergency Demand Response Program Manual*. One such methodology is entitled “The Average Day CBL[8] for Weekdays”.[9] The following subsection describes this method in detail.

[8] Customer Baseline

[9] New York Independent System Operator, “Emergency Demand Response Program Manual”, Manual 7, October 2013, p. 5-4.

The Average Day CBL

This methodology first identifies the peak load hour within the event period for the previous 30 days. This peak load hour value is multiplied by 25% for an initial value. Then one looks back starting with the previous day to the event day. NYISO holidays in the previous 30 days are excluded, SCR, EDRP or TRDP[10] events where the resource was eligible to participate and prior day are excluded, and any days in the past 30 days where the resources DADRP bid was accepted and prior day.

Low usage days are where the average daily event period usage is less than the initial value defined in the previous paragraph. Low usage days are eliminated from consideration in the CBL calculation. The day prior to the event day is excluded. Then going backward the highest average daily event period usage five days of 10 eligible days are considered in the CBL calculation. The simple average of these five days then defines the CBL for weekdays.

The Event Final adjustment Factor is calculated using event day load looking back four hours and then using the first two hours. The next two hours are not used. The average of the two hours is the Adjustment Basis Average Load. The Adjustment Basis Average CBL is the average of the same two hours for the CBL. The Gross Adjustment Factor is the Adjustment Basis Average Load divided by the Adjustment Basis Average CBL. The Final Adjustment Factor is obtained by rounding down to 1.2 if the Gross Adjustment Factor is greater than 1.2 and rounding up to 0.8 if the Gross Adjustment Factor is less than 0.8. The Adjusted CBL is obtained by multiplying the hourly average CBL values by the Final Adjustment factor.

Residential / Small Commercial Population

On an hour-by-hour basis, the Actual load is subtracted from the Adjusted CBL to obtain the hour-by-hour DR performance.

Large Commercial & Industrial Population

This section describes the proposed method to evaluate the impact of the load curtailment events for the large C&I population. These customers agree to provide 4 hours of curtailment for typical DR events and up to 8 hours of curtailment for special emergency situations that could result from extreme circumstances, including but not limited to, temperature exceeding 95 degrees, temporary loss of distribution infrastructure, or temporary loss of transmission infrastructure.

The Average Day CBL is calculated in the same manner as detailed above. If the customer has selected a weather-adjusted CBL, the Event Final adjustment Factor is applied to the calculated CBL.

For each C&I customer, on an hour by hour basis, the Actual load is subtracted from the Adjusted CBL to obtain the hour by hour DR performance. The portfolio performance is the sum of the individual C&I customer performance values for each hour.

The seasonal performance is determined as follows. If an event is four hours or less, all hours from the event will be included in the seasonal performance. If the event exceeds four hours, the four consecutive

[10]See NYISO manual for definitions of these abbreviations.

hours with the highest total portfolio performance value will be included in the seasonal performance. The seasonal performance for an individual customer will be the average of the hourly performance values over all test hours and all event hours as described above. An individual C&I customer's seasonal performance value is greater than or equal to 0 kW.

7. Other Operational Considerations

Please refer to Appendix K, Central Hudson's BCA Handbook, for information regarding Other Operational Considerations that currently can be included within a BCA. The BCA Handbook provides methods and assumptions that may be used to inform BCAs applied to the following categories of DER procurement or investment:

1. Investments in DSP capabilities
2. Procurement of DERs through competitive selection
3. Procurement of DER through tariffs
4. EE programs

The identification and quantification of operational benefits provided by DERs can be found within Section 4 and 5 of Central Hudson's BCA Handbook.

VIII. Distribution Grid Operations

A. Summary of System Operations Impacts of High DER Penetration

1. Overview

As customer interest in DER continues to increase in New York State, so does the need to evolve existing interconnection standards, technology, as well as regulatory policies. As of May 31, 2016 the amount of solar PV interconnected within Central Hudson's territory was 50.5 MW that represents 4.8% of Central Hudson's 2015 system peak. As mentioned in Section VI, Central Hudson has experienced a significant increase in solar PV applications since the launch of the Community DG program. As a result, the total interconnected and proposed DERs in queue equals 751.1MW, which is well over Central Hudson's system minimum load and represents 70.9% of the 2015 system peak. Reviewing and integrating these DERs is affecting various departments within Central Hudson including engineering, customer service, and system construction; however, once in service, this level of penetration will also have a significant impact on the daily operations.

As the interest within Central Hudson's service territory has primarily been solar PV, the near-term effects, regulatory changes anticipated, and DER communication/control concerns described further are focused primarily on PV technology. DERs at lower penetrations, such as those associated with NWA projects will initially involve a small number of aggregators, with Operating policies and procedures standardized as experience is gained. The case is similar for longer term planning initiatives such as energy storage that are in the R&D stage. Even for solar PV, operational experience to date has been primarily limited to behind-the-meter resources, and policies and procedures will continue to evolve and develop as experience is gained, smart inverter technology becomes more mature with standards and testing procedures accepted by IEEE, NIST, NREL, and other national standards organizations, and REV markets develop.

Central Hudson continues to collaborate with EPRI to learn national and international best practices, and participates in the ITWG at the New York State level. Monitoring and control of PV inverters is a significant topic of discussion and information sharing in these forums to ensure lessons learned from other jurisdictions are integrated into Central Hudson's practices.

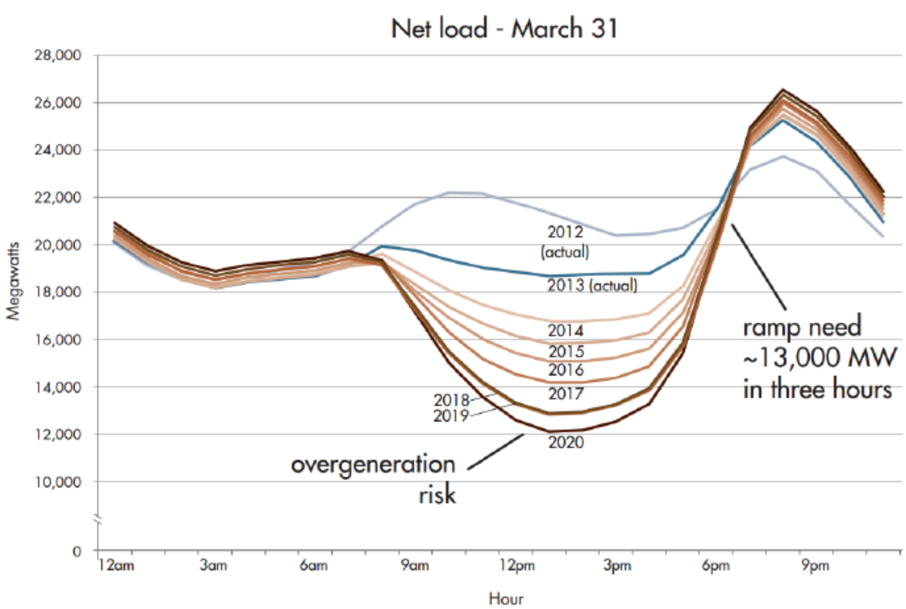
2. Expected or Potential Near-term Effects of Increased DER Penetration

DER impacts studies are currently analyzed during a static point in time, during the worst-case scenario. Depending on the type of resource, this scenario will differ for time of day and season. An n-1 contingency (breaker or recloser lockout) analysis is also typically included as part of the study to account for potential operational reconfigurations. Due to the dynamic nature of the distribution system, however, there are infinite possible scenarios that could occur simultaneously or independently at any given time. This includes various outages throughout branches of a feeder, automated load transfer schemes described in Section IV that will transfer load (and any DER interconnected) to an adjacent circuit, as well as future circuit reconfigurations that may be required due to operational constraints. While a small quantity of DER spread throughout the system does not have a significant impact on operations, as levels of DER penetration increase, it limits the operational flexibility to switch circuits and hinders the ability to permanently move load. Since operational flexibility is crucial to providing adequate and reliable service, this limitation has the potential to negatively impact customer reliability.

While the distribution system will see the effects of DER first, as penetration levels increase, impacts on the bulk power system are expected to also transpire. As described in NERC's *Performance of Distributed Energy Resources During and After System Disturbance*[11] report, voltage and frequency issues as a result of DER penetration is a concern, particularly for inverter-based DER that complies with current UL 1741 standards. As stated within the report, high penetration of DER simultaneously tripping offline due to voltage drop from a transmission fault would compound a transmission contingency and increase the probability of a cascading disturbance. There is also currently no provision for staggered restart of DER (all inverters reconnect after 5 minutes of system voltage being restored above 88% of nominal levels) in order to avoid possible problems during system recovery. As penetration increases, it will become critical for DER to remain online during transient faults to maintain system stability.

Another impact on the bulk power system due to high penetration of DER is the evolution of the duck curve. This phenomenon occurs when DER output produces over generation that does not align with system demand. In the case of California, over-generation occurred between the hours of 9am-6pm and caused a significant reduction in the overall system load during low-demand periods. Because California's system peak occurs just after the over generation drop-off, this creates a steep ramp in generation required. As seen in Figure VIII-1 below included in NREL's report, California projected in 2020 that DER penetration in that state will result in ramp of 13,000MW needed within a three-hour window.

Figure VIII-1: The CAISO Duck Chart[12]



11NERC. (2013). Performance of DERs During and After System Disturbance.

[12] National Renewable Energy Laboratory, "Over-generation from Solar Energy in California: A Field Guide to the Duck Chart", NREL/TP-6A20-65023, November 2015, pg. 3.

Similar to California, Central Hudson's system peak typically occurs between the hours of 4pm-6pm. This is outside the hours where solar output is at its highest. The common concern behind the issue of the duck curve is the ability for system operators to maintain system stability, including voltage and frequency, due to a large change in system demand within a short period of time.

Another effect of high penetration of DERs is the ability for system operators to accurately manage and forecast load. As solar is intermittent and not available at all times of day, it may mask the true load at certain times of the year, but at any given point could need to be compensated with other sources of generation. Forecasting and determining "net" loads versus "gross" loads will be crucial for operators to have a solid understanding of system conditions in order to ensure the distribution system does not experience overloads due to quick reductions in generation output. Loss of DER during low-voltage transmission events due to periods of high demand could also result in a net load increase and exacerbate low-voltage conditions and potentially result in a collapse.

3. Changes to Existing Policy and Processes

In order to ensure reliability and safety are maintained while still enabling DER to be encouraged and integrated, various regulatory and operational processes and procedures will need to be implemented. Customers currently install solar with the intent to reduce electric bills and provide green energy. In order to see a financial return on their investment, they look to maximize the output of their system. During a high penetration scenario; however, system operators may need to curtail or adjust PV systems in order to maintain adequate power quality or reliability on the T&D system. Therefore, clear rules must be established, including non-discriminatory dispatch priorities for controlling DER[13], not just at the NYISO level, but also at the distribution level. A coordinated effort between the NYISO and the DSPs will be required regarding resources connected at all voltage levels. Where the utility has existed to maintain the reliability and safety of the grid, this responsibility drives the need for supervisory control as well as generator guidelines to ensure some level of responsibility and accountability.

In the near term, Central Hudson is developing procedures and updating its operations and maintenance (O&M) to manage local transmission, substation, and distribution switching where solar PV larger than 1 MW is located to maintain safety and reliability of the system, and ensure thermal overloads or risk of islanding is not increased when feeders are in alternate configurations. As the DMS is installed and there is 24/7 oversight by Distribution System Engineers, the DMS will be a tool to access the risk of specific scenarios and DERs will be able to remain online more frequently when in alternate configurations. This will be further developed as weather forecasts enable more real-time DER load shapes to predict the daily operational impacts of these intermittent resources.

As DER penetration continues to increase, more widespread system impacts and operational changes will become necessary. In order to continue to promote integration, mitigation solutions such as smart inverters and battery storage will need to be pursued further. The IEEE 1547 standard and UL 1741 testing procedures must evolve and be adopted within New York State. Regulatory policies will need to be

[13] Lawrence Berkley National Laboratory. (2015). Distribution Systems in a High Distributed Energy Resources Future. pp. 22 -23.

constructed to require inverter manufactures to include necessary smart inverter functions such as low-voltage ride-through, Volt/VAr support, or provide monitoring capabilities within their inverters moving forward. Some level of retrofitting existing DER systems may also be required; therefore, requirement to install firmware-upgradeable inverters should be supported within the SIR as soon as possible. New grid codes and interconnection agreements will be needed to ensure a high degree of reliability not just for the distribution system, but for the bulk power system. This includes ensuring that generators have a degree of disturbance tolerance (such as low-voltage ride-through), which is necessary to prevent cascading outages following voltage or frequency excursion that occur during normal system operation.

Separate grid codes and operating procedures will need to be established for microgrids. As the concept of a microgrid is to intentionally island, this contradicts most existing interconnection rules and regulations today. Depending on the complexity of an established microgrid, which could include only a few customers in a campus style, or hundreds to thousands in a community style, this could require higher integration costs due to additional protection that may be required. For example, a customer owned generator that was not constructed as part of an initial microgrid connection, could cause power quality issues while within the microgrid mode and thus be required to trip off during this alternate operating scenario.

4. Visibility and Communications

With the increase in DER systems and high levels of penetration, visibility and control to these systems will become crucial. Policies to date within Central Hudson have focused on monitoring requirements and capabilities, direct transfer trip, and simple remote trip/close capabilities for DERs. Central Hudson requires remote monitoring and control through an electronic recloser for solar PV systems with nameplate ratings greater than 1 MW, but a lower value will likely be necessary in the future, as is being pursued through the ITWG and the Supplemental DSIP stakeholder engagement sessions. Static power factor adjustments may be allowed to alleviate the need for utility system upgrades, but direct monitoring and control of the inverter or autonomous adaptability of inverters to system conditions is still under development in the industry as a whole. With high penetration of DERs, this will need to evolve quickly to mitigate retrofit costs of existing equipment and prepare for the near future.

Inverters will need to provide a level of adaptability and autonomy to both the distribution system and bulk power system, such as Volt-VAR, Volt-Watt, and low-voltage ride through, but will also need to be controlled as system conditions require. In the case of native net loads vs. gross loads, understanding the true native load on a system will be crucial for system operators to have awareness of operational flexibility in order to not generate a system overload that ultimately impacts customer reliability. In the case of the duck curve and system demand requirements, inverter communication would be essential in order to curtail DER systems output to maintain stability. Communications to these inverters will need to be real-time to successfully implement these capabilities.

EPRI's White Paper *Standard Language Protocols for Photovoltaics and Storage Grid Integration*[14] lists common priority smart inverter functions and the drivers behind them. The seven priority functions listed

[14] Standard Language Protocols for PV and Storage Grid Integration: Developing a Common Method for Communicating with Inverter-Based Systems, EPRI White Paper, May 2010

include: connect/disconnect from grid, power output adjustment, VAr management, storage management (charging/discharging), event/history logging, status reporting/reading, and time adjustment. These functions indicate a wide range of specific information that is to be exchanged between the controlling entity and the field devices. This EPRI work was performed using IEC 61850 architecture, which as explained in Pacific Northwest National Laboratory's 2015 *Grid Architecture,*[15] is a family of standards that allows for event messaging, data exchange, and configuration, and was originally intended for electrical substations but has grown to encompass PMU's and DA. Pacific Northwest's *Grid Architecture* report also provides a list of the other various architectures currently available as well as their associated organizations.

There are currently not only multiple architectures available but also open communications to address smart inverter control and visibility. In order to map the data points and functions into communication protocols in a standardized way, EPRI has been performing work using the IEC 61850 architecture and mapping using DNP3 and Smart Energy Profile 2.0. More testing and validation is required to ensure the validity of these methods.

As part of the recommendations that emerged from California's Energy Commission and Public Utilities Commission's smart inverter working group, various smart inverter functions and protocols were addressed as well as cyber security requirements. As listed in *Recommendations for Utility Communications with DER Systems with Smart Inverters,*[16] California's default protocols are SEP 2.0 and IEEE 2030.5 but they enable other protocols to be used by requiring a 3rd party certification process for validating implementations. This report provides detailed use cases for communication options, platforms, specific functions, the level of visibility required (seconds vs. minutes), and associated protocols.

As inverter manufacturers currently pursue their own forms of communication protocols, which are not tied to any specific regulations, when supporting open methods of communication, these mediums support protocols with least complexity and least security. Standardized communication protocols and inverters with accurate and real-time readings will be crucial for system operators to understand and react to the conditions of the grid.

In order to ensure the correct protocols and communication methods are chosen, as well as smart inverter functions, more work, research, and field demonstrations will be needed to ensure cyber security is not altered when communicating and controlling these 3rd party devices. Requiring the standardization of these communication protocols through varying inverter manufacturers will be crucial as well. These items will be discussed within the ITWG and next steps should be determined to ensure Central Hudson and the other utilities within New York State adopt smart inverter functionality as quickly as possible where benefits are available, learning from other jurisdictions, while maintaining reliable and safe operations of the grid.

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[15] Pacific Northwest National Laboratory . (2015). Grid Architecture, PNNL-24044.

[16] California Energy Commission (CEC); California Public Utilities Commission (CPUC). (2015). Recommendations for Utility Communications with DER Systems with Smart Inverters.

IX. Distribution System Administration

A. Overview of Distribution System Administration

Central Hudson is committed to providing customers and developers the data to identify potential opportunities to offer solutions that can improve the efficiency of the system and add value to customers. The exchange of data about system needs, locational value, and loads is crucial to the development of markets for DERs. As the DSP provider, Central Hudson is committed to facilitate the exchange of data. There are, however, numerous challenges regarding the exchanging data, particularly customer data.

Central Hudson held four DER engagement sessions to discuss the overall DSIP and stakeholder system data needs. These sessions included three stakeholder reviews inviting our most active DER providers and a general overview session open to a wider audience. All of these sessions helped identify the types of information that would be beneficial to our stakeholders. The information included as part of this Initial DSIP filing is aligned with the stakeholder needs.

B. System Data Acquisition & Sharing

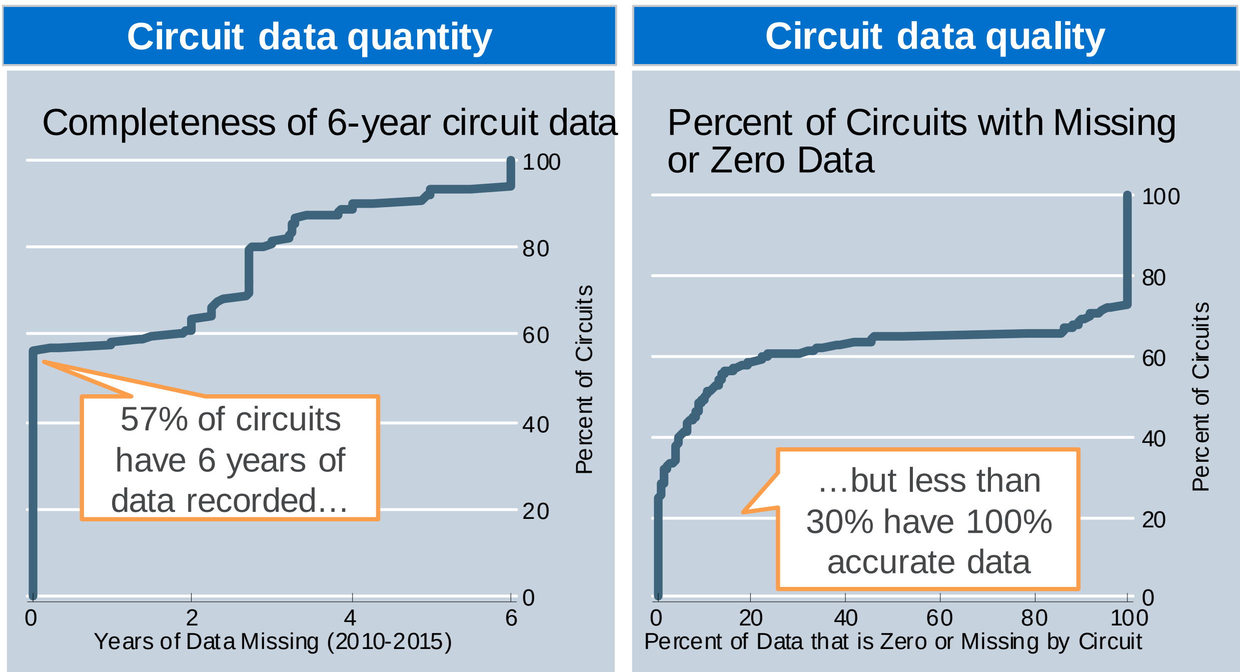
1. Data Available

The system data available to stakeholders includes:

- Central Hudson's 2017–2021 Corporate Capital Forecast and 2017 Capital Budget Summary Book Electric Section, which identifies and provides details (cost, schedule, needs assessment) on our electric capital projects;
- Hourly (8760) load data for 54 distribution load serving substations where detailed metering information was available, including five years of historical data (where available) and five years of forecast data with uncertainty bands;
- Up to five years of historic 8760 load data for each of approximately 270 circuit feeders (where available);
- Indicative map for solar installations highlighting areas of our system where it may be more costly to interconnect;
- A road map outlining future efforts to both develop a common hosting capacity methodology with the joint utilities and Central Hudson's plans to develop and make available hosting capacity maps;
- Location specific avoided T&D cost study identifying areas of potential future need based on probabilistic planning methodologies;
- Potential projects under consideration for future NWA solicitations; and
- CenHub.

Of Central Hudson's 70 distribution load serving substations, 54 (77%) have reliable hourly data. Substations that lack hourly loads still record peak loads. Of Central Hudson's approximately 270 circuit feeders, 164 (75%) have at least one year of data of valid data. Figure IX-1 shows the quantity and quality of circuit feeder data. In total, 61% of feeders have data recorded for 2010-2015. Many additional circuits have data recorded but lack data for the full time span. For sites with data; however, data quality can be an issue. A substantial share of sites have missing or zero values in the data. The availability of data and its quality is a pre-requisite for developing location specific forecasts and marginal costs. Without multiple years of historical data, estimates of growth trends are overly sensitive and can be misleading.

Figure IX-1: Circuit Feeder Data Quantify and Quality



For locations with meters, data quality is concern since the data include outages, data gaps, and temporary or seasonal load transfers. Load transfers, in particular, can be mistaken for load growth or decreases in loads. Many substations and circuit feeders have only a few years of data available because meters to record hourly patterns were only installed recently. In general, however, data quality is higher for larger substations and circuit feeders that account for the bulk of the loads and customers. Central Hudson relied on data analytics to identify load transfers, data gaps, and outages from substation level data. When there was data recorded for periods before and after gaps, loads were estimate via an econometric model. Estimates are clearly identified in the available data to ensure they are not confused with actual values.

2. Process for Providing System Data

Existing, historical data is available currently but requires an explicit request and the process for downloading data is not yet automated. Data will be extracted and delivered to entities requesting it on a first come, first serve basis, and may take up to two weeks to deliver. Due to the volume of files, we recommend requesting data for specific beneficial locations rather than for the entire service territory.

Parties should submit data requests to disp@cenhud.com

3. Future Process to Share System Data

The current process for sharing system data is manual rather than instantaneous. Based on stakeholder feedback on the interest of data, a manual approach is suitable in the interim. Ultimately, however, the goal is to allow customers and stakeholders to be able to view dashboards and download system data from an online portal that serves as a central repository. This would include:

- The ability to specific and download historical and forecast data by substation and feeder
- The ability to visualize for transmission areas, substations, and feeders:
  - ✓ Location specific annual forecasts with uncertainty, including the likelihood of exceeding design rating by year
  - ✓ Substation and feeder load shapes
  - ✓ Load duration curves
  - ✓ Solar installations, including heat maps of where it is more costly to interconnect
  - ✓ Locational specific avoided costs of T&D capacity by location and year based on probabilistic methods

C. Customer Data & Engagement

The exchange of customer data between all persons and entities participating in the development of competitive energy markets is crucial to the development of those markets. As the DSP provider, Central Hudson is committed to facilitate the exchange of customer data to those that need it for purposes of market development. There are, however, numerous challenges regarding the exchange of customer data.

Central Hudson collects and assembles certain customer data on an individual customer basis and on an aggregated basis. It has been time consuming and expensive for Central Hudson to collect and assemble the customer data. Central Hudson has developed the systems and personnel that collect and assemble the data over a long period of time. Central Hudson continues to invest in customer data collection and assembly and anticipates the need to continue significant information technology and labor investment so that Central Hudson can collect, maintain, assemble, and disseminate the customer data it needs to provide reasonably priced regulated utility service for customers. The customer data currently held by Central Hudson is not available in the market and cannot be replicated except through great effort and expense by market participants and, therefore, has value to market participants.

Customer data requested by market participants that is not currently collected by Central Hudson or that requires a different assembly or form than that used by Central Hudson may be expensive to produce. It may also have substantial value to market participants and/or customers.

Central Hudson permits two uses of customer data.

- First, customer data is used in the provision of regulated utility service. Central Hudson, for example, maintains some customer data in its customer information system (CIS), which is available to its customer service representatives so that they may answer inquiries from customers. Central Hudson may also hire a vendor to provide regulated utility service, such as EE service, on its behalf. In such cases, Central Hudson makes customer data available to the vendor just as it does to its customer service representatives; so that customers may receive high quality reliable regulated utility service. Both Central Hudson's employees and its vendors are required to maintain the confidentiality of the customer data.

- Second, Central Hudson provides customer data to third parties if the third party receives documented customer authorization. This permits customers to provide customer data to Energy Service Companies (ESCO), or other competitive providers that may have need for the customer data and with whom the customer wants to communicate. In most circumstances where the customer authorizes transmission of their data to a third party the third party is required to keep the customer data confidential. The customer, however, does have the option to make public customer data pertaining to them.

The New York State Commission, in Case 07-M-0548, discussed at length the reasons for, and the need to maintain the confidentiality of customer data.[17] In its Order on Rehearing the Commission recognized and affirmed the principal that customers must authorize the utility to provide customer data to an entity, in that instance ESCOs, that sell services to customers before the utility may provide the data to the requesting entity.[18] In Case 14-M-0224, the Commission has ordered the utilities to make an exception to the general rule that an entity obtain customer authorization before it can obtain customer data from utilities.[19] Specifically, the Commission requires utilities to provide customer data to Community Choice Aggregators (CCA) without customer authorization under specified circumstances to eliminate barriers to CCA formation.[20]

These facts give rise to certain principles regarding the dissemination of customer data that are reflected in Central Hudson's DSIP. Central Hudson will continue to gather and assemble the customer data that it needs to provide utility service for customers directly or through vendors. In instances where Central Hudson receives assistance from vendors to provide utility service and those vendors require customer data to perform their responsibilities, Central Hudson will continue to require that those vendors protect customer data as vigorously as does Central Hudson. Central Hudson will continue to make customer data available to customers in a secure manner through means convenient to the customer, including over the telephone and through Central Hudson's website.

Central Hudson will also continue to make customer data available to entities selling competitive services to customers, including ESCOs, if they receive and maintain customer authorization in a manner consistent with the Uniform Business Practices (UBP). In accordance with the Commission's directive Central Hudson will provide customer data to CCAs without customer authorization under the circumstances proscribed by the Commission. Central Hudson will provide the information that it has readily available to customers and entities free of charge, just as it does today. But, if a customer or entity

[17] Case 07-M-0548 et. al. - Proceeding on Motion of the Commission Regarding an EE Portfolio Standard (Order on Rehearing Granting Petition for Rehearing) (Issued and Effective December 3, 2010).

[18] *Id*. at 9.

[19] Case 14-M-0224 - *Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs* (Order Authorizing Framework for Community Choice Aggregation Opt-Out Program at 42-46) (Issued and Effective April 21, 2016).

[20] *Id*.

requests information in a manner that currently requires a charge, or that requires Central Hudson to gather new information or assemble the information in a new manner, Central Hudson will appropriately charge the customer or entity for the data.

1. Summary of Technical Conference on Customer & Aggregated Data

The Commission, in Case 14-M-0101 issued a notice on November 3, 2016, that it would hold a technical conference on December 16, 2015, regarding the provision of customer and aggregated energy data.[21] On December 4, 2015 the Commission issued an agenda for the December 16, 2015 technical conference.[22] On December 23, 2015 the Commission issued a notice that it would hold a second customer data technical conference on January 20, 2016.[23] Central Hudson participated in both technical conferences.

The technical conferences sought information from the utilities regarding their dissemination and treatment of customer data. Central Hudson indicated that it provides data to customers and ESCOs through its website with My Account, Green Button Download My Data. Central Hudson also provides data to ESCOs through Electronic Data Interchange (EDI). Before a customer or ESCO gains access to the customer data they must enter the customer's account number, which provides a reasonable measure of security. ESCOs, and applicable vendors who may receive customer data and are required to obtain customer authorization must maintain records of the authorization so that the Commission may verify their compliance with UBP requirements.

Central Hudson has investigated the deployment of AMI. Central Hudson is committed to facilitate market development consistent with the Commission's intent regarding REV. As market development pertains to AMI, Central Hudson will allow any customer that wants an AMI meter to obtain one through an advanced data service on a subscription basis, but does not plan to require all customers to take an AMI meter. Central Hudson continues to study AMI deployment but does not believe that a benefit cost analysis justifies universal implementation in its service territory.

Central Hudson is committed to continue to permit customers to access their data. Currently, customers, ESCOs or other applicable vendors may access data by telephone or through Central Hudson's website at CenHub My Account, through Green Button Download My Data, through EDI, and through custom web transactions such as the Specific Account Usage Inquiry. Central Hudson understands that a transition from Green Button Download My Data to Green Button Connect is expensive. Utility experiences in California, have shown that Green Button Connect may cost $5 million to $19 million to implement and may not provide customers with significant benefits. In regard to the cost of data provision Central Hudson agrees with the Commission that it is important to market development to ensure that market

[21] Case 14-M-0101 - *In the Matter of Reforming the Energy Vision* (Notice of Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues) (Issued November 3, 2015) (hereinafter Case 14-M-0101 shall be referred to as REV).

[22] REV (Notice of the Agenda for Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues) (Issued December 4, 2015).

[23] REV (Notice of Second Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues) (Issued December 23, 2015)

participants, customers and vendors, have access to the data that they require, but data provision comes at a cost. Automation of data provision does not lesson the cost of data provision. The cost, and the rate charged for data provision, simply becomes a question of the amortization period over which to spread the automation costs. Ultimately, all customers, or the specific market participants that request the data, must pay for the customer data.

The Commission's vision of REV requires innovation and cooperation among all stakeholders to increase the efficiency and productivity of energy production. The Commission's vision applies equally to the production of customer data. Central Hudson will continue to examine existing customer data provision methods and develop new ones in an efficient and productive manner that meet customers' needs.

2. Summary - Data Provision & Data Portal

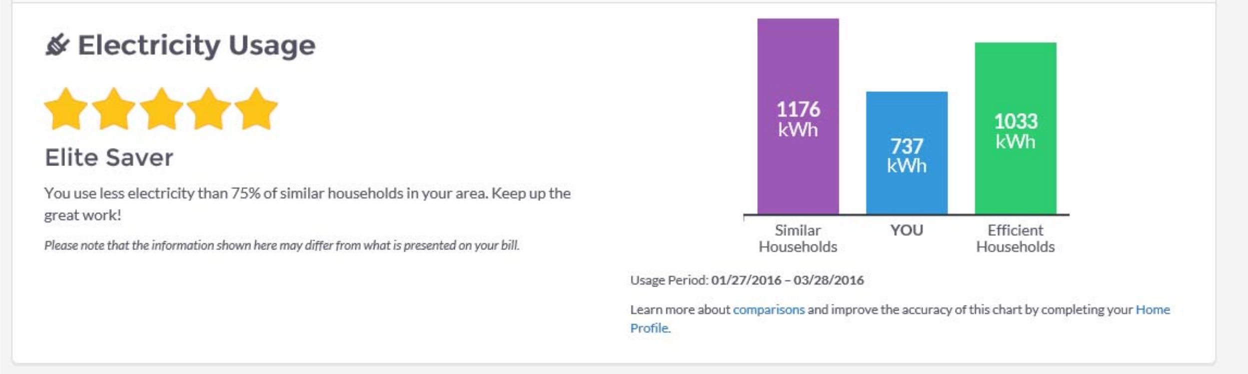
Through the CenHub online platform, customers have access to information about their usage in a number of ways.

Beyond the Billing & Usage History screen that has been available through MyAccount, once the customer has signed into the rebranded CenHub My Account they are provided with a new tab in the navigation menu called, CenHub Insights. Within CenHub Insights there are two options (1) Overview and (2) My Usage, which provide a new way of viewing and understanding their energy usage that goes beyond a tabular display of meter read data.

Overview Screen

The Overview provides the customer with a side-by-side comparison of their usage to l similar households and to efficient households as shown in Figure IX-2.

Figure IX-2: Overview Screen

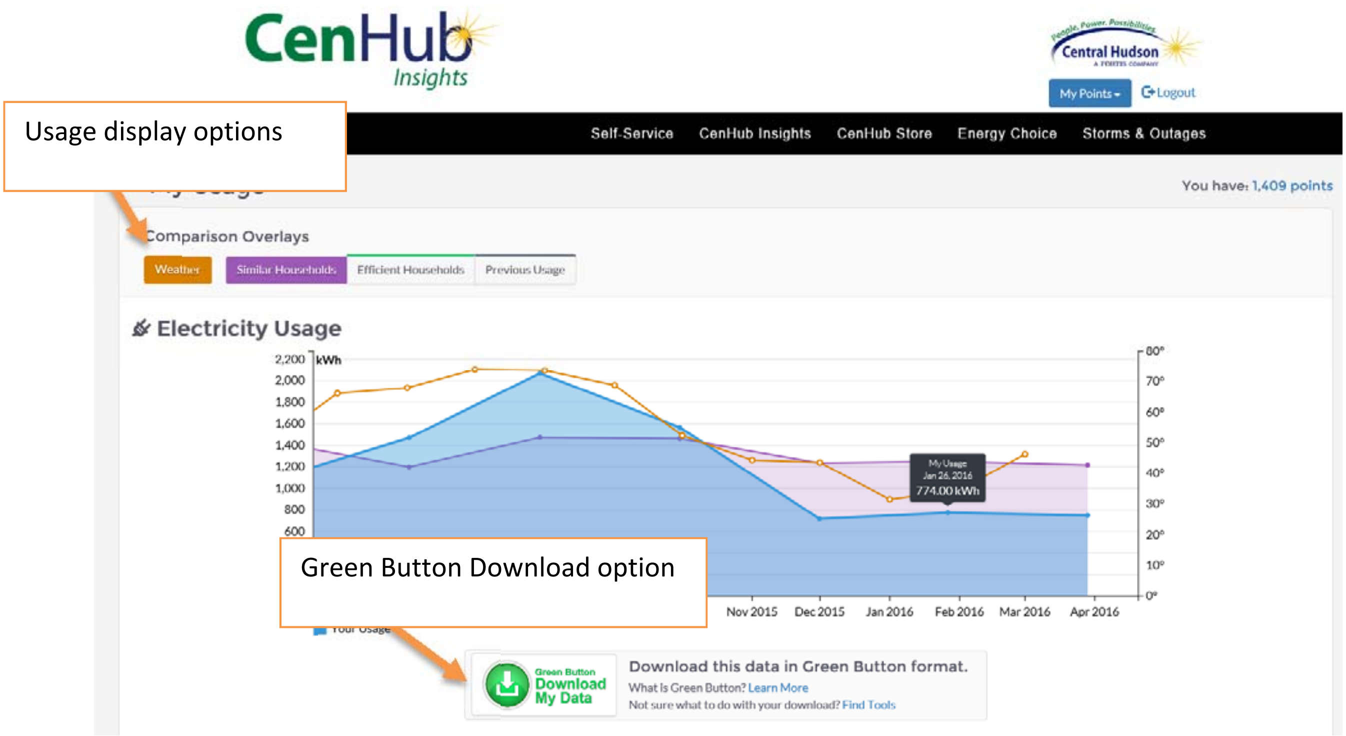


My Usage

The My Usage screen, illustrated in Figure IX-3 provides customers with a graphical display of their usage data points and provides the ability to overlay the usage data with their historic usage pattern, the usage pattern for similar or efficient homes, and the weather.

In addition, customers can also access their data through the Green Button Download My Data, which provides the customer with an XML file of their usage data per the Green Button Download My Data defined standard.

Figure IX-3: My Usage Screen



3. Customer Data and Engagement

Central Hudson remains committed to making its customer data available to customers, CCAs, ESCOs and other vendors through easily accessible means including Central Hudson's website and call center. Central Hudson will work with New York State DPS Staff, customers, CCAs, ESCOs and other vendors to find other appropriate means to accumulate, assemble, formulate, and transfer data. Regardless of the method used to make customer data accessible to those that need access to it, the customer data needs to remain secure

Data Fields

The information that Central Hudson does, and will continue to provide is consistent with the information that the UBP requires Central Hudson to provide to a customer and/or ESCO, and includes, for gas and electric service as applicable, the customer's:

1. Service address;
2. Electric or gas account indicator;
3. Sales tax district used by the utility and whether the utility identifies the customer as tax exempt;
4. Rate service class and subclass or rider by account and by meter, where applicable;

5. 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. 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. Standard Industrial Classification (SIC) code;
9. 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. 12 months, or the life of the account, whichever is less, of customer data via EDI if an ESCO, and, upon separate request, an additional 12 months, or the life of the account, whichever is less, 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; and
12. Electronic interval data in summary form (billing determinants aggregated in the rating periods under a distribution utility's tariffs).
13. If gas customer, weather normalization forecast of the customer’s gas consumption for the most recent 12 months or life of the account, whichever is less, and the factors used to develop the forecast;
14. Meter reading date or cycle and reporting period;
15. Billing date or cycle and billing period;
16. Life support equipment indicator;
17. If gas customer, gas pool indicator;
18. If gas customer, gas capacity/assignment obligation code;
19. If electric customer, Customer’s location based marginal pricing zone, for electric accounts only;
20. Budget billing indicator;
21. Credit information for the most recent 24 months or life of the account, whichever is less, including the number of times a late payment charge was assessed and incidents of service disconnection; and
22. A direct customer shall receive usage data and estimated consumption for a period and, upon request, a class load profile for its service class.

Provision of the above listed customer data by Central Hudson is contingent upon the information that Central Hudson has in its possession. Not all customers provide all of the data requested and neither Central Hudson’s equipment nor its employees gather all of the requested information. Additionally, Central Hudson will provide additional information or information assembled in a format different than its standard format, at an additional charge. Central Hudson will file tariffs to set the charges for additional and nonconforming information requested by a customer, CCA, ESCO, or other vendor.

Means by which Utility Customers can Obtain Information Regarding their Energy Usage

Today, Central Hudson's customers may access their account data in two ways. They can go to http://www.centralhudson.com/ and Access CenHub My Account, which is prominently displayed throughout the website. Customers may also call 845-452-2700 or 800-527-2714 to speak with a customer service representative who will help a customer gain access to their account information. A fax number is also available as is a number for our speech and hearing impaired customers.

Central Hudson provides 24 months of data at no charge upon the request of customers, ESCOs, and other applicable vendors. A customer or vendor may request the same data twice within a 12-month period. There is a minimal charge of $15 per request for each additional request after the first two requests during the current 12-month period and requests for information older than 24 months if it is available. Additionally, a customer, ESCO, or other authorized third party can utilize the Specific Account Usage Inquiry to view 24 months of customer usage data. The Specific Account Usage Inquiry is free of charge, can be utilized multiple times and can be found at http://inet.cenhud.com/RetailChoice/ICforESCOs/InqAcct.aspx.

It is time consuming and expensive to collect customer data. The reasons that it is time consuming and expensive to collect customer data are that: (1) some of the data must be collected from customers who may be unwilling or able to provide the data; (2) not all customers are available to provide data at the same time causing Central Hudson to collect data from customers over long periods of time as Central Hudson has contact with customers; and (3) information systems must be developed, implemented or amended to collect, process and format information in the manner requested, if the information can be collected at all. The cost of providing customized data must be recovered by Central Hudson, including a reasonable return on Central Hudson's investment.

Extent and Granularity of Data is Currently Available for Customers to Review

As previously discussed, Central Hudson makes 24 months of account data available to its customers. Additional account data is available for a nominal charge. The account data that is currently accessible to customers is set forth in Section IX(D)(3). Central Hudson believes that whether additional data granularity becomes available to customers is largely a market function. If customers want, and are willing to pay for more detailed data, Central Hudson will explore the costs associated with data provision and file a tariff provision seeking the Commission's approval for cost recovery and, where appropriate a reasonable return. It is also possible that some customers will receive data from sources other than Central Hudson. Customers that obtain service from solar developers that use smart invertors, security and heating and cooling providers that offer in home energy services, and customers that choose to install smart meters may all receive granular data from competitive vendors.

Processes for Making the Data Available to Customers

Central Hudson, as previously discussed, makes account data available to customers through its website and its call center. Central Hudson's website uses Green Button Download My Data through CenHub. Security is provided by requiring the user enter a unique user name and password to access CenHub.

Central Hudson will continue to research and explore new and improved processes to make account data available to customers including Green Button Connect. Central Hudson will examine each option through a benefit cost analysis. Currently, Central Hudson is unaware of a data transfer process beyond those it currently uses that would provide additional benefits to customers at a reasonable cost.

Plans to Expand the Collection of Granular Usage Data and how to Make it Available to Consumers

Central Hudson collects data from three primary sources: (1) customers when they fill out service applications and other documentation they must provide to Central Hudson on occasion; (2) from Central Hudson’s facilities, including meters, its website and other social media; and (3) from vendors that work on behalf of Central Hudson. REV offers the opportunity to partner with vendors to gain new information about the types of services that customers may want at particular price points.

As customers choose to use new technology Central Hudson may have the opportunity to collect new data and provide it to customers in new ways. Customers, for example, may decide to purchase smart meters, which may permit the collection of storm outage and restoration, peak demand and DR data. It may also allow for direct communication with the premises through the meter. Central Hudson may find new software applications through which it may communicate with customers. Central Hudson will continue to look at new data dissemination tools including Green Button Connect. If new communication tools have net benefits for customers Central Hudson will work with DPS Staff to explore how to provide those benefits to customers.

Plans to Enhance the Ability of Utility Customers to Obtain Information Regarding their Energy Usage

Central Hudson has a long history of embracing the development and implementation of innovative processes and technology. Recent examples include robots that identify structural issues in gas pipe, underground fault indicators that distinguish between a cable fault and transformer failure, and an online gas locator tool that provides residential customers with 24 hour seven day a week access to information about the availability of natural gas service at their home.

Central Hudson as the DSP has dedicated an Energy Transformation & Solutions team to developing innovative customer solutions that Central Hudson may implement and facilitating the development and implementation of innovative solutions that the market may provide to customers. The Energy Transformation & Solutions team successfully developed and implemented CenHub, an electronic market and communications platform where customers can make energy beneficial purchases and exchange information. The Energy Transformation & Solutions team will continue to develop new services for customers through Central Hudson and market development, including enhanced information dissemination.

4. Vendor Access to Customer Data

As was previously discussed, vendors have access to customer information: (1) through Central Hudson with appropriate security if they are providing utility services on behalf of Central Hudson; (2) through the customer who can provide the XML file download from Green Button Download My Data accessed through CenHub; (3) through Central Hudson's call center if they have customer information; (4) through the Specific Account Usage Inquiry: and (5) through EDI, also with customer authorization. Central Hudson is constantly looking for new and better ways to partner with vendors, including appropriate data access methodologies.

How Vendors can Obtain Customer Specific Information from the Utility, with Authorization from the Customer

Vendors that provide services to customers on their own behalf must obtain customer authorization before they may obtain customer data from Central Hudson. Vendors' may obtain customer authorization in writing, orally or electronically, but must maintain a record of the authorization that it can provide upon request so that the Commission may verify compliance with the UBP and other authorization statutes, rules, regulations, and orders.

Once the vendor obtains customer authorization, if it is an ESCO, the vendor accesses customer data through EDI because that is how an ESCO must initiate and terminate service.

If a vendor requires a unique customer data set or customer data in a unique format, it must contact Central Hudson and explain exactly what it needs. Central Hudson will evaluate whether it can obtain the requested information in the requested format and the cost of the vendor's request. If analysis of the vendor's request shows that Central Hudson has the ability to obtain the customer data, put it in the requested format and results in a customer benefit, Central Hudson shall propose a tariff to the Commission for approval. If the Commission approves the tariff Central Hudson will produce the information for the vendor, and, upon request, to other vendors eligible to receive the information under the tariff.

Extent and granularity of the customer-specific energy usage data that is currently available for sharing

Vendors have access to the same customer data as set forth in Section IX(D)(3). It has been suggested that additional data granularity may cost less once the data gathering and dissemination systems have been automated.[24] Because automation itself is costly this may not be accurate. Automation is costly because it may require significant information system investment, data acquisition systems, and other facility investments. It also may lead to pricing issues. Pricing issues may occur because it may be impractical to charge the first vendor to request additional data granularity 100% of the incremental costs associated with the provision of the granularity, including automation. Central Hudson's cost recovery with a reasonable return, if applicable, may need to be charged over time to a variety of vendors. This may render the automated collection and dissemination of more granular data impractical if there is not sufficient market support.

[24] Case 14-M-0224 - *Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs* (Order Authorizing Framework for Community Choice Aggregation Opt-Out Program at 45) (Issued and Effective April 21, 2016).

Central Hudson will propose tariffed charges for performing the analysis associated with requests for data that it does not currently provide or does not provide in the form requested. Once a request for additional data is made, Central Hudson will perform the analysis to determine whether granting the request will provide a benefit to customers and propose a tariff, if it is reasonable to do so, for Commission approval. If the tariff is approved Central Hudson will provide the information to the vendor pursuant to the approved tariff.

Process(es), protocol(s) and practice(s) for customers to share information with third parties they designate and how the data is transmitted to authorized third parties DG

Central Hudson's customers may share account data with vendors they authorize to receive the data. Authorized ESCOs may receive customer data through EDI. Authorized ESCOs and other vendors may also receive account data directly from the customer after the customer has accessed CenHub, and downloaded the XML file through Green Button Download My Data.

5. Enhancements to Customer Data

The demands of regulation and market requirements may ultimately drive the need to enhance the customer data and the form in which it is available through utilities, vendors, and customers. If new data sets and/or formats permit Central Hudson to improve the provision of utility service at a reasonable cost Central Hudson will request, with an appropriate rate change, Commission approval of the new data set and/or format. Similarly, if market sellers or buyers require new data sets and/or formats from Central Hudson they will make such a request of Central Hudson, which will analyze the request, and if the proposal benefits customers, seek Commission approval to gather and provide the data in the requested format. In other instances, market participants may gather and disseminate the data among themselves at a market price without the need for Central Hudson's involvement.

As the aforementioned needs for enhanced data emerge, so too will new technologies and processes. These new technologies and process will change the nature of data collection and dissemination. Data collection, analysis, and dissemination are rapidly emerging industries. It is, therefore, not possible to predict what future best practices may become. Central Hudson will continue to monitor data collection, analysis and dissemination tools like Green Button Connect regarding customer and vendor needs. As different data tools become available Central Hudson will strive to facilitate the use of the most productive, efficient, and applicable data tool(s).

Extent to which Existing Data Transfer Processes and Protocols Described Above can Accommodate Increasingly Granular Customer Usage Data Transmitted at More Frequent Intervals

Central Hudson's CIS is aging. It is capable, in the short run, of maintaining the customer data that Central Hudson collects. Maintenance of CIS is costly as are added fields and protocols. Thus, CIS can accommodate increasingly granular customer usage data transmitted at more frequent intervals for a cost. Central Hudson constantly evaluates its need for new software and hardware to meet customers' needs as does DPS Staff. As Central Hudson determines that it needs new software and hardware to meet customers' needs, it will make those needs known to DPS Staff, who will decide whether to join with

Central Hudson and recommend rate adjustments necessary for Central Hudson to obtain and install the new software and hardware.

Explain whether an alternative national standard protocol should be explored to accommodate the need to transmit such granular data, if acceptable, and identify plans to move toward that new standard

Central Hudson is not opposed to exploring any standard, national in scope or not. Central Hudson, however, believes that each utility and the market it serves should remain free to adopt the standard that best fits its service territory and market characteristics. Even if all New York utilities moved to one set of data standards, due to the differing characteristics of their information technology, data gathering, implementation and dissemination systems, the utilities would need to implement the protocol over different periods of time at different costs.

Central Hudson believes that REV requires that the market determine its own data needs. The market will decide which customers and vendors need data at a specified price. While Central Hudson appreciates the Commission's desire to allow it to create new revenue streams as the DSP, Central Hudson has not seen any evidence to suggest that customer data will rise to the level of a new core business that will allow Central Hudson, or any other utility to take on additional business or financial risk. If, under the regulatory paradigm, the Commission orders Central Hudson to provide data under a specific protocol at a just and reasonable rate because the Commission determines that there is a customer benefit, Central Hudson will comply, but a regulatory order is different than the demands of market participants.

Further, neither Central Hudson, nor the Commission, or other market participants should speculate about future data needs. Thus far, Central Hudson has provided all data requested of it by providing basic available data free of charge. In at least one case, a data requester decided not to pursue the data after Central Hudson informed it of the expected costs of data production.

Plans to Enhance the Ability of Customer-specific Information to be provided to Third Parties with Customer Authorization, Using Industry-standard Protocols

There are a number of industry standard data protocols and processes. The big data industry is developing new standard protocols and processes for the collection, assembly, and dissemination of data. Central Hudson, DPS Staff and all market participants should review their data needs and the protocols and processes available and ask for the data they require at the price that they are willing to pay. After performing an appropriate benefit cost analysis, Central Hudson and DPS Staff will determine if they can provide the data in the format and at the price requested. Similarly, other market participants selling data will decide if they can do the same.

Central Hudson is partnering with its vendors and customers to collect and assemble new data. Central Hudson is actively looking for innovative ways to put that data to use as the DSP to help facilitate market development. Central Hudson will continually look for enhanced opportunities to obtain, assemble, and disseminate customer data.

Required Enhancements to Privacy and Security Requirements and Practices to Accommodate Increased Data Sharing that will Accompany a Movement to DSP Markets

Central Hudson will more thoroughly discuss this topic in Section XI of this Report. Privacy and security requirements are necessary to protect customers from the substantial harm they may experience if information is improperly disclosed. Central Hudson requires all vendors providing utility services on its behalf to enter a non-disclosure agreement or enter a confidentiality mandate as part of its contract with Central Hudson. Additionally, Central Hudson requires such vendors to demonstrate adherence to minimum security standards so that Central Hudson is assured that customer information in the hands of the vendor is secured in the same fashion as it is secured by Central Hudson. Central Hudson's vendors are also required to submit to an annual security audit.

Vendors that require customer authorization before they may receive customer data have similar requirements unless the data transaction does not involve Central Hudson or the Commission permits some reduced standard as may occur for CCAs. Central Hudson understands the damage a security breach can cause and requires its vendors to maintain vigilant security.

Through the build out of CenHub, Central Hudson has made advancements in the backend security of our systems. The customer sees the end result of a seamless navigation experience but what has driven that is much more complex. We have invested in a Forgerock identity access management solution that is driving changes to the structure of customer usernames and passwords to make them more secure. In addition, we are moving sensitive customer information out of our mainframe system and into a dedicated repository; we are also integrating systems to validate customers and to expose data to that customer based on validating the customer's credentials and account attributes.

X. Advanced Meter Functionality

In the context of REV, AMI deployment is primarily meant to extend REV market access to retail customers. This is accomplished by providing customers access to their energy usage data and by enabling the utility to support additional demand side management options through rates and programs enabled by AMI, including, but not limited to, time varying pricing and improved performance visibility for NWAs. However, when considering which customer resources to incorporate into the REV market, it is pertinent to consider the potential value of services rendered (e.g. energy savings, demand reduction, load shifting) as compared to the cost to measure, verify, and integrate these services (e.g. via some means of telemetry and/or control). Appendix F includes a full benefit cost analysis and discussion about the implications of AMI.

In an effort to thoroughly understand whether AMI presents a cost-effective opportunity for Central Hudson customers to incorporate resources into the REV market, AMI deployment was assessed from various perspectives (societal, utility, ratepayer), scenarios (full and partial), and benefit categories (operational only versus incremental AMI enabled benefits contingent on regulatory changes). The philosophy behind full deployment is that deploying to the full population spreads foundational costs across the greatest number of meters while maximizing total benefits. For Central Hudson, the philosophy supporting its partial deployment scenario is that deploying to a targeted set of customers contributing a disproportionate share of demand and energy use enables a greater portion of resources to be incorporated into markets at a fraction of deployment costs. For the partial deployment scenario, Central Hudson assumed targeting AMI metering to the roughly 4% of accounts that are demand metered but that do not currently exceed the 300 kW threshold for mandatory hourly pricing. While these accounts make up 4% of meters, they constitute approximately 12% of system demand and 27% of total electricity consumption.

In general, the approach taken reflects the intent to understand the potential net benefits of AMI for a variety of options. However, across all of these analyses there was consistently a significant and unavoidable gap between benefits and costs. Under no perspective, scenario, or benefit category did the benefits of AMI outweigh the costs. The details of the analyses are included in Appendix F.

A. Describe the Characteristics of Utility Service Territory and Customer Base that Impact Economics of AMI Deployment

Central Hudson serves a diverse territory with unique characteristics that influence both the incremental benefits achievable and costs incurred through AMI deployment. These include factors that reduce the potential for operational cost savings, such as reductions in meter reading costs and utility outage management costs (thereby reducing AMI benefits) and factors that reduce the potential for customer fairness benefits, such as improvements in metering accuracy (thereby reducing AMI benefits).

The gap between operational AMI benefits and costs for full deployment is explained by the following Central Hudson characteristics:

- The approved deployment of DA will capture a substantial portion of benefits in the form of VVO and outage location identification, leaving little incremental benefits from AMI.
- 50% of customer meters are electronic with advanced meter reading. By 2020, when AMI deployment would begin, about 60% of customer meters will have electronic meters with advanced meter reading. Electronic meters already capture the full or partial benefits for several categories, including meter reading (from walk-by or drive-by reading) and meter accuracy improvements.
- Bi-monthly meter reading for a majority of customers means meter reading costs are already relatively low.
- The presence of gas meters at roughly 25% of customer sites impose the cost of AMI installation to capture meter reading benefits but bring little other incremental benefit.
- The remote geography leads to reduced operational savings (e.g. meter reading) and incremental costs due to the need for additional network infrastructure and cellular meters.

In addition to the characteristics of the current Central Hudson landscape that cause a full deployment to be cost-ineffective, there are two more primary reasons why partial deployment of AMI is also cost-ineffective. In particular:

- Foundational IT investments are required independent of the number of meters deployed
- Fewer meters means reduced savings for operational benefit categories proportional to meter deployment (e.g. meter reading, outage management)

B. Describe Major Component Technologies Required for a Deployment

For the full deployment scenario the major technology components required would include AMI meters (mostly wireless mesh, but also some cellular), a communications network, and a foundational IT platform. The partial deployment scenario would require cellular AMI meters and a foundational IT platform.

AMI meters would replace existing meter units for electric customers (both advanced meter reading and electromechanical), and gas meters would be retrofit with an AMI module. AMI meters can measure and transmit energy usage readings in frequent intervals via a network (either cellular or wireless mesh). Most meters deployed as part of a full deployment scenario would not rely on an existing 3rd party cellular network to support communications. Instead, the utility would build and maintain a wireless mesh network to support communications with the wireless mesh meters. Mesh meters are less costly than cellular meters and there are no recurring communication fees, but an investment must be made to build and maintain concentrators and radios for the wireless mesh network.

Cellular meters would be needed for sparse deployments (either for customers in outlying areas that cannot be reached via wireless mesh or for partial deployment). These customers would need to be served via a cellular connection that would be established with a cellular modem/ radio embedded in the AMI meter. This additional piece of hardware comes at an incremental cost. Monthly communications fees are paid to a cellular provider for the use of their network.

A communications network would be needed to support a full deployment scenario. This would be an extension of the backbone network of data collectors and concentrators already being deployed to facilitate DA. This extension would consist of additional concentrators and wireless radios.

AMI mesh meters relay usage readings via a wireless network to data concentrators installed throughout the territory. Many concentrators would already be deployed prior to AMI deployment as part of the planned DA rollout. Wireless radios installed alongside data concentrators are the backbone of the wireless mesh network. It is via these radios that AMI meters send usage data to concentrators and that concentrators relay this data to the utility. In addition, it is via radios that the utility can send communications to customers, establishing two-way data flows. While many radios would already be installed along with concentrators as part of DA, additional radios may be needed to support the higher volume of data transfers for AMI (though likely not for a partial deployment scenario).

Finally, both a full and a partial AMI deployment would require IT components (hardware / software / systems integration) necessary to support and operate the AMI system. This would include the AMI head end, the Meter Data Management (MDM) System, and integration of these into existing IT systems (e.g. CIS and billing). The volumes of data collected from AMI meters would be managed via a MDM system, which is connected through a meter data head end system. This, in turn, is integrated with the utility's other systems. The MDM and head end systems can be hosted and managed by either the utility or by a technology vendor. For this analysis, a utility hosted MDM was assumed for the full deployment of AMI to the roughly 285 thousand electric and 78 thousand gas meters reachable by remote communications, while a vendor hosted MDM system was assumed for the partial deployment to the roughly 12 thousand demand meters.

In addition to the MDM and head end systems, an AMI deployment would require additional IT costs. Specifically, Central Hudson would need to upgrade its billing system and integrate the head end with other internal systems such as the OMS and the CIS. These costs include an upfront capital investment as well as ongoing cost O&M expense.

C. AMI Business Case Scenarios

1. Full AMI Deployment

This scenario consists of deploying AMI to all customers who can be reached by a wireless mesh or cellular network. Deployment would begin in 2020 and would be implemented over five years. The assumption is that meters for the majority of customers can be reached via a wireless mesh network. However, a small portion of customers reside in outlying areas that cannot be reached via wireless mesh and will need to be served by a cellular network. About 95% of meters are reachable by remote communications (wireless mesh or cellular); about 2% of these are only reachable via cellular communications. In total, about 360,000 AMI meters would be deployed. The remaining meters, about

5% (19,000), are located in areas that are out of range of wireless mesh or cellular service and, therefore, will not receive AMI meters. These meters will still require drive by meter reading.

Table X-1 summarizes the net benefits and the benefit cost ratio for the operational business case. As demonstrated by these summaries, full AMI deployment would not be cost effective for Central Hudson customers from any of the three perspectives. The societal cost test shows a net benefits gap of about $58.8 million and a benefit cost ratio of 0.50.

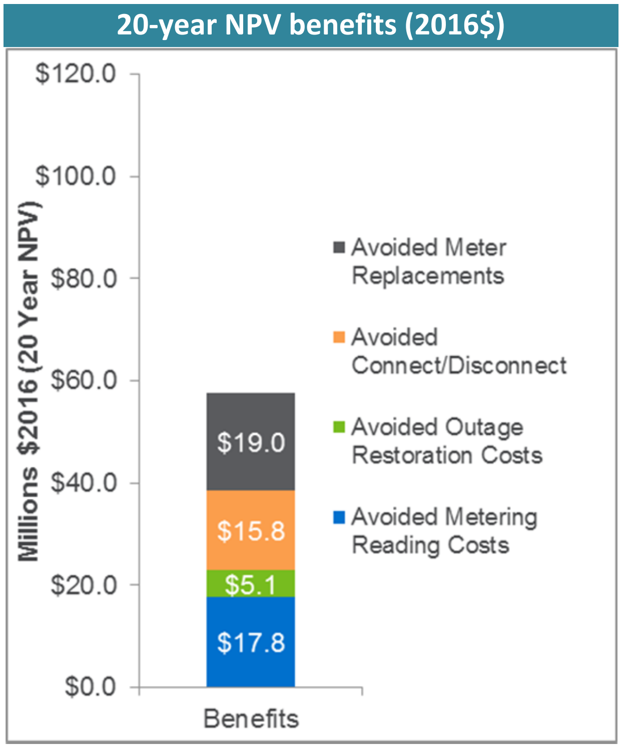
Table X-1: Operational Business Case Benefit and Cost Summary, Full Deployment

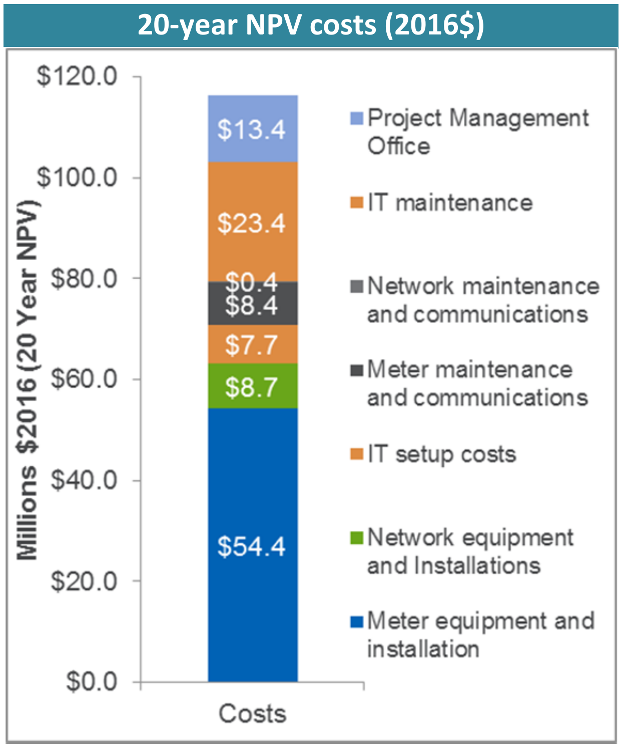
Benefit Cost Analysis (20-year NPV, 2016 $000)	Societal Test	Utility Tests	Rate Payer Impact
Benefits	$57,654.0	$45,621.8	$63,879.5
Costs	$116,450.6	$106,439.9	$106,436.9
Net Benefits	($58,796.6)	($60,815.2)	($42,557.5)
B/C Ratio	0.50	0.43	0.60

Figure X-1 shows the detailed breakdown of cost and benefit categories for the societal cost test for the full deployment operational business case. The right panel shows the breakdown of costs. The one time and maintenance IT costs include MDM and head end costs along with other IT costs. The largest cost category is meter equipment and installation at about $54.4 million, or nearly half the total cost. This is followed by ongoing IT maintenance costs, which contribute $23.4 million in costs.

The panel on the left shows the breakdown of the four operational benefit categories. Though the largest benefit category is avoided meter replacements, avoided meter reading costs, and avoided connect / disconnect (field operations) contribute a similar magnitude of benefits, each between $16 million and $19 million. By comparison, avoided outage restoration costs contribute a smaller portion of benefits, about $5 million.

Figure X-1: Operational Business Case Societal Benefit and Cost Details, Full Deployment

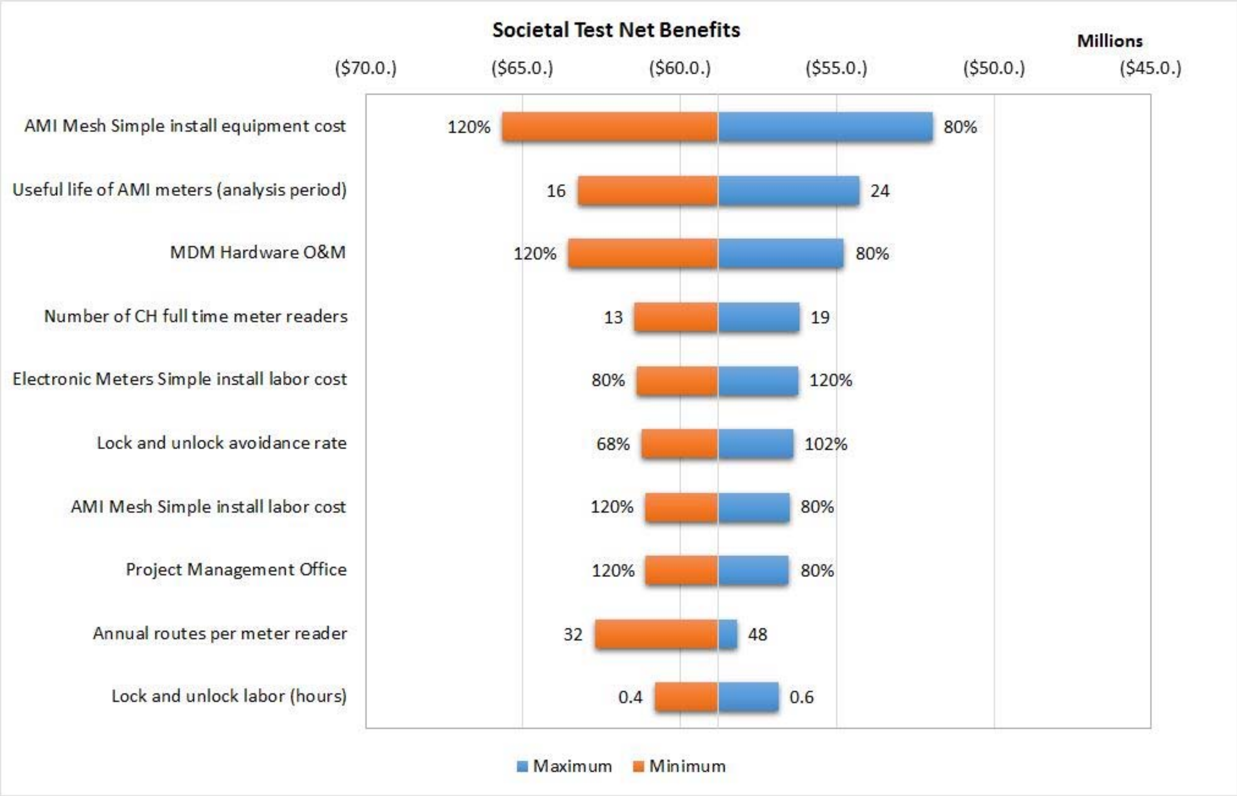




We analyzed the key drivers of cost-effectiveness through a systematic sensitivity analysis designed to identify the inputs that contribute most to net benefits. This is accomplished by varying each component by 20% while holding all other inputs constant. The goal is to identify which inputs have the greatest impact on the results and whether the results will change substantially or directionally by varying or fine tuning inputs. The key finding from the sensitivity analysis is that each individual input has only a small impact on the result.

Figure X-2 shows the sensitivity results for the assumption inputs with the greatest impact on the societal cost test. The top 10 assumptions can be said to be the top 10 drivers of the result. The mid-point where the blue and orange lines meet is the societal test net benefit of about negative $59 million. The conclusion that full AMI deployment is not cost-effective is supported by the sensitivity analysis.

Figure X-2: Top 10 Drivers of Full Deployment Societal Benefit Cost Results



2. Targeted AMI Deployment

This scenario consists of deploying AMI to accounts on demand metered rates that are not currently subject to the provisions of mandatory hourly pricing (about 12k of 380k total meters), which account for approximately 12% of system demand and 27% of total energy usage and consumption. Deployment would begin in 2020 and would be implemented over two years. Due to the dispersion / low concentration of such meters, this will be a cellular only deployment. However, there will still be about 5% of demand metered customers residing in areas so remote as to be out of range of cellular service and therefore will not receive AMI meters.

Table X-2 summarizes the net benefits and the benefit cost ratio for the operational business case. As demonstrated by these summaries, partial AMI deployment would not be cost effective for Central Hudson customers from any of the three perspectives. The societal cost test shows a net benefits gap of about $26.3 million and a benefit cost ratio of 0.07.

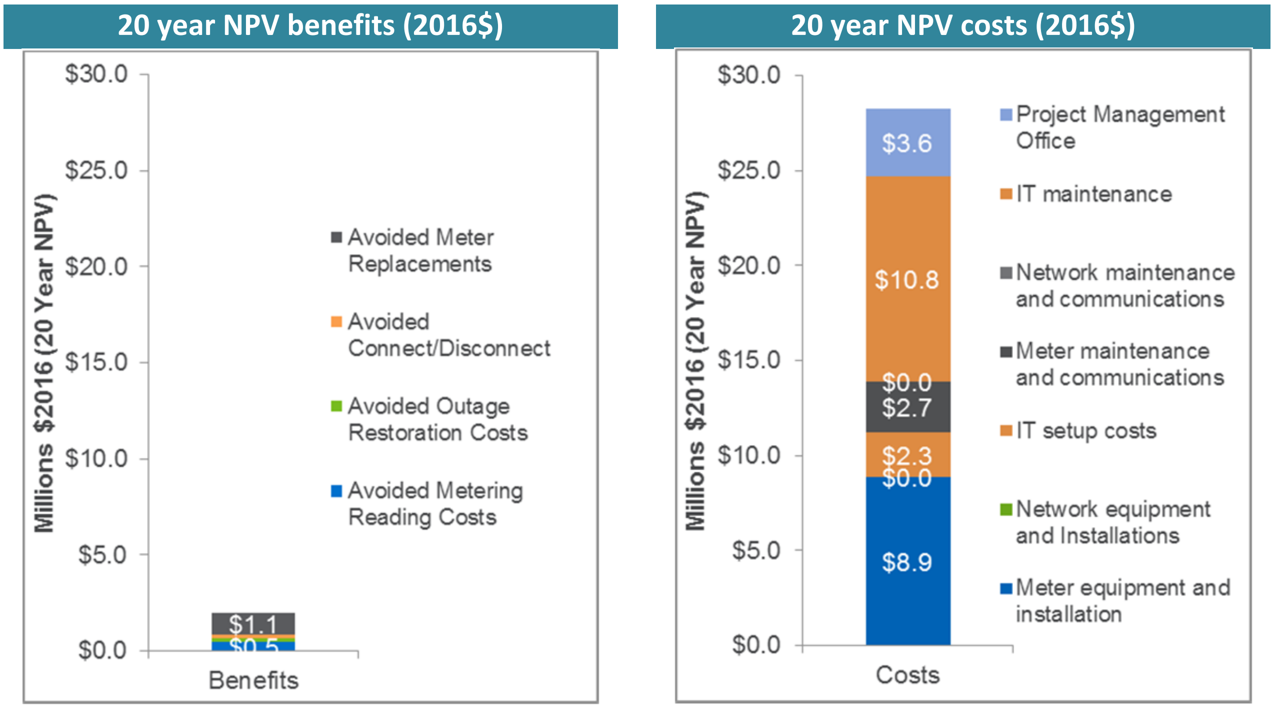
Table X-2: Benefit and Cost Summary, Partial Deployment, Operational Business Case

Benefit Cost Analysis (20-year NPV, 2016 $000)	Societal Test	Utility Costs Tests	Rate Payer Impact
Benefits	$1,956.2	$1,494.1	$5,284.2
Costs	$28,243.2	$25,151.7	$25,151.7
Net Benefits	($26,287.0)	($23,657.6)	($19,867.5)
B/C Ratio	0.07	0.06	0.21

Figure X-3 shows the detailed breakdown of cost and benefit categories for the societal cost test for the partial deployment operational business case. The right panel shows the breakdown of costs. The one time and maintenance IT costs include MDM and head end costs along with other IT costs. The largest cost category is IT maintenance ($10.8 million), followed closely by meter equipment and installation ($8.9 million). IT maintenance is a larger portion of total costs and is higher relative to one-time IT costs for the partial deployment in part because IT maintenance includes the vendor hosted MDM and head end systems, for which cost per meter is higher and for which ongoing costs are higher than one-time costs (there are no one-time costs for a vendor hosted MDM).

The panel on the left shows the breakdown of the four operational benefit categories. Benefits are essentially negligible in magnitude when compared to costs for a partial deployment. The largest two benefit categories are avoided meter replacements and avoided meter reading costs, just as with the full deployment scenario.

Figure X-3: Operational Business Case Societal Benefit and Cost Details, Partial Deployment



3. Opt-In AMI Metering Model

This scenario consists of the opt-in AMI metering pilot explored by Central Hudson and approved by the Commission as a REV demonstration project. In this program, customers will be able to opt to receive AMI meters and access to their usage data through a customer engagement portal.

D. How can REV Markets Work without a Full AMI Deployment

A guiding principal for a functional, efficient market is a focus on deploying resources to markets for which the greatest value can be captured at the lowest cost and for which the marginal cost of integrating resources does not surpass the marginal value of those resources. In other words, value captured by the market should outweigh the cost of participation. Therefore, when considering which resources to incorporate into a market, it is pertinent to consider the potential value of services rendered as compared to the cost of integrating them into the market (e.g. via some means of telemetry and/or control). However, to have a functional market, it is also necessary to sustain participation / resource volume large enough to provide sufficient benefits.

Many resources can be incorporated into REV markets without full AMI deployment but at additional cost. For example, 3rd party aggregators of DR or EE resources can include monitoring of delivered loads. Opt-in AMI provides market access to customers who are sufficiently engaged to enroll in and bear the participant cost of AMI and therefore who may deliver more resources. Finally, DER loads can be leveraged via smart inverters (PV, batteries) or lower cost submeters (EVs) that also provide usage or demand monitoring capabilities.

E. How can Benefits be Achieved without a Full Deployment

Full deployment of AMI is just one potential means of achieving several types of operational utility and societal benefits. Operational benefits include increased distribution system visibility and control, reduced outage management costs, and reduced energy usage. Incremental societal benefits that can be achieved without full AMI deployment primarily include carbon savings. For example, Central Hudson's approved and planned DA implementation will provide a substantial amount of the benefits that are envisioned under full AMI deployment at a lower cost to customers. Other possible alternatives include targeted opt-in AMI for large customers, sub-metering, and smart inverters.

Central Hudson will design the DA system to include the hardware and software necessary to provide VVO benefits. Specifically, it will include control and visibility of voltage levels at many points along each feeder and DMS capabilities that will enable system optimization, including VVO. The design of VVO and the amount by which voltage can be reduced may be slightly lower without AMI, but DA alone will capture a majority of the benefits. A large portion of the VVO related operational savings comes from reduced overall energy usage and reduced peak demand resulting from more efficient operation of the grid. For the utility this means avoided wholesale energy purchases.

The combination of telemetry hardware and a DMS will also provide the majority of the visibility that AMI could have contributed. Among other things, this visibility will reduce outage management costs by enabling Central Hudson dispatchers and crews to more quickly pinpoint the circuits where an outage has occurred and if service has been restored to the circuit (though not to individual end points). These operational savings represent a large portion of benefits full AMI deployment could provide. The limitation is that the DA telemetry and DMS may not provide visibility all the way to secondary level residential endpoints, but it will provide valuable real time visibility down to the primary level. In addition, the DA will provide grid control, or the ability to use telemetry to manage the distribution grid in real time based on telemetry and DMS data. Such capabilities are not accorded by AMI and will facilitate management of DERs by providing visibility into power disturbances and hosting capacity.

The DA related energy savings also result in reduced carbon emissions, the primary societal benefit achievable via a full AMI deployment. Carbon savings can also be achieved through expansion of EE, which may or may not be enabled by opt-in AMI for key large customers. In addition, improved customer engagement in energy usage, which can lead to energy and carbon savings as well as customer empowerment, can be enabled by non-AMI monitoring options. These include data loggers, and more recently, sub-metering, which involves the installation of a lower cost usage monitoring device on DER related end uses, such as EV charging, solar PV production, and AC load switches. New smart inverter technology, which is increasingly included in distributed PV installations, can also be configured to provide monitoring capabilities. These monitoring alternatives facilitate market encouragement of DER loads and other end uses, which also result in carbon reduction (PV and EV).

F. Opt-in Advanced Meter Services

Central Hudson currently has a demonstration project underway to provide customers with advanced metering services. CenHub is a web-based, energy services platform designed to provide customers with information on energy management and access to third party products and services.

To test customers’ desire for more granular and timely information, Central Hudson will offer an enhanced data service on a subscription basis. The enhanced data service will require installation of a smart meter and will include 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 and DR programs as the demonstration evolves.

Central Hudson worked with a third party partners under a new business model to create a customer driven, web-based, energy services platform. The third party partners in this demonstration provide and continue to maintain elements such as the customer interface; ecommerce platform; access to the products and services offered; the meter data and analytics tools. This should be distinguished from a third party provider who provides products and services on the platform. CenHub provides a platform for third party providers to offer Central Hudson customers EE products and services in a central location.

The platform is accessible to all residential customers, but the product and service offerings are expected to be expanded over time and to be inclusive of commercial customer offerings. The proposed platform will not preclude alternative providers of energy products and services and will not limit customers’ ability to choose alternative providers.

XI. Cyber Security & Privacy

A. Cyber Security & Privacy

1. Cyber Security

Central Hudson's Cyber Security Working Group serves as a governance committee that oversees the enterprise wide cyber security program. The program consists of a strategic plan, policies and procedures, security controls, risk management program, security awareness program, incident response, third party security and privacy reviews, security assessments performed by a third party, administering and monitoring security tools, and addressing and resolving security alerts. There are four groups that work closely together to protect Central Hudson's information assets: Cyber Security, Corporate Security, IT Technical Support, and EMS, which consists of customer information and critical infrastructure information.

Central Hudson is continually assessing its cyber security program for further enhancements, such as:

- Performing an assessment in 2016 against the National Institute of Standards and Technology's (NIST) Cybersecurity Framework. See section XI.B below for further information.
- Proposing the implementation of a System Information and Event Management (SIEM) solution. A SIEM solution would enable Central Hudson to store and interpret its electronic records, called logs, of incoming and outgoing data allowing for near real-time analysis of potential threats to enable Central Hudson to act more quickly. The SIEM solution would enhance Central Hudson's threat intelligence capabilities and the time it takes to currently assess security alerts and respond to them. The cost for purchasing and implementing a SIEM solution is estimated at $300,000 and would require an additional full time resource to monitor and respond to the alerts.

2. Privacy

Central Hudson's Legal Compliance, Ethics & Privacy Committee serves as a governance committee that oversees the enterprise wide compliance, ethics, and privacy initiatives. In regard to privacy, Central Hudson has a Chief Privacy Officer that serves as the chairperson of the Legal Compliance, Ethics & Privacy Committee, and has developed an internal privacy policy, in conjunction with its confidentiality policy that employees are required to comply with. Central Hudson also has an external privacy statement that communicates to our customers how Central Hudson protects their privacy, the information gathered when a customer uses Central Hudson's web site, and who to contact for a customer to make corrections to his/her information.

Central Hudson's cyber security program supports its privacy initiative, through its policies and procedures, security controls, risk management program, third party security and privacy reviews, and administration and monitoring security tools.

Central Hudson is continually assessing its privacy initiative for further enhancements, such as:

- Performing an assessment in 2016 against American Institute of Certified Public Accountants (AICPA) Generally Accepted Privacy Principles (GAPP). See section XI.B below for further information.
- Implementing a Data Loss Prevention (DLP) system and a DLP program to effectively address and manage alerts. The system would monitor network traffic for customer information in transit. The system is configurable to either block the transmission or notify an individual that the information falls under Central Hudson's Confidentiality Policy and should ensure that they are in compliance with that policy prior to transmitting the information. The system would then log this activity and send an alert to a designated employee(s) responsible for reviewing the activity and, if necessary, taking additional steps to properly resolve an alert. Central Hudson implemented the DLP system and is currently developing the DLP program to support it, which would require an additional resource to monitor and respond to alerts.

B. Cyber Security and Privacy Framework

The Joint Utilities have created a framework (JUNY Framework) to guide New York Utilities as they develop their own governance and risk management process to address cyber security and privacy risks that may arise from any REV related initiative. Central Hudson will leverage that framework to enhance its current cyber security and privacy programs.

Central Hudson will perform an assessment of its current control environment against two industry recognized frameworks that are leveraged in the JUNY Framework: NIST Cybersecurity Framework and AICPA GAPP. This assessment is anticipated to be completed by the end of 2016 and may result in the identification of additional control enhancements. Central Hudson will implement control enhancements in 2017 and is planning to initiate a process to performing ongoing monitoring of our cyber security and privacy controls against these frameworks. Central Hudson envisions its ongoing monitoring to consist of periodically reviewing the controls for design effectiveness and performing self-assessments on the controls' operating effectiveness. As the cyber security and privacy industries continue to evolve over time, Central Hudson will continue to enhance its cyber security and privacy governance, risk and compliance program.

Using the JUNY Framework, Central Hudson plans to map its current security and privacy controls to the stated security and privacy design principles and control topics. This may identify areas for control enhancements, which Central Hudson will address by identifying the proper resolution and implementing it.

Central Hudson recognizes that a REV project may involve a system that falls under the regulatory requirements of NERC's CIP Standards. In those situations, the NERC CIP Standards will be the framework used in developing the cyber security controls over that system.

C. Risk Management Process

The JUNY Framework recognizes that a risk methodology needs to be implemented as part of the REV initiative in its entirety, as well as for each individual REV project. Central Hudson has an established risk methodology that it will utilize to assess the REV initiative, with a focus on protecting customer and critical infrastructure information. The risks identified will be assessed against Central Hudson's current control environment to determine the residual risk. For any residual risk that is not acceptable according to Central Hudson's risk methodology, an implementation plan will be developed to properly mitigate that risk to an acceptable level.

Central Hudson recognizes that the successful implementation of REV initiatives will require partnering with third parties. As a result, Central Hudson developed a third party security review process with elements employed during the negotiation of the new third party relationship, when a current third party relationship changes, or at the contract terms expiration. The process includes assessing a third party's security and privacy controls, which consist of a risk questionnaire, interviews, and a review of third party audit reports. Central Hudson also developed security and privacy terms to be included within the contractual agreement with the third party. Central Hudson is planning to implement an ongoing periodic monitoring process of third parties compliance with the contract terms and their control environments.

A REV project may include implementing a new system, which Central Hudson would govern under its IT Project Management Office. Using recognized industry framework, Project Management Body of Knowledge, the IT Project Management Office developed its project management processes. As part of this process, the project management process recognizes the importance of cyber security and protecting customer information. Central Hudson Cyber Security Group and its IT Technical Support Group serve as subject matter experts to advise project management teams on the security and privacy risks related to system implementation and to ensure that cyber security risks are properly mitigated.

D. Additional Resources

Central Hudson's REV initiative consists of multiple projects and multiple vendors. In order to fully meet cyber security and privacy requirements for all REV projects, Central Hudson will need to hire additional personnel, which is described in further detail below.

1. Cyber Security Technical Analyst

The Cyber Security Technical Analyst would be responsible for the following:

- Administering, configuring, and monitoring the SIEM solution, as well as addressing and resolving SIEM alerts.
- Configuring and maintaining the DLP solution.
- Acting as one of the subject matter experts to assist in system implementation projects by participating in the system design phase to ensure that cyber security is properly incorporated and the test phase to ensure that the security controls are operating effectively.

2. Cyber Security & Compliance Analyst

The Cyber Security Analyst would be responsible for the following:

- Performing ongoing monitoring and self-assessments of the NIST Cybersecurity Framework.

- Performing security reviews of the third parties that are participating in REV, which consist of initial review, contract negotiations, and ongoing periodic monitoring of third party compliance with the contract terms and their control environments.
- Acting as one of the subject matter experts to assist in system implementation projects by participating in the system design phase to ensure that cyber security is properly incorporated and the test phase to ensure that the security controls are operating effectively.

3. Privacy & Compliance Analyst

The Privacy Compliance Analyst would be responsible for the following:

- Perform ongoing monitoring and self-assessments of the AICPA GAPP.
- Maintaining an inventory listing of where customer information is stored and customer information data flow diagrams.
- Perform privacy reviews of the third parties that are participating in REV, which consists of initial review, contract negotiations, and ongoing periodic monitoring of third party compliance with the contract terms and their control environments.
- Acting as the subject matter expert to assist in system implementation projects by participating in the system design phase to ensure that privacy controls are properly incorporated and the test phase to ensure that the controls are operating effectively.
- Monitoring, addressing, and resolving DLP alerts.

The cost (salary and benefits) for each of the above positions is estimated at $150,000 for a total of $450,000. The basis for this estimate relates only to REV's initial requirements. As Central Hudson implements REV through incremental IT investment, DSP investment, and other REV initiatives, Central Hudson's need for additional employees to ensure adherence to cyber security standards, and simply to implement REV is expected to grow.

XII. Costs & Cost Recovery

REV strives to fundamentally change the function of the electric distribution utility. In particular it asks that electric distribution utilities facilitate market development. Market development facilitation requires the exchange of information, partnerships with market participants that need to interact and/or interconnect with utility facilities and utility support of market functions. Central Hudson embraces its new role and will strive to facilitate market formation. REV, however does not fundamentally change the need for capital investment into the electric distribution system, the need for revenues to cover the costs associated with maintaining and operating the electric distribution facilities, or the need for an electric distribution utility, including Central Hudson, to earn a reasonable return.

REV adds elements to the current rate structure. Those elements include the capital investment and O&M costs made by market participants, the effect of NWA projects on rate base and earnings, and of particular import to Central Hudson's DSIP, DSP costs, and cost recovery. Central Hudson agrees with the Commission's adoption of DPS Staff's proposal for DSP cost recovery, which permits electric distribution utilities to recover and earn a reasonable return on their prudently incurred foundational DSP capital investments and recover their O&M costs associated with those investments.[25] The Commission has ordered the utilities to undertake REV initiatives,[26] and will approve Central Hudson's investments before they are made. If Central Hudson's DSP investments and O&M expenses are prudent at the time they are made Central Hudson should receive full cost recovery and a reasonable return.

A. Capital & Operating Expenditures to Build & Maintain DSP Function

Central Hudson has prepared itself well for the evolving roles of the electric distribution utility. With the continued support from the Commission for our deployment of cost justified foundational investments including DA, DMS, and Network Strategy all of which provide tangible net benefits to customers the current identified future requirements to build and maintain DSP functions are limited. These items have been discussed throughout the document and are summarized below.

1. Interconnection/Planning

As described throughout the document, the introduction of intermittent DERs and probabilistic planning methodologies will increase the complexity of the system planning process. More sophisticated analytics will be required, and additional labor resources will be necessary to develop forecasts, analyze results, and make complex decisions that maintain the safety and reliability of the electric system while also improving its efficiency. Data and results will need to be packaged in a transparent yet concise manner for public review. The following resources will be required for this effort in the near term:

- (1) – Transmission Planning Engineer – probabilistic planning, integration of DERs into the process

[25] REV (Order Adopting a Ratemaking and Utility Revenue Model Policy Framework at 105-107) (Issued and Effective May 19, 2016).

[26] *Id*. at 106.

- (2) – Distribution Planning Engineers – documentation of new planning process, probabilistic planning, DSIP updates, integration of DERs into the process

In addition, as penetration of DERs continues to increase, along with the requirements to review and approve applications, the technical challenges will become more complex. Moreover, Planning and Operating procedures will need to be developed and maintained. The following resources will be required to manage in the integration of DER resources in the near term:

- (2) – Engineering Technicians – reporting requirements, functional testing, customer interface
- (2) – Interconnection Engineers – Engineering review of applications, participation in state and national working groups to increase penetration of DERs and leverage smart inverter technology, development and maintenance of Planning and Operating procedures

It is estimated that these additional resources will result in approximately $700,000 of annual incremental expense within Distribution Engineering.

Finally, while Central Hudson complies with the current requirements for an Interconnection Portal, as described in Section VI. F., a new, externally developed portal will be required to meet future needs. Based upon preliminary discussions with vendors, Central Hudson's estimated 5-year capital and maintenance cost for this portal is $1.2 million. This assumes an average of 4,000 applications received annually and includes a technical screening module, support contract, and vendor costs associated with integrating the software into Central Hudson's existing mainframe/GIS systems. It does not include costs for modifications to existing systems to complete the integration. Please note that this cost is based on estimates provided as of 2016 and pricing is subject to change due to change in demand.

2. Hosting Capacity

As discussed within the body of this document, Central Hudson has worked in conjunction with the Joint Utilities and EPRI to develop a whitepaper outlining a proposed roadmap for hosting capacity in New York State. Recognizing the importance DER providers have placed on the availability of hosting capacity data, Central Hudson has acquired high-level estimates to complete hosting capacity analysis for all of our feeders. The completion of the analysis would be dependent on the availability of accurate circuit modeling data. Central Hudson is in the process of developing this circuit modeling data as part of our Smart Grid initiates. The high level cost for a system wide (all feeders) hosting analysis is estimated between $6M and $7M. The analysis could be performed in staged approach to spread the costs out over time as long as it coordinated with our modeling efforts. These expenditures are not included within our current five-year plan.

3. Distribution System Operations

The transition to a centralized Distribution System Operations to support the requirements of the DSP functions will include the addition of one Senior System Engineer – Distribution, 12 Distribution System Engineers, the DMS, and two associated application support staff. This addition will be included in a future rate filing. The estimated expense payroll for these 12 positions is approximately $1.4M annually. These resource additions will create the need for both additional office space for the Distribution Control

Center and additional workstation space to hold the necessary computer monitors. This additional space must be included as part of the overall considerations for this project.

Central Hudson contracted with a design consultant to develop a conceptual design to modify its existing Transmission PCC facility to accommodate the addition of Distribution System Operations. The consultant has provided a high-level cost estimate of $1.9M for console and casework systems. In addition, General Construction, which includes construction and demolition services, architectural engineering, cost estimation, and mechanical/electrical/plumbing engineering are estimated to cost $3.0M. Central Hudson plans to develop more detailed estimates for this work and include them in the Company's capital plan that will be part of the next rate filing. It is anticipated that construction work could be completed in late 2018 to early 2019.

4. Cyber Security

As described in more detail in Section XI of the report the increased data access required by third parties anticipates the need for additional resources to support the increasing cyber security requirements in protecting IT systems and system data. In addition to approximately $300,000 in new software solution requirements it is anticipated that three additional cyber security analysts will be needed at an estimated annual expense of $450,000. These requests will be included in the Company's next rate filing.

5. Additional Items

While some known requirements have been articulated above, Central Hudson has not yet identified all of the capital and operating expenditures it must make to build and maintain the DSP function. Some of those remaining additional expenditures are, however self-evident. Central Hudson must build and maintain systems to facilitate the exchange of information, including system data, between Central Hudson, customers, and market participants. Central Hudson's CenHub demonstration project, already operating, is a significant system that permits the exchange of information among REV stakeholders.

In order to identify the necessary attributes of a DSP Central Hudson will work with DPS Staff, customers and market participants. Once these additional attributes are identified Central Hudson will seek the Commission's approval to implement the attributes and recover the costs associated with implementation. Central Hudson will not proceed with implementation absent appropriate cost recovery, including a reasonable return on its investment.

B. Revenue Requirement

The revenue requirement for the DSP should be determined using the traditional rate making formula; rate base * rate of return + O&M = revenue requirement. The traditional rate making formula should apply to DSP costs and investments because the DSP is a foundational investment necessary to implement REV and it has been ordered by the Commission. Further, the DSP is the facilitation platform necessary to develop the market and as such, may benefit all customers. Because all customers may benefit from the DSP, all customers should pay for the DSP.

C. Cost Recovery Mechanism

Central Hudson suggests that DSP costs should be recovered through a rate tracker to segment the costs and revenue requirement from base delivery rates associated with the traditional utility function in order to provide transparency regarding foundational REV costs to the Commission, customers, market participants, governmental entities, and others. Before Central Hudson is required to build and implement the DSP the Commission must approve cost recovery. In order to effectuate approval of cost recovery Central Hudson will apply for cost recovery through a petition or as part of its next rate case.

The cost recovery mechanism should allow for cost recovery during the contemporaneous rate period just as Central Hudson recovers the cost of providing electric power to full service delivery customers through the market price charge on a monthly basis. The reason that DSP cost recovery should occur through a monthly tracker similar to the market price charge is to minimize carrying costs for customers who pay carrying costs equivalent to the pre-tax weighted average cost of capital (pre-tax WACC). Cost recovery during a contemporaneous rate period also sends the proper price signal to customers regarding the cost of service. Capital investment included in the DSP tracker should be amortized over an appropriate period of time. Central Hudson will specify for Commission approval the costs to be recovered by it through the DSP tracker as part of Central Hudson's cost recovery petition or in its next rate case. Thus, a mechanism similar to the rate adjustment mechanism approved by the Commission in Cases 15-E-0283 et. al., New York State Electric and Gas Corporation's and Rochester Gas and Electric Corporation's recent rate cases.

The suggested DSP tracker is also similar to the cost recovery treatment the Commission recognized for manufactured gas plant recovery costs in Case 11-M-0034 and implemented in each utility's rate case.[27] In that proceeding the Commission determined that utilities should recover prudently incurred remediation costs associated with manufactured gas plant sites. There the Commission did not approve a tracker, but did set annual recovery rates and amortization schedules for MGP costs.

[27] Case 11-M-0034 - *Proceeding on Motion of the Commission to Commence a Review and Evaluation of the Treatment of the State's Regulated Utilities' Site Investigation and Remediation (SIR) Costs* (Order Concerning Costs for Site Investigation and Remediation at 23) (Issued and Effective November 28, 2012) (National Fuel proposed an automatic flow through mechanism similar to the DSP tracker proposed herein and the market price charge approved by the Commission for electric commodity cost recovery).