Central Hudson Initial Distributed System Implementation Plan Appendices

June 30, 2016

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Index of Appendices

Appendix A Initial DSIP Stakeholder Engagement

A.1 Initial DSIP Stakeholder Engagement - System Data

A.2 Initial DSIP General Information Session

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NY Rev Distributed System Implementation Planning

System Data Sharing Discussion

May 16, 2016

Agenda

- REV Background
- System Data Sharing Objectives and Definition
- DSIP Order – System Data Issues
- Overview of Central Hudson's (CH) Position
- Overview of Distributed Energy Resource (DER) Provider Position
- Detailed Discussion
  - Historic and Forecasted Load
  - Power Quality and Reliability
  - Information Security
  - Monitoring and Control
  - Hosting Capacity

REV Background

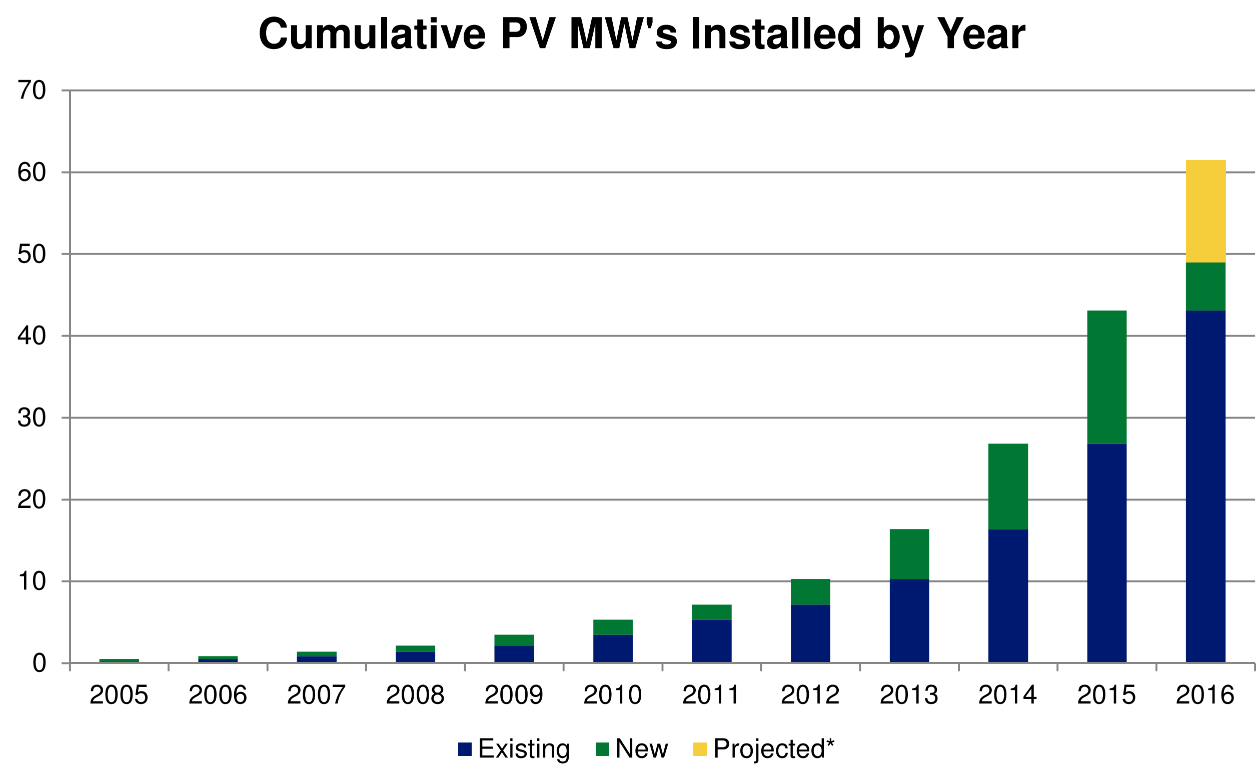
- Reforming the Energy Vision (REV) is an initiative to transition the energy industry in New York State, bringing regulatory changes with several policy goals in mind.
  - Self-assessments and roadmaps to facilitate evolution of planning and operations to be included in Distributed System Implementation Plans (DSIP) filed by the utilities
- Order on the DSIP filings filed on April 20, 2016
- May 5th Stakeholder Engagement Plans
- As an aspect of the REV orders and discussions with the DPS Staff, the topic of System Data was highlighted as an area where the utilities would benefit from a stakeholder engagement process that will be used to inform development of their DSIP filings

System Data Sharing - Objectives

- Develop mutual understanding of the information currently available from each party vs. needs and business models of DER providers.
- Identify gaps and what alternatives or additions can be provided while meeting essential adequacy, safety, resiliency and reliability needs.
  - Data, frequency, and granularity
  - Market participation

SOLAR GROWTH A DRIVER OF DATA SHARING NEEDS

System Data Sharing - Objectives



*2016 projection is regression-based and will likely be higher based upon current CDG queue.

As of 4/30/2016			
Net-Metered Non-Wind	Connected	Proposed	Total
MW	49.021	685.030	734.051
# of systems	5,339	1,158	6,497

System Data Definition

- As modeling and technology advance, an increasingly greater volume of data becomes available to generate insightful information. This information can be valuable in supporting real-time grid operations, forecasting and planning, and encouraging the appropriate siting and development of DERs.
- Potential data elements include:
  - Planning: historic coincident & non-coincident peak loads, load profiles, forecasted coincident and non-coincident loads, DER penetration forecasts and load/output profiles, existing distribution characteristics at substation and feeder-level, capacity levels, capital plans, projected investment plans/needs, historic reliability
  - Grid Operations: historic or real time voltage, current, power factor, real and reactive power, and status of DERs
  - Market Ops: Customer load data and Customer information (out of scope of today's discussion)

DSIP Order – System Data Issues

- Guidance was initially more prescriptive – The Order is less detailed
  - The Initial DSIPs will require the utilities to provide a base level of data, including information related to forecasts, planned investments, and operating systems, and a description of their system planning practices
  - The Initial DSIPs should include a base level of system planning data and information that will allow DER providers to make economic decisions regarding best locations for future DER investments
  - Utilities should identify specific locations within the distribution system that are the highest priority for distribution capacity and operational relief (beneficial locations)
  - Utilities should define and provide current hosting capacity data and how it is calculated
  - Utilities should provide current forecast method and include granular forecast data
  - Granular substation and feeder level data should also be provided, recognizing that, the full range of system data is not likely to be available at this time. However, utilities should identify those data gaps and plans to address system data collection and sharing
  - data access policies for customer and system data,

CH Position Overview

- CH supports sharing insightful information to achieve increased participation of third parties toward establishing sustained investments which will benefit the grid.
- Stakeholder engagement discussions such as this and the larger engagement process in support of the Supplemental DSIP should be used to develop data acquisition and information sharing approaches.
- Security issues must be considered in sharing information.
- We will need to adapt current data collection systems and information processing to support stakeholder informational needs including investing in systems and staff. Stakeholder input is helpful to guide this process.
- This will be a continuing and evolving process.

Stakeholder Discussion

- Questions for DER providers:
  - What are your business processes and needs to expand DER resources on the NY grid?
  - What are the highest priority needs for utility system data and information?
  - How do you intend to use such data?
  - Will data need to be shared outside of your Company?
  - Are there concerns about sharing data back to Central Hudson?
  - Are there concerns about Central Hudson sharing your data?

Discussion – Historic and Forecasted Load

- Central Hudson Highlights
  - Available historical load data varies significantly, even within the service territory
    - Approximately 78% of Central Hudson circuits have electronic 8760 metering data.
    - Approximately 22% of Central Hudson circuits have chart data only.
    - Gathering/inputting chart data is a manual process. Central Hudson only inputs winter and summer coincident peaks for circuits with chart data.
  - Even metered or real time, 8760 data requires correcting or scrubbing by utilities. Peak and minimum loads can be skewed due to:
    - Metering Errors
    - Load Transfers/Switching
    - Outages
  - System wide net load forecasts and substation load forecasts anticipated in Initial DSIP filing
    - Will include Solar PV, Energy Efficiency, and other DERs.

Discussion – Historic and Forecasted Load

- Questions for DER Providers
  - How does historical and forecast load data by circuit contribute to DER development success?
  - How is this different from Hosting Capacity?
  - Is there a preference for corrected or un-corrected/raw metered data, and why?
  - What is the highest level of granularity which value can be derived (system, substation, feeder, etc.)?
  - What type of Historic and Forecasted load information is most useful for you?
    - Peak load
    - Representative Day hourly load,
    - annual hourly load
    - Circuit Minimum load levels

Discussion – Power Quality and Reliability

- Central Hudson highlights
  - SAIFI (frequency) and CAIDI (duration) of interruptions is provided by feeder annually
  - In addition some power quality concerns.
  - System power factor studies completed annually.
  - Measured voltage is not readily available.

- Questions for DER providers
  - How does voltage, VAR, and reliability data contribute to DER development success?
  - Does the currently available information in utility filings provide enough useful information? If not, what is lacking?

Discussion – Information Security

- Joint Utility practices
  - Standardization still underway at the national level
  - Working towards common framework of standards
  - Should a portal be developed, any access to confidential information will require the user to be registered and comply with secure password and registration protocols.

- Questions for DER providers
  - Please identify any concerns related to registration, confidentiality, privacy and cyber requirements.
  - To the extent that information on DERs will become shared information, please identify your concerns?

Discussion – Monitoring and Control

- CH may require inverter data and/or other from solar developers for the following reasons:
  - Facilitate greater penetration of DERs
  - Ensure system stability and voltage/flicker maintained in standard ranges
  - Operate within thermal ratings of equipment
  - Ensure operational flexibility is maintained
  - Enable participation in REV markets

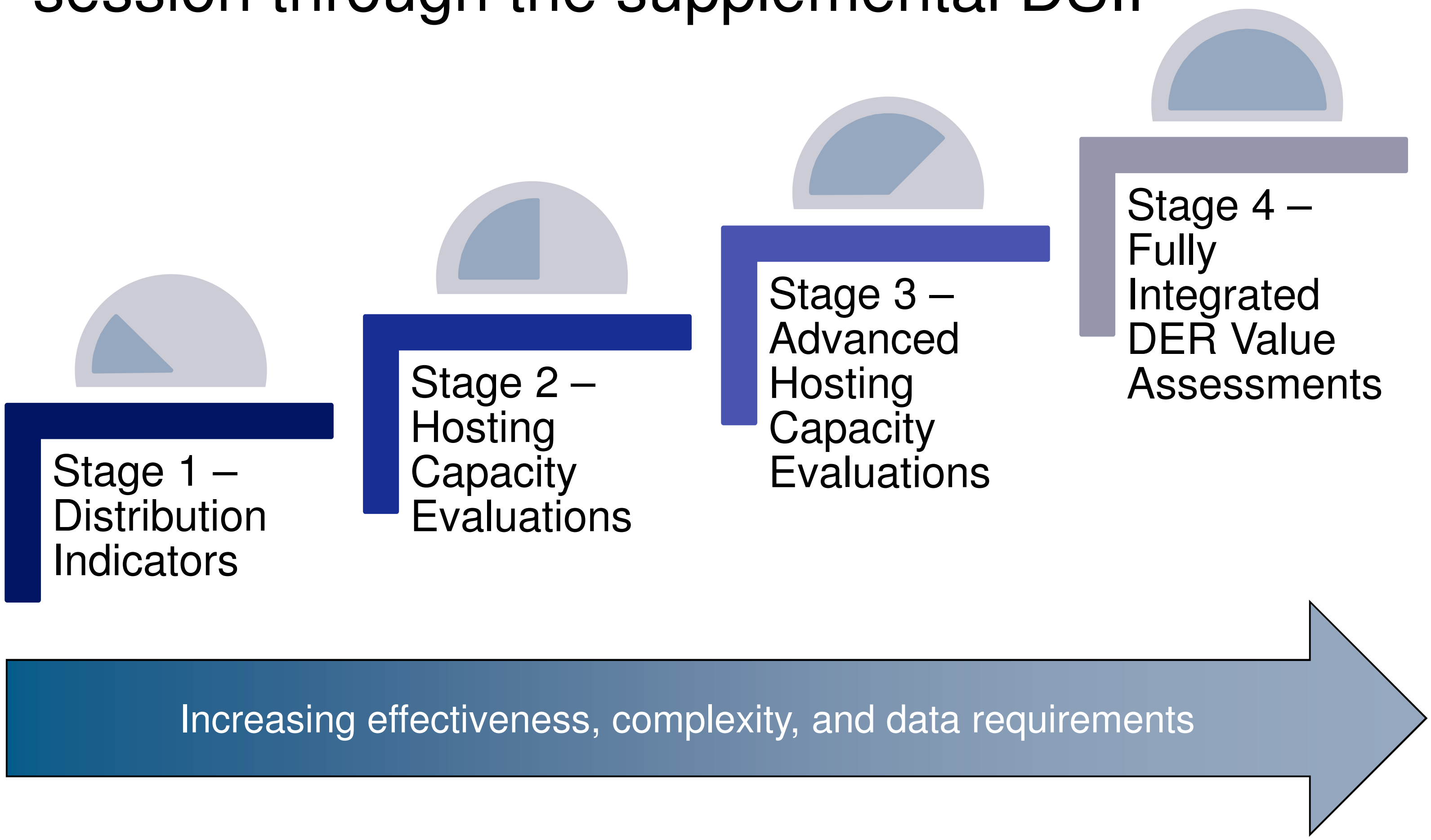
- Monitoring and Control will be discussed further in the Interconnection Technical Working Group meetings

Discussion – Monitoring and Control

- Questions for DER providers
  - At what system size would you consider installing smart inverters? What functionality would they have?
  - What size systems do you currently remotely monitor?
  - What is the frequency of polling, latency and communication medium for inverter data currently?
  - How would you propose transferring data to the utility?
  - Do you currently transfer data to any utilities? If yes, please discuss how the data is transferred, what communication medium and protocol is used, and how it is integrated with the utility system.
  - What alternatives to telemetry are available for smaller scale resources (and what threshold is considered smaller scale)?
  - How do you maintain confidentiality of the data?

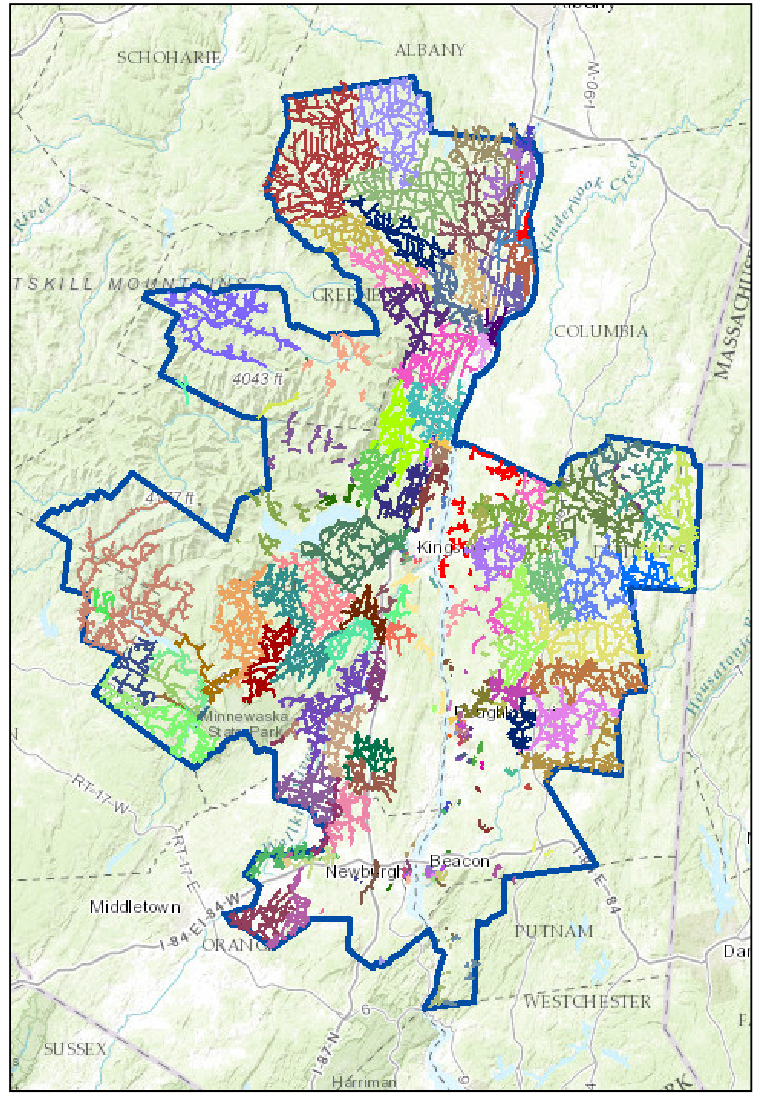
Discussion – Hosting Capacity

- Utilities developing a 4 stage approach to be discussed in a separate stakeholder engagement session through the supplemental DSIP



Discussion – Hosting Capacity

- Questions for DER Providers
  - How does hosting capacity contribute to DER development success?
  - Does hosting capacity assist DER providers or aggregators in developing new products to serve the grid needs and benefit society?



NY REV Initial DSIP General Information Session

June 21, 2016

Agenda

- Introduction
- REV and DSIP Background
- DSIP Filing
- Action Plans & Demonstration Projects
- Data Sharing

REV and DSIP Background and History

REV Background

Reforming the Energy Vision (REV) is an initiative to transition the energy industry in New York State, bringing regulatory changes with several policy goals in mind.

Essential purpose is to:

1. Improve system efficiency
2. Empower customer choice
3. Encourage greater penetration of distributed energy resources (energy efficiency, demand response, distributed generation)

REV Background

Initiated in 2014 with the Following Stated Policy Goals:

- Enhance customer knowledge and tools that will support effective management of their total energy bill
- Market animation and leverage of ratepayer contributions
- System-wide efficiency
- Fuel and resource diversity
- System reliability and resiliency
- Reduction of carbon emissions
- Affordability

REV Background

What is Driving REV:

- Increased adoption of Distributed Energy Resources
- Aging infrastructure in NYS
  - $30 billion in the next 10 years
- Inefficient grid
  - 60% utilization; design for peak
- Rising energy costs
  - Delivery rates/surcharges
- Increased demand for uninterrupted service

REV Background

- Initial REV Order established utilities as DSP
- Required each utility to file a Distribution System Implementation Plan (DSIP)
- Described the goal of the DSIP
  - Transparency – a source of public information regarding DSP plans
  - Template – a way to articulate an integrated approach to planning
  - Consistency – enable the Commission to oversee the implementation

DSIP Guidance

- October 2015 DPS Staff issued its proposed DSIP Guidance Document
- Recommended a two step approach to the filing of the DSIP
  - Initial DSIP to be filed June 30, 2016
  - Each Utility to file its own Initial DSIP
  - Supplemental DSIP to be filed September 1, 2016
  - The utilities must Jointly file the Supplemental DSIP
- Many meetings held with DPS Staff to try to clarify aspects of the Guidance

DSIP Guidance Order

- April 20, 2016 - Order on the DSIP filings
  - May 5th Stakeholder Engagement Plans
  - June 30, 2016, Individual Utility Initial DSIP Plans to be filed
  - November 1, 2016, Joint Utility Supplemental DSIP Plans to be filed

Other REV related filings

- Distribution Level Demand Response Tariffs
- Non Wires Alternative/Targeted Demand Response Program
- Benefit/Cost Analysis (BCA) Handbook
- Clean Energy Standards (CES) – Advisory Committee Charter
- Net Energy Metering Filing
- Community Distributed Generation Tariff
- Energy Efficiency Transition Implementation Plan (ETIP)
- Demonstration Projects

DSIP Filing

Filing Overview

Initial DSIP – an invitation to innovate

- Self Assessment and Near Term Initiatives
- Foundational Investments
- Demonstration Projects
- Distribution Planning
- Load and DER Forecasting
- Interconnection and Hosting Capacity
- Distribution Grid Operations
- Distribution Market Operations
- Capital Plans
- Data Sharing
- AMI – Advanced Metering Infrastructure (Smart Meters)
- CYBER Security
- DSP Costs

Supplemental DSIP filing –

The other Major filing in REV

- Must be a Joint Utility Filing
- Efforts to be done in parallel with the Initial DSIP filing
- Should further the concepts of the Initial DSIP
- Must involve Stakeholders/Market Participants in the Development
- Will focus on the same 3 areas as the Initial DSIP
  - Distribution System Planning
  - Distribution Grid Operations
  - Distribution Market Operations

DSIP Filing

Purpose of the Plan

Initial DSIP

- Based on the October 2015 DSIP Guidance Document and the subsequent April 2016 DSIP Guidance Order
- Initial DSIP to be filed June 30, 2016
  - Each Utility to file its own Initial DSIP

Initial DSIP Report

- Why the DSIP is being developed
- Where we are today and where we are going in the near term
- What we need to do now and in the near term to meet the REV goals
- How we perform the functions of Planning, Operations, and Markets today and how they are changing

Initial DSIP Report

- Order described the goal of the DSIP
  - Transparency – a source of public information regarding DSP plans
  - Template – a way to articulate an integrated approach to planning
  - Consistency – enable the Commission to oversee the implementation

DSIP Filing

Overview of Self Assessment and Current State

Where Are We Today

- Distribution Planning
  - Provides for safe, reliable electric service
  - Integration of DER and new technology require changes on how we perform our planning
  - Non-Wires Alternatives are being built into the capital planning process
  - Distribution Automation and a Distribution Management System are well under way
- Distribution Operations
  - Provides for the safe operation of the distribution system
  - Have developed a roadmap through pilot projects for Communication Network Strategy, CVR, and DMS.
  - Have identified gaps to implementation,
- Distribution Markets
  - Central Hudson has developed a new forecasting methodology to develop annual load curves and better incorporate DER
  - Central Hudson has developed new maps and portals to provide system and customer information

DSIP Highlights

- System Data
  - Will provide 8760 Historic Load Data by Circuit
  - Will provide 8760 Forecasted Load Data by Substation
  - Will provide the impact of DER on the Load Forecast
- Central Hudson has significant areas of low load growth
  - There are limited Beneficial Location areas
  - Central Hudson has identified new areas where Non-Wires Alternatives will be considered
- Interconnection Portal and Hosting Capacity Improvements
- Customer Data access through CenHub
- AMI
  - Central Hudson will not have either a Full or Partial deployment of AMI
  - Explanation to follow below
- Significant Additional Costs beyond the already in progress Foundational Investments will not be needed

DSIP background
AMI business case

“Filings should examine the issue of AMI deployment from the perspective of three alternative scenarios:

(a) full AMI implementation by the utility,

(b) utility implementation of AMI to 20% of customers, with remaining customers receiving AMR (automated meter reading) meters, and

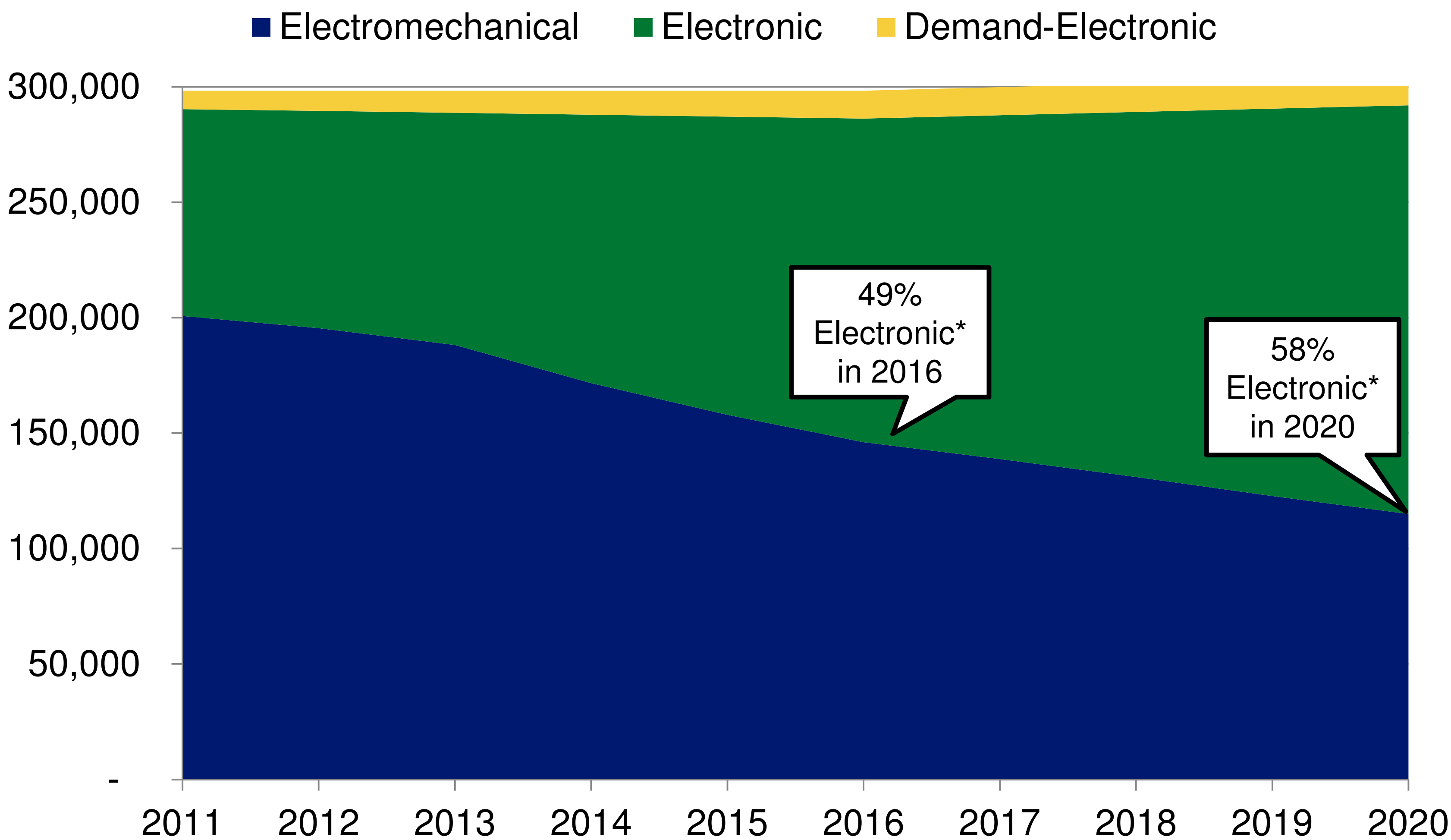
(c) AMR implementation by the utility, with AMI deployed to individual customers by ESCOs and/or competitive DER providers.

In each scenario, assume the utility will maintain the communications network, and meter data management systems. Compare the costs and risks of each alternative scenario, including flexibility, scalability, and level of ratepayer investment, as well as overall net benefits.”

Central Hudson – Current Landscape

- Approximately 300,000 electric customers and 79,000 gas customers
- Service territory is 2,600 square miles, stretching from 25 miles north of NYC to 10 miles south of Albany
- Sizeable portions of the territory have limited or no network access
- Almost 50% of electric meters are AMR or demand electronic
- Bi-monthly meter reading, with nearly half the meter reading sub-contracted
- Plan for Distribution Automation in the service territory has been approved by the Commission
  - Significant portions of the VVO/CVR and outage location benefits will already be achieved

Context: Central Hudson is on track to have 58% electronic meter deployment by 2020

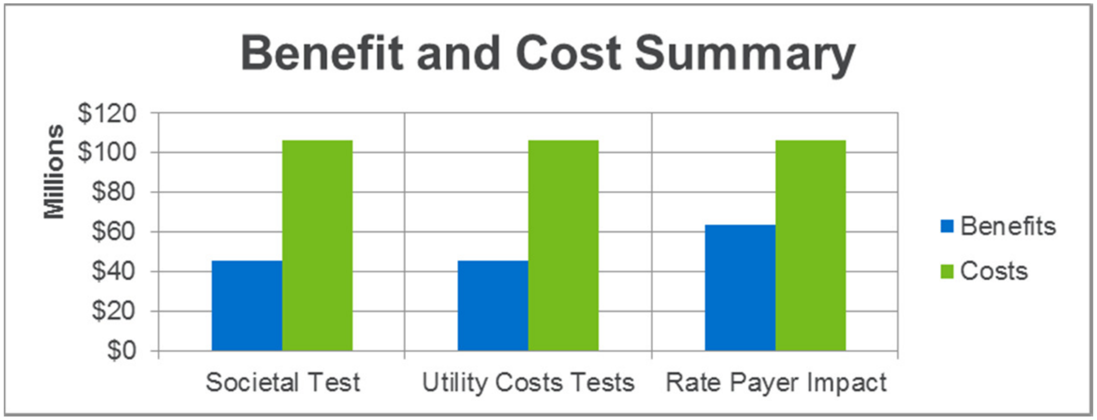


* Electronic including Demand-Electronic

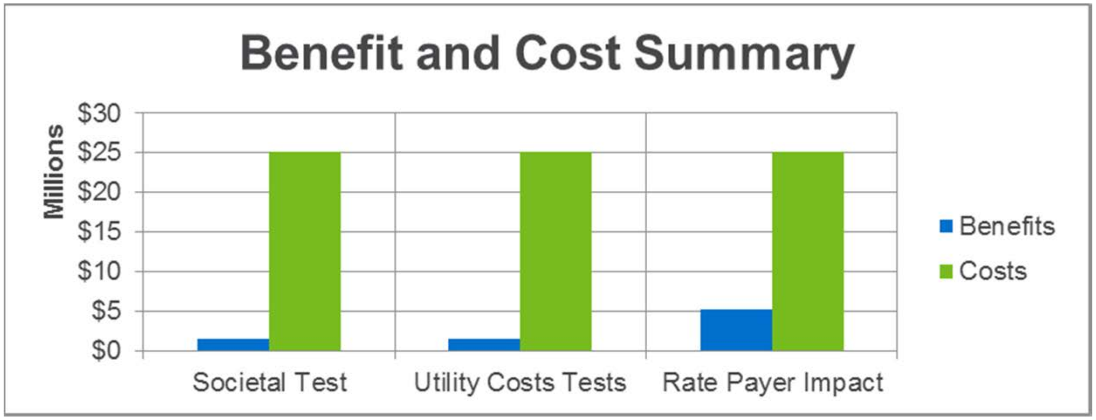
Context: Significant portion of system demand and usage concentrated in a small percentage of customers

	Number of Customers	% of Customers	% of System Demand	% of Usage
Interval Metered (HPP)	310	0.1%	27%	21%
Demand Metered	12,000	4.0%	12%	25%
Total	12,310	4.1%	39%	46%

The full deployment scenario doesn't pay for itself



…the partial deployment scenario doesn't pay for itself either



Questions?

NY REV Initial DSIP General Information Session

Action Plans & Demo Projects

June 21, 2016

Non-Wires Alternatives & Demand Response

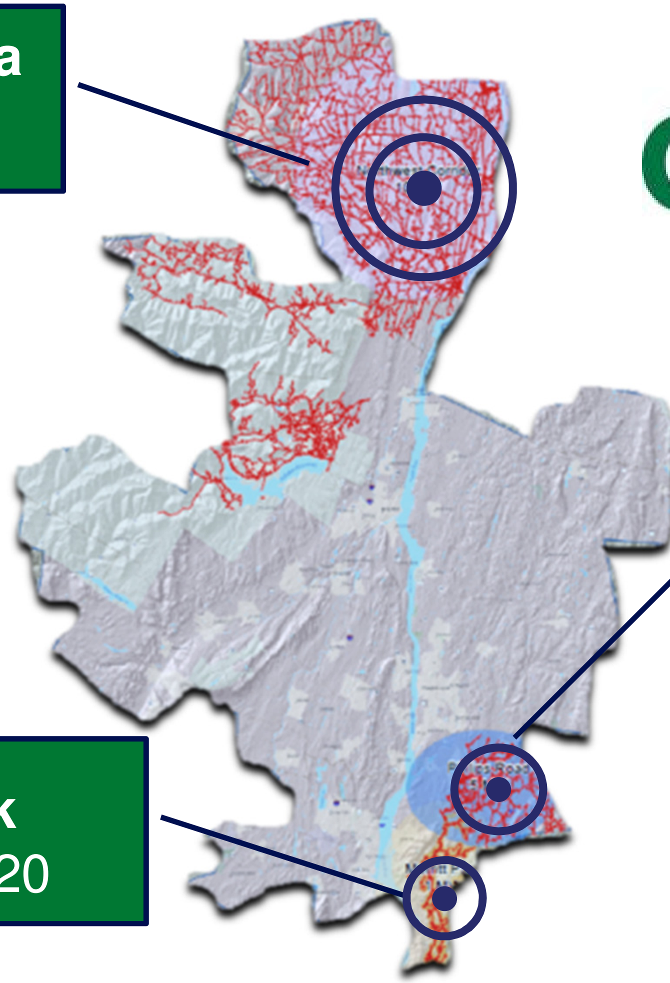
Mark Sclafani
Senior Program Coordinator

Non-Wires Process

- Identification of future Capital projects that may be avoided through a non-wires alternative project
- Request for Proposal (RFP) sent out, which includes a detailed description of the system need
- Third Party Evaluation – assists in analyzing the proposed solutions for effectiveness and cost
- Revise traditional benefit cost model to allow for innovative projects
- Select winning proposal(s) – enter into contract negotiations

Non-Wires: System Need

North West Area
10MW by 2019



CenHub
Peak Perks

Shenandoah/ Fishkill Plains
5MW by 2020

Merritt Park
1MW by 2020

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Targeted Demand Response Solution

CenHub
Peak Perks

comverge
energy made better

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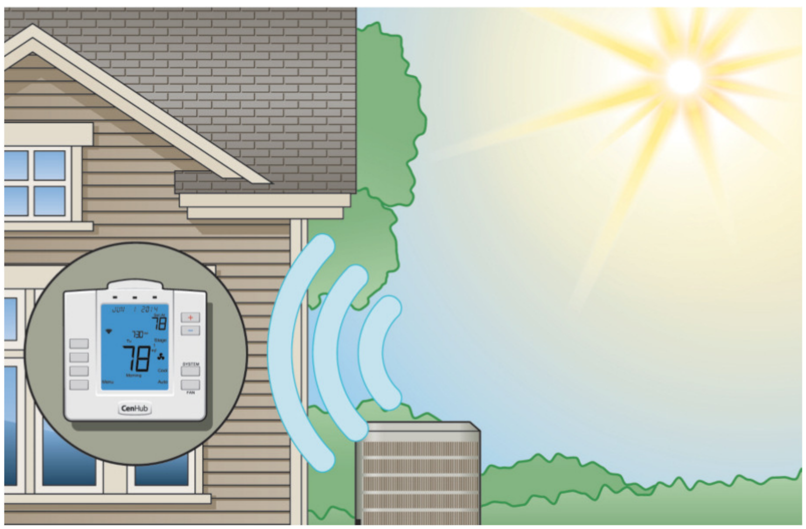
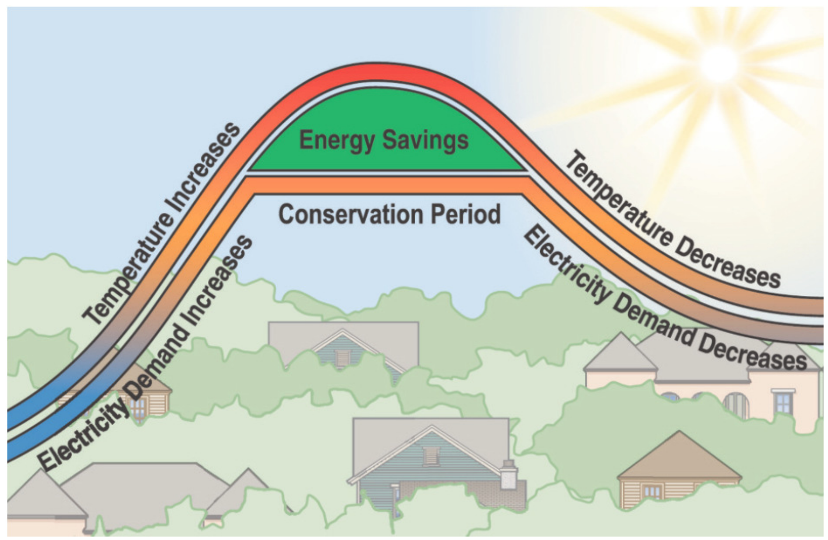
How Demand Response Works

- Deploy controllable devices to curtail load
- Cycling of equipment
- Utilize real time two-way communication to measure impact
- Dispatch to reduce magnitude of system peak
- Central Hudson's peak typically occurs during the hottest summer afternoons





Targeted Demand Response Incentives

	Residential incentives		***Commercial incentives***	
	Installation	Annual	Installation	Annual
Central air	**$85**	**$50**	**$125**	**$75**
Water heater	**$25**	**$24**	**$40**	**$36**
Pool pump	**$85**	**$50**	**$125**	**$75**

Customers will receive free WiFi-enabled thermostats, switches and installation of these devices

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Tariff Program: Dynamic Load Management

- BYOD (Bring your own device) Program
  - Available to residential & small commercial customers anywhere within the service territory
  - Customers can purchase a compatible WiFi enabled thermostat on the CenHub Store
  - $25/year incentive for participation

- CSRP (Commercial System Relief Program)
  - Available to large commercial & industrial customers anywhere within the service territory
  - Custom curtailment strategies
  - Minimum curtailment commitment of 50kW
  - Pay-per-performance

Questions?

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CenHub
REV Demonstration Project

Stakeholder Engagement Information Session

June 21, 2016

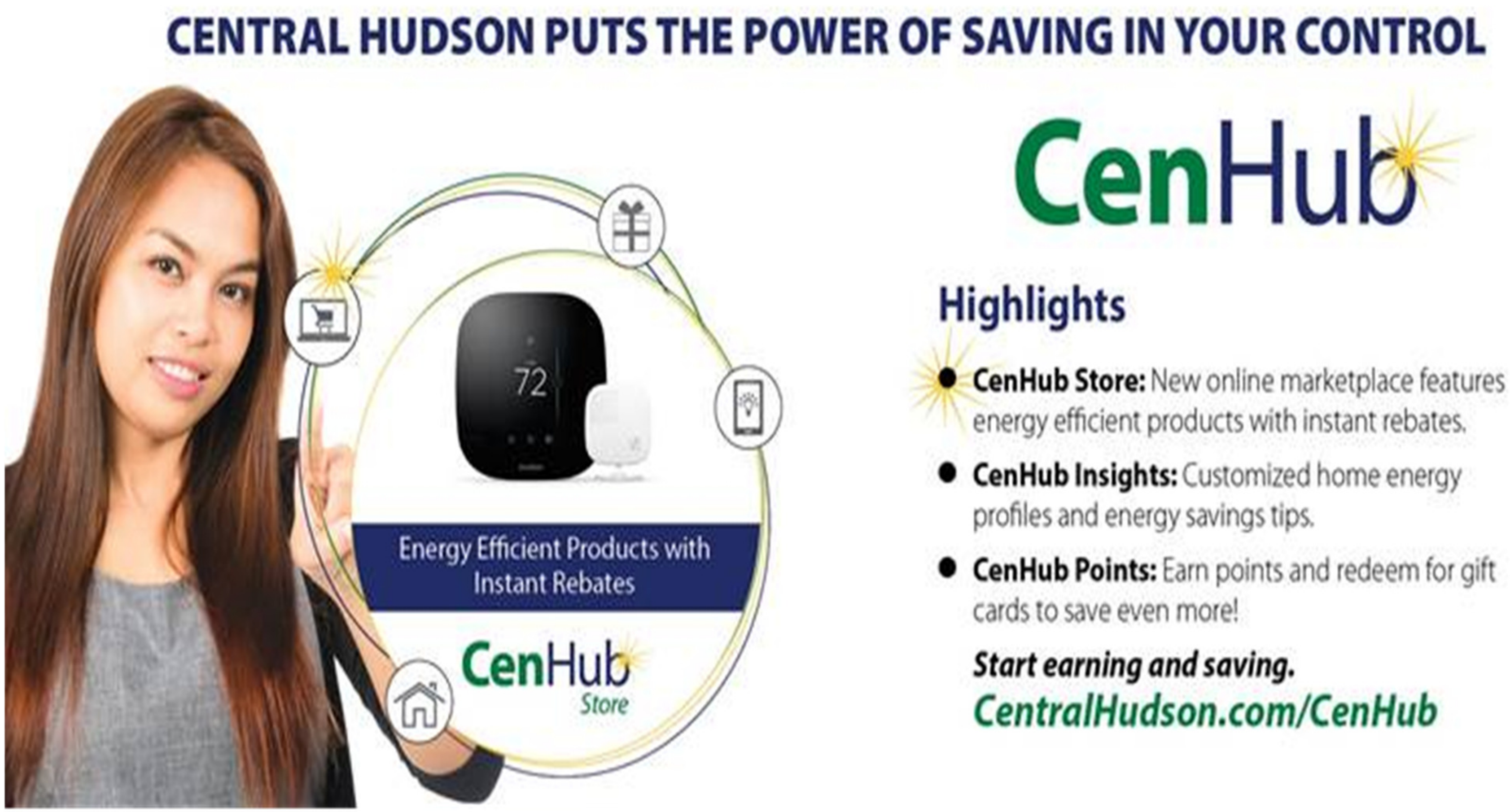
Strategy

ACCESSIBILITY

CHOICE

COMMUNITY

Soft Launch


CENTRAL HUDSON PUTS THE POWER OF SAVING IN YOUR CONTROL
72
Energy Efficient Products with Instant Rebates
CenHub Store
CenHub
Highlights
CenHub Store: New online marketplace features energy efficient products with instant rebates.
CenHub Insights: Customized home energy profiles and energy savings tips.
CenHub Points: Earn points and redeem for gift cards to save even more!
Start earning and saving.
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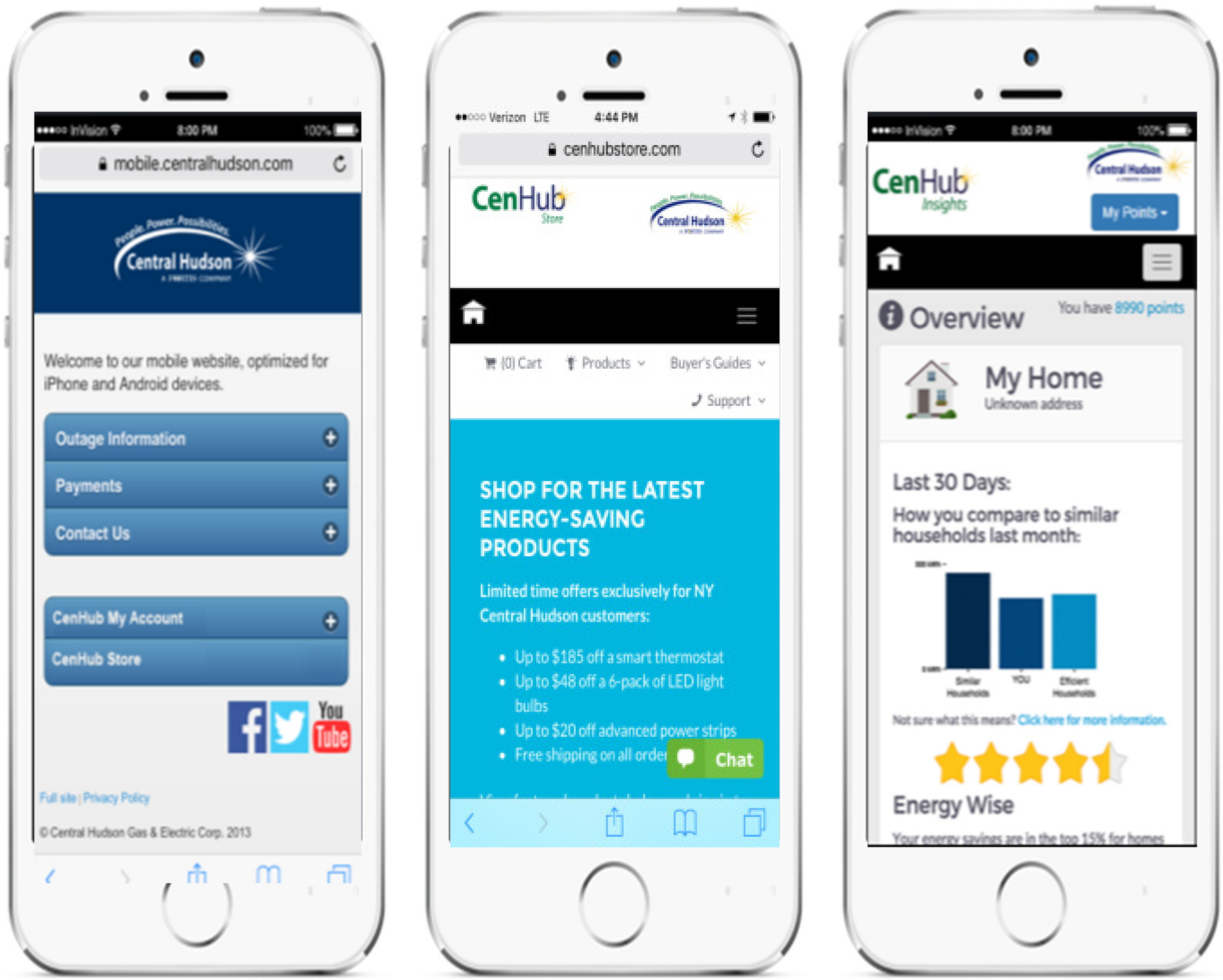
Appendix A2 - Initial DSIP General Information Session




CenHub
Insights
Central Hudson
My Points
Logout
Self-Service
CenHub Insights
CenHub Store
Energy Choice
Storms & Outages
If you're looking to save energy you've come to the right place. The tips below will help you use less energy and save money.
You have: 1,529 points
29
Incomplete
9
Completed
Explore Tips in the Virtual Home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Store
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My Points
Logout
Self-Service
CenHub Insights
CenHub Store
Energy Choice
Storms & Outages
(1) Cart
Products
Buyer's Guides
Support
TWO WEEKS ONLY - $70 OFF AN ECOBEE3
LIMITED TIME OFFER
Marked down from $249 to $179 after instant rebate* and manufacturer discount
Control from your phone, tablet or PC
Free shipping
Claim yours now! This special offer ends 6/23 at 2:59am EST
*Valid only for qualified NY Central Hudson customers.
FEATURED ENERGY-SAVING PRODUCTS
Sale
$249
72
Offer ends June 23 at 2:59am EST
6
pack
65w
equivalent
ECOBEE3 HOMEKIT-ENABLED
GE ENHANCE 10W LED BR30
TRICKLESTAR 7-OUTLET APS

Coming Soon

Phase 2

- Online Account Security Enhancements
- Enhancing the underlying web infrastructure to streamline future integration processes

Phase 3

- Offer customers the ability to subscribe to value added services

Continued Enhancements

- New Tips & Reward Opportunities
- New Product offerings

NY REV Initial DSIP General Information Session

Data Sharing

June 21, 2016

Capital Plan Overview – 2017-2021

Five-Year Capital Forecast

- Corporate Plan encompasses three business areas:
  - **Electric**
  - **Gas**
  - **Common**

Central Hudson Five-Year Forecast Summary

ELECTRIC PROGRAM 2017-2021 FORECAST	$448,113
GAS PROGRAM 2017-2021 FORECAST	$284,040
COMMON PROGRAM 2017-2021 FORECAST	$212,426
CORPORATE TOTAL 2017-2021 FORECAST	$944,579

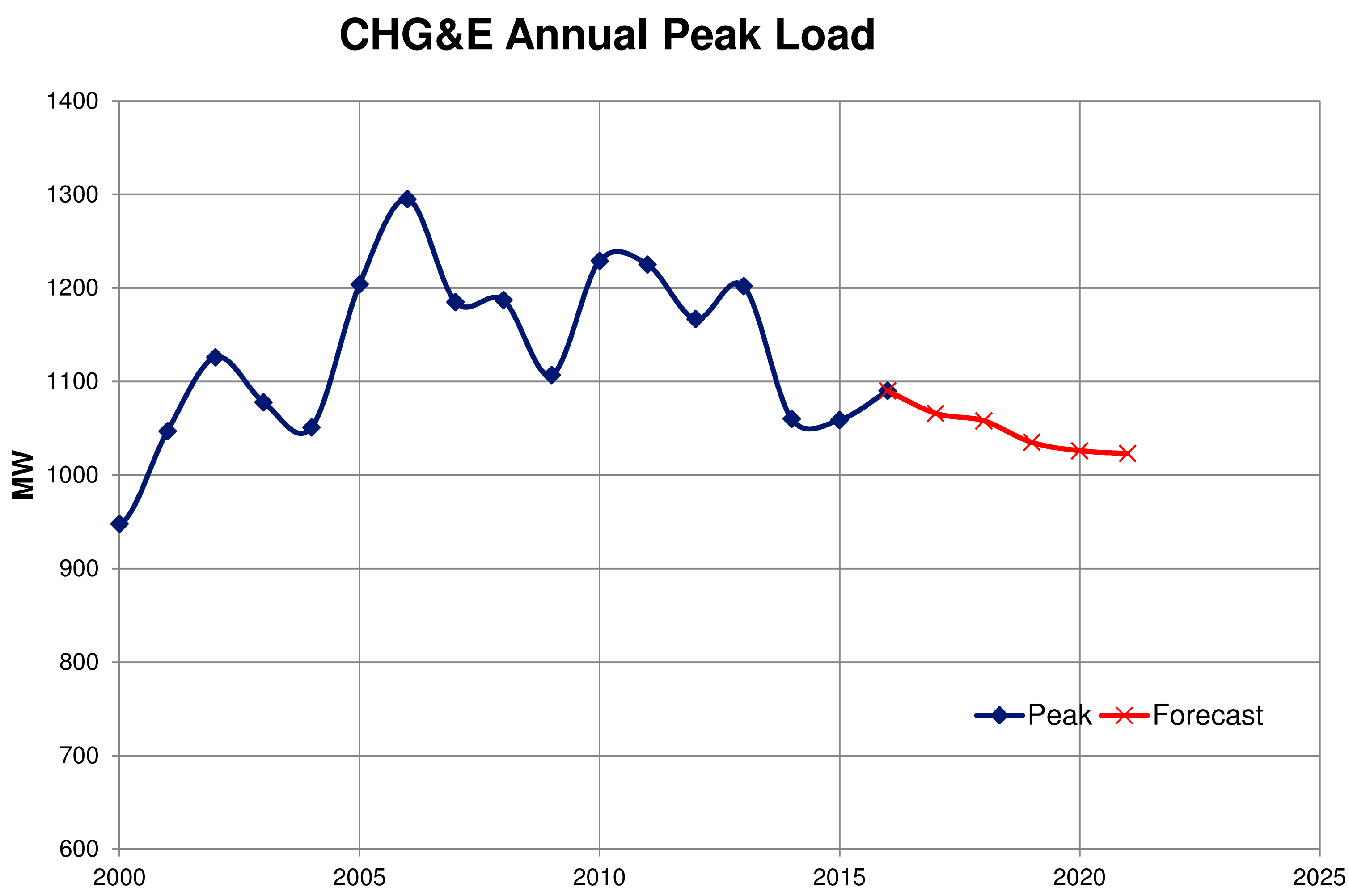
Five-Year Plan Development

- Developed annually
- Based on updated load forecasts
- Based on newest inspection data
- Modified for changes in business (i.e. new compliance requirements)

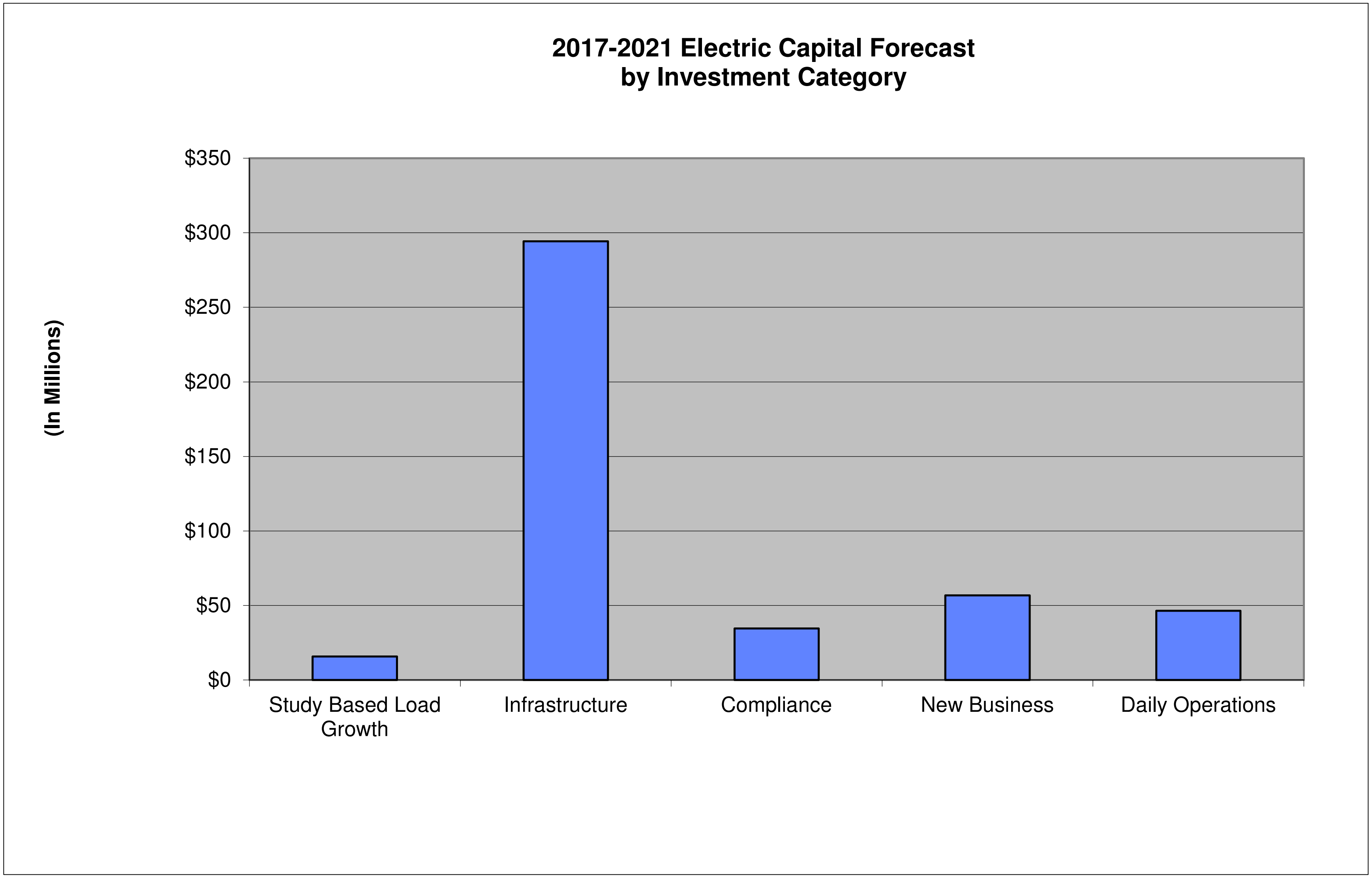
Key Capital Plan Drivers

Responsible for safe & reliable operation of the electric system

- Daily operational needs
- Compliance requirements
- Maintain reliability
- Forecasted load and DER
- Address aging infrastructure through condition-based replacement programs



CHG&E Annual Peak Load
MW
1400
1300
1200
1100
1000
900
800
700
600
2000
2005
2010
2015
2020
2025
Peak
Forecast

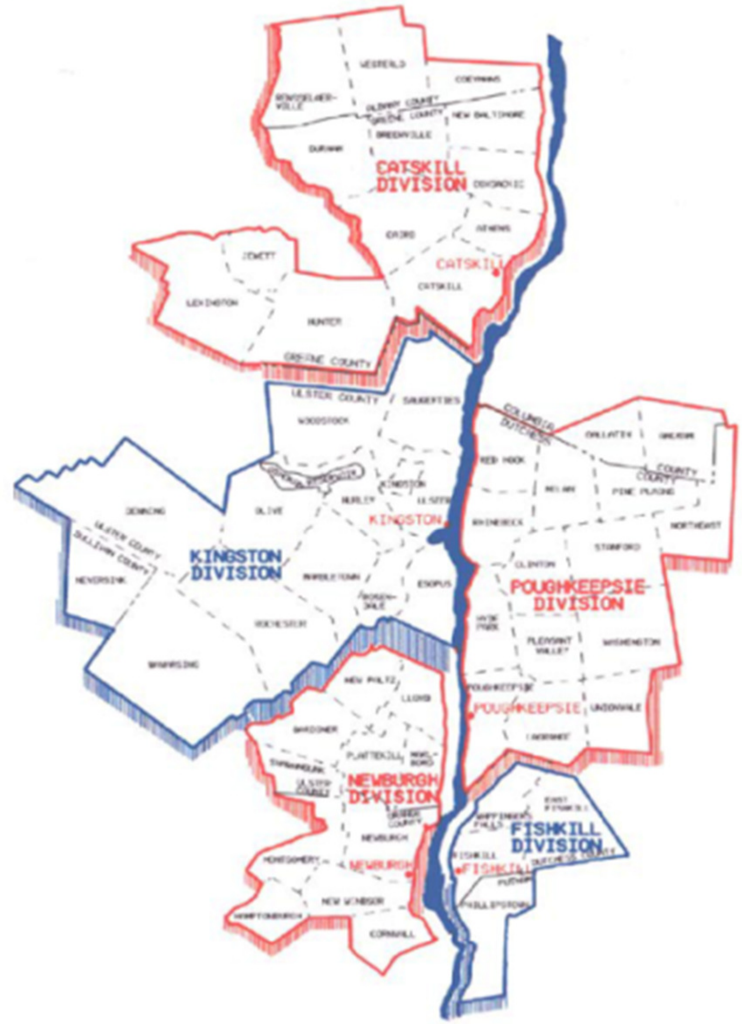

2017-2021 Electric Capital Forecast
by Investment Category
(In Millions)
$350
$300
$250
$200
$150
$100
$50
$0
Study Based Load Growth
Infrastructure
Compliance
New Business
Daily Operations

CHG&E Electric System

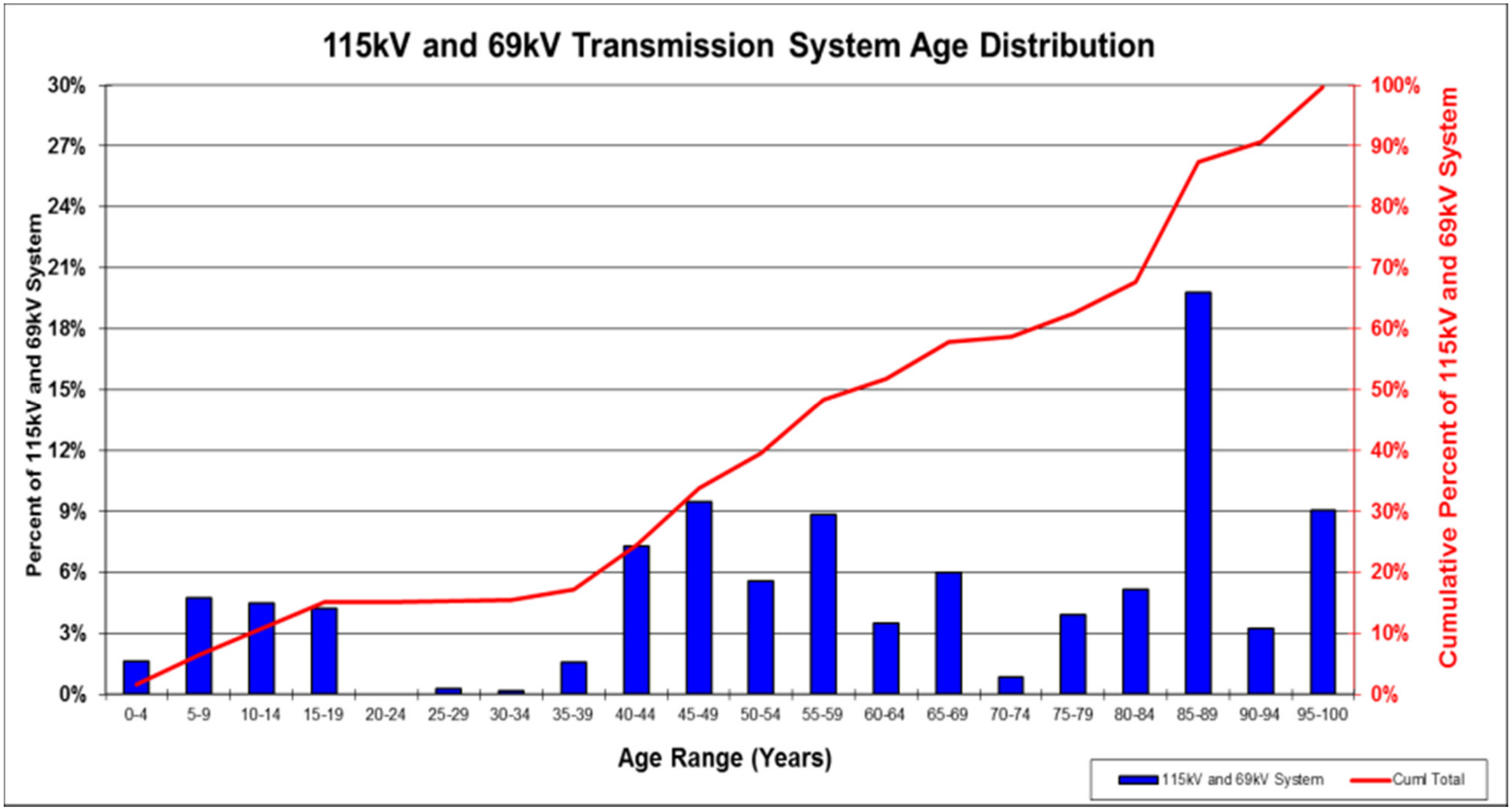
600 Miles Transmission Lines
345kV, 115kV, 69kV

80 Electric Substations

8700 Miles Distribution Circuits



Transmission



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Transmission cont'd

- High Priority Replacements
  - Based on comprehensive aerial/ground inspections

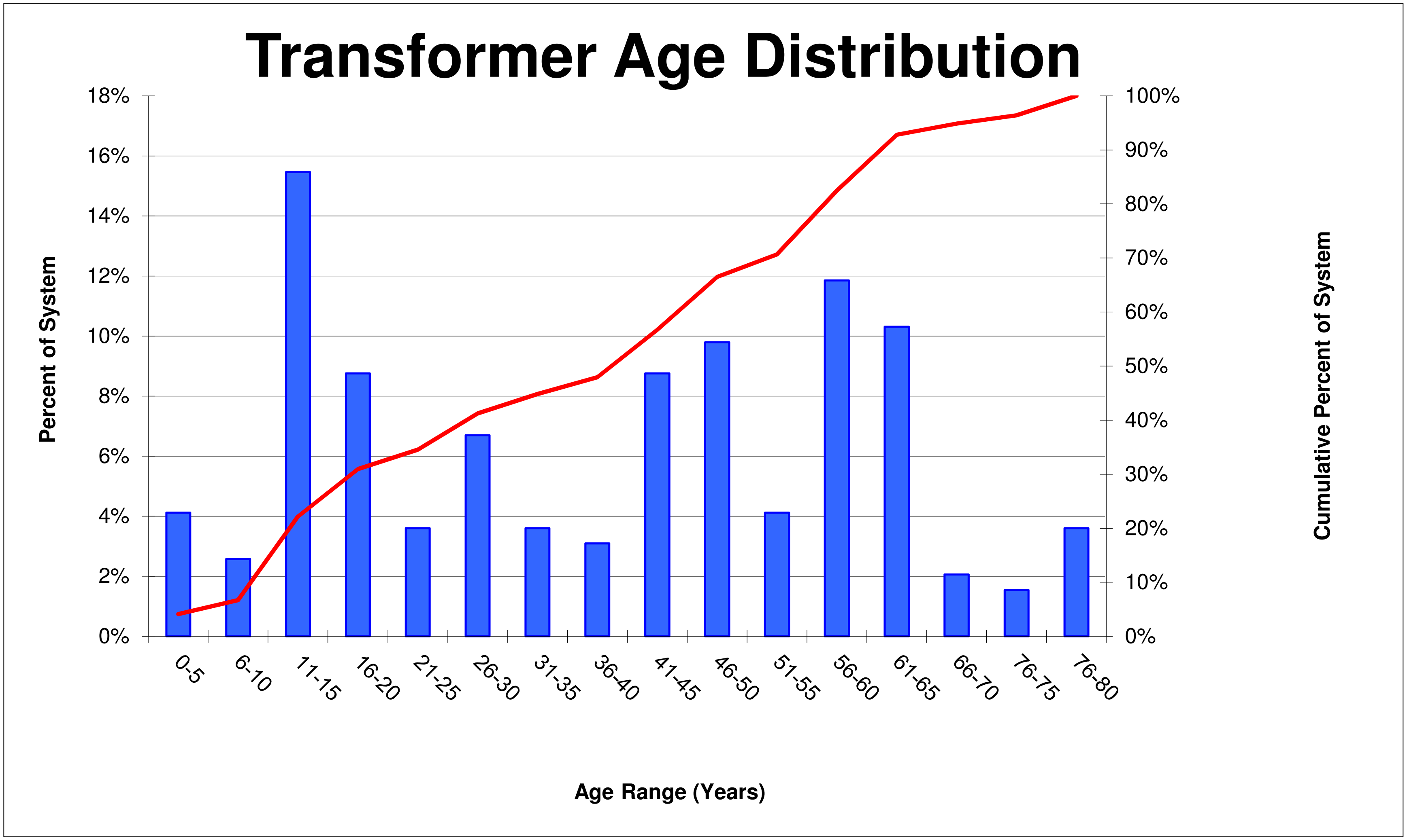
Transmission cont'd

- Condition Based Line Rebuilds -
  - WH-1/WH-2 Lines
  - P & MK Line

    structure replacements
  - G Line North
  - KM/TV Line
  - EF Line rebuilds
  - CL Line rebuilds
  - H & SB Line rebuilds

Transmission Rebuilds

Substation


Transformer Age Distribution
Percent of System
Cumulative Percent of System
18%
16%
14%
12%
10%
8%
6%
4%
2%
0%
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0-5
6-10
11-15
16-20
21-25
26-30
31-35
36-40
41-45
46-50
51-55
56-60
61-65
66-70
76-75
76-80
Age Range (Years)

Substation cont'd

- Major Infrastructure related rebuilds:
  - Sturgeon Pool
  - Knapps Corners
  - Greenfield Road
  - Modena
  - Union Avenue
  - Woodstock
  - Montgomery

Substation cont'd

- Condition Based Infrastructure Replacement
  - Power Transformers
  - Power Circuit Breakers
  - Circuit Switchers/Disconnect Switches
  - Relaying, Controls, Communications & Metering

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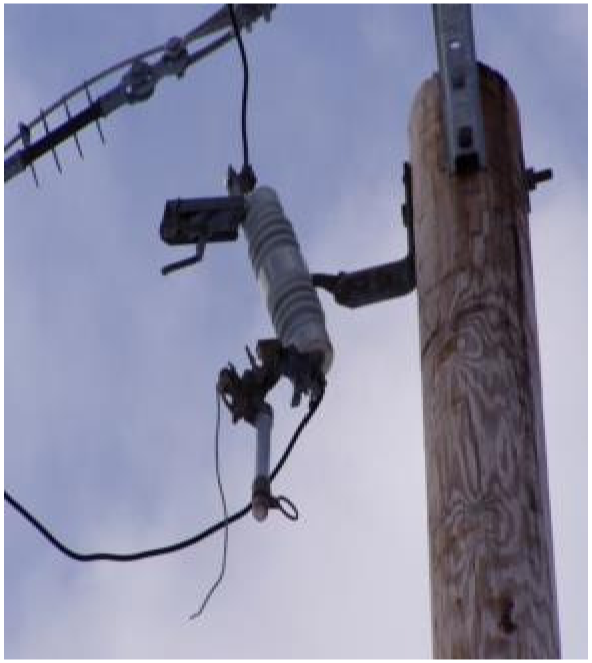
Substation Capital Work

Distribution Improvements

- Day-to-day operations
  - Distribution Improvements (small)
  - Relocations
  - Road Rebuilds
  - Conversions
- Thermal/Voltage Issues –
  - Capacity related – ability to supply peak demand
  - Voltage constraints
  - Stepdown transformer replacements
  - Conversions/Rebuilds/Extensions

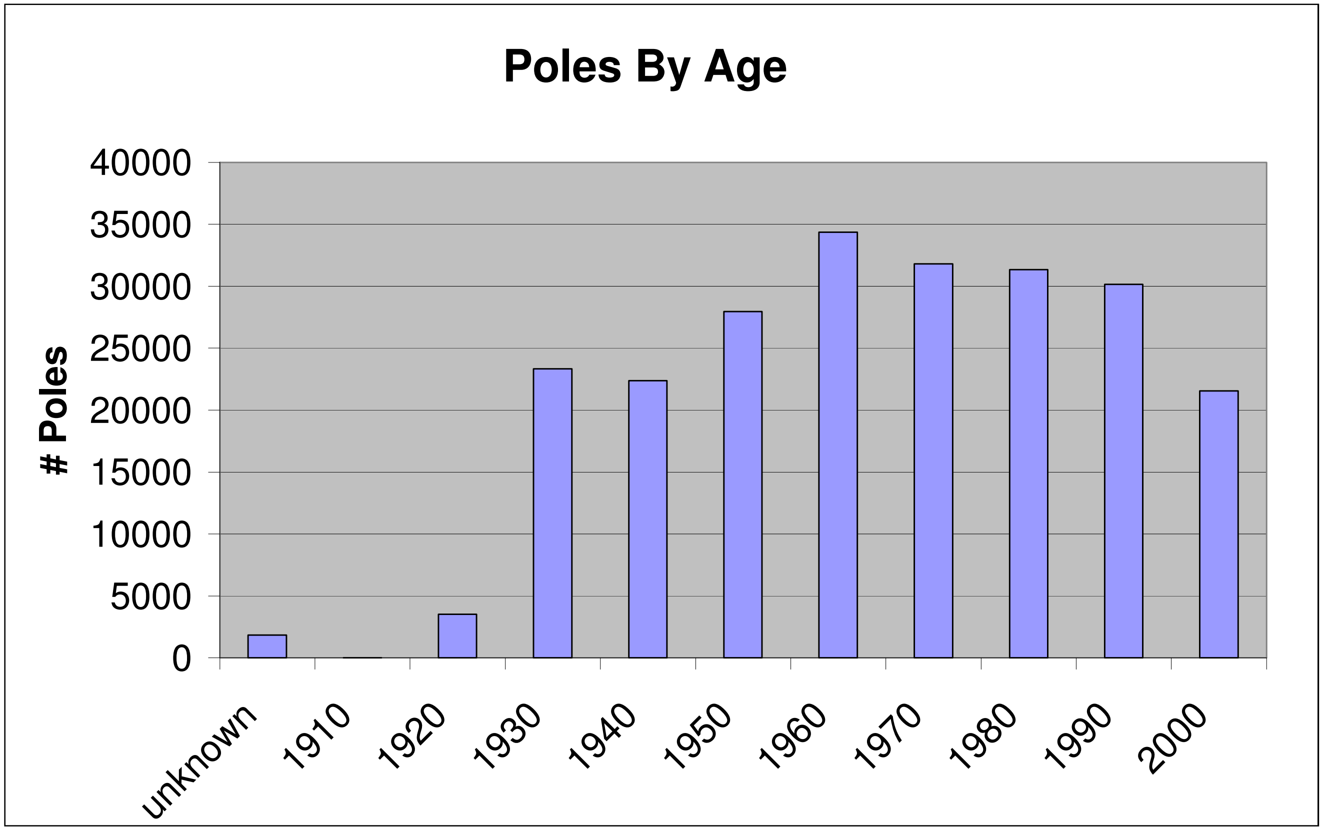
Distribution cont'd



- Reliability/Resiliency
  - $/COA criteria
  - Operating improvements
  - 10X Program
  - Targeted replacements (i.e. porcelain cutouts)
- Infrastructure
  - Reconductoring or rebuild projects
  - Distribution pole replacements
  - 5kV Aerial Cable/Copper Wire/4800 V Conversions/Open Wire Secondary etc.

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Distribution cont'd



Distribution cont'd

- Substation/Transmission related
  - Circuit exits/integration studies/conversions
  - Coordinated with substation work
- Distribution Automation

New Business, Meters, and Transformers

- Requirement to serve new customers/ upgrades for existing customers

People. Power. Possibilities.
Central Hudson
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Foundational Investments

Distribution Automation

~ $34.4M in five-year forecast ($42M total)

DMS/DSCADA

~ $1.3M in the five-year forecast ($7.5M total)

Network Strategies

~ $17M in the five-year forecast ($22M total)

DSP Foundational Investment Plans

Data Sharing

Central Hudson's Foundational Investment Strategy

- Distribution Automation commenced at Central Hudson approximately 14 years ago with significant reliability benefits
- Benefits would soon plateau without an integrated, centralized approach that considered the utility on a holistic basis
  - System efficiency, available technology, aging infrastructure

Gaps Identified:

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

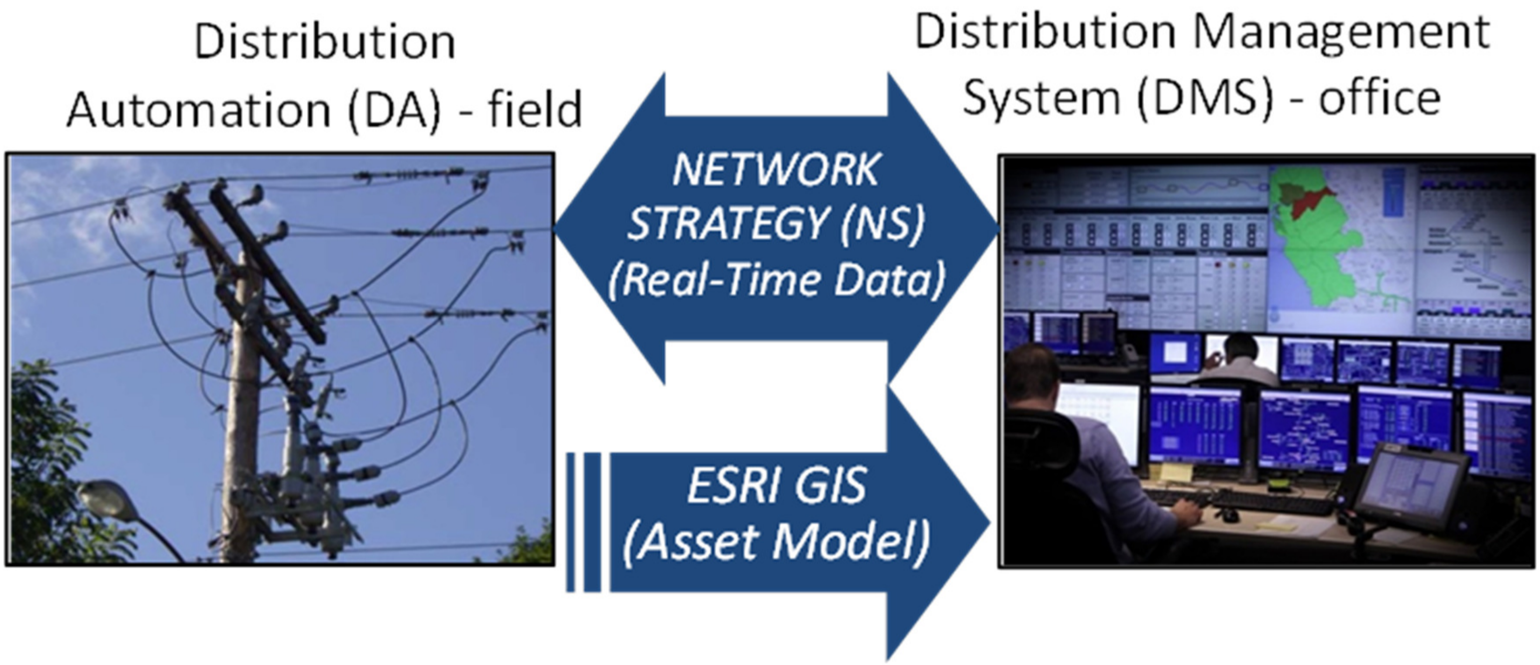
Transition began in 2011 via Pilot Projects and Cross-Functional Teams

Future State:

- Real time system model with detailed asset information
- 2-way communication with control via Operations Center
- Centralized communications through single strategy
- Central Hudson led communications via vendor partnership
- Integrates customer-owned Distributed Energy Resources

Central Hudson's Foundational Investment Strategy

- Foundational to our core strategy / pre-dates REV (2011)
- Foundational for REV
- Three key components underpinned with the ESRI Model

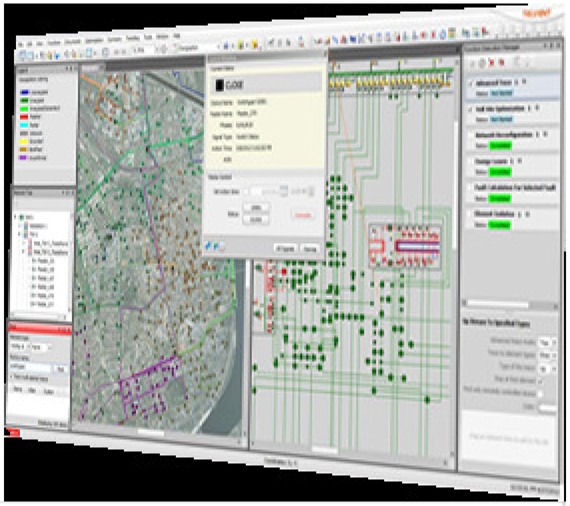


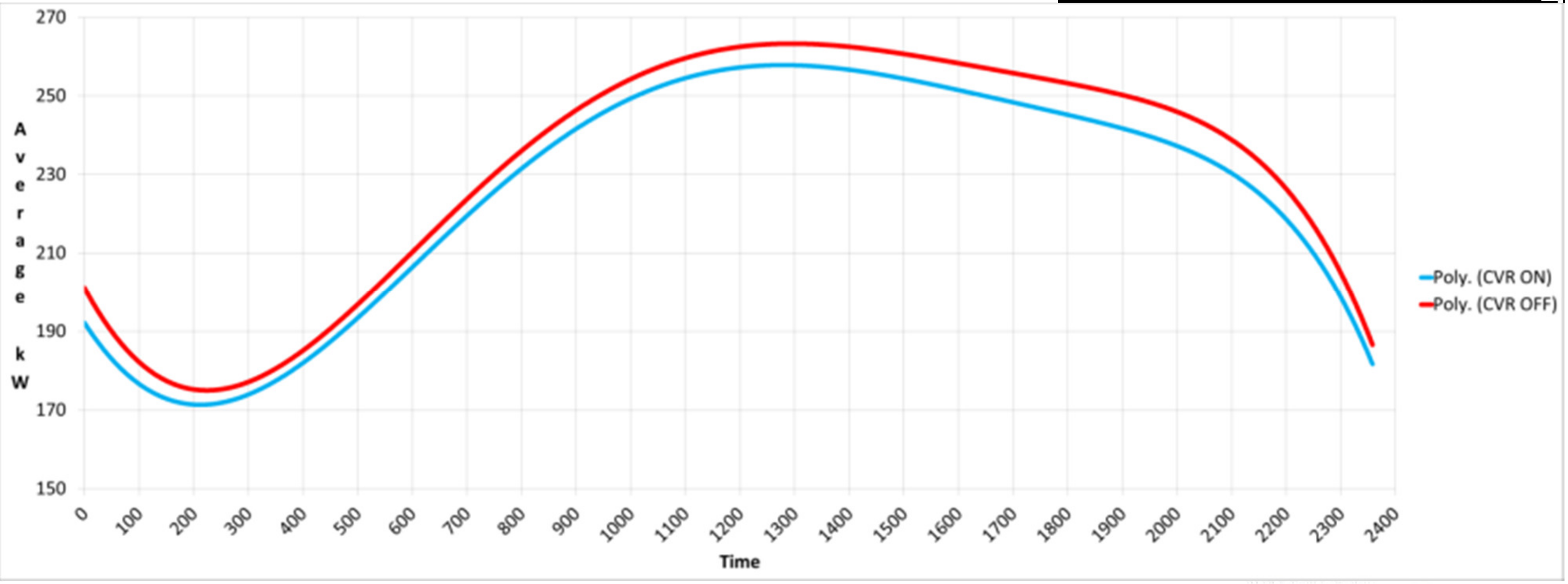
Distribution Automation (DA)

- Install intelligent devices capable of providing 2-way status and control
  - Electronic Reclosers/ Mid Point Ties
  - Switched Capacitors
  - Regulators
  - Monitors & Sensors
- Upgrade key portions of our existing distribution circuitry to current standards
  - Increase switching capabilities
  - Improve voltage profile
  - Reduce losses
- Two Key Objectives accomplished via DMS:
  - CVR/VVO
  - FLISR/Automatic Load Transfer

Distribution Management System (DMS)

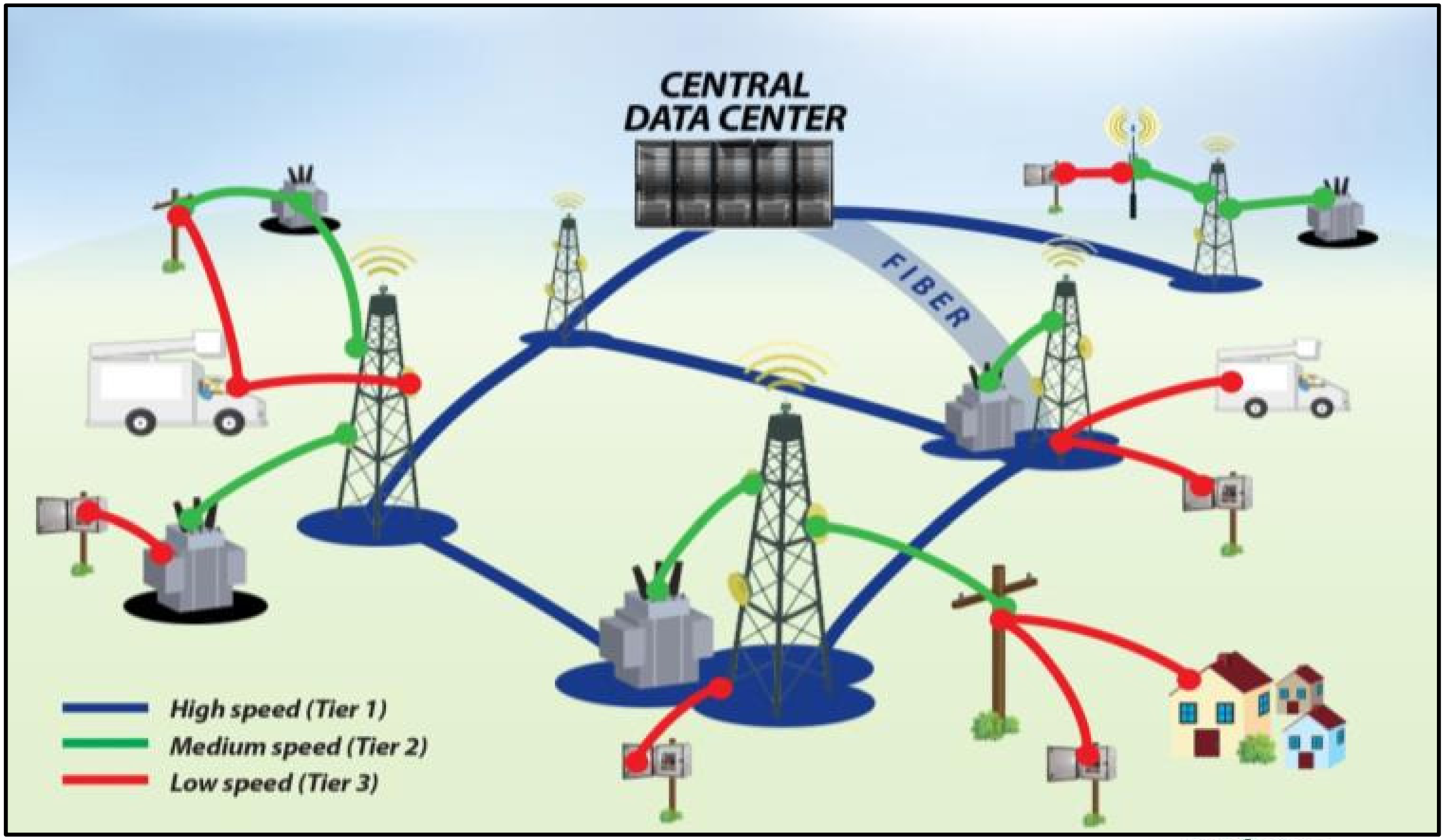
- "Brains" of the operation
- Two Key Objectives:
  1. CVR/VVO
  2. FLISR/Automatic Load Transfer
- Integrate Distributed Energy Resources





Network Communications Strategy (NS)

- Two-way Communications and Control



Foundational Investments - Schedule

Distribution Automation	• In-progress • >80% completion by 2020
Distribution Management System	• In-progress • Site acceptance by 2017 with continued development through 2020+
Network Communications Strategy	• In-progress • >80% completion by 2020

Beneficial Locations – Method and Map

Data Sharing

Three types of locations:

- Beneficial Locations – potential T&D System constraints based on probabilistic load forecasting methods
- Non Wires Alternatives (NWAs) locations – areas where DERS are considered to defer or eliminate planned T&D upgrades due to forecasted capacity constraints
- Remainder of our service territory – DR Tariff Programs

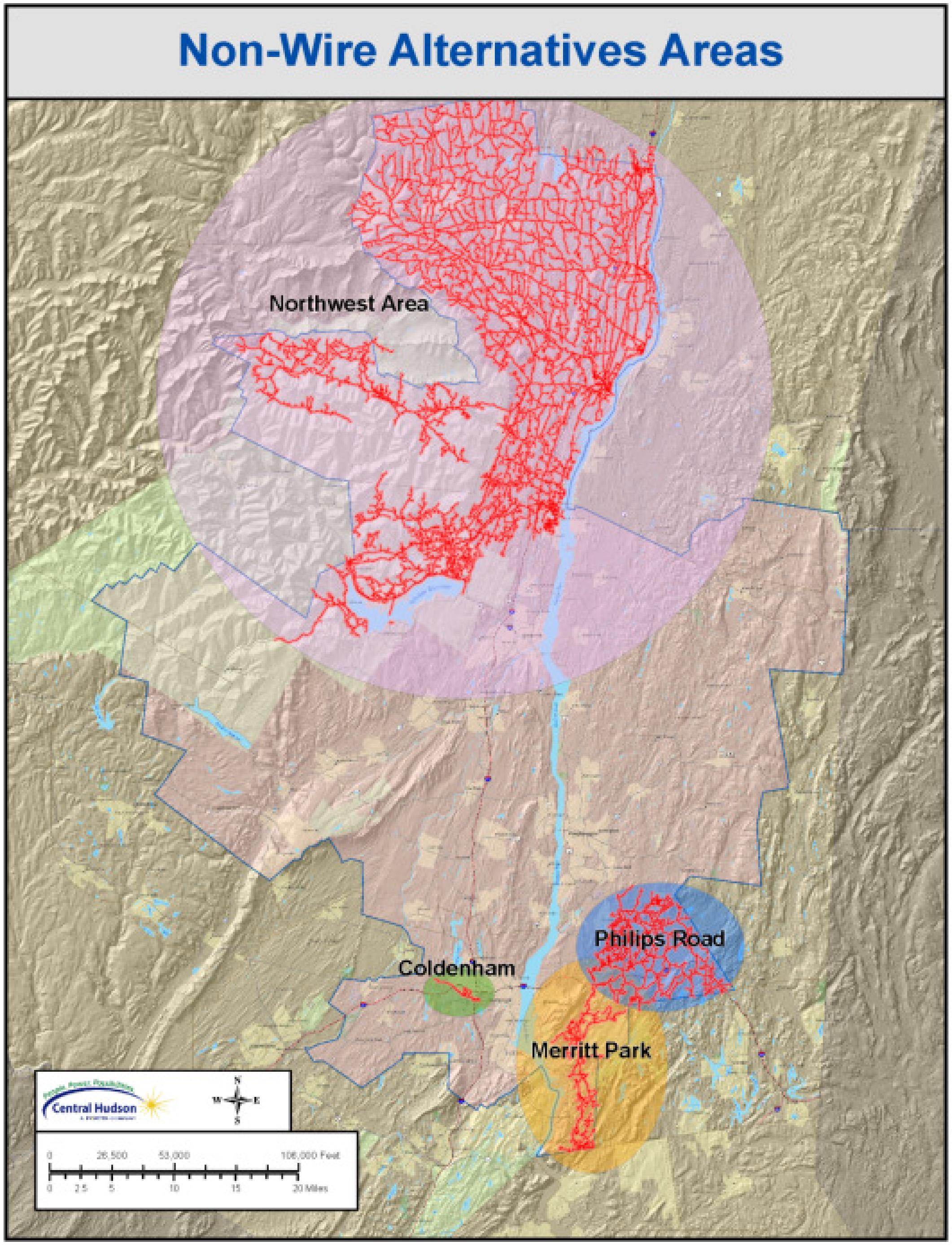
NWAs

Three existing:

- **Northwest Area (Transmission Area)**
- **Philips Road (Substation Area)**
- **Merritt Park (Distribution Area)**

One new:

- **Coldenham (Distribution Area)**


Non-Wire Alternatives Areas
Northwest Area
Philips Road
Coldenham
Merritt Park
Central Hudson
N
W
E
S
0
26,500
53,000
106,000 Feet
0
2.5
5
10
15
20 Miles

Beneficial Locations

- Based on growth trends/rates probability exists that facility design ratings may be exceeded
- Uncertainty and allowable risk are factored into decision making
- Utilized probabilistic methods - > 5% probability of exceeding rating within a 10 year period
- No reinforcement projects for these areas in our current forecast
- Not assigning value – in some cases mitigation can be low or no cost load transfers, other cases may require T&D investments

Beneficial Locations

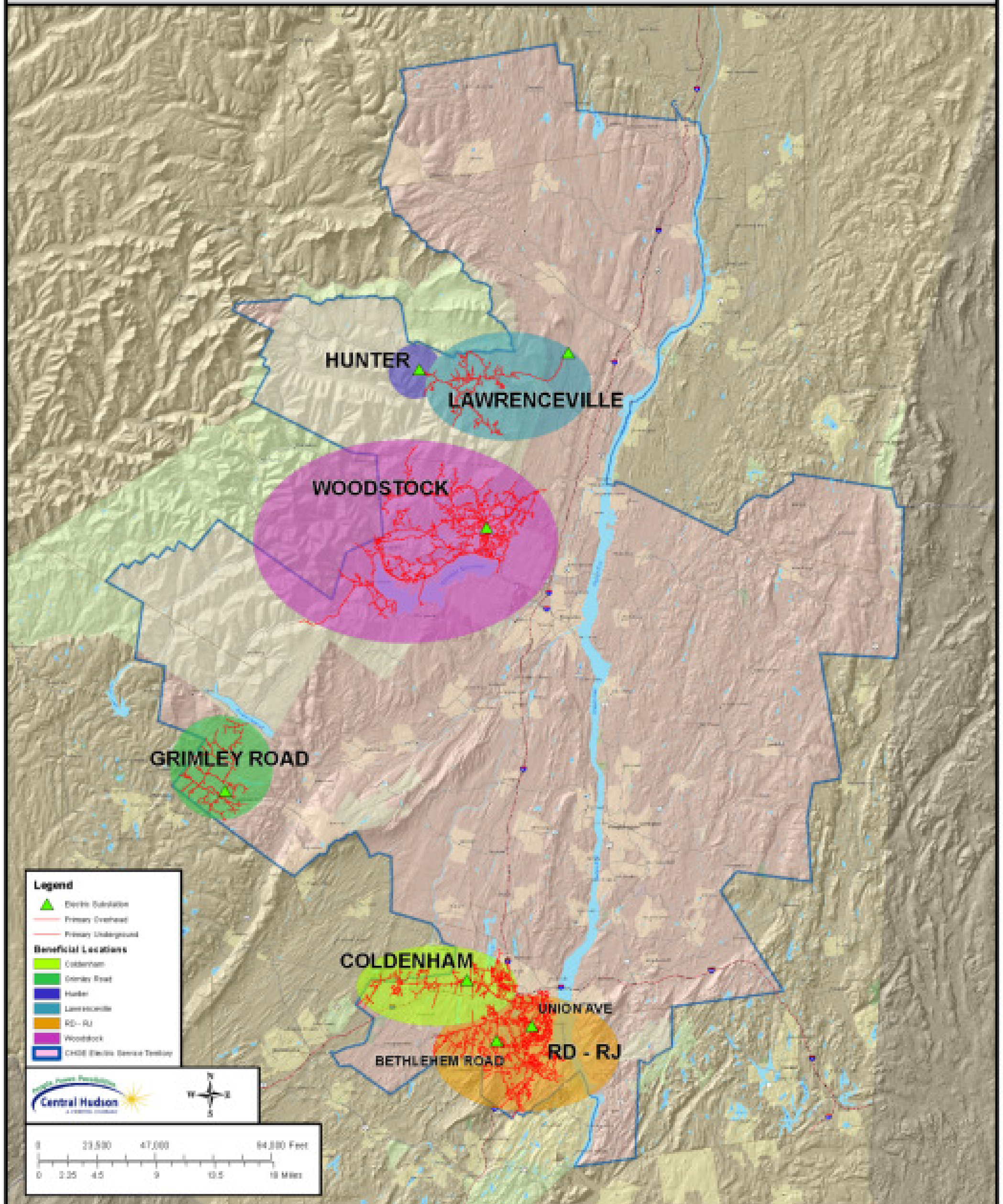
Four substation areas:

- Woodstock
- Lawrenceville
- Grimley Road
- Coldenham

One transmission area:

- RD-RJ Lines

Beneficial Locations

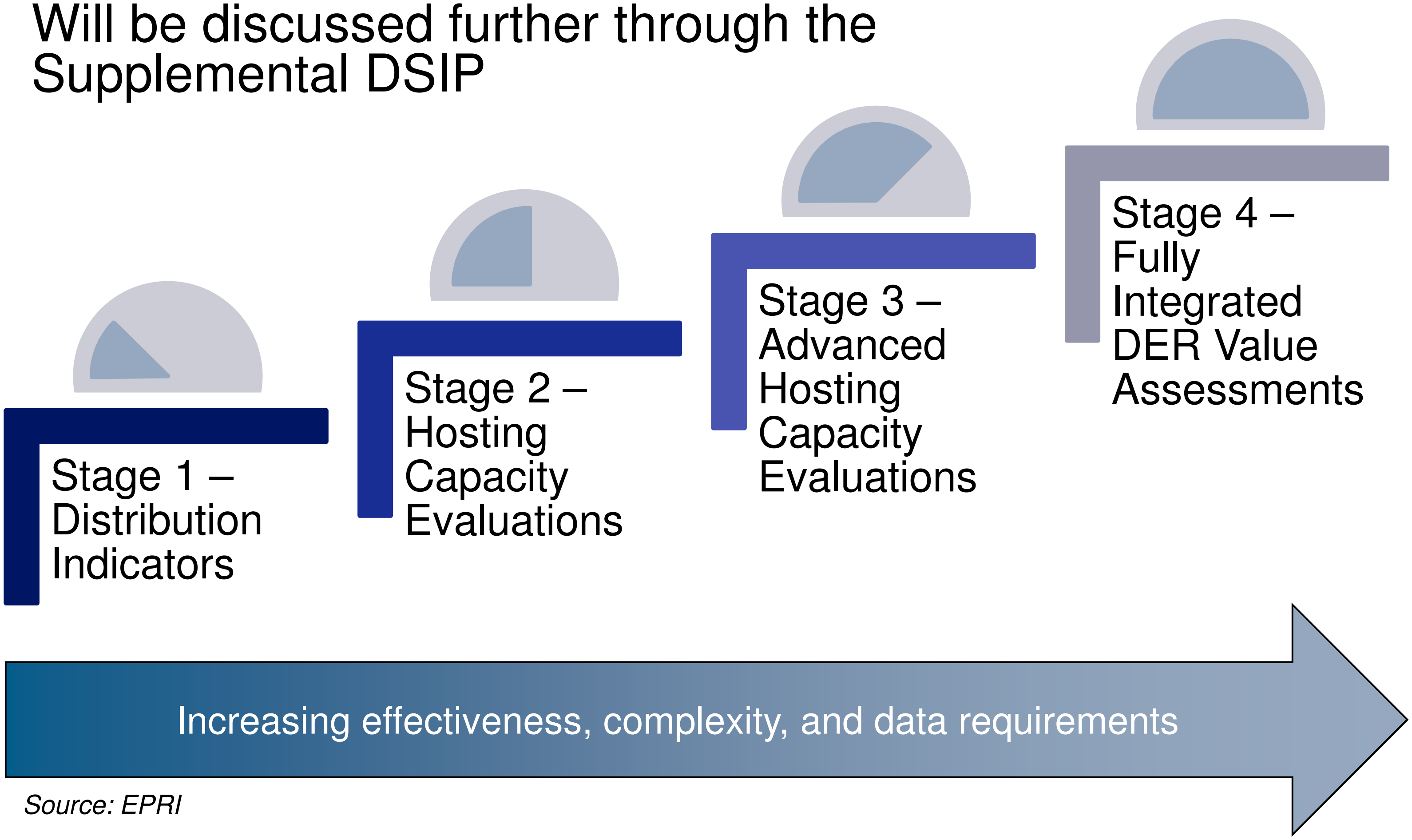


DER System Indicator Map

Data Sharing

Hosting Capacity Evolution

- Joint Utilities worked with EPRI to develop a whitepaper including a four-stage approach
- Whitepaper included in Initial DSIP
- Will be discussed further through the Supplemental DSIP



Source: EPRI

DER Stage 1 System Indicator Map

The locations highlighted fall into 4 categories based upon the current queue:

Category 1

- Low voltage circuitry (5kV class)

Category 2

- Single phase circuitry

Category 3

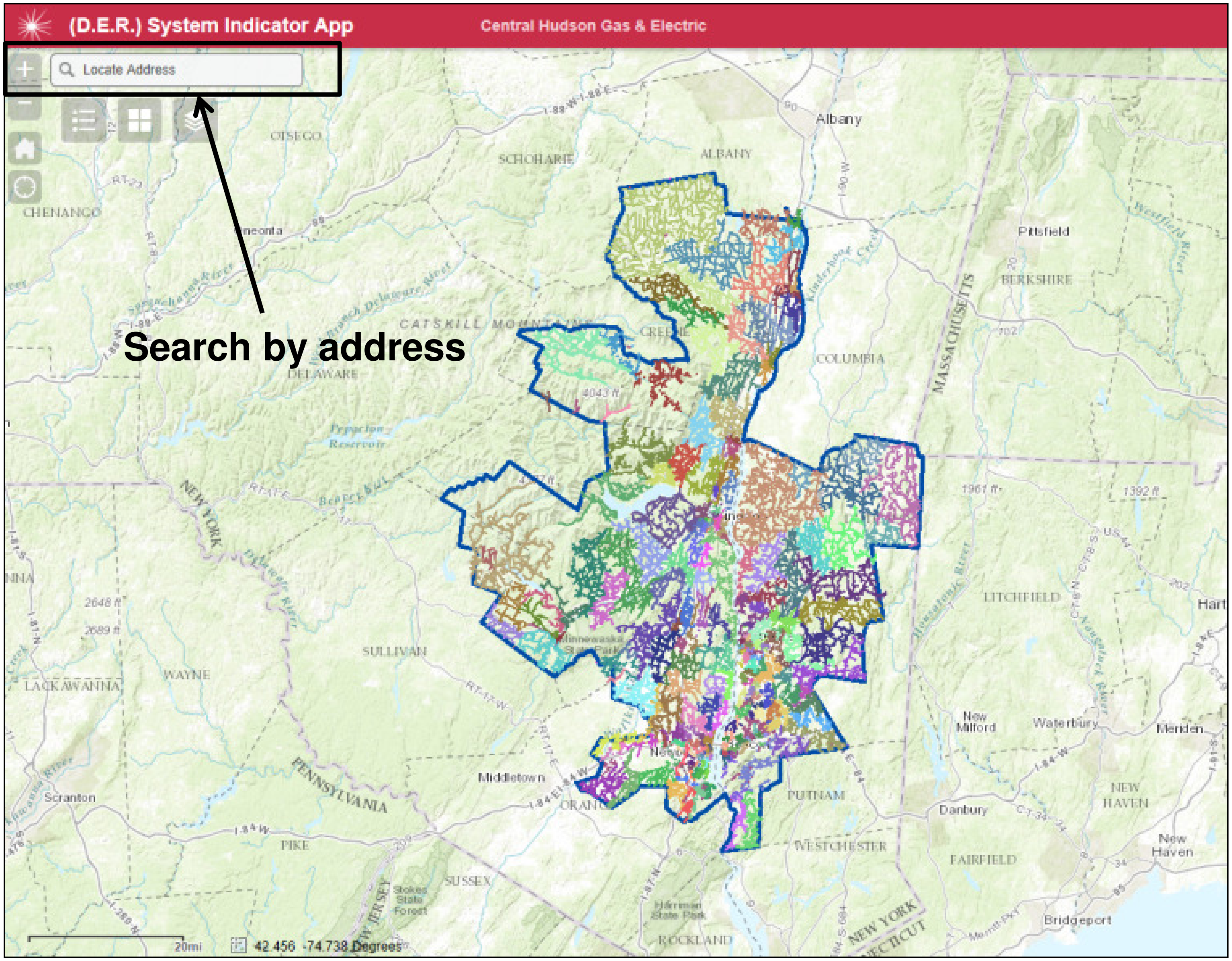
- Feeders where minimum load is anticipated to be significantly exceeded (>4 MW of solar PV in queue)

Category 4

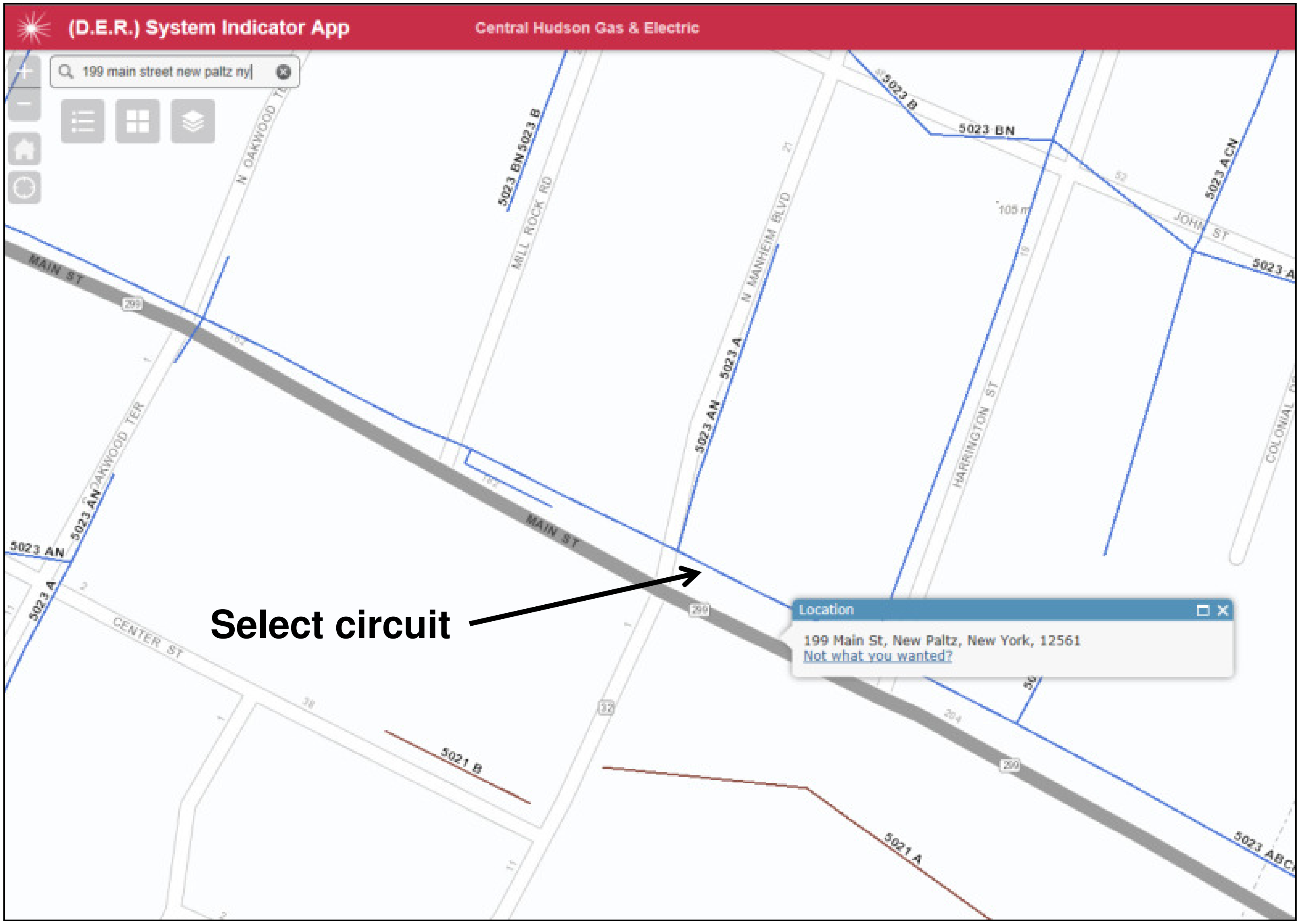
- Feeders emanating from a substation transformer that is anticipated to experience significant backfeed (average of 4 MW per feeder in queue emanating from a particular substation bus)

Link: http://centralhudson.com/dg/DERmap.aspx

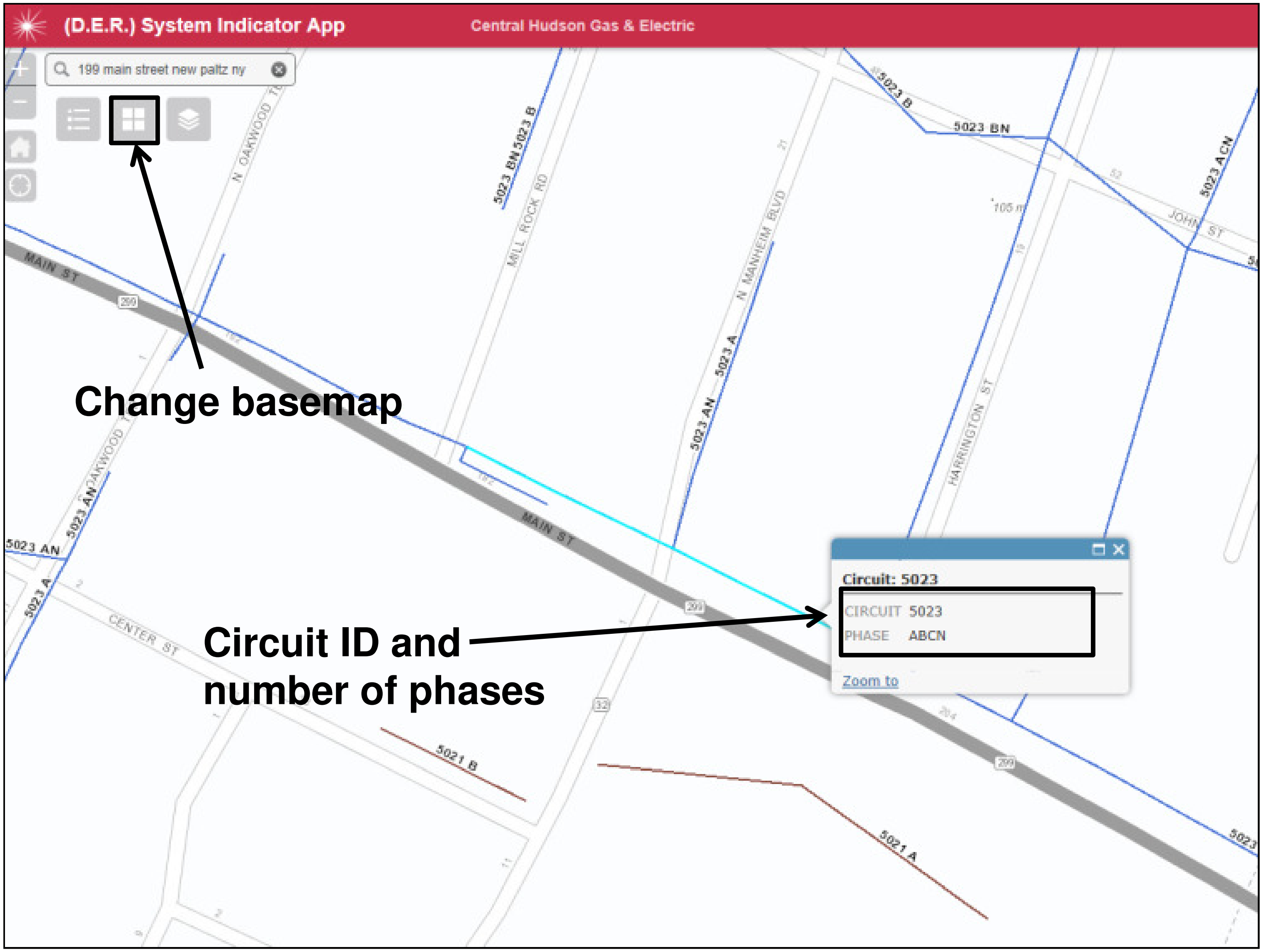
DER System Indicator Map



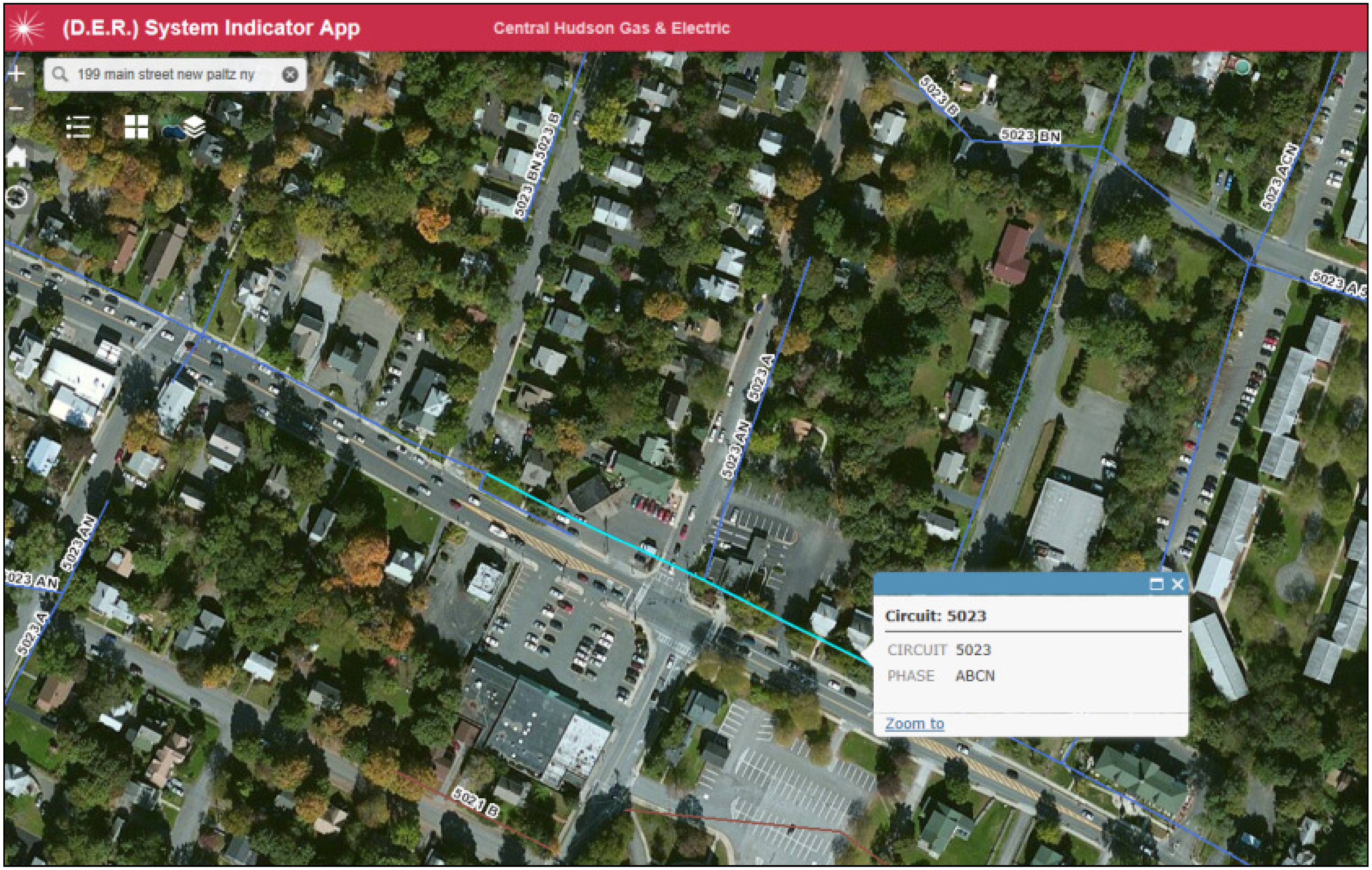
DER System Indicator Map



DER System Indicator Map



DER System Indicator Map

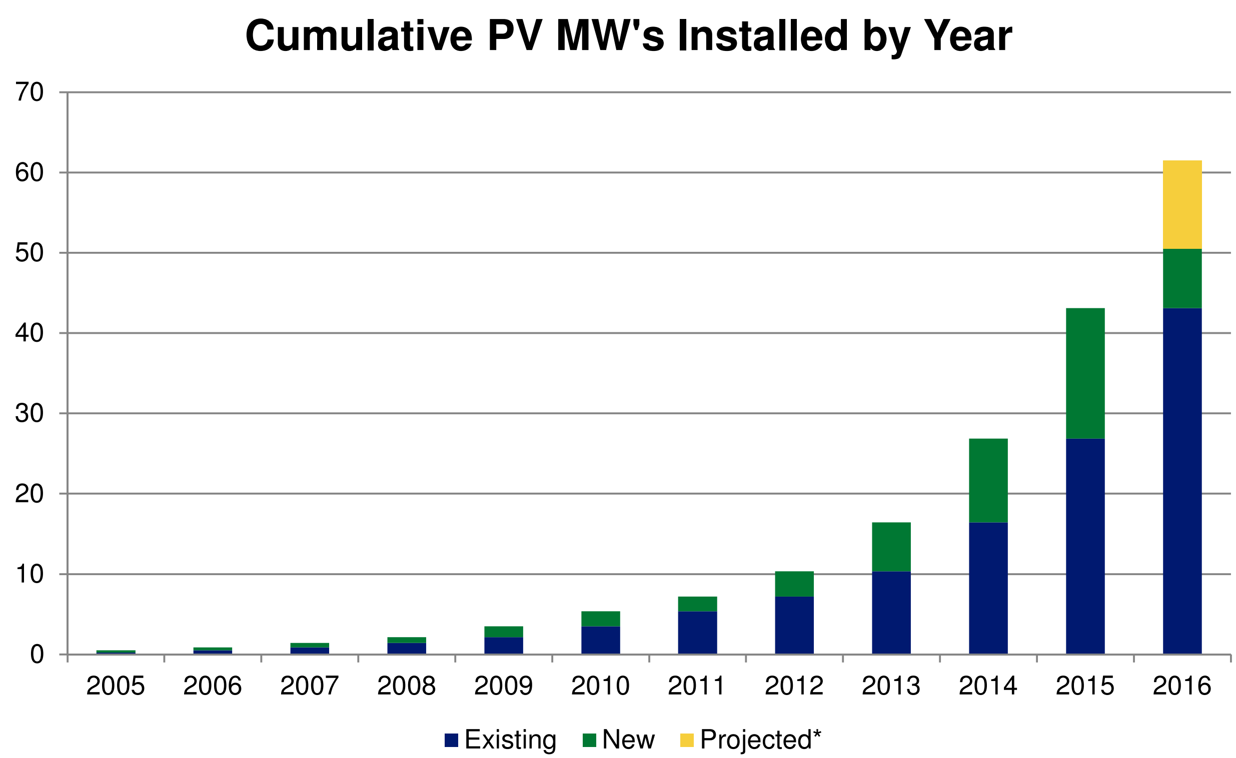


Interconnection Process Improvements

Data Sharing

SOLAR PV GROWTH A DRIVER OF DATA SHARING NEEDS

Interconnection Growth



*2016 projection is regression-based and will likely be higher based upon current CDG queue.

As of 5/31/2016			
Net-Metered Non-Wind	Connected	Proposed	Total
MW	50.525	726.648	777.173
# of systems	5,486	1,215	6,701

SOLAR PV GROWTH A DRIVER OF DATA SHARING NEEDS

Internal Improvements & Best Practices

Online Portal
- Contractor number allows for autofill
- Required fields reduce deficiencies

Customer/Developer Interaction
- Central phone number and e-mail address
- Transitioned from mailing approval letters to electronic only
- Host solar summit annually

Database & Load-Flow Software
- Approval letters automatically pull customer data
- Load-flow software automatically pulls in existing and proposed DG systems

SOLAR PV GROWTH A DRIVER OF DATA SHARING NEEDS

Industry Process Improvements

Interconnection Technical Working Group (ITWG)

- Provide transparency for technical requirements
- Develop better understanding of technical challenges
- Build consensus solutions

Ombudsman Working Group

- Establish clear rules for managing interconnection queue
- Resolve disputes between utilities and customers/developers
- Share best practices

Queue Management

- Utilities are working directly with developers to clean up queue
- Most developers are being cooperative and voluntarily removing projects

Questions?

Appendix B Beneficial Location Load Characteristics

Section VI identified one transmission area and four substations where DER deployments could be beneficial because of the risk of triggering an infrastructure upgrade within the next ten years. This section provides additional detail about the transmission areas and substation where DER deployments could be beneficial, including:

- Historical peak days and load shapes
- Load duration curves
- Weather sensitivity
- Historical growth trends and forecasts with uncertainty

B.1 RD-RJ Transmission Area

The RD-RJ transmission area (Figure B-1) comprises the Union Avenue and Bethlehem Road Substations located in Orange County, South of Newburgh. The area load serving capability is 144 MW. Potential upgrades to the area include a project to increase load serving capability to 177 MW and, if needed, an upgrade from 177 MW to 230 MW. There is sufficient load serving capability to accommodate growth over the next five years with little to no risk of overloads, but the loads since 2010 have been growing at a 2.1% per year pace. Given the uncertainty in forecast, there is a 6% chance and upgrade would be needed by 2025.

Figure B-1: RD-RJ Transmission Area

Figure B-2 summarizes the hourly loads for each annual peak from 2010 to 2015. Figure B-3 summarizes the load duration curve for the top 250 hours for each year over the same time frame. The area tends to peak during summer months, mostly but not exclusively between 12 to 6 pm. The area loads are relatively weather sensitive as illustrated in Figure B-4, with demand growing larger during afternoon hours of hotter days. The figure shows the average hourly load curves at different temperature ranges. Figure B-5 shows the historical peak loads and forecast, with uncertainty, over the next 10 years.

Figure B-2: RD-RJ Historical Peak Day Load Patterns

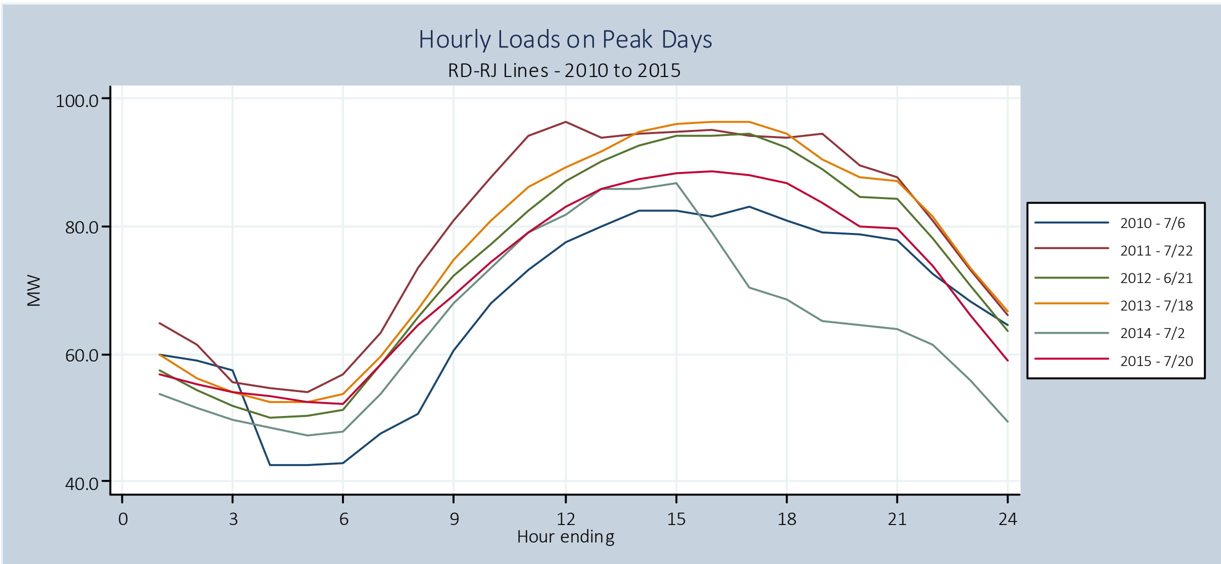


Figure B-3: RD-RJ Historical Load Duration Curves

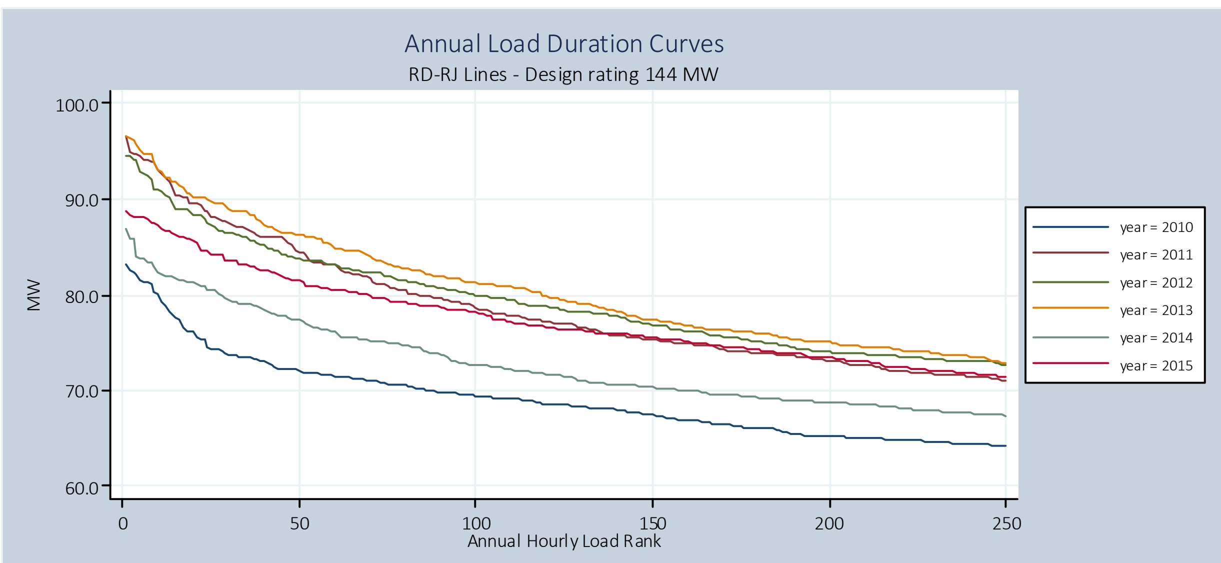


Figure B-4: RD-RJ Weather Sensitivity

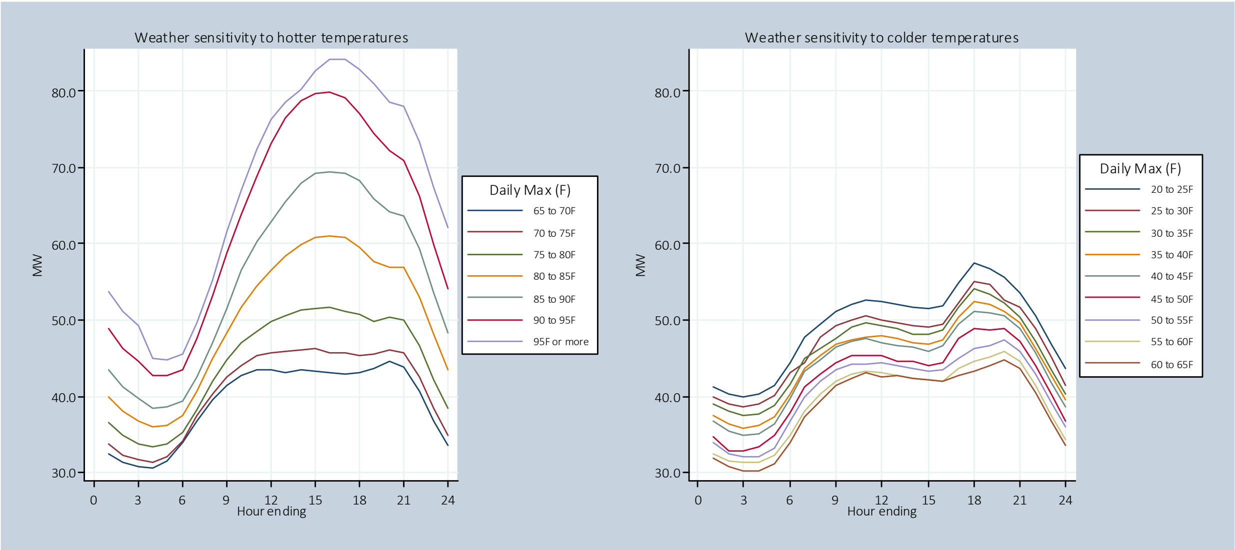
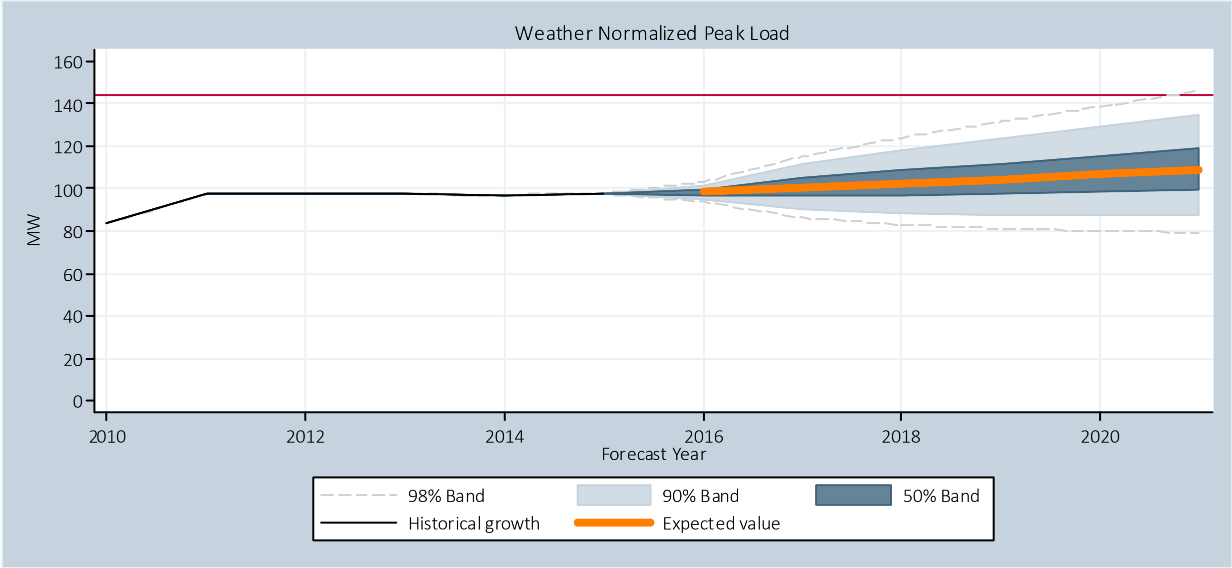


Figure B-5: 1-in-2 Normalized Historical Peaks and Probabilistic Forecast



B.2 Coldenham Substation

The Coldenham Road Substation (Figure B-6) is located near the village of Walden in Orange County, East of the Hudson River. The substation's load serving capability is 47.8 MW. Expanding capacity would likely require installing a third transformer. It should be noted, however, that a neighboring substation, Maybrook, is currently being upgraded and it is possible to transfer loads to it and temporarily alleviate loads in Coldenham. Since 2010 peak demand at Coldenham has been growing at a rate of 1.5% per year. Given the uncertainty in forecast, there is a 14.8% chance and upgrade would be needed by 2025.

Figure B-6: Coldenham Station

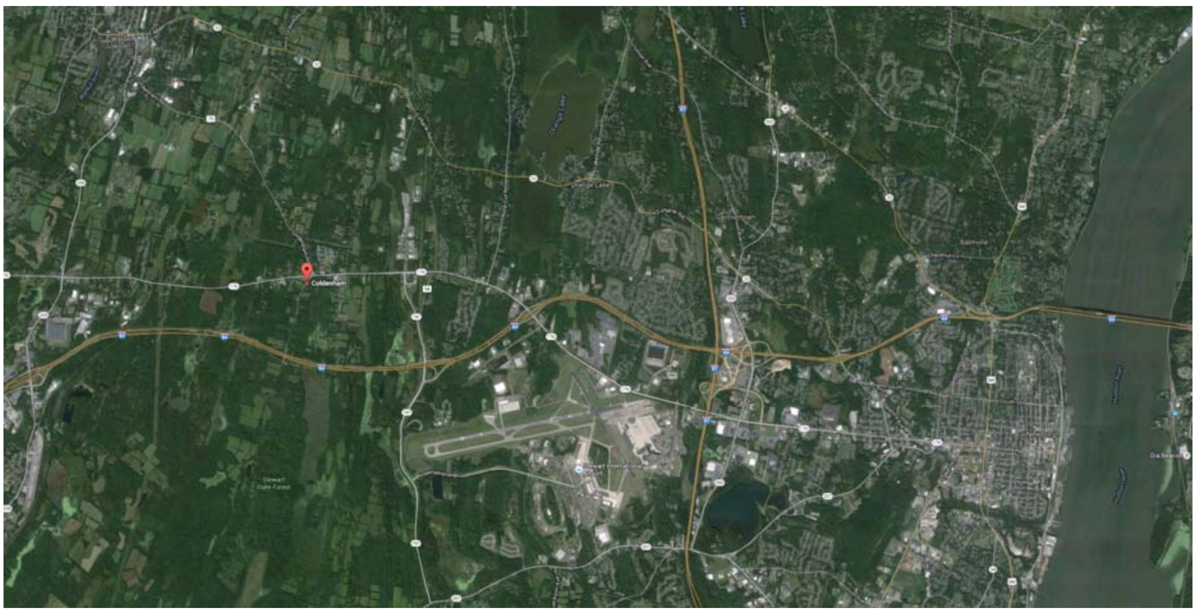


Figure B-7 summarizes the hourly loads for each annual peak from 2010 to 2015. Figure B-8 summarizes the load duration curve for the top 250 hours for each year over the same time frame. The 2013 peak loads were substantially higher than 2014 and 2015, in part due to differences in weather conditions. The area tends to peak during summer months, mostly but not exclusively between 11 am and 7 pm. The loads for Coldenham are relatively weather sensitive as illustrated in Figure B-9, which shows average hourly load curves at different temperature ranges. The demand follows a classic summer peaking pattern with loads growing larger during afternoon hours of hotter days. Figure B-10 shows the historical peak loads, normalized for 1-in-2 weather year conditions, and the 10 year forecast, with uncertainty.

Figure B-7: Coldenham Historical Peak Day Load Patterns

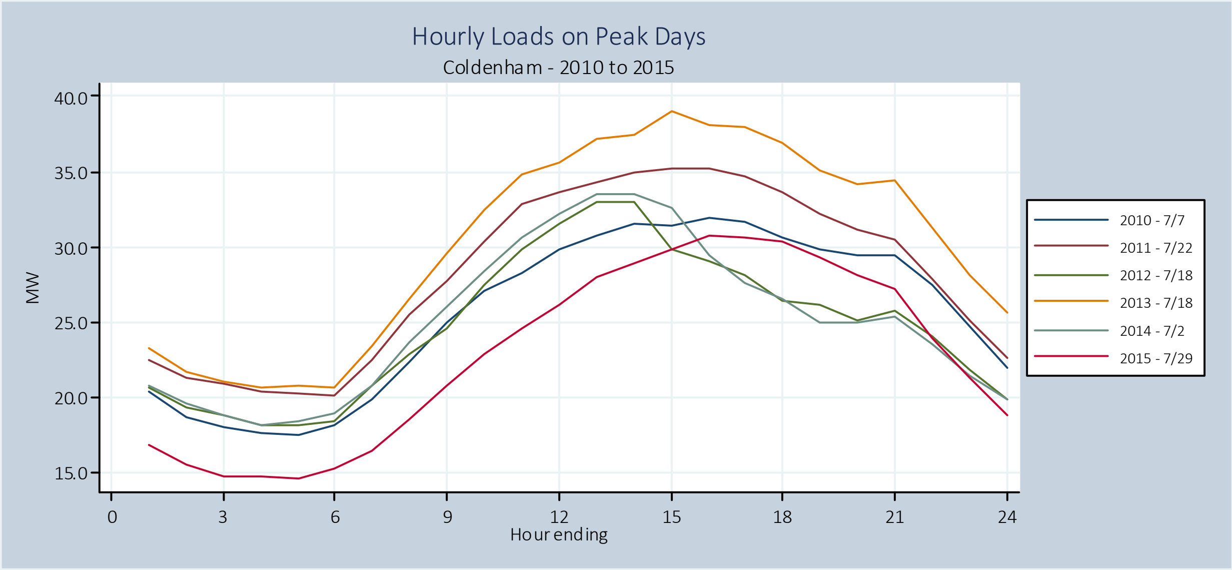


Figure B-8: Coldenham Historical Load Duration Curves - Top 250 Hours

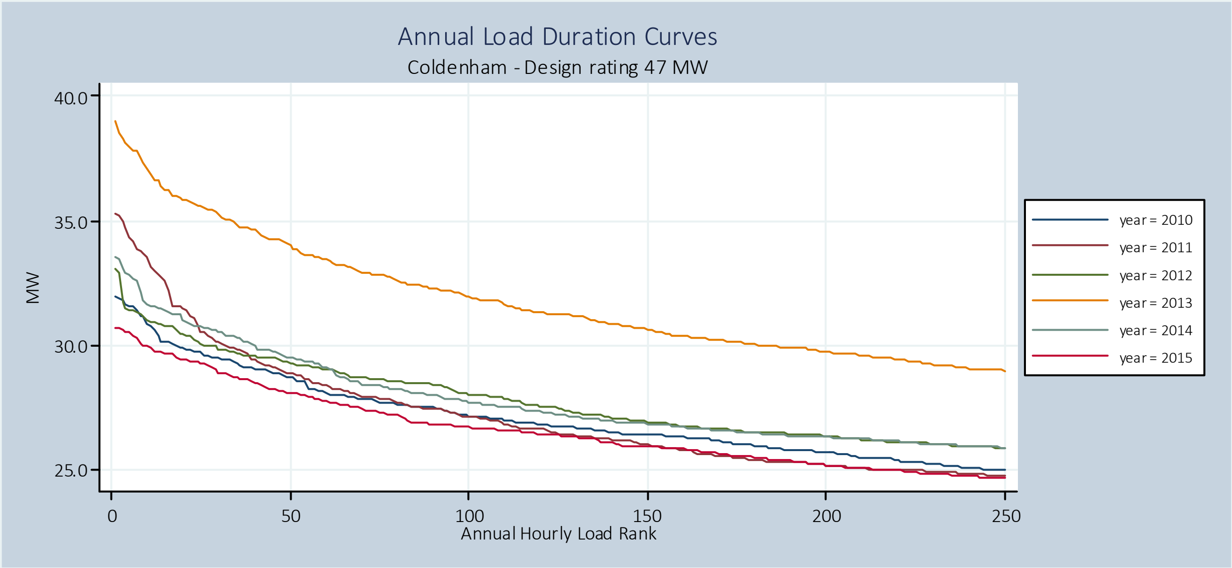


Figure B-9: Coldenham Weather Sensitivity

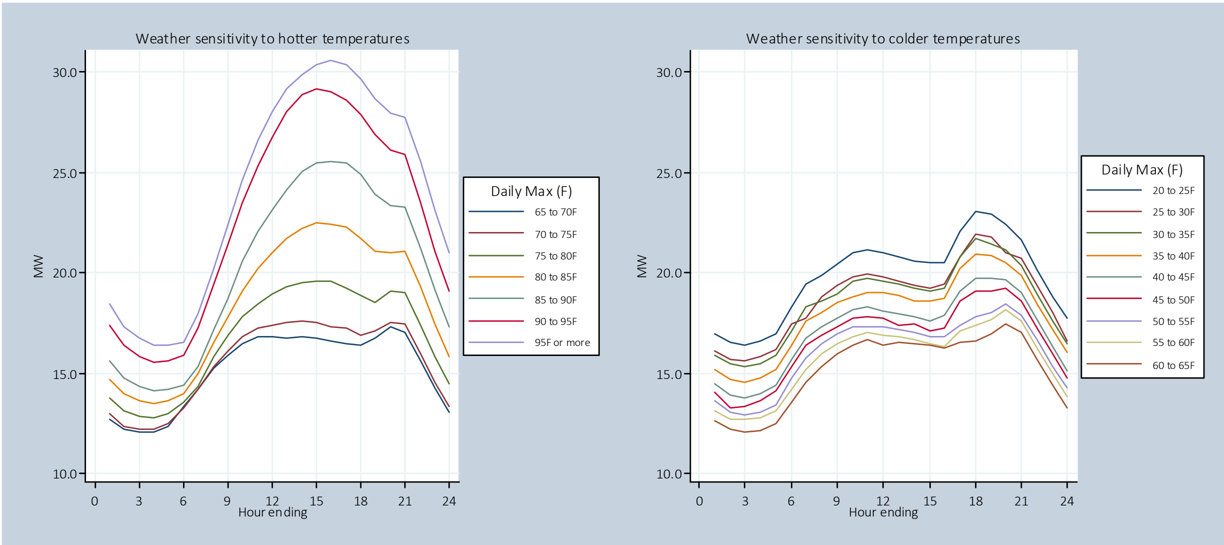
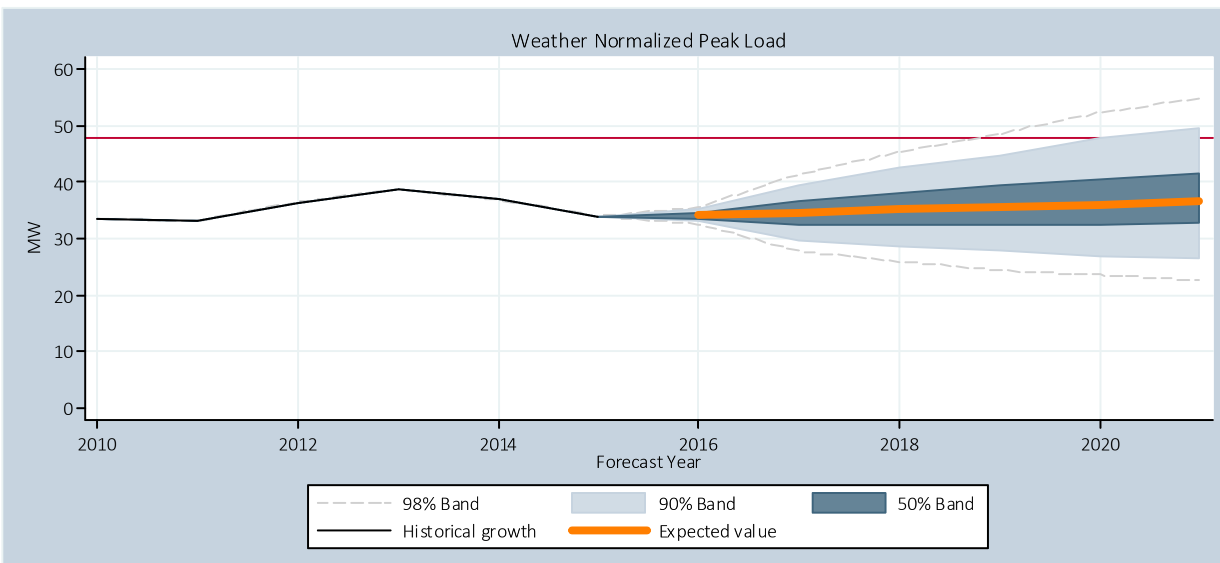


Figure B-10: Coldenham 1-in-2 Normalized Historical Peaks and Probabilistic Forecast



B.3 Grimley Rd Substation

The Grimley Rd Substation (Figure B-11) is located in the Ellenville load area and has a load serving capability of 7.2 MW. The cost of alleviating capacity needs in the region may be low due to the ability to transfer loads to neighboring substation. Since 2013, however, peak demand at Coldenham has been growing at a rate of 3.6% per year. Due to limited, valid data prior to 2013, estimates on the rate of growth are highly sensitivity and the uncertainty regarding the growth pattern is substantial. Based on the data available, there is a 38.6% and upgrade would be needed in five years and a 76.6%% chance and upgrade would be needed by 2025.

Figure B-11: Grimley Rd Substation

Figure B-12 summarizes the hourly loads for each annual peak from 2010 to 2015. Under hotter temperatures, such as in 2013, the loads can be high for a substantial number of hours, driving peaks in the evening hours. Figure B-13 summarizes the load duration curve for the top 250 hours for each year over the same time frame. The 2013 peak loads were substantially higher than 2014 and 2015, in part due to differences in weather conditions. The loads for Grimley Rd are relatively weather sensitive as illustrated in Figure B-14, which shows average hourly load curves at different temperature ranges. Figure B-15 shows the historical peak loads, normalized for 1-in-2 weather year conditions, and the 10-year forecast, with uncertainty.

Figure B-12: Grimley Rd Historical Peak Day Load Patterns

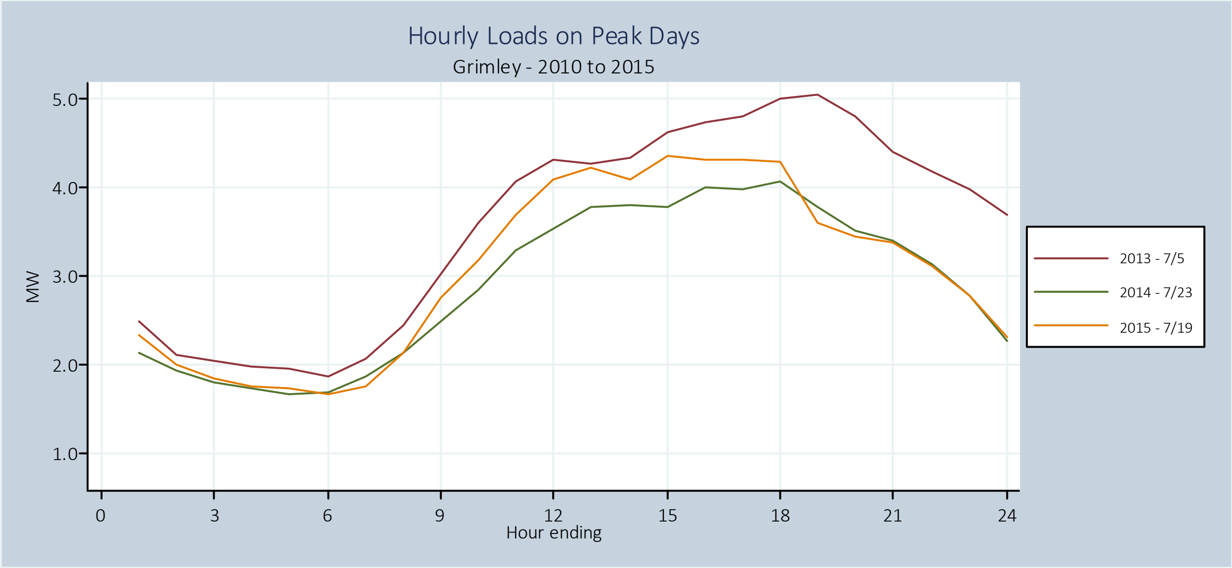


Figure B-13: Grimley Rd Historical Load Duration Curves

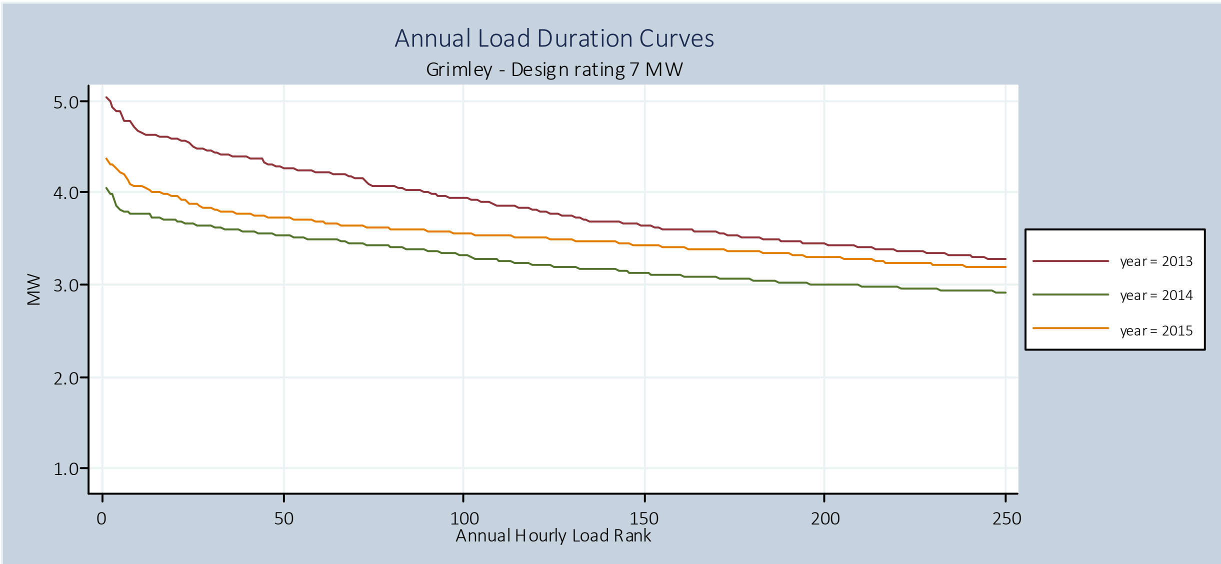


Figure B-14: Grimley Rd Weather Sensitivity

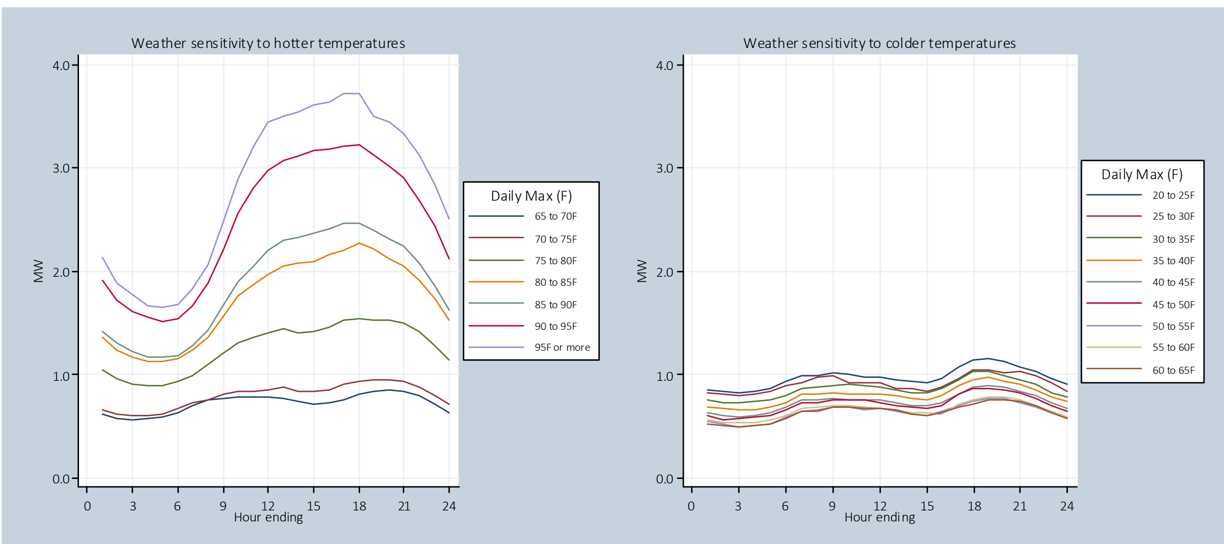
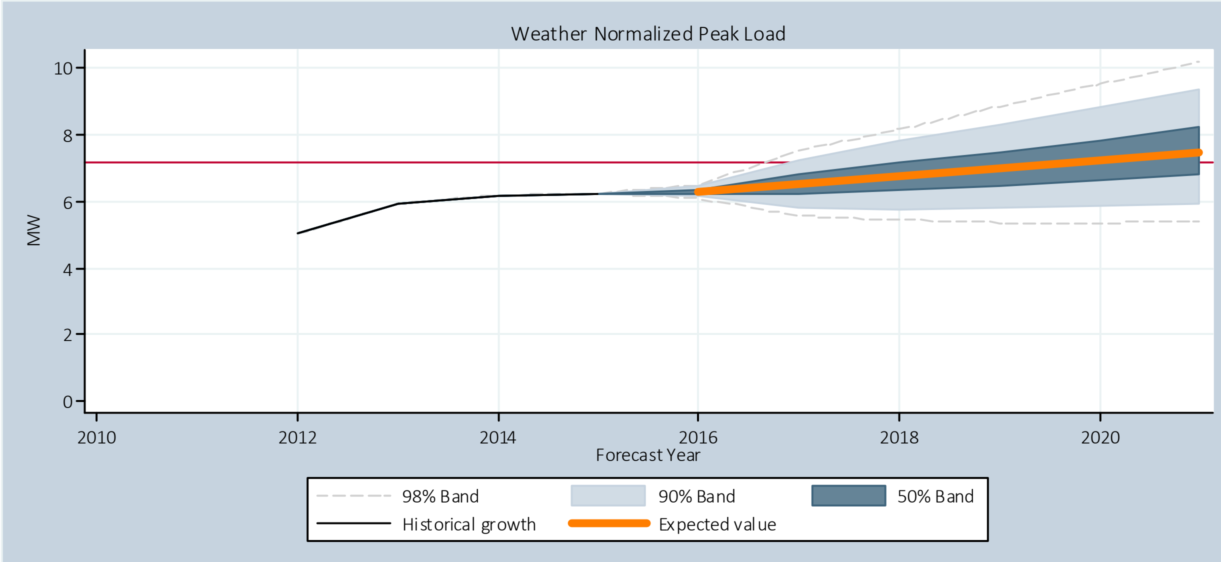


Figure B-15: Grimley Rd 1-in-2 Normalized Historical Peaks and Probabilistic Forecast



B.4 Lawrenceville Substation

The Lawrenceville Substation (Figure B-16) is located near Hurley Mountain in the Northwestern part of Central Hudson's territory. The areas is winter peaking and experiences prolonged peaks. The substation is capable of serving 19.2 MW of load and experiences peaks of 17.0 MW. Increasing load serving capability would most likely require replacing a transformer at a cost of $2M. Due to limited, valid data prior to 2013, estimates on the rate of growth are highly sensitivity and the uncertainty regarding the growth pattern is substantial. Based on the data available, the area loads are growing at a rate of 6.8% per year. There is a 9.7% chance and upgrade would be needed in five years and a 47.9% likelihood an upgrade would be needed by 2025.

Figure B-16: Lawrenceville Substation

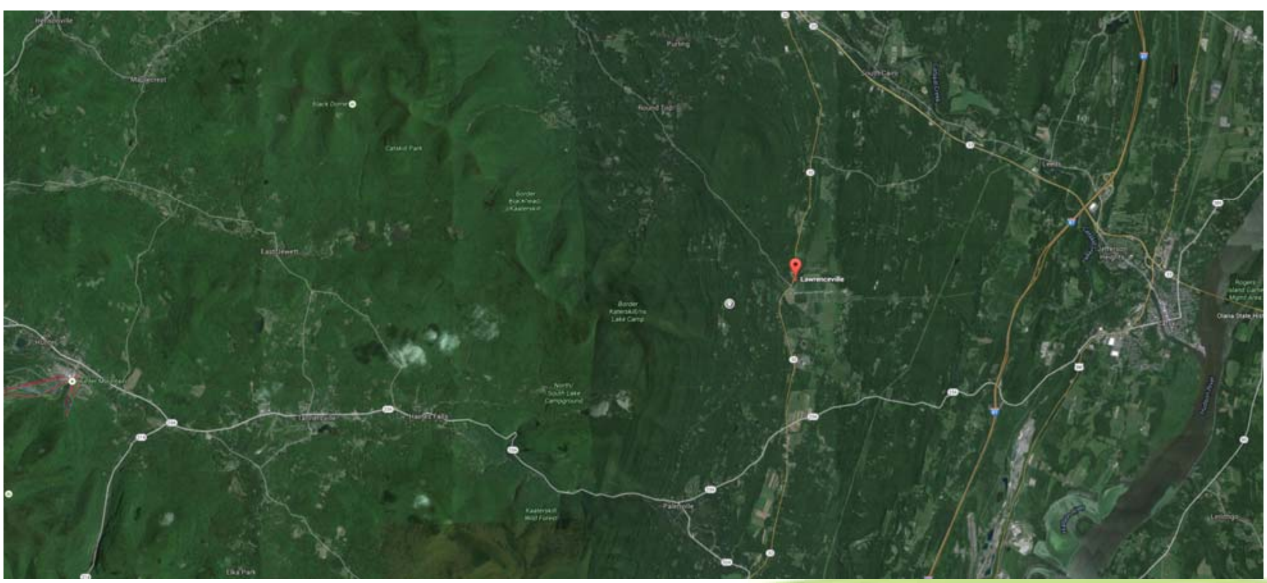


Figure B-17 summarizes the hourly loads for each annual peak from 2010 to 2015. Because of when the data for the study was extracted, it did not include December 2015, which is the typical peak month for Lawrenceville. Figure B-18 summarizes the load duration curve for the top 250 hours for each year over the same time frame. The loads for Lawrenceville are relatively weather sensitive as illustrated in Figure B-19, but unlike most regions, loads grow substantially larger the colder it gets. Figure B-20 shows the historical peak loads, normalized for 1-in-2 weather year conditions, and the 10-year forecast, with uncertainty.

Figure B-17: Lawrenceville Historical Peak Load Patterns

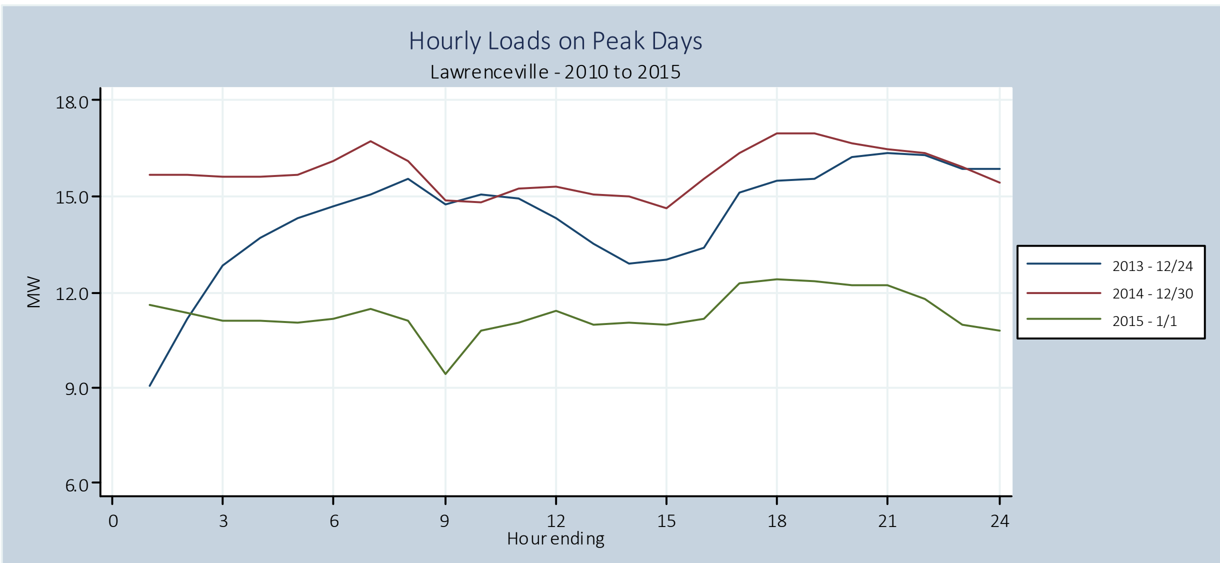


Figure B-18: Lawrenceville Historical Load Duration Curves - Top 250 hours

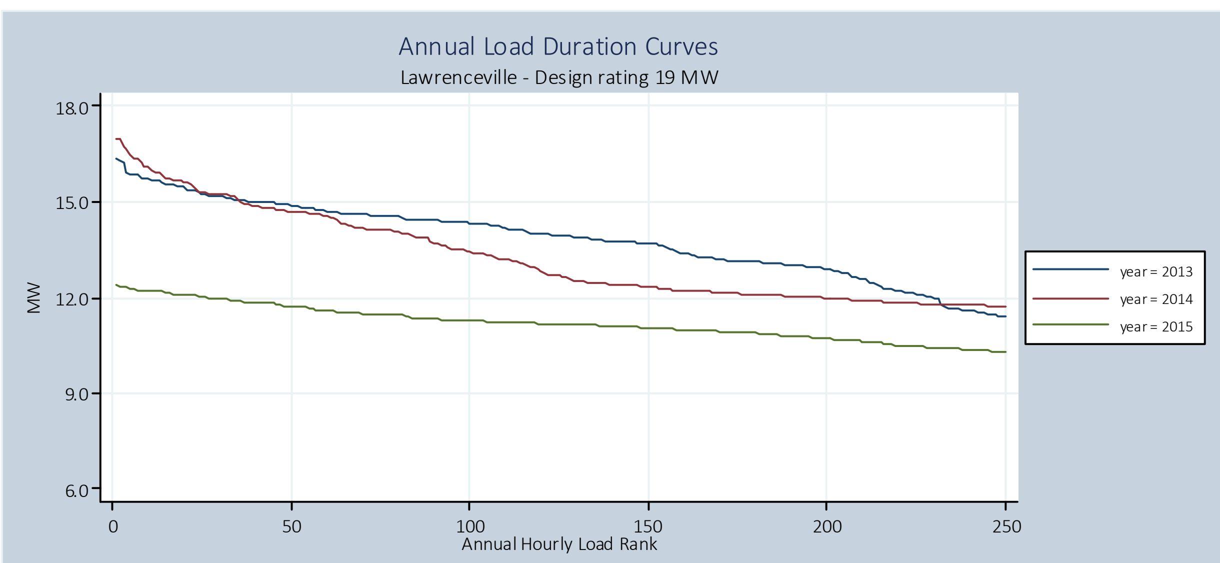


Figure B-19: Lawrenceville Weather Sensitivity

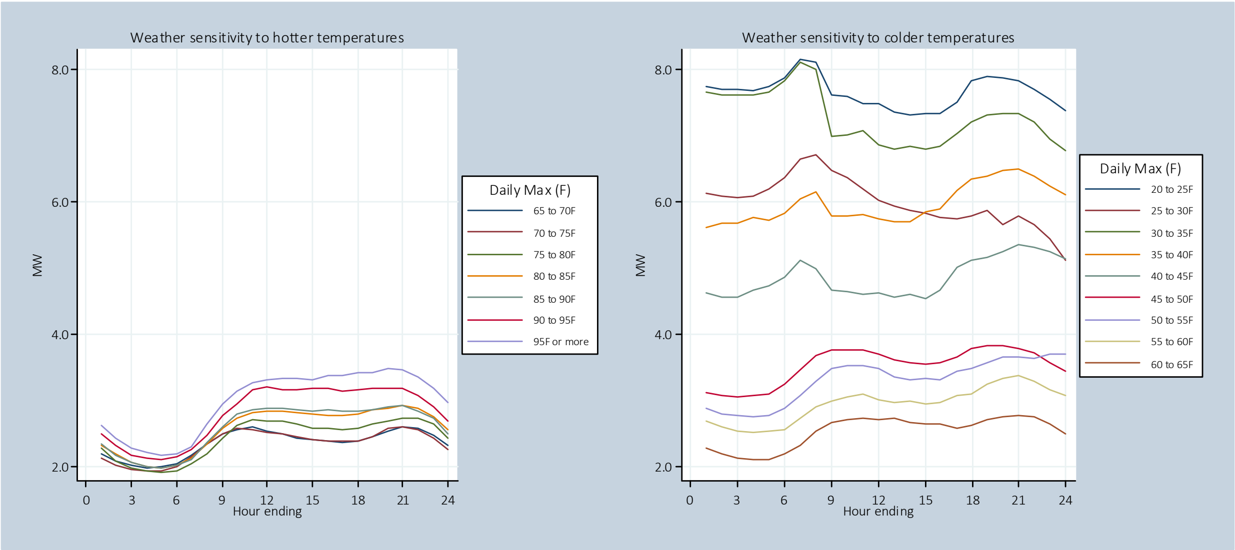
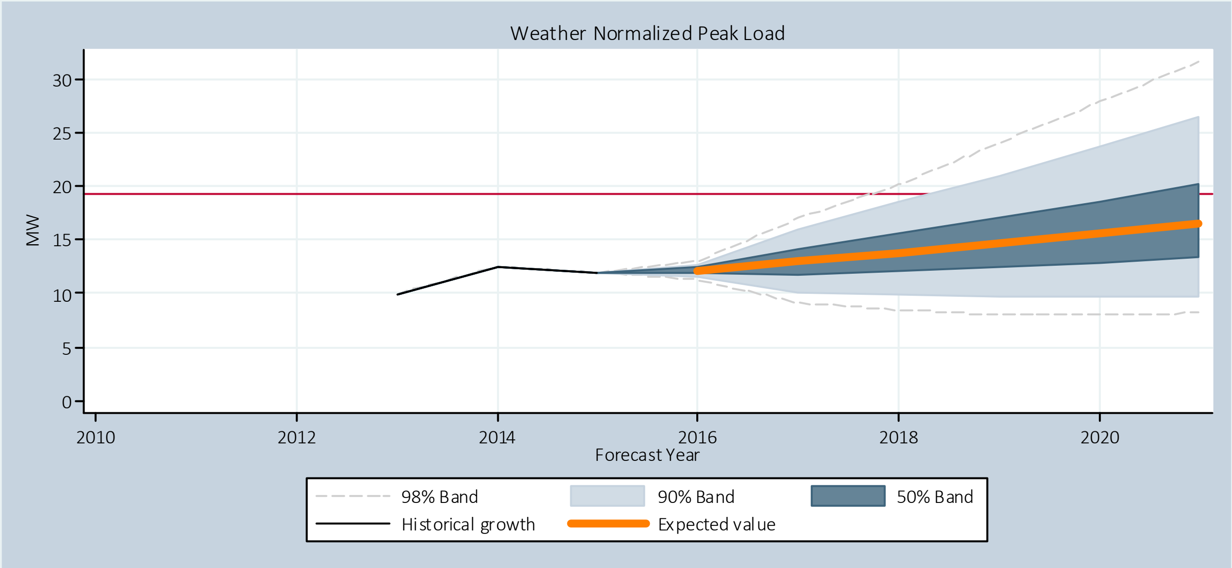


Figure B-20: Lawrenceville 1-in-2 Normalized Historical Peaks and Probabilistic Forecast



B.5 Woodstock Substation

Woodstock substation (Figure B-21) is located in the northern part of the Ulster County, northwest of Kingston, and lies within the borders of the Catskill Park. The substation has a load serving capability of 20.9 MW. In 2014 and 2015, the substation loads peaked at 20.9 MW and 20.2 MW, respectively. The area is dual peaking – peak loads during summer and winter and relatively similar. Alleviating loads, however, may be facilitated by the ability to transfer loads to neighboring substations. Since 2010, substation peak loads have been growing at a rate of 1.2% per year. Because of the uncertainty in forecasts and ability to exceed the design rating, there is a 23.5% chance an upgrade would be needed in five years and a 47.1% likelihood an upgrade would be necessary by 2025.

Figure B-21: Woodstock Substation

Figure B-22 summarizes the hourly loads for each annual peak from 2010 to 2015. The historical peak days reflect the dual nature of substation loads. In 2011 and 2013, loads peaked during the summer in the month of July. In all other years, the peak occurred in winter months. The winter and summer load shapes are quite distinct. Figure B-23 summarizes the load duration curve for the top 250 hours for each year over the same time frame. Figure B-24 shows the weather sensitive of the customer loads at Woodstock. Unlike most regions, loads grow substantially with both hotter and cooler weather. Figure B-25 shows the historical peak loads, normalized for 1-in-2 weather year conditions, and the 10-year forecast, with uncertainty.

Figure B-22: Historical Peak Day Load Patterns

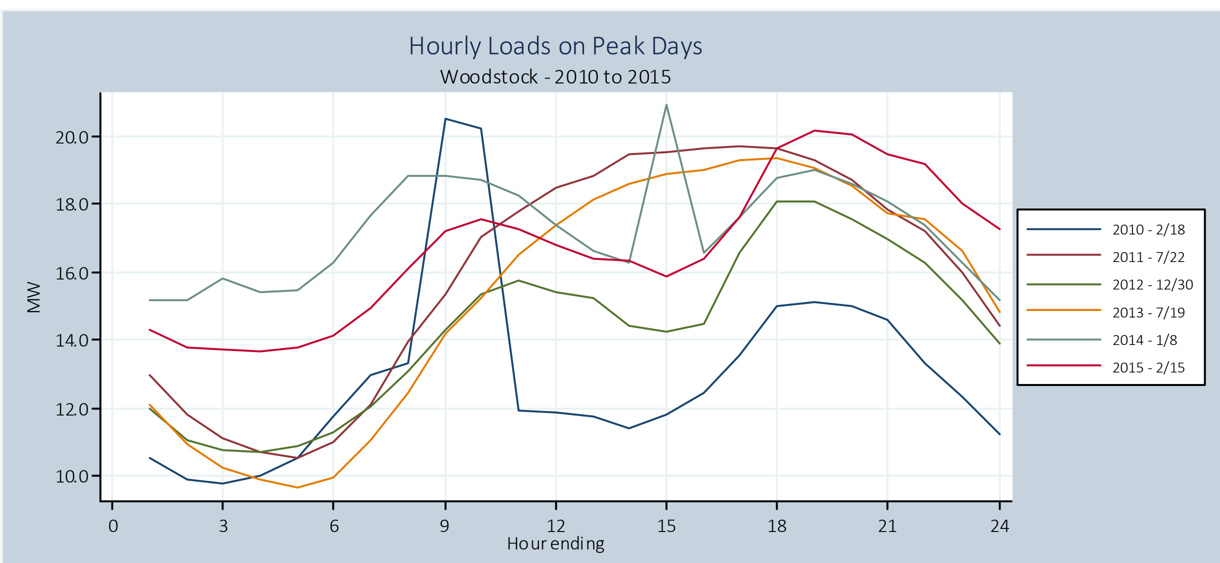


Figure B-23: Historical Load Duration Curves - Top 250 Hours

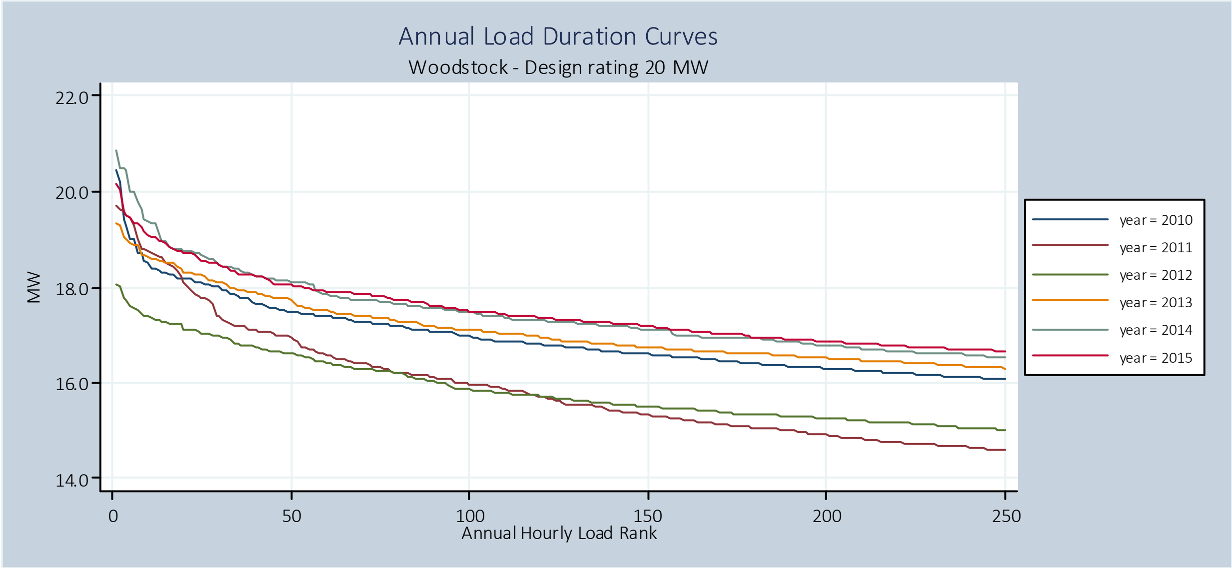


Figure B-24: Woodstock Weather Sensitivity

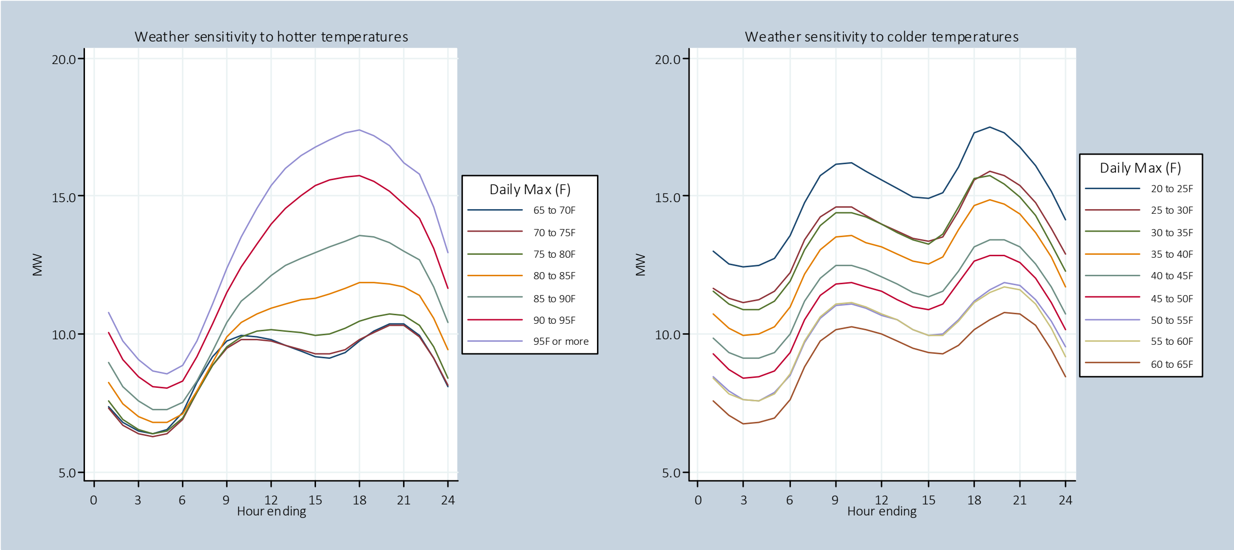
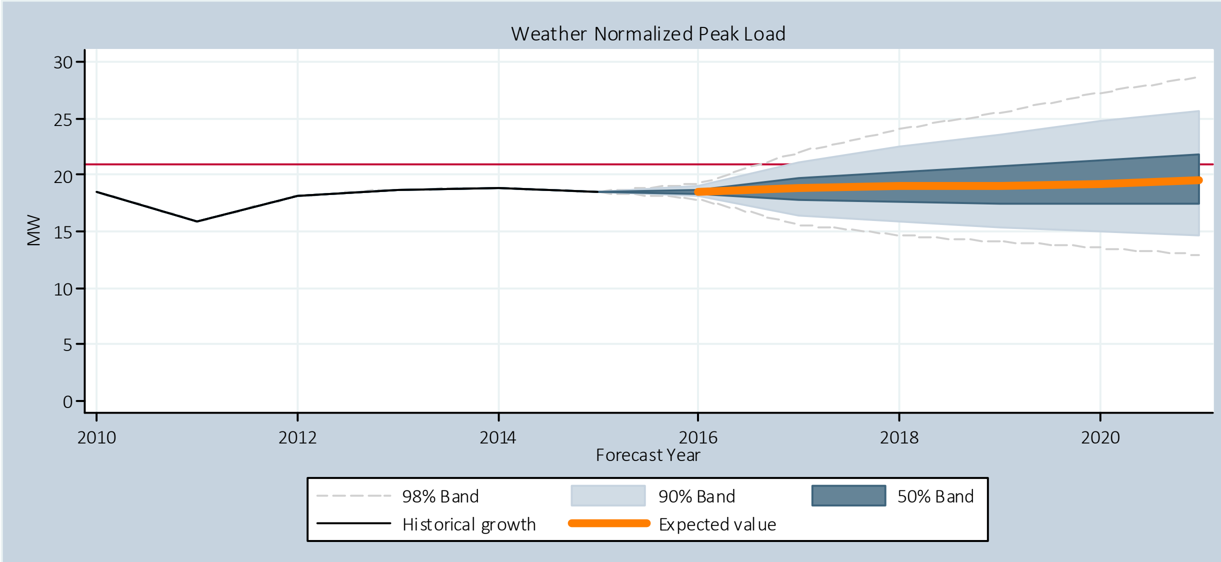


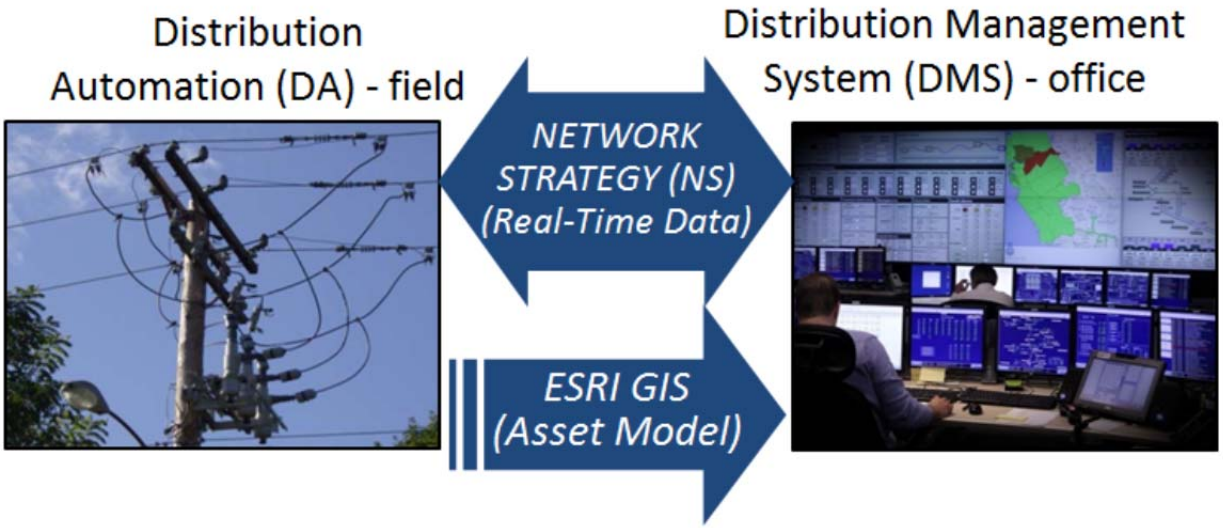
Figure B-25: Woodstock 1-in-2 Normalized Historical Peaks and Probabilistic Forecast



Appendix C Electric Distribution System Operations Whitepaper

A key component of Central Hudson's Smart Grid Strategy is the role of Distribution System Operations. Above all, the mission of Distribution System Operations is to provide for the safe operation of the distribution system. In the model that summarizes Central Hudson's Smart Grid Strategy, Distribution System Operations is the organization responsible for the use of the Distribution Management System and the continued safe and reliable operations of the Company's distribution system of a 24/7 real time basis. Figure C-1 illustrates how these projects interact, along with the underpinning ESRI GIS Asset Model.

Figure C-1: Smart Grid Projects



In order to meet these new requirements staffing additions for Distribution System Operations will be needed. It is anticipated that the skill sets needed for the individuals staffing these positions will be more technical than what is the current requirements are for the transmission system operators. As such it is likely that these positions will be filled with degreed engineers. It is anticipated that one of these positions will be filled initially with the individual responsible for the development of the policies and procedures necessary to establish the Distribution System Operations Department. It is ultimately anticipated that an additional twelve (12) operating positions will be needed with similar technical skills as described above. The purpose of this whitepaper is to provide a general direction as we transform to Centralized Operational Authority of the Distribution System.

C.1 Operational Authority

Operational Authority for the Distribution System will be centralized under the control of the Senior System Engineer – Distribution, and his or her staff of Distribution System Engineers. This Operational Authority for the Distribution System will fall within the context of the Operational Authority for the

Transmission System as defined in OP-1, and will have specific exceptions. There will be provisions for the delegation of the Operational Authority for both Storm and Non-Storm operating modes.

A device designated as "TD" (Transmission-Distribution) is defined as the point of demarcation between facilities under the Operational Authority of Senior System Operator – Transmission and the Operational Authority of the Senior System Engineer - Distribution. A "TD" device is under joint jurisdiction of both the Senior System Operator – Transmission and the Senior System Engineer – Distribution. Any changes in state (i.e. open or close) of these devices must be coordinated with both Operating Authorities.

There are specific exceptions to the Operational Authority of the Senior System Operator - Distribution. These exceptions include all facilities operating at secondary voltages and all distribution fuses that serve single transformers (single phase and three phases). Secondary voltages are defined for this purpose as being 600 volts phase to phase or less. Operational Authority for these devises resides with the District Operating Superintendents.

C.2 Electric Emergency Operations Mode

Declaration of an Electric Emergency, consistent with the Electric Emergency Plan will allow the Senior System Engineer – Distribution to delegate Operational Authority for the Distribution System to one or more District Operating Superintendents. This delegation will be a formal written documentation that is effectively communicated to the entire organization. This delegation will remain in effect until the District Operating Superintendent returns Operational Authority for the specific operating district back to the Senior System Engineer – Distribution. Again, this return of Operational Authority will be a formal written documentation that is effectively communicated to the entire organization. Decentralized operation of the Distribution System can be broken down into smaller areas at the discretion of the District Operating Superintendent.

C.3 Distribution Management System—Modes

The Distribution Management System will have two modes. There will be a Control Mode and a Read Only Mode. Under normal system operating conditions, workstations with Control Mode will only reside within the Centralized Distribution System Operations Center. Workstations with Read Only Mode will reside with District Operating Superintendents. Under Electric Emergency Operations Mode, the workstations for the Distribution System Operators will be converted to Read Only Mode for any district (or portion of a district) where Operational Authority has been delegated.

C.4 Security

Any workstations with Control Mode will reside within a secure environment. This secure environment will consist of a physical security perimeter with controlled access, monitoring and logging. Access control lists will be developed and maintained by the Senior System Engineer – Distribution, and reviewed and approved on a quarterly basis.

The Distribution Management System will be afforded the same cyber security protection as that of the Energy Management System, although the components of the Distribution System will not be considered

Critical Cyber Assets. The Distribution Management System components will reside within an electronic security perimeter. All access points to the electronic security perimeter will be identified, documented, monitored and protected.

C.5 Switching and Tagging

The Manual of Safe Practices Section 12 and Section 14 cover General Requirements for Equipment Tagging and Procedures for Switching, Valving, and Tagging Electric and Gas Facilities under the Operational Authority of System Operations. No changes to these documents are recommended.

Distribution Switching Orders for planned work will continue to be developed as they currently are, although potentially using the DMS as a platform for the development and testing of the Distribution Switching Order. Distribution Switching Orders will be executed by the Distribution System Operators.

Distribution Switching Orders for unplanned work (i.e. fault restoration) will be developed by the DMS and executed by the Distribution System Engineers. It is anticipated that eventually these Distribution Switching Orders will be executed automatically by the DMS.

C.6 Distribution Management System—Application Maintenance

Application Maintenance of the DMS will reside with the System Specialist Project Leader for the DMS. This application will interface with other applications including the EMS, ESRI Database, and the Outage Management System. Maintenance responsibility of the ESRI Database will reside with the Drafting Supervisor. Policies and procedures will be developed for controlled updates to the production version of the database. Consideration will be given to the long-term goal of integrating the DMS and the OMS into one product.

C.7 EMS / DMS Boundary / Application Overlap

The substation fence, in most all locations, will serve as the boundary between the EMS and the DMS. The EMS will be used as the SCADA interface to the distribution feeder breaker and the substation load tap changer. The DMS will use applications, notably Volt-VAR control and FLISR that will need to use the EMS SCADA interface to the distribution feeder breaker and the substation load tap changer. Typically, the distribution feeder breaker will be a TD point with joint jurisdiction. For the purpose of Volt VAR control schemes, substation load tap changers will also have similar joint jurisdiction.

C.8 Distribution System Operator Training and Qualification

Policies and procedures will be developed for the training and development of new Distribution System Operators by the Senior System Engineer – Distribution. This training and development will prepare new Distribution System Engineer for a Qualification Test.

Distribution System Engineers will work on a rotating shift similar to Transmission System Operators.

C.9 Coordination with Distribution Dispatching

Distribution Dispatchers[1] will be assigned to work with Distribution System Operators. This relationship will be one to one or one to many, but will not include two Distribution System Operators sharing a single Distribution Dispatcher. A team consisting of a Distribution System Operator and Distribution Dispatcher(s) will be assigned a geographical location consisting of one or more Operating Districts.

Distribution Dispatchers will have responsibility for dispatching gas orders, and commercial locks and unlocks. Distribution Dispatchers will have primary responsibility for using ARCOS to perform callouts, although this will not preclude Distribution System Operators from performing callouts.

It is generally anticipated that the Distribution System Operator and Distribution Dispatcher(s) will be located in close proximity to ensure effective communications, although if technically feasible solutions exist, consideration will be given to alternative solutions.

C.10 Progression / Coordination with Transmission System Operations

It is generally anticipated that there will be a progression for the Distribution System Engineers and more junior personnel will be paired with more experienced personnel.

It is generally anticipated that Distribution Operations and Transmission Operations will be located in close proximity to ensure effective communications, although if technically feasible solutions exist, it is not a requirement.

C.11 Logistical Requirements

The transition to Distribution System Operations will include the addition of one Senior System Engineer – Distribution, 12 Distribution System Engineer, the Distribution Management System, and two associated application support staff. This 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 Primary Control Center 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. More detailed estimates of this project will be included in Central Hudson's next rate filing. Subject to approval it is planned that construction of the new Distribution Control Center will be complete by late 2018 to early 2019.

[1] For the purpose of this document, the term Distribution Dispatcher is generic and refers to the family of positions including Junior Distribution System Operator and Assistant Distribution System Operator. [Note: we will be developing a new title for this position other than Distribution Dispatcher.]

C.12 Labor Costs

As described above, Central Hudson plans to add an incremental twelve (12) Distribution System Engineers starting in order to meet the new requirements operating as a DSP. The detailed justification for these additions will be included in a future rate filing. The estimated payroll for these 12 positions is approximately $1.4M annually.

Appendix D Location Specific Forecasting and Marginal T&D Cost Study

REPORT

Nexant

Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods

June 2016

Prepared for
Central Hudson Gas & Electric

Prepared by
Josh Bode, M.P.P., Vice President
Shannon Hees, Project Analyst
Jennifer Gai, M.S., Project Analyst
Nexant, Inc.

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1 Introduction

One vital role of the electric utility is to ensure that electricity supply remains reliable. By projecting future demand and reinforcing the local distribution network so that distribution capacity is available to meet local needs as they grow over time, costly outages are avoided.

A key focus of the New York Public Service Commission's REV proceeding is to defer or eliminate the need for traditional T&D infrastructure investments by using DERs. This requires quantifying the potential to avoid or defer infrastructure upgrades as granularly as possible.

The growth of DERs is fundamentally changing the nature of distribution system forecasting, planning, and operations. Forecasting location specific loads and DERs using probabilistic methods is becoming increasingly critical for T&D planning. However, local demand growth trajectories based on historical growth are inherently uncertain and those forecasts grow more uncertain further into the future. Location specific, granular forecasts are also essential to establishing the location specific value of DERs and identifying locations where DERs are beneficial. Simply put, location specific forecasting and planning methods have direct implications for DER integration.

To our knowledge, no other utility to date has attempted to implement a location specific avoided T&D cost study that relies on probabilistic analysis and quantifies the option value of reducing peak demand. We emphasize that the development of probabilistic load forecasts and avoided T&D costs at a granular, local level is a new endeavor and will require refinements and improvements with more applied experiance.

This study focuses on substation and transmission costs (it does not include circuit feeders) and was designed to meet the following objectives:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level
- Develop location specific forecasts of growth with uncertainty
- Quantify the probability of any need for infrastructure upgrades at specific locations
- Calculate local avoided T&D costs by year and location using probabilistic methods
- Identify beneficial locations for DERs

There are several aspects of the study that make it unique. First, the T&D avoided costs estimates being produced are at a local level. Most studies of avoided T&D costs have been conducted in the context of energy efficiency and focused on producing system wide values, often concentrating on historical T&D expenditures rather than future infrastructure investments.

Second, the study uses a bottom-up approach to quantify historical year-to-year growth patterns and the amount of variability in growth.

Third, we develop load growth forecasts and avoided cost estimates using probabilistic methods rather than straight-line forecasts. The approach takes into account the reality that we have much greater uncertainty 10 years out than a year out, and accounts for the risk mitigation value of resources that manage local peak loads.

As a general rule, only growth-related T&D investments that are shared across multiple customers can be avoided by DERs or demand management. As loads grow, the excess distribution capacity that provides reliability dwindles. If a customer helps reduce coincident demand, either by injecting power within the distribution grid or by reducing demand, the unused capacity can accommodate another customer's load growth, thereby helping avoid or defer investments required to meet load growth. Avoided or deferred T&D investments free up capital for other alternate uses, improving the efficient use of resources.

Not all distribution investments are driven by local, coincident peak loads. Some investments are tied to customer interconnection costs and are essentially fixed. Other investments must take place because of aging or failed equipment or because of the need to improve reliability and modernize the grid. These investments typically cannot be avoided by managing loads with DERs.

The value of distribution deferral varies significantly across local distribution areas because of:

- Load growth rates and anticipated changes in load curve shapes, which affect whether infrastructure upgrades can be avoided and how long they can be deferred;
- The amount of existing excess capacity or the amount of additional load that can be supported without upgrades;
- The magnitude, timing, and cost of projected distribution upgrades; and
- The design of the distribution system.

In areas with excess distribution capacity—or areas where local, coincident peaks are declining or growing slowly—the value of distribution capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of distribution capacity relief can be quite substantial, especially if it is possible to delay or defer distribution infrastructure upgrades for a substantial time. However, many Central Hudson distribution areas have declining or slowly growing loads, or they have sufficient capacity already built such that distribution investments are not needed in the foreseeable future.

The remainder of this report is organized in five sections.

- Section 2 provides an overview of the methodology.
- Section 3 presents the historical growth estimates.
- Section 4 details the avoided costs and the risk of triggering infrastructure upgrades or load transfers by location. We separately present the avoided T&D costs.
- Section 5 discusses how probabilistic forecasting and valuation is used to identify locations where DERs can be beneficial.
- Section 6 summarizes the key findings and conclusions.

2 Methodology

This section details the risk tolerance for different types of equipment, data sources used, and key steps in developing location specific forecasts and avoided T&D cost. Before doing so, we discuss why probabilistic methods are critical not only to forecasting, but also to quantifying location specific avoided T&D costs.

2.1 Risk Tolerance for T&D Components

When demand exceeds normal and emergency equipment ratings, equipment can become overloaded and degrade more quickly, considerably increasing the risk of an adverse reliability event, although overloads are uncommon. With the exception of rural substations, most of Central Hudson's system is designed to withstand the loss of the highest rated source (e.g., the loss of a transmission line, transformer, or other component) without violating thermal or voltage limits – that is, the substation or area design rating is often equal to the rating of the lowest equipment rating. As a result, loads in excess of the load serving capability, or design rating, do not automatically result in overloads or an infrastructure upgrade. However, Central Hudson also does not wait for loads to exceed the allowable risk to begin construction.

Central Hudson has specified explicit risk tolerances and detailed the total hours that forecasted load can exceed design ratings. The risk tolerance varies by component and more risk is tolerated for less critical components, as shown in Table 2-1. The risk tolerance levels are based on the total hours design ratings are exceeded.

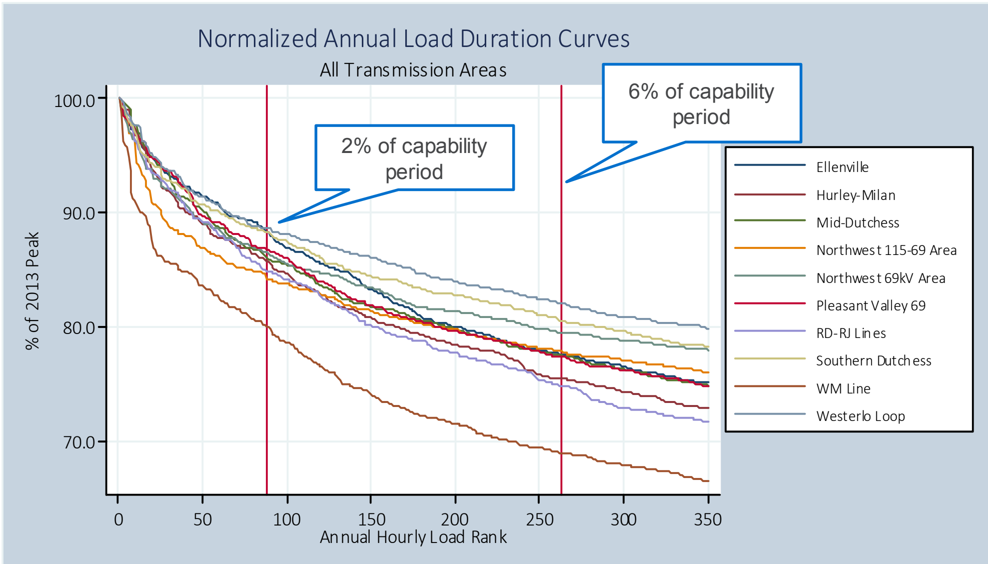
Table 2-1: Risk Tolerance Levels

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

Figure 2-1 illustrates the practical implications of the risk tolerance levels on the demand level that can be accommodated. The graphs reflect the 2013 load duration curves for Central Hudson's 10 transmission areas. All of the lines rank demand for each hour in the year from highest to lowest. The graph only shows the top 350 (<4% of hours) in the year. All of the load duration curves show hourly demand as a percent of each area's 2013 (1-in-2) peak, allowing side-by-side comparisons for areas with a different magnitude of demand.

Because of inherent variation in load duration curves, the amount by which loads can exceed the design ratings varies for individual transmission areas and substations. For transmission networks—Ellenville, Northwest 115-69 kV, Northwest 69 kV, and Pleasant Valley 69kV—this means loads can exceed design ratings by 13-16% without exceeding the allowable risk tolerance. For transmission loops, loads can exceed design ratings by 20-45%.

Figure 2-1: Normalized Load Duration Curves



2.2 Why Use Probabilistic Forecasting and Planning Methods?

No one knows in advance precisely when loads will exceed design ratings or by how much; however, linear forecasts assume precise knowledge. In practice, actual growth trajectories are rarely linear and growth patterns trend across time – both load growth and load declines follow cyclical patterns.

Figure 2-2 contrasts a linear forecast against two simulated potential growth trajectories, all using the same 1.5% growth rate. The linear forecast indicates loads will exceed the design rating in 10.5 years and the risk tolerance cutoff in exactly 21 years. But actual growth rarely follows a linear pattern. Loads could exceed the design and risk tolerance far earlier, as shown by Path 1, or never at all, as shown by Path 2. But the two potential outcomes are not equally probable.

Figure 2-2: Comparison of Linear Forecast and Potential Growth Patterns

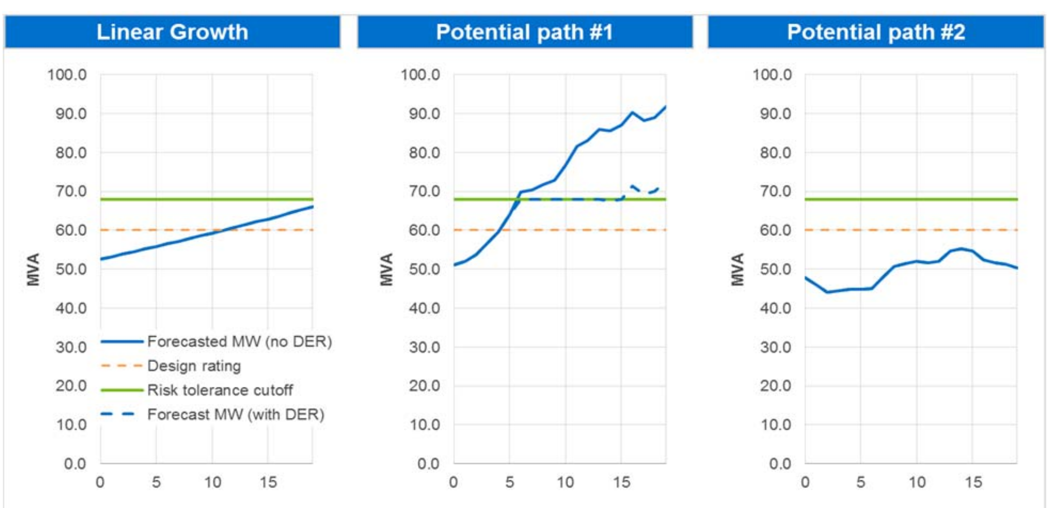
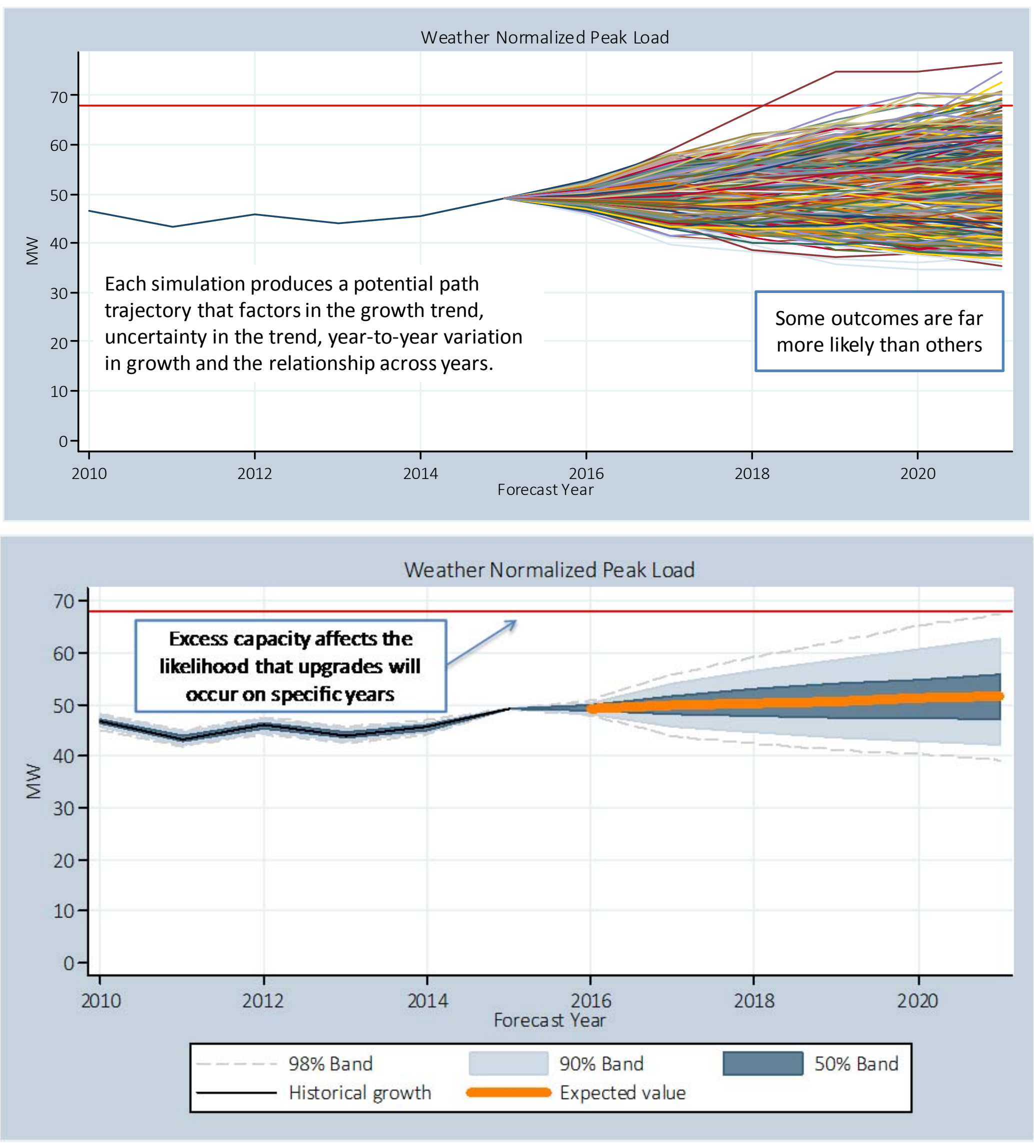


Figure 2-3 illustrates the critical role of probabilistic, location-specific forecasts. This type of forecasting requires estimating historical load growth patterns and simulating potential load growth trajectories thousands of times, as shown in the top panel. Some outcomes are far more likely than others and are summarized into probabilistic bands that identify the likelihood of load growth falling within specific confidence bands, as shown in the bottom panel.

Forecasts inherently include uncertainty and become more uncertain further into the future. Because a linear forecast assumes exact knowledge, no value is assigned to the years before the linear forecast exceeds the risk tolerance. Probabilistic methods, on the other hand, reflect the potential reality that infrastructure could be triggered earlier. Probabilistic methods will assign value to periods earlier than the linear forecast would dictate based on the probability of triggering an earlier infrastructure upgrade.

Figure 2-3: Illustration of Location Specific Simulations and Probabilistic Forecasts



2.3 Data Sources

The study relied on six main data sources:

1. 2010–2015 hourly interval data for most substations and each transmission area;
2. 2010–2015 weather data from the Dutchess County Airport;
3. 1-in-2 weather year peak conditions data;
4. 1-in-2 forecasted Central Hudson System loads;
5. Design rating information for each substation and transmission area; and
6. Costs for infrastructure upgrades.

With the exception of the 2010–2015 weather data, all of the above data was supplied by Central Hudson. A few points are noteworthy, however. First, the 2010–2015 time period was selected because of data availability and due to the significant shift in loads that occurred with the 2009 economic downturn.

Secondly, not all substations have hourly interval data, and the quality and availability of the data degrades when longer time spans are included.

Third, resources that have been procured as part of Central Hudson's NWA projects are incorporated by adjusting the design rating. The additional resources reduce loads, thereby leading to additional room for growth.

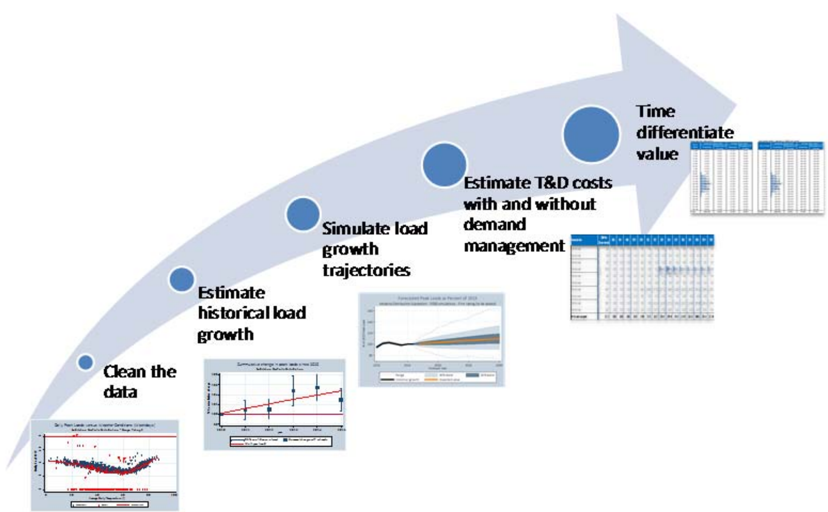
Finally, the quality of the data improves for larger aggregation points, such as transmission areas, where all of the historical data is available. Not all substations and feeders have hourly data and among those that do, not all of them have the same amount of historical data. To define the growth trends one needs several years of data.

Because multiple years of data are required, the forecasts and location specific estimates of T&D avoided costs were developed for locations with at least three years of valid hourly data. This includes 54 of Central Hudson's 62 distribution load serving substations. All of the transmission areas were included in the analysis.

2.4 Key Analysis Steps

describes the main steps in developing location specific avoided T&D costs using probabilistic methods. The process was implemented for each substation, load area, and transmission area with at least three years of valid, historical hourly data. Importantly, the 2,000 or 10,000 simulations of potential growth trajectories are critical to both the forecast and to estimating T&D costs with and without demand management.

Figure 2-4: Key Steps in Estimating Location Specific Avoided Costs

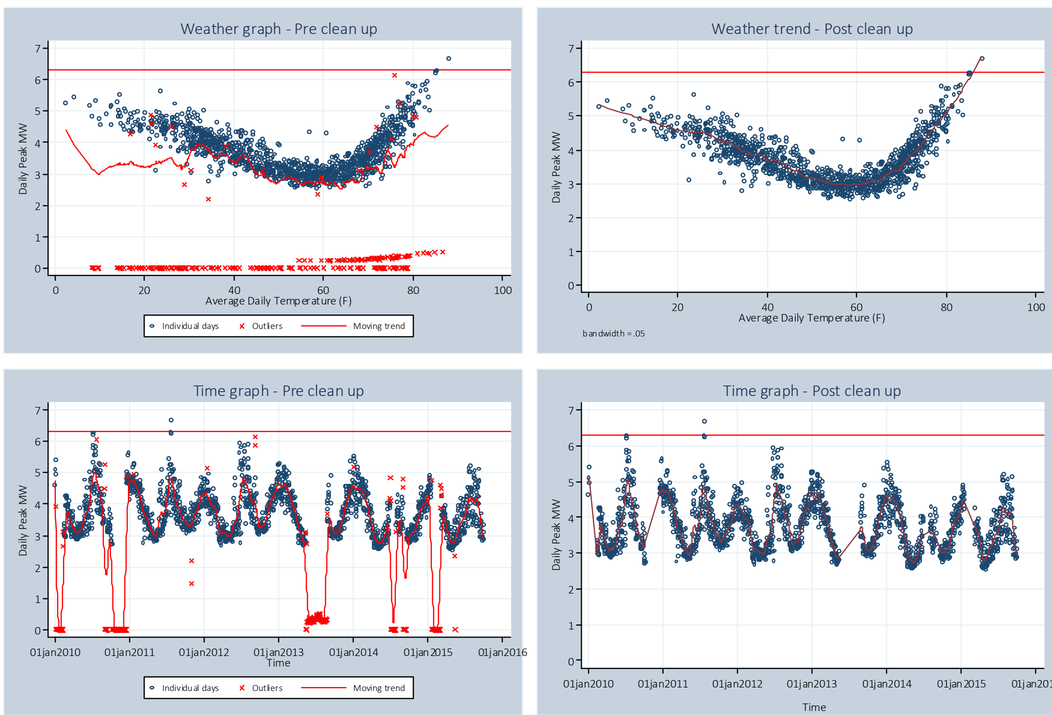


Clean the data

One of the key challenges in estimating load patterns and growth at granular locations is the quality of data. Not all substations have metered data over the relevant historical period and, for those that do, it is important to identify and remove load transfers, outages, data gaps, and data recording errors. Nexant used data analytics to identify loads with irregular patterns, load transfers, data gaps, and outages from substation level data. We subsequently reviewed those loads with Central Hudson's engineers to confirm dates where load transfers occurred.

Figure 2-5 below illustrates an example of a location with load transfers, which, unless detected, can be mistaken for a load increase and distort the sensitivity of the area's loads to weather.

Figure 2-5: Example of Data Cleaning

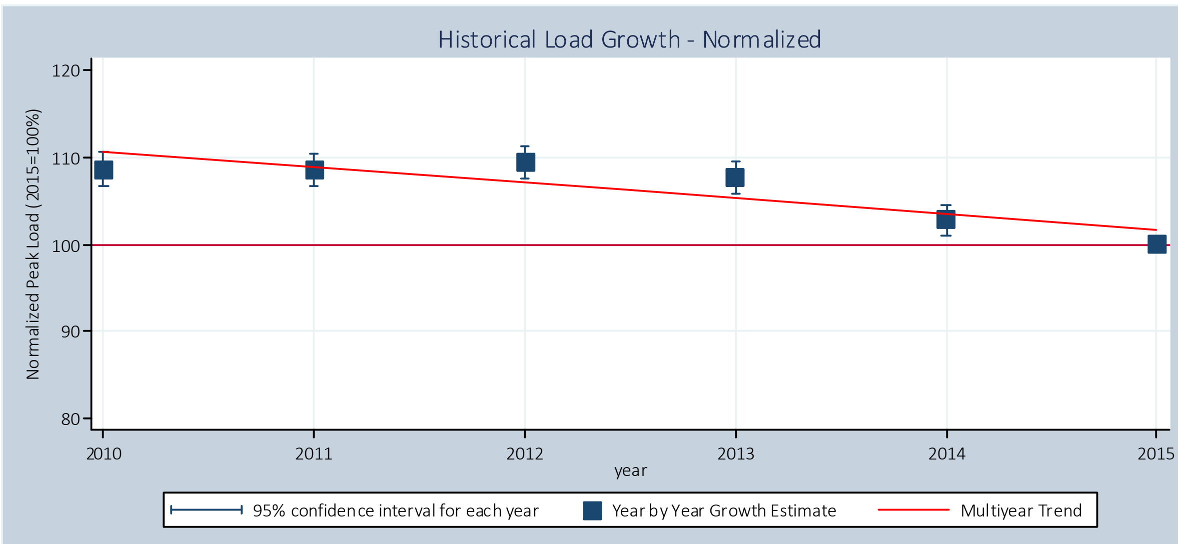


Estimate historical load growth.

The objective of this step 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 of load growth patterns; the degree of growth in a given year was related to growth during the prior year—technically known as *auto-correlation*. The econometric models were purposefully designed to both estimate historical load growth and allow us to weather normalize loads for 1-in-2 weather peaking conditions. We normalized 2010–2015 peaks for 1-in-2 weather peak conditions because it is Central Hudson's criteria for distribution design. Appendix A describes the econometric models.

Figure 2-6 illustrates some of the key outcomes from this analysis. First, the analysis produces year-by-year estimates of the historical growth or decline in loads after controlling for differences in weather, day of week, and season. Second, the year-by-year estimates allow us to estimate the growth trend. In the below example, loads are declining at a rate of 1.8% per year. Third, the results enabled us to estimate of the variability in year-to-year growth patterns (also known as the standard error of the forecast).

Figure 2-6: Year-by-year Estimates of Historical Growth



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 2,000 simulations were implemented for each substation and load area, and 10,000 simulations were implemented for each transmission area. Each simulation produced a distinct growth trajectory that took into account the historical trend, variability in growth patterns, and the fact that growth patterns are auto-correlated.

The simulations are based on historical growth patterns from the econometric models. Each forecast year's growth is a combination of an independent growth component and the prior year's growth trajectory.[1] The independent growth component is based on a random draw that factors in the historical trend, the uncertainty around the trend, and the year-to-year variation at the location. The forecasts are cumulative, meaning that each simulation's forecast trajectory builds on the prior year, producing a path. The process was repeated 2,000 times for each substation & load area and 10,000 times for each transmission area. The result is a full picture of the possible load growth outcomes by year. Each of the 2,000 (or 10,000) simulated growth trajectories produces specific information about if and when the design rating

[1] $Annual\ growth_t = Independent\ growth_t \cdot (1 - autocorrelation) + Annual\ growth_{t-1} \cdot autocorrelation$

would be exceeded and the amount of demand management required to maintain loads below the design ratings.

Estimate costs with and without demand management

The estimates of the avoided T&D costs are based on the load growth forecast and the outcome of each simulation run. The process involved applying the below four steps to each of 2,000 (or 10,000) simulation runs for each location:

1. Identify the timing of the infrastructure investments for each simulation run, location, and year. For each location, each simulation run produced a potential growth trajectory, which either exceeded the design rating or remained below it. As noted earlier, when loads exceed design ratings, they do not automatically trigger infrastructure upgrades. Loads can exceed design ratings without triggering overloads and Central Hudson has explicit risk tolerance levels where less risk is tolerated for more critical components. Because load growth doesn't follow a perfect linear trajectory, loads also can exceed the design ratings for a year or two, but revert to levels below the design rating. To reflect this complexity, the timing of infrastructure upgrades was simulated to occur the year after loads exceeded design ratings for two consecutive years.
2. Identify the magnitude of demand management needed to maintain loads below the design rating. Once demand management resources were needed, we assumed they were in place for 10 years.
3. Model T&D infrastructure costs with and without demand management for each simulation run, location, and year. When the design ratings were exceeded for two consecutive years, the costs of the infrastructure investments were included in the third year and allocated based on the book life of the upgrade. For example, equipment worth $15 million with a 50-year book life would be spread or annualized over 50 years, with a 20% carrying cost.

   The operations and maintenance costs were included using standard values for transmission, distribution substations, and feeders.[2] This replicated how the T&D costs would be reflected in the rate base. We also implemented the same calculations but instead assumed the investment could be deferred for up to 10 years or until 10% of the peak was managed through DERs, whichever came first. This process reflected the reality that most projects cannot be postponed indefinitely and the length of deferral may be shorter in areas with rapid growth.
4. Calculate the avoided costs per kW for each simulation run, location, and year. If loads were not projected to exceed the respective design rating, no costs are avoided since a growth related infrastructure investment would not have taken place anyhow. If the loads in a particular simulation exceeded the design rating, reducing loads to levels below the design rating would avoid or defer growth related infrastructure investment. Thus, the avoided costs are the difference between the costs with and without the reduction in loads necessary to avoid or defer the upgrade.

The detailed calculations for each of the 2,000 or 10,000 simulations at each site were subsequently used to estimate the expected avoided costs per kW at each location for each year.[3] Because the analysis relied on probabilistic

[2] The annualized cost were calculated using the below standard formula, where *r* is the post-tax discount rate and *n* is asset book life:

$$Annualized\ Cost = Total\ cost \cdot \frac{r(1+r)^n}{(1+r)^{n-1}}$$

[3] The expected avoided costs is calculated across all simulation runs for each year (t) at an individual location (i) by using the ratio of the average avoided costs and average demand reductions required to attain them.

methods, the avoided cost estimates reflects the risk mitigation value of managing loads to remain below the design rating. That is, the probabilistic method assigns T&D avoided costs to location and year with, for example, a 10% likelihood of an upgrade. In contrast, a linear forecast would not assign any value to that year.

Figure 2-7 illustrates the process with and without demand management for a single simulation at one location, assuming a $5M infrastructure upgrade. This process is repeated thousands of times.

Figure 2-8 illustrates the probabilistic approach to avoided costs. In the example, 68% of the simulations do not lead to any infrastructure upgrades over the immediate 10 years. A straight line forecast would lead to an avoided cost estimate of zero (p50), yet due to the probability of exceeding design rating, DERs still provide value.

2.5 Integration of DERs

One of the most important considerations is accurately reflecting the locational value of incremental resources. This creates a paradox: including DERs which have not yet been built and installed into forecasts, lowers load forecasts and dilutes the locational value of DER resources. The forecasts reflect the trends in net loads and, arguably reflect naturally occurring DER and energy efficiency targets, which in the near term are similar to past goals. They do not include incremental DER resources which are not naturally occurring since the goal of the study is to quantify the avoided T&D infrastructure costs per unit of demand reduction.

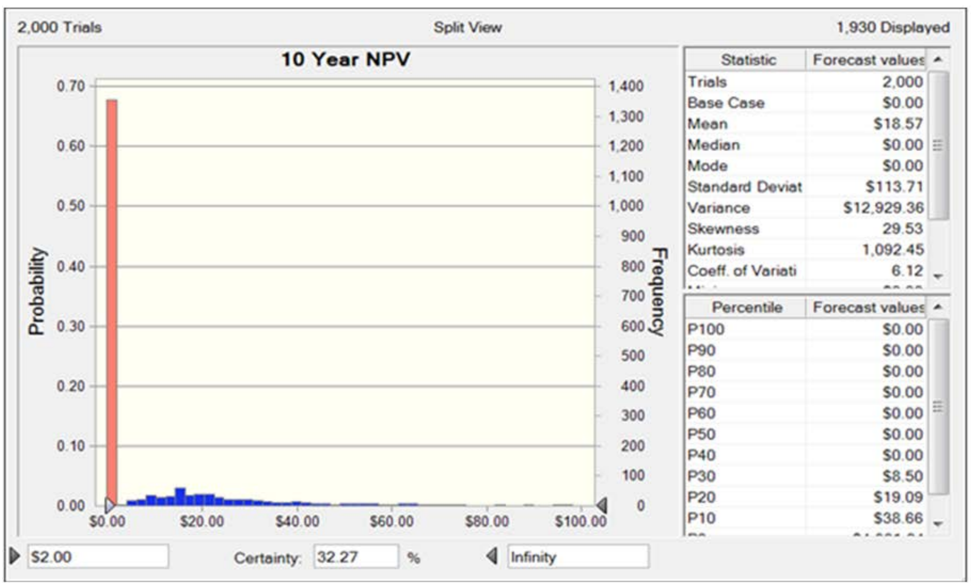
$$Expected\ Avoided\ Costs_{i,t} = \frac{\sum_{r=1}^{2,000} Avoided\ Cost_{i,t,r}}{\sum_{r=1}^{2,000} MW\ reduction\ required_{i,t,r}}$$

Figure 2-7: Example Calculation of T&D Costs with and without Demand Management

Calculations

Forecast year	Annual growth	Cummulative growth multiplier	Forecasted MW (no DER)	Risk tolerance cutoff	MW over	DER resources needed	Forecast MW (with DER)	Costs without DER: Annualized capital cost	Costs without DER: O&M	Costs with DER: Annualized Upgrade Cost (w DER)	Costs with DER: O&M	**Avoided cost**	**$/kW**
0	5.3%	105.3%	54.8	65	0.0	0.0	54.8	$0	$0	$0	$0	$0	**$0.00**
1	4.8%	110.9%	57.6	65	0.0	0.0	57.6	$0	$0	$0	$0	$0	**$0.00**
2	4.5%	116.2%	60.4	65	0.0	0.0	60.4	$0	$0	$0	$0	$0	**$0.00**
3	1.2%	121.5%	63.2	65	0.0	0.0	63.2	$0	$0	$0	$0	$0	**$0.00**
4	1.9%	123.0%	64.0	65	0.0	0.0	64.0	$0	$0	$0	$0	$0	**$0.00**
5	1.6%	125.3%	65.2	65	0.2	0.2	65.0	$636,624	$176,584	$0	$0	$813,208	**$4,857.66**
6	-0.6%	127.4%	66.2	65	1.2	1.2	65.0	$636,624	$180,292	$0	$0	$816,917	**$664.08**
7	-2.0%	126.6%	65.8	65	0.8	1.2	64.6	$636,624	$184,079	$0	$0	$820,703	**$667.16**
8	-0.8%	124.1%	64.5	65	0.0	1.2	63.3	$636,624	$187,944	$0	$0	$824,568	**$670.30**
9	4.3%	123.0%	64.0	65	0.0	1.2	62.8	$636,624	$191,891	$0	$0	$828,515	**$673.51**
10	2.6%	128.4%	66.7	65	1.7	1.7	65.0	$636,624	$195,921	$0	$0	$832,545	**$477.71**
11	1.8%	131.7%	68.5	65	3.5	3.5	65.0	$636,624	$200,035	$0	$0	$836,659	**$241.26**
12	2.5%	134.0%	69.7	65	4.7	4.7	65.0	$636,624	$204,236	$0	$0	$840,860	**$178.85**
13	2.7%	137.4%	71.4	65	6.4	6.4	65.0	$636,624	$208,525	$0	$0	$845,149	**$131.31**
14	4.2%	141.1%	73.4	65	8.4	8.4	65.0	$636,624	$212,904	$0	$0	$849,528	**$101.41**
15	3.0%	147.0%	76.4	65	11.4	8.4	68.1	$636,624	$217,375	$783,683	$267,588	-$197,272	**-$23.55**
16	4.0%	151.4%	78.7	65	13.7	8.4	70.4	$636,624	$221,940	$783,683	$273,207	-$198,327	**-$23.67**
17	1.8%	157.4%	81.9	65	16.9	8.4	73.5	$636,624	$226,600	$783,683	$278,945	-$199,403	**-$23.80**
18	1.4%	160.2%	83.3	65	18.3	8.4	74.9	$636,624	$231,359	$783,683	$284,803	-$200,503	**-$23.93**
19	2.2%	162.4%	84.4	65	19.4	8.4	76.0	$636,624	$236,218	$783,683	$290,783	-$201,625	**-$24.07**

Figure 2-8: Example of Probabilistic Avoided Cost Estimates



Year	Risk of triggering upgrade (no DER)
0	0%
1	0%
2	0%
3	1%
4	4%
5	7%
6	12%
7	17%
8	23%
9	28%
10	32%

3 Historical Load Growth Trends

This section presents the data on historical peak loads, design ratings, and load growth estimates. The results are presented separately for transmission and distribution areas. A key distinction between probabilistic and straight line forecasts is that the former approach explicitly accounts for the reality that forecasts are more uncertain further into the future.

Growth can slow down or accelerate in comparison to recent growth patterns and, in practice, actual growth trajectories rarely are linear. When a location has more room for growth, the chances it will exceed the design rating and trigger the need for infrastructure upgrades is lower. The results presented in this section focus on the growth rates, loading factors, and the standard error of the forecast.[4]

3.1 Transmission Load Growth Estimates

Locations with potential T&D infrastructure deferral value are areas where loads are growing but there is limited room to accommodate growth. Areas with sufficient load serving capability and areas where local, coincident peaks are declining are less likely to trigger growth related infrastructure upgrades.

Figure 3-1 compares the annual load growth rate to the loading factor (peak / design rating) for each of Central Hudson's ten transmission areas. The majority of Central Hudson's transmission areas are experiencing slowing or declining loads or have ample room for growth without having to upgrade the transmission system. However, upgrades may be required due to aging equipment or grid modernization efforts.

Locations with a growth factor above 0% are experiencing growth and locations where the 2015 loading factor is closer to 100% have less room for growth. All other things equal, a location with a 2.0% annual growth rate will exceed ratings in half the time as a location with a 1% growth rate. The chart, however, does not factor in the uncertainty of future growth patterns.

Figure 3-1: Transmission Area Growth Rates Versus Room for Growth

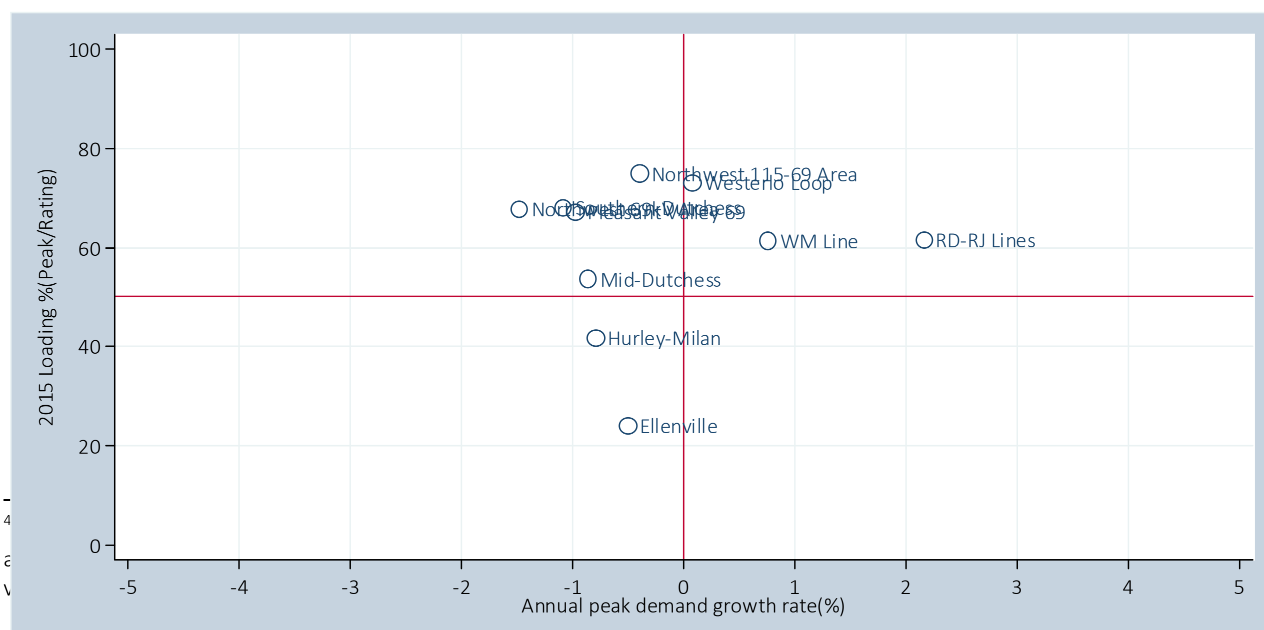


Table 3-1 summarizes the historical year by year growth for each transmission area, the growth trend, and the variability in the growth patterns, also known as the standard error of the forecast. The year-by-year growth estimates are indexed so 2015 equals 100%. They were estimated using econometric models designed to disentangle year by year growth rates from differences in weather patterns, day of week effects, and seasonality. For the most part, the year by year estimates of growth are relatively precise. The confidence bands around those estimates and the explanatory power of the models are summarized in Appendix A. Historical year by year growth does not follow a linear pattern and varies around the general trend line. This variation was used to develop the standard error of the forecast, which reflect how year to year growth can vary. This variability or uncertainty in the growth pattern is critical to probabilistic forecasting. Because growth and declining loads compound over time, growth patterns can deviate substantially from the straight line forecast. An area where loads are projected to remain flat can exceed the load serving capability five to ten years out due to the uncertainty in the forecast, though the likelihood of doing so is lower than for an area that is growing.

Table 3-1: Transmission Area Historical Load Growth Estimates (2010-2015)

Transmission area	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Historical annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Ellenville	60.7	251	101.6%	100.2%	95.3%	97.3%	96.7%	100.0%	-0.5%	2.5%
Hurley-Milan	80.7	193	104.2%	102.9%	103.3%	101.3%	101.2%	100.0%	-0.8%	0.5%
Mid-Dutchess	121.6	226	103.2%	103.1%	106.0%	103.4%	99.0%	100.0%	-0.9%	2.1%
Northwest 115-69 Area	116.3	155	-	102.1%	101.1%	101.2%	101.4%	100.0%	-0.4%	0.5%
Northwest 69kV Area	95.0	140	110.5%	101.8%	100.3%	101.1%	101.6%	100.0%	-1.5%	3.1%
Pleasant Valley 69	67.2	100	106.7%	106.0%	104.8%	111.3%	103.6%	100.0%	-1.0%	3.6%
RD-RJ Lines	88.7	144	85.7%	99.7%	99.9%	99.7%	99.5%	100.0%	2.2%	4.9%
Southern Dutchess	143.8	211	106.1%	103.6%	105.0%	103.5%	101.3%	100.0%	-1.1%	1.0%
WM Line	41.8	68	96.1%	88.4%	94.0%	90.3%	92.5%	100.0%	0.8%	4.3%
Westerlo Loop	66.4	91	101.4%	99.2%	99.9%	101.9%	101.6%	100.0%	0.1%	1.2%

Figure 3-2 summarizes the likelihood that loads will exceed design ratings for each transmission area by year. However, loads can exceed design rating without automatically triggering an infrastructure upgrade. Sustained growth needs to be observed before transmission lines are upgraded. Figure 3-3 summarizes the likelihood of triggering an infrastructure upgrade due to load growth. Based on the trajectory and variability in load growth, with the exception of the RD-RJ lines, the likelihood that loads will trigger an infrastructure upgrade over the next 10 years is less than 5% for all areas.

Figure 3-2: Probability of Load Exceeding Design Ratings

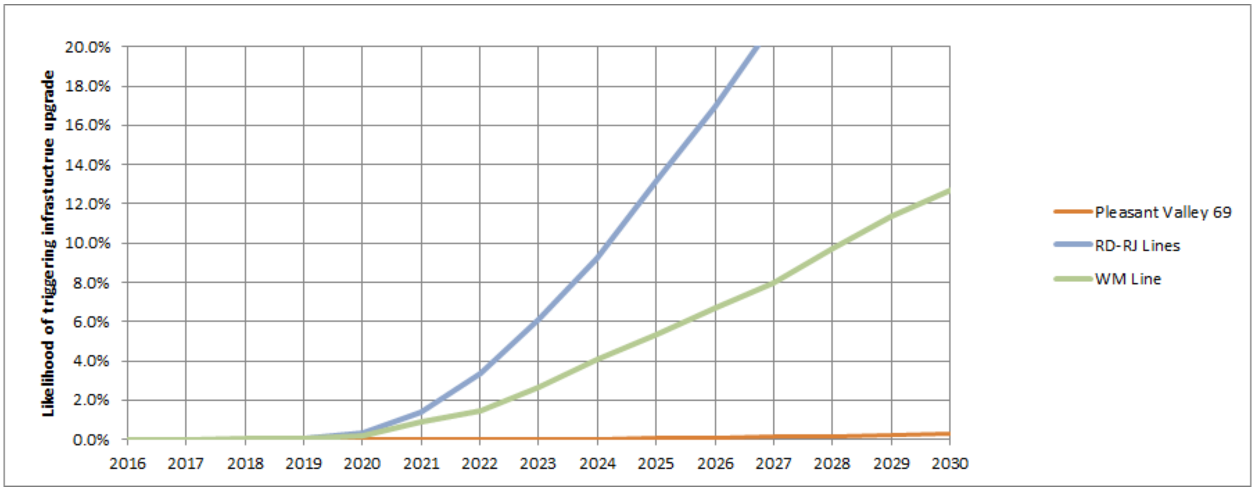
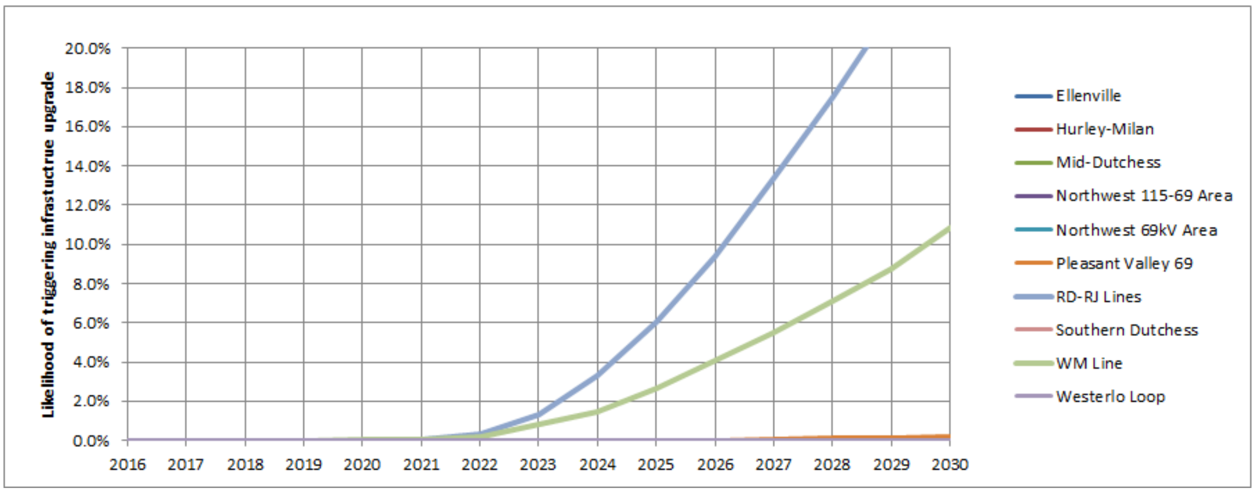


Figure 3-3: Probability of Growth Related Infrastructure Upgrade



3.2 Distribution Load Growth Estimates

Figure 3-4 compares the annual load growth rate to the loading factor (peak / design rating) for each of Central Hudson's substations with at least 3 years of hourly data. The majority of substations are experiencing slowing or declining loads or have ample room for growth without having to upgrade them. Locations with a growth rate above 0% are experiencing growth and locations where the 2015 loading factor is closer to 100% have less room for growth. Some substations, such as Lawrenceville and Grimley, are experiencing high growth levels but the growth trajectory is more uncertain because those substations have less historical hourly data than other sites. The only substation with limited room for growth is Woodstock. However, because of the distribution configuration, loads at Woodstock can be easily transferred to neighboring substations.

Figure 3-4: Substation Growth Rates Versus Room for Growth

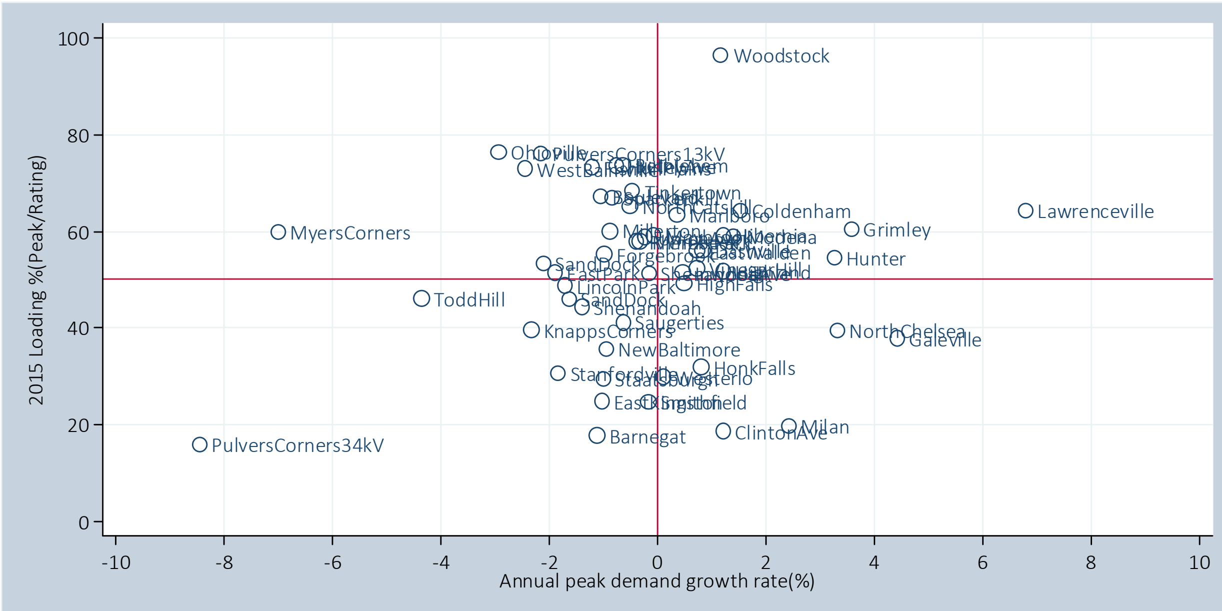


Figure 3-5 summarizes the likelihood that loads will exceed design ratings for each substation by year. However, loads can exceed design rating without automatically triggering an infrastructure upgrade. Sustained growth needs to be observed before substations are upgraded. Figure 3-6 summarizes the likelihood of triggering an infrastructure upgrade due to load growth. Based on the trajectory and variability in load growth, four substations – Coldenham, Grimley, Lawrenceville, and Woodstock – exhibit more than a 5% probability of triggering a growth related upgrade over the next 10 years. In some cases, upgrades can be deferred for longer periods through relatively low costs distribution upgrades or load transfers. DERs are still beneficial at those locations and their costs can be compared to the distribution upgrade and load transfer options.

Figure 3-5: Probability of Loads Exceeding Design Ratings

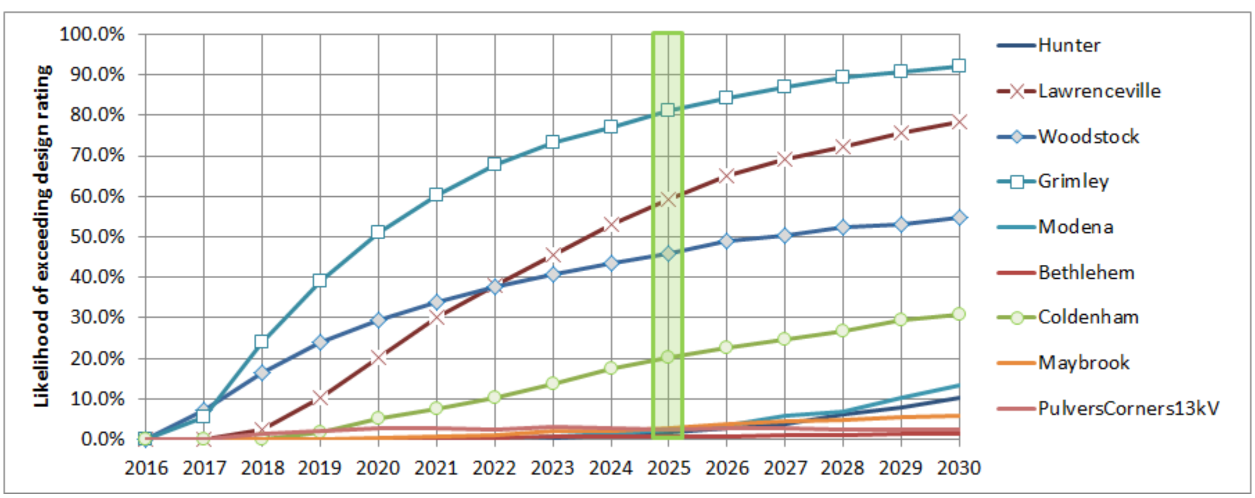
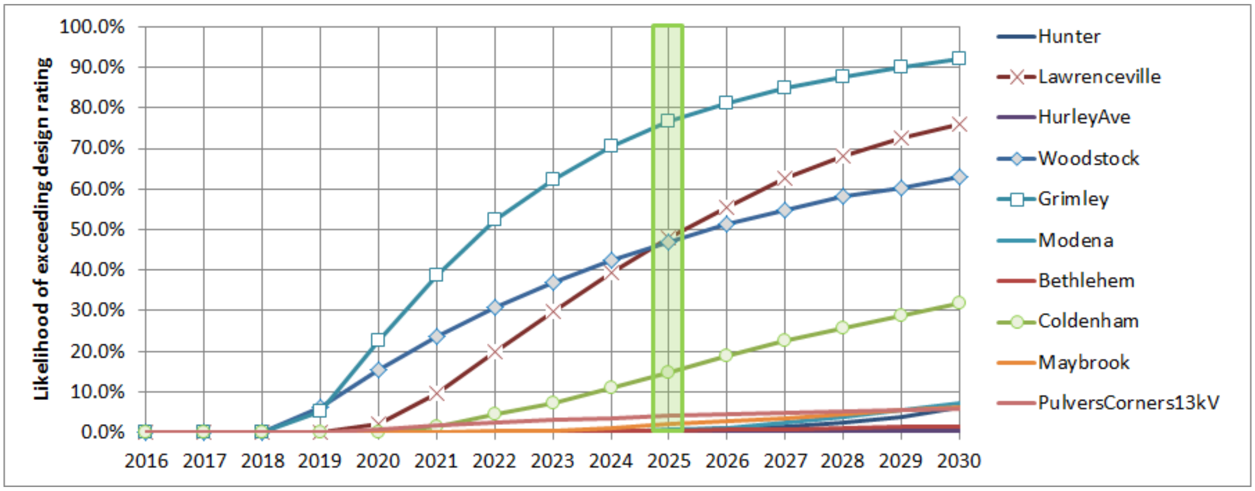


Figure 3-6: Probability of Growth Related Infrastructure Upgrade



Central Hudson groups substations in 10 distinct planning load areas. They represent adjacent geographic regions, but, more importantly, nearly all load transfers between substations occur within planning load areas. While the load growth estimates for specific substations can be influenced by load transfers and outages, the load areas provide a more stable unit of analysis.

Tables 3-2-through 3-10 summarize the results of the historical load growth analysis for each of the distribution load serving substations with at least three years of hourly data in each load area. Similar to the transmission areas, most of the substations have ample room to accommodate additional load growth.

Table 3-2: Northwest Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Hunter	10.7	19.5	84.1%	99.7%	102.1%	113.6%	106.0%	100.0%	3.3%	8.7%
Lawrenceville	12.4	19.3	-	-	-	83.3%	104.3%	100.0%	6.8%	10.3%
New Baltimore	9.2	25.8	105.9%	99.9%	98.6%	99.8%	99.0%	100.0%	-1.0%	2.4%
North Catskill	22.8	35.1	103.4%	100.6%	100.3%	101.5%	99.9%	100.0%	-0.5%	1.0%
Vinegar Hill	9.8	18.8	98.4%	95.1%	95.7%	99.7%	99.5%	100.0%	0.7%	1.9%
Westerlo	8.1	27.0	102.3%	99.5%	99.4%	103.0%	103.2%	100.0%	0.1%	2.0%
Overall load area	**66.2**	**0.0**	**88.8%**	**91.6%**	**91.1%**	**97.1%**	**102.9%**	**100.0%**	**2.7%**	**2.5%**

The Hunter and Lawrenceville substations both show relatively high growth forecasts; however, both are winter peaking—rather than summer peaking—and therefore are not managed by Dynamic Load Management programs designed for the summer. The growth in these regions was driven by the addition of large customers and seasonal activity and may or may not reflect future growth patterns.

Most of the substations in the Kingston-Saugerties load area are experiencing load declines rather than growth. With few exceptions, most of the substations have ample capacity to accommodate additional load growth. While the Boulevard and Hurley substations have experienced relatively high loadings in the past—87% and 89%, respectively—loads in these substations have been declining and the likelihood of an infrastructure upgrade is minimal. Woodstock had a historical high loading factor and the substation's loads have been growing. However, because of the distribution configuration, the additional loads can be easily transferred to neighboring substations at minimal cost.

The Ellenville load area substation loads are generally growing. However, they also have ample capacity to accommodate additional growth over the next 10 years.

Table 3-3: Kingston-Saugerties Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Boulevard	20.6	30.6	106.8%	104.0%	104.6%	106.1%	102.2%	100.0%	-1.1%	1.7%
East Kingston	12.0	48.0	105.8%	103.2%	105.3%	102.1%	101.9%	100.0%	-1.0%	1.2%
Hurley Ave	17.0	23.1	106.8%	100.9%	100.5%	103.4%	102.2%	100.0%	-0.8%	2.3%
Lincoln Park	41.0	84.0	108.1%	107.2%	105.1%	102.8%	101.6%	100.0%	-1.7%	0.4%
Saugerties	20.6	50.0	-	-	-	101.2%	101.3%	100.0%	-0.6%	0.6%
Woodstock	20.2	20.9	100.2%	85.9%	98.3%	101.2%	101.8%	100.0%	1.2%	6.0%
Overall load area	**105.0**	**0.0**	**106.1%**	**102.0%**	**103.1%**	**101.1%**	**102.0%**	**100.0%**	**-0.9%**	**1.3%**

Table 3-4: Ellenville Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Clinton Ave	1.4	7.7	96.7%	96.5%	95.6%	103.4%	103.1%	100.0%	1.2%	2.8%
Dashville	1.1	2.0	97.1%	99.6%	100.8%	102.1%	103.9%	100.0%	0.8%	1.9%
Grimley	4.4	7.2	-	-	80.4%	94.9%	99.0%	100.0%	3.6%	4.9%
High Falls	17.0	34.5	98.9%	97.4%	97.9%	100.8%	100.2%	100.0%	0.5%	1.2%
Honk Falls	5.8	18.2	98.3%	92.9%	98.0%	98.3%	100.8%	100.0%	0.8%	2.4%
Overall load area	**24.5**	**0.0**	**97.7%**	**94.6%**	**97.9%**	**100.3%**	**101.5%**	**100.0%**	**1.0%**	**1.8%**

Table 3-5: Modena Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Galeville	10.9	28.7	71.5%	80.1%	84.2%	86.1%	88.1%	100.0%	4.4%	3.0%
Highland	17.0	32.9	95.4%	94.9%	96.4%	99.3%	100.4%	100.0%	1.2%	1.0%
Modena	12.4	21.1	90.7%	98.2%	101.4%	99.9%	99.3%	100.0%	1.4%	3.2%
Ohioville	22.7	29.7	120.0%	110.5%	106.9%	108.3%	108.4%	100.0%	-2.9%	3.6%
Overall load area	**61.4**	**0.0**	**92.2%**	**98.2%**	**99.3%**	**100.2%**	**101.1%**	**100.0%**	**1.4%**	**2.2%**

The substations in the Modena distribution load area are experiencing growth but generally have ample capacity to accommodate additional growth without triggering infrastructure. The single exception is Ohioville, where loads have exceeded the current design rating in the past.. Ohioville was one of the initial locations included in Central Hudson's non-wire alternative demonstration projects. However, the DER resource bids were unable to cost-effectively address the need within the required timeframe.

Four of the substations in the Newburgh distribution load area are experiencing moderate growth but the remaining three substations are experiencing declining loads. There are three substations that have experienced high loading factors of 96.7%, 94.3%, and 90.2% in the 2010-2015 timeframe—Bethlehem Road, Maybrook, and West Balmville, respectively. However, loads at Bethlehem and West Balmville exhibit a downward trend and, as a result, loads are not forecast to exceed the design ratings. Maybrook loads are growing, albeit slowly. The low growth rate seen in Maybrook's historical data may be due, in part, to the recent history of transferring portions of the Maybrook areas to adjacent substations to accommodate new large loads that are fed from Maybrook. These circuit transfers will need to be reversed in the near future for reliability purposes.

With a few exceptions, the Northeastern Dutchess distribution load area substations have been experiencing declining loads. The two substations that have been experiencing growth—Hibernia and Milan—have ample capacity to accommodate additional load growth over the foreseeable future.

Table 3-6: Newburgh Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Bethlehem	35.2	47.8	104.4%	102.8%	95.3%	97.6%	102.2%	100.0%	-0.6%	3.6%
Coldenham	30.7	47.8	98.2%	97.7%	107.2%	114.0%	108.4%	100.0%	1.5%	6.8%
East Walden	14.6	26.2	99.3%	93.5%	97.4%	98.2%	100.3%	100.0%	0.7%	2.4%
Marlboro	19.6	30.9	96.6%	95.6%	99.4%	97.7%	94.3%	100.0%	0.4%	2.3%
Maybrook	17.7	30.0	93.3%	88.0%	84.6%	79.4%	83.4%	100.0%	-0.1%	8.3%
UnionAve	55.6	94.5	-	98.9%	102.8%	100.5%	98.2%	100.0%	-0.2%	2.0%
West Balmville	34.9	47.8	113.3%	112.3%	102.5%	104.1%	106.7%	100.0%	-2.4%	3.5%
Overall load area	**203.9**	**0.0**	**95.0%**	**96.6%**	**94.1%**	**99.8%**	**97.3%**	**100.0%**	**0.9%**	**1.8%**

Table 3-7: Northeastern Dutchess Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
East Park	12.4	24.2	106.0%	110.4%	105.1%	102.2%	99.4%	100.0%	-1.9%	2.5%
Hibernia	10.5	17.8	94.3%	99.1%	99.2%	102.1%	102.5%	100.0%	1.2%	2.2%
Milan	5.1	25.9	87.8%	88.3%	87.0%	90.8%	95.6%	100.0%	2.4%	2.6%
Millerton	5.0	8.3	106.3%	100.7%	100.9%	99.7%	100.9%	100.0%	-0.9%	1.9%
Pulvers Corners 13kV	4.4	5.8	109.5%	99.0%	101.1%	93.7%	91.3%	100.0%	-2.2%	5.4%
Pulvers Corners 34kV	2.7	17.2	137.7%	137.6%	138.7%	136.0%	103.4%	100.0%	-8.4%	11.0%
Rhinebeck	27.7	47.8	102.7%	100.7%	101.9%	101.5%	100.8%	100.0%	-0.4%	0.7%
Smithfield	1.4	5.8	100.8%	101.3%	102.0%	95.6%	103.7%	100.0%	-0.2%	3.0%
Staatsburgh	8.0	27.2	106.8%	102.7%	103.9%	105.7%	101.6%	100.0%	-1.0%	1.9%
Stanfordville	5.2	17.0	108.6%	108.5%	109.4%	107.6%	102.8%	100.0%	-1.8%	2.2%
Tinkertown	13.0	19.1	105.3%	98.9%	101.6%	102.1%	102.1%	100.0%	-0.5%	2.2%
Overall load area	**92.8**	**0.0**	**105.8%**	**104.1%**	**104.5%**	**100.7%**	**98.8%**	**100.0%**	**-1.4%**	**1.3%**

Based on the historical analysis, loads in the Poughkeepsie distribution load area have been trending downward. Moreover, the existing substations can accommodate substantial growth, should it occur, without growth related infrastructure upgrades.

Most of the substations in the Fishkill load area have been experiencing declining loads. The sole substation experiencing load growth, North Chelsea, has enough capacity in place to accommodate growth over the foreseeable future. One substation, Myers Corners, experienced a substantial drop in loads over the 2010-2015 period due in part to the closure of a large industrial facility.

The Poughkeepsie industrial substations have been experiencing moderate declines in peak loads and, more importantly, have ample capacity to accommodate load growth, should it occur. One of the load areas with a single substation is excluded because it exclusively serves a single large customer.

Table 3-8: Poughkeepsie Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Inwood Ave	24.6	47.8	94.3%	109.1%	94.7%	97.9%	103.0%	100.0%	0.5%	6.2%
Reynolds Hill[1]	34.7	45.9	113.8%	108.3%	106.6%	105.4%	100.0%	-	-2.7%	0.0%
Spackenkill	32.0	47.8	-	-	102.5%	101.4%	100.4%	100.0%	-0.8%	0.3%
Todd Hill	22.0	47.8	119.2%	118.3%	103.7%	101.3%	101.0%	100.0%	-4.4%	4.5%
Overall load area	**78.0**	**0.0**	**110.8%**	**124.7%**	**135.2%**	**132.8%**	**102.4%**	**100.0%**	**-3.0%**	**15.5%**

Table 3-9: Fishkill Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Fishkill Plains	38.7	52.8	105.2%	104.5%	106.4%	103.1%	100.0%	100.0%	-1.2%	1.6%
Forgebrook	26.2	47.4	106.7%	101.5%	104.0%	102.5%	101.5%	100.0%	-1.0%	1.6%
Knapps Corners	18.9	47.8	-	-	106.9%	102.1%	98.5%	100.0%	-2.3%	2.3%
Merritt Park	30.3	52.2	100.1%	102.4%	98.7%	98.1%	99.1%	100.0%	-0.3%	1.5%
Myers Corners	21.0	35.1	132.2%	126.9%	127.5%	121.0%	100.1%	100.0%	-7.0%	6.1%
North Chelsea	19.1	48.3	78.8%	95.9%	99.0%	99.7%	98.5%	100.0%	3.3%	6.1%
Sand Dock	4.3	8.0	108.3%	102.5%	111.6%	101.7%	100.5%	100.0%	-2.1%	4.0%
Shenandoah	9.2	18.0	106.3%	99.2%	104.7%	110.8%	106.3%	100.0%	-0.2%	4.9%
Overall load area	**179.0**	**0.0**	**113.6%**	**107.7%**	**102.9%**	**98.9%**	**92.9%**	**100.0%**	**-3.4%**	**4.1%**

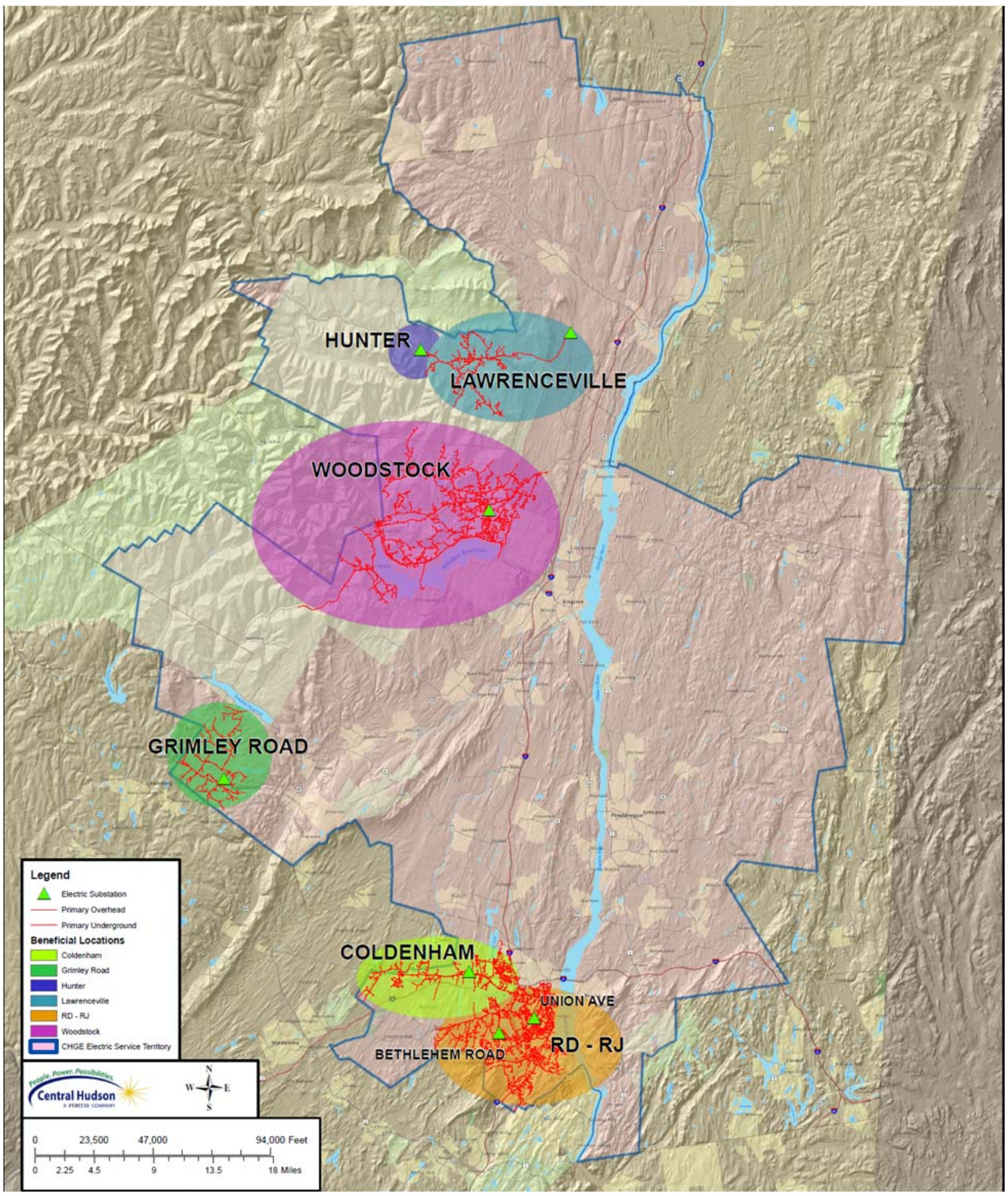
Table 3-10: Poughkeepsie Industrial Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Barnegat	8.5	47.8	103.7%	116.2%	120.5%	116.0%	111.2%	100.0%	-1.1%	8.6%
SandDock	23.4	51.0	103.9%	110.4%	106.8%	101.3%	99.5%	100.0%	-1.6%	3.3%
Overall load area	**31.7**	**0.0**	**103.5%**	**112.0%**	**110.8%**	**105.4%**	**102.4%**	**100.0%**	**-1.3%**	**4.3%**

3.3 Beneficial Locations for DERs

Locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering an infrastructure investment by 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. While the locations can benefit from DER's, in some instances Central Hudson can provide temporary relief through load transfer or other low cost steps. For areas that lack distribution engineering options for deferring upgrades further, more costs are avoided by placing the right type of DERs with the right availability at those locations.

Figure 3-7: Map of Beneficial Locations for DERs



4 Avoided T&D Cost Estimates

Historically, avoided T&D cost studies have not produced location specific estimates and have not relied on probabilistic methods, which quantify the risk mitigation value of managing demand.

The estimates produced here are based on 2,000 or 10,000 simulations of potential load growth patterns for each substation and transmission area, respectively. For each simulation, we are thus able to assess if the relevant design rating is exceeded, identify the timing of infrastructure upgrade, quantify the magnitude of demand reductions needed to avoid the infrastructure upgrade, and calculate what the avoided costs associated with deferral of infrastructure upgrades would be if demand reductions were in place. The detailed calculations from each of the simulations at each location are used to estimate the expected avoided costs per kW. That is, the probabilistic method assigns T&D avoided costs when, for example, only 10% of potential growth trajectories leads to infrastructure upgrades. This approach quantifies the risk mitigation value provided by resources that reduce demand at the right times at each location.

The purpose of producing avoided T&D costs estimates is not necessarily to establish payments or incentives for DERs. The objective is to allow distributed energy resources to compete against each other and against traditional engineering solutions – wires, transformers, etc. – and thus increase competition and improve efficiency. The avoided cost estimates signal to DER providers not only where DERs are most beneficial but where they are most likely to be monetized. They also provide a reference point and allow comparison of DER costs to traditional engineering solutions.

To deliver value, however, DERs needs to ramp up at the right time and the right place, for the right hours, with the right amount of availability, and the right level of certainty.

4.1 Avoided Transmission Costs

Table 4-1shows the avoided cost estimates for each transmission area and year, as well as the 10-year levelized avoided cost by location. None of the areas are expected to exceed the design ratings over the next few years, but there is a small probability the ratings will be exceeded due to the uncertainty in the growth patterns.

For most transmission areas, the probability of triggering infrastructure upgrades is negligible even at ten years out. As shown in Figure 3-3, the likelihood of triggering an upgrade by 2025 is 6.0% for the RD-RJ lines and 2.6% for the WM Line. Despite the fact that infrastructure upgrades are low probability events, due to the magnitude of the anticipated investments – $5.5M for the RD-RJ lines and $3M for the WM line – demand reductions provide risk mitigation value. The 10 year levelized cost for the RD-RJ lines is 58.05 $/kW-year and $102.11 $/kW-year for the WM line.

The majority of the transmission areas experience little or no avoided costs from DER investments. In practice, all avoided T&D costs are location specific. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low. We include a system wide value, but highlight that it is a weighted average of beneficial locations and locations without any T&D avoided cost value

Table 4-1: Avoided Transmission Cost Estimates ($/kW-Year) – 2016-2030

Forecast Year	Transmission ($/kW-year)										
	Ellenville	Hurley-Milan	Mid-Dutchess	Northwest 115-69 Area	Northwest 69kV Area	Pleasant Valley 69 kV	RD-RJ Lines	Southern Dutchess	WM Line	Westerlo Loop	**Territory wide (Untargeted)**
2016	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2017	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2018	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2019	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2020	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$231.66	$0.00	**$12.38**
2021	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$148.58	$0.00	$233.00	$0.00	**$26.65**
2022	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$165.01	$0.00	$233.33	$0.00	**$31.52**
2023	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$139.04	$0.00	$176.03	$0.00	**$36.28**
2024	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$143.78	$0.00	$175.36	$0.00	**$37.42**
2025	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$147.15	$0.00	$177.41	$0.00	**$38.82**
2026	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$144.97	$0.00	$176.77	$0.00	**$38.89**
2027	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$145.94	$0.00	$177.93	$0.00	**$39.47**
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$149.59	$0.00	$185.31	$0.00	**$55.99**
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$148.50	$0.00	$186.25	$0.00	**$56.19**
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$152.71	$0.00	$187.10	$0.00	**$58.02**
$/kW-Year (10-year levelized)	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$58.05**	**$0.00**	**$102.11**	**$0.00**	**$14.33**

Notes: (1) For semi-targeted and untargeted values, the estimates take into account the % of load in the areas with growth related investments; (2) The discount rate, 9.43%, was used to annualize the avoided costs; and (3) All values are nominal $.

4.2 Avoided Distribution Substation Cost Estimates

Table 4-2 shows the 10-year levelized avoided cost estimates by substation and load area. A total of three substations have potential avoided costs – Lawrenceville, Coldeham, and Hunter. Most substations either have ample room for growth or declining loads. For a couple of substations – Grimley and Woodstock – load growth can be addressed via relatively low cost permanent load transfers to neighboring substations. Without targeting, the likelihood that reductions will be at a location where it might help defer or delay substation upgrades is relatively low, diluting the value to $0.23 /kW-year.

Table 4-2: Avoided Substation Cost Estimates ($/kW-Year) – 10 Year Levelized Value

Load Area	Substation	$/kW-Year (10-year levelized)	Load Area	Substation	$/kW-Year (10-year levelized)
1 Northwest	Hunter	$31.46	6 Northeastern Dutchess	EastPark	$0.00
	Lawrenceville	$275.34		Hibernia	$0.00
	New Baltimore	$0.00		Milan	$0.00
	North Catskill	$0.00		Millerton	$0.00
	Vinegar Hill	$0.00		Pulvers Corners 13kV	$0.00
	Westerlo	$0.00		Pulvers Corners 34kV	$0.00
	Load area (untargeted)	$1.04		Rhinebeck	$0.00
2 Kingston - Saugerties	Boulevard	$0.00		Smithfield	$0.00
	East Kingston	$0.00		Staatsburgh	$0.00
	Hurley Ave	$0.00		Stanfordville	$0.00
	Lincoln Park	$0.00		Tinkertown	$0.00
	Saugerties	$0.00		Load area (untargeted)	$0.00
	Woodstock	$0.00	7 Poughkeepsie	InwoodAve	$0.00
	Load area (untargeted)	$0.00		Spackenkill	$0.00
3 Ellenville	Clinton Ave	$0.00		ToddHill	$0.00
	Dashville	$0.00		Load area (untargeted)	$0.00
	Grimley	$0.00	8 Fishkill	Fishkill Plains	$0.00
	HighFalls	$0.00		Forgebrook	$0.00
	Honk Falls	$0.00		Knapps Corners	$0.00
	Load area (untargeted)	$0.00		Merritt Park Industrial	$0.00
4 Modena	Galeville	$0.00		Myers Corners	$0.00
	Highland	$0.00		North Chelsea	$0.00
	Modena	$0.00		Sand Dock	$0.00
	Ohioville	$0.00		Shenandoah	$0.00
	Load area (untargeted)	$0.00		Load area (untargeted)	$0.00
5 Newburgh	Bethlehem	$0.00	9 Poughkeepsie Industrial	Barnegat Industrial	$0.00
	Coldenham	$119.91		Sand Dock Industrial	$0.00
	East Walden	$0.00		Load area (untargeted)	$0.00
	Marlboro	$0.00	10 Fishkill Industrial	Shenandoah Industrial	$0.00
	Maybrook	$0.00		Load area (untargeted)	$0.00
	Union Ave	$0.00			
	West Balmville	$0.00			
	Load area (untargeted)	$0.60			
Territory wide (untargeted)					$0.23

Notes: (1) For semi-targeted and untargeted values, the estimates take into account the % of load in the areas with growth related investments; (2) The discount rate, 9.43%, was used to annualize the avoided costs; and (3) Values are in $2016.

Table 4-3 summarized the expected avoided costs (in nominal $) by year for each substation with potential for avoided costs.

Table 4-3: Substation Locational Specific Avoided Cost by Year ($/kW)

Forecast Year	Coldenham	Hunter	Lawrenceville	System-wide untargeted
2016	$0.00	$0.00	$0.00	$0.00
2017	$0.00	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00	$0.00
2020	$0.00	$0.00	$414.81	$0.03
2021	$343.87	$0.00	$544.89	$0.19
2022	$292.97	$0.00	$607.05	$0.43
2023	$285.85	$0.00	$610.35	$0.62
2024	$298.68	$445.78	$604.95	$0.85
2025	$313.39	$0.00	$649.32	$0.95
2026	$324.93	$626.94	$628.66	$1.07
2027	$321.31	$655.33	$578.95	$1.14
2028	$316.23	$648.10	$687.88	$1.25
2029	$313.80	$653.86	$616.11	$1.25
2030	$339.49	$698.17	$595.83	$1.45
$/kW-Year (10-year levelized)	**$119.91**	**$31.46**	**$275.34**	**$0.23**

Notes: (1) For system-wide untargeted values, the estimates take into account the likelihood reductions would be in areas with value (2) Values are in nominal dollars.

4.3 Total Avoided System Cost Estimates

Table 4-4 summarizes the system wide avoided T&D costs by year and includes the 10 year net present value used to annualize future value. As noted several times, in practice, all avoided T&D costs are location specific. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low. For system-wide untargeted values, the estimates take into account the likelihood reductions would be in locations with value due to random chance. We emphasize that system wide value is essentially a weighted average of a few beneficial locations with numerous locations where reductions do not lead to avoided T&D costs. As beneficial locations are included for non-wire projects, they are removed from the system-wide value.

Table 4-4: System Wide Avoided T&D Cost Estimates for 2016–2026

Forecast Year	Distribution Substation	Transmission	Total
2016	$0.00	$0.00	$0.00
2017	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00
2020	$0.03	$12.38	$12.41
2021	$0.19	$26.65	$26.84
2022	$0.43	$31.52	$31.94
2023	$0.62	$36.28	$36.90
2024	$0.85	$37.42	$38.27
2025	$0.95	$38.82	$39.76
2026	$1.07	$38.89	$39.95
2027	$1.14	$39.47	$40.62
2028	$1.25	$55.99	$57.24
2029	$1.25	$56.19	$57.43
2030	$1.45	$58.02	$59.47
10 Year Levelized Cost ($/kW-year)	$0.23	$14.33	$14.55

Notes: (1) For system-wide untargeted values, the estimates take into account the likelihood reductions would be in areas with value (2) Values are in nominal dollars

5 Key Findings and Conclusions

The key findings from the analysis are:

- Most substations and transmission areas are experiencing declining loads or have ample room for growth over the next 10 years.
- The expected avoided costs vary by location and year and are highly concentrated. Avoided costs are realized if additional resources are placed in the right locations. Without targeting, the value of distributed resources is diluted.
- For many distribution substations and transmission areas that have expected growth, the potential for avoided infrastructure upgrades through DER resources is minimal because there is already sufficient capacity built in the area to meet load growth.
- The avoided cost estimates reflect the uncertainty in the forecasts and the risk mitigation value of demand management. Despite a low likelihood of exceeding design rating in the next 10 years, DER resources can provide risk mitigation value at targeted transmission areas and substations if they are at the right locations, target the right hours, and are available at the right times.
- In practice, all avoided T&D costs are location specific. For system-wide untargeted values, the estimates take into account the likelihood reductions would be in locations with value due to random chance. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low.

The study demonstrates the value of developing T&D avoided cost estimates at a local level using probabilistic methods. Because the methodology is relatively novel, it may require future refinements and improvements. Future studies can be further bolstered by conducting sensitivity analyses and refinement of engineering rules, which trigger T&D infrastructure upgrades.

Appendix A Econometric Models Used to Estimate Historical Growth

The econometric models were purposefully designed to both estimate historical load growth in percentage terms and allow us to weather normalize loads for 1-in-2 weather peaking conditions. The key to this process was to model the natural log of the daily peak loads as the dependent variable and include year-specific coefficients to estimate the percent change in loads, after controlling for other factors. By using the natural log as the dependent variable, all of the explanatory variables reflect the percent change in load associated with a unit change in the independent variable.

The regressions were estimated on the highest 75 local peak days for each year in the 2010 to 2015 timeframe for a total of up to 450 observations per location. The goal was to include a sufficient number of days that reflected peaking conditions for each year. The number of observations by location varies slightly because of differences in the amount of data available and because peaks occurring on weekends or holidays were excluded. The model estimated daily peaks as a function of weather interacted with day of week, month, and historical year. Weather was included using a process that avoids assumptions about the type of relationship between weather and load. Rather than assume a constant linear relationship, the weather data is split into equally sized bins and a separate relationship is estimated for different temperature ranges—also known as a *spline regression*. All models were estimated using time series methods to take into account auto-correlation.[5]

Figure A-1 illustrates the model output for one location. A separate model was estimated for each substation, transmission area, and planning area. The model explained 98.3% of the variation and, more importantly, produced estimates of the percent change in loads—the *load growth*—relative to 2010, after controlling for weather, day of week, and other factors. Figure A-2 shows the year-to-year growth and the general trend. The growth trend and the amount of year-to-year variation differ by location and are central to developing the probabilistic load forecasts. In addition, the confidence bands for the historical growth estimates are linked to the explanatory power of the models. When explanatory power is high, confidence bands are tight. When explanatory power is lower, confidence bands are broader.

The estimates of year-to-year historical load growth also were used to assess the degree to which growth patterns are related to each other—that is, the degree to which growth in the prior year predicts growth in the following year, technically known as *auto-correlation*. Each individual site had a limited number of individual year growth estimates—five years at most—so the estimate of auto-correlation was developed across all sites. The auto-correlation in growth was 0.75 for substations and 0.52 for transmission areas.

[5] We relied on an iterative feasible GLS model with first order auto-correlation. Other time series options—such as ARIMA and the Newey-West model—do not handle gaps in the time series as easily. All options, however, produce consistent estimates.

Figure A-1: Example Load Growth Econometric Model

Prais-Winsten AR(1) regression — twostep estimates

Linear regression			
	Number of obs	=	370
	F(30, 336)	=	.
	Prob > F	=	.
	R-squared	=	0.9832
	Root MSE	=	.04923

lndailypeak	Coef.	Semirobust Std. Err.	t	P>|t|	[95% Conf.	Interval]
year						
2011	-.0314738	.0114131	-2.76	0.006	-.0539239	-.0090236
2012	-.0190394	.0124406	-1.53	0.127	-.0435106	.0054319
2013	-.0041588	.0143032	-0.29	0.771	-.032294	.0239763
2014	-.0592701	.0111966	-5.29	0.000	-.0812943	-.0372459
2015	-.0781381	.0099249	-7.87	0.000	-.0976608	-.0586154
month						
2	-.0087784	.0093905	-0.93	0.351	-.0272501	.0096932
3	-.0043992	.0158393	-0.28	0.781	-.0355558	.0267574
5	-.0935041	.0450242	-2.08	0.039	-.182069	-.0049392
6	-.054681	.0444931	-1.23	0.220	-.1422012	.0328391
7	-.0333242	.0437045	-0.76	0.446	-.1192932	.0526447
8	-.0249745	.0434934	-0.57	0.566	-.1105281	.0605792
9	-.0399489	.0442698	-0.90	0.367	-.1270298	.047132
11	.0667566	.0156461	4.27	0.000	.03598	.0975333
12	-.026894	.0110624	-2.43	0.016	-.0486544	-.0051337
dow						
2	-.0039519	.0096568	-0.41	0.683	-.0229473	.0150436
3	.0030018	.0103159	0.29	0.771	-.01729	.0232937
4	.0004244	.0114791	0.04	0.971	-.0221556	.0230043
5	-.0146542	.0131222	-1.12	0.265	-.0404661	.0111577
cdd60	.0199863	.0017218	11.61	0.000	.0165994	.0233731
dow#c.cdd60						
2	.0016199	.0009015	1.80	0.073	-.0001534	.0033932
3	.0012651	.0009084	1.39	0.165	-.0005217	.0030519
4	.0012951	.0009638	1.34	0.180	-.0006008	.003191
5	.0007154	.0010129	0.71	0.480	-.001277	.0027077
bins_cdd						
1	.1937983	.0323063	6.00	0.000	.1302502	.2573465
2	.1760443	.1233678	1.43	0.155	-.0666261	.4187148
3	-.0030568	.0740123	-0.04	0.967	-.1486427	.142529
4	-.0943377	.0997578	-0.95	0.345	-.2905663	.1018908
5	0	(omitted)				
cdd60	0	(omitted)				
bins_cdd#c.cdd60						
1	0	(omitted)				
2	-.0208899	.0143867	-1.45	0.147	-.0491892	.0074095
3	-.0023679	.0063728	-0.37	0.710	-.0149035	.0101677
4	.0053657	.0070509	0.76	0.447	-.0085038	.0192352
5	0	(omitted)				
bins_hdd						
3	.0404254	.0385893	1.05	0.296	-.0354817	.1163325
4	-.0062006	.0138347	-0.45	0.654	-.0334142	.0210129
5	0	(omitted)				
hdd60	.0040388	.0006694	6.03	0.000	.0027222	.0053555
bins_hdd#c.hdd60						
3	0	(omitted)				
4	0	(omitted)				
5	0	(omitted)				
_cons	2.65174	.0307021	86.37	0.000	2.591348	2.712133
rho	.3315186					

Dependent variable

Explained variation

% Change in load relative to 2010

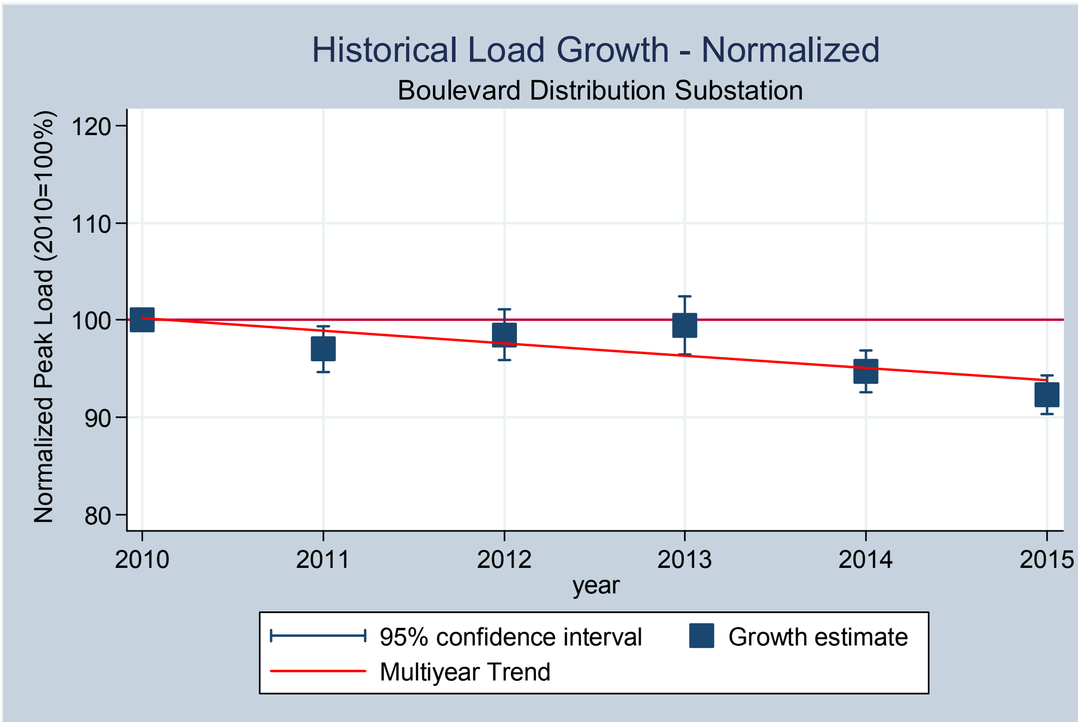
Seasonal effects (independent of weather)

Day of week effects

Weather interaction with day of week

Weather Effects (Spline)

Figure A-2: Example of Historical Load Growth Estimates



Appendix E Hosting Capacity

ELECTRIC POWER RESEARCH INSTITUTE

Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State

June 2016

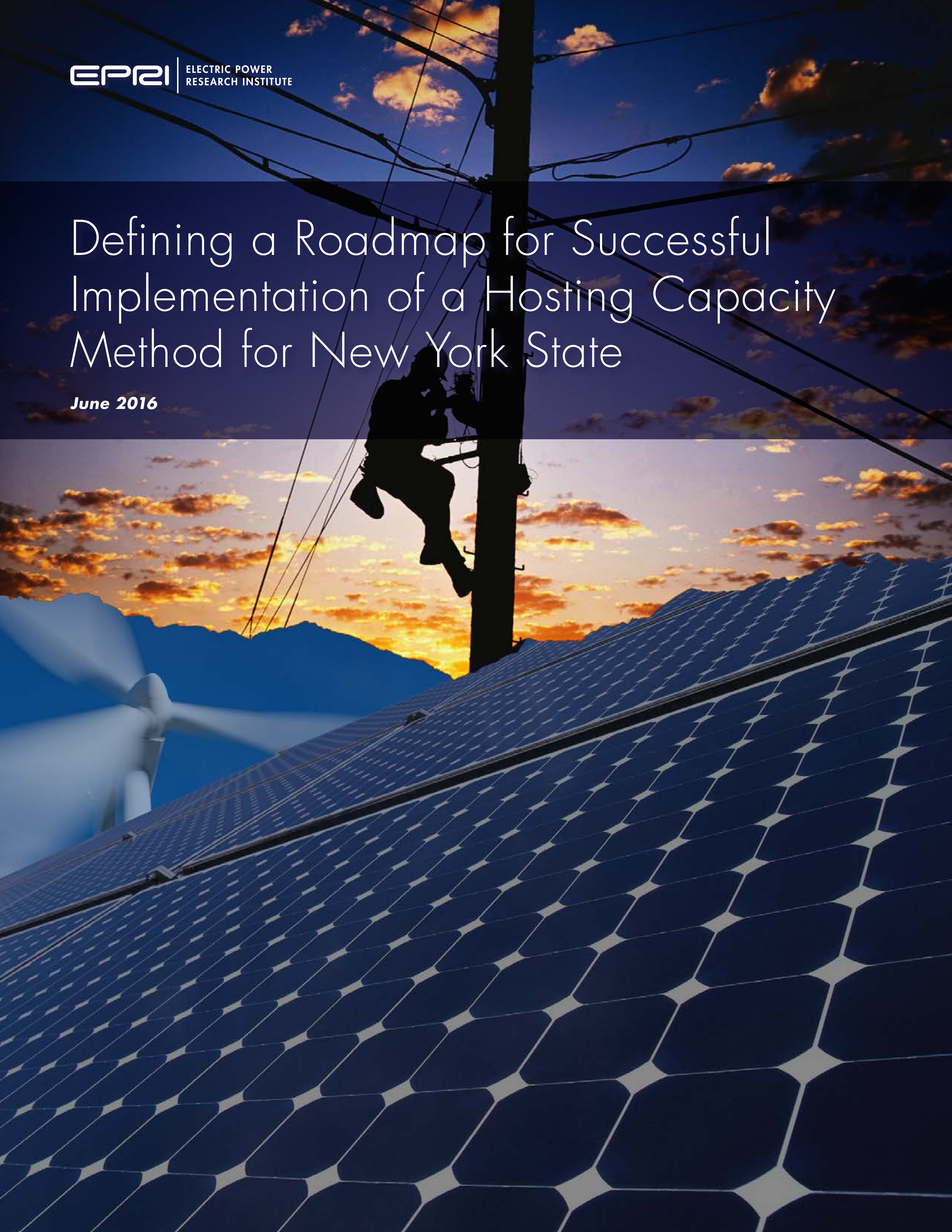


Table of Contents

Introduction

Change to the electric grid is occurring due to the addition of distributed energy resources (DER). The result is a new set of challenges for planning and operating the grid, especially on the distribution system that serves these new resources. Utilities are faced with making decisions on how to consider this growing penetration of DER.

With this change in mind, the New York State Public Service Commission (PSC) issued an Order Instituting Proceeding to launch its Reforming the Energy Vision (REV) initiative. This initiative aims to reorient both the electric industry and the ratemaking paradigm and intends to more fully integrate and utilize distributed energy resources (DER) with distribution planning and operations.

The Joint Utilities of New York are required to establish a structure for a transparent planning process in addition to identifying where DER can be best accommodated. Separately, utilities must identify where DER participation may provide the greatest benefit on local distribution systems.[1] As both methodologies are established and mature, they can then be quantified and integrated together into a single map. Advances in distribution planning methods are expected to help provide visibility, consistency and transparency into the process.

For these things to become reality, there is a need for a consistent method to understand impacts of distributed resources in the electric system. A foundational element these analyses is the capability to assess the ability of distribution systems to "host" DER capacity.

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.

Hosting capacity assessments should consider a wide range of grid impact factors, including voltage/flicker, protection, thermal impacts, as well as safety, reliability, and power quality. The range of DER a feeder can host depends on the location of interconnection and the characteristics of both the feeder and DER. Additionally, hosting capacity will change over time as load, DER and circuit configurations changes.

Models of the entire distribution system are necessary to perform hosting capacity analysis. Hosting capacity is intended to inform interconnection processes and facilitate DER developer understanding as to where there may be more costs to interconnect. It is also foundational to planning the distribution system of the future.

While hosting capacity analysis is foundational and also enables other more advanced system analysis, there are also challenges to utilizing this method to its fullest today. The main challenge consists of the data and models needed to perform the analysis. In most cases, utilities do not have their entire system modeled. Data that currently exist on paper needs to be translated into the planning tools utilities use and validated based on current operating conditions. In addition, the existing DER needs to be captured within utility planning/GIS tools to be able to be utilized as part of the evaluation process. Currently utility planning tools are beginning to incorporate this method as part of the analysis toolset, but this process will take time.

1 Joint Utilities – Informal Feedback on Draft Report of the Market Design and Platform Technology Working Groups – July 31, 2015

In this whitepaper an approach and method is recommended by the NY Joint Utilities to be applied to DER hosting capacity in NY State. It focuses on methods that support the REV objectives related to effective integration of DER. The main outcome of this paper is to inform stakeholders of the recommended approach and methods, needs and challenges for implementation, and applications in NY.

Hosting Capacity Analysis Described

Providing safe, reliable, and affordable service to all customers remains paramount and the responsibility of the distribution utilities. With the addition of DER, utility engineers must ensure it does not adversely impact power quality or reliability. Currently, customers and developers, as well as utilities, do not have visibility into the potential impacts of DER across the distribution system and where DER may have less of an impact. Performing detailed studies requires a great deal of data and time, but there is a need to better understand: How much DER can be accommodated, what potential issues may arise over time, as well as where DER can be more optimally located.

What is it and Why is it so Important?

This "hosting capacity" of a distribution system is the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades. Hosting capacity can vary across feeders, along a single distribution feeder, as well as within a secondary distribution system. Hosting capacity will also change over time as the distribution system infrastructure and operations change. Hosting capacity can sometimes be increased with infrastructure upgrades or through the use of DER with smart inverters[2] or other advanced control schemes.

Responding to the DSIP Order issued in April, the Joint Utilities of New York are seeking a structured and transparent planning process as part of the DSIP. Under this planning process, it will be the DSP's responsibility to identify where DER adversely impacts the distribution system and where DER participation provides the greatest benefit to the local distribution system.[3]

The objectives are to provide increased transparency as to where each utility has hosting capacity, provide developers/customers visibility into better or worse locations for DER, and to understand where and how DER impacts the entire distribution system. Over time, combining this analysis with existing DER penetration and long-term DER forecasts, it can help inform where infrastructure upgrades may be considered.

Hosting Capacity: Providing a Foundation

The concept of hosting capacity is not new, but the uses of it are becoming more widespread as the industry needs a comprehensive approach to understanding the impacts of DER. The concept of hosting capacity and associated methods for analysis were first introduced to the US industry back in 2011,[4, 5] in which EPRI published a consistent, repeatable, and transparent method for performing detailed hosting capacity studies. EPRI then worked with many utilities through the next few years and examined millions of PV deployment scenarios across dozens of distribution feeders.[7] The engineering time associated with the detailed study on a single feeder was on the order of weeks and required significant engineering and computation time to perform. The lessons learned from this broad industry effort led EPRI to develop a more streamlined and efficient method to determine feeder hosting capacity for PV and other forms of DER, thus allowing engineers to analyze feeders within a matter of minutes using automated methods that work with existing distribution planning tools. Due to automation, this method can be applied across an entire distribution system service territory. Working with a number of utilities, over 3000 distribution feeders have been analyzed to date using this methodology. EPRI is also working with vendors of commercial distribution planning tools for incorporation into their existing toolset.[8]

2 *Grid Impacts of Distributed Generation with Advanced Inverter Functions: Hosting Capacity of Large-Scale PV Using Smart Inverters.* EPRI, Palo Alto, CA: 2013. 3002001246.

3 Joint Utilities – Informal Feedback on Draft Report of the Market Design and Platform Technology Working Groups – July 31, 2015.

4 Joint Utilities – Informal Feedback on Draft Report of the Market Design and Platform Technology Working Groups – July 31, 2015.

5 *Impact of High-Penetration PV on Distribution System Performance: Example Cases and Analysis Approach.* EPRI, Palo Alto, CA: 2011. 1021982.

6 *Analysis of High-Penetration Solar PV Impacts for Distribution Planning: Stochastic and Time-Series Methods for Determining Feeder Hosting Capacity.* EPRI, Palo Alto, CA: 2012. 1026640.

7 *Distributed Photovoltaic Feeder Analysis: Preliminary Findings from Hosting Capacity Analysis of 18 Distribution Feeders.* EPRI, Palo Alto, CA: 2013. 3002001245.

8 *A New Method for Characterizing Distribution System Hosting Capacity for DER: A Streamlined Approach for PV.* EPRI, Palo Alto, CA: 2014. 3002003278.

The simulations and impacts observed through application of the Streamlined Approach on specific feeders can be beneficial in determining how DER can impact the distribution system as well as providing the utility criteria for the particular feeder.

Figure 1 – Broad Application of Utilities Participating in EPRI's Hosting Capacity Projects

The hosting capacity method that has been defined and implemented has been used by utilities across the country and internationally (Figure 1). Hosting capacity methods have served as a foundation and have been built upon in order to perform:

- *Mapping:* One requirement of the DSIP guidance is for DER developers and others to have greater visibility into what areas of the utility system may be better suited for accommodating DER. The ability to provide maps, similar to what has been done in California, has been a central discussion point as it relates to streamlining interconnection processing in NY. Having a defined hosting capacity method gives developers/others the ability to understand better/worse locations for DER on the system as an indicator of potential costs.

  There are some considerations concerning the presentation of this information that must be understood. Maps illustrate a point-in-time representation of the hosting capacity. Any new applications that have been received into the queue, approved or installed, may not be represented on a previously-developed map and could impact the hosting capacity. Similarly, any change in utility operation on particular portions of the feeder may also change the hosting capacity. Due to the operational requirements of the distribution system and rate of application acceptance, the information provided is not real-time. As such, utilities should clearly identify the date on which the analysis was performed and have an established refresh process.

- *Interconnections:* A key objective outlined in the Track 1 Order is an improved interconnection process and establishing greater consistency across the state. Hosting capacity information helps guide developers to apply for interconnection where detailed engineering studies are less likely to be required, improving efficiency of the process. As hosting capacity reaches advanced stages, incorporation into internal processes could help facilitate the interconnection process.

  There are similar challenges with interconnection as with mapping. Particularly important in this process is to ensure that DER applications in the queue and existing DER are considered. The frequency of updates to this data and of refreshing the hosting analysis should be done as applications are approved.

- *System Planning:* As the NY utilities develop an integrated planning roadmap, hosting capacity analysis is a critical piece in the analytical framework and methodologies needed. Hosting capacity can be enhanced with load and DER forecasts to evaluate different planning scenarios on a feeder-by-feeder basis. Under these scenarios, utilities can evaluate potential mitigating factors, infrastructure upgrades, as well as a system-wide cost benefit assessments of DER. In the future, this enhanced level of analysis will enable utilities to determine the ability of the distribution system to utilize services from DER, the impacts of DER on grid reconfiguration, operational strategies, as well as smart inverter technologies.

- *Locational Value:* The ability to determine variations in locational value of DER for grid operations is a key objective of REV. The data, tools, and processes utilized in hosting capacity analysis can also help identify locations where benefit from DER can be maximized without incurring additional costs.

Implementation Plan – A Roadmap to Successful DER Integration

While an effective hosting capacity method has been developed and is compatible with existing planning tools, implementation of hosting capacity analysis requires time and resources to obtain and maintain the required data necessary for application across an entire distribution service territory. Each utility may be starting from a different state of readiness with respect to the necessary data. Therefore, a phased approach is recommended (Figure 2) that outlines a roadmap to fully integrated DER value assessments. This implementation roadmap would provide increased effectiveness, complexity

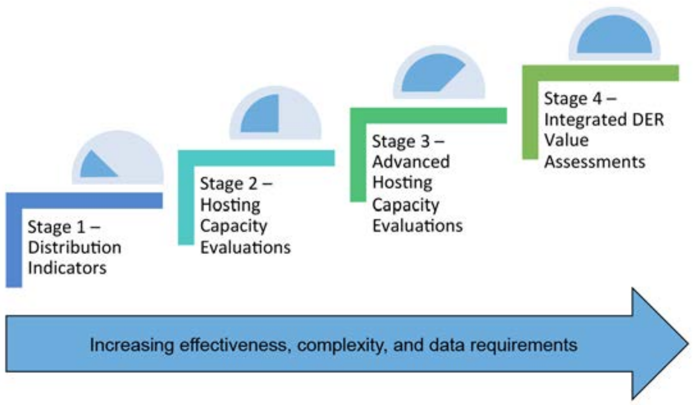


Figure 2 – Phased Implementation Plan

and data requirements over time. It should also be noted that initial efforts will focus on solar PV in New York State, but other DERs can be prioritized into the process. The four phases include:

- ***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.

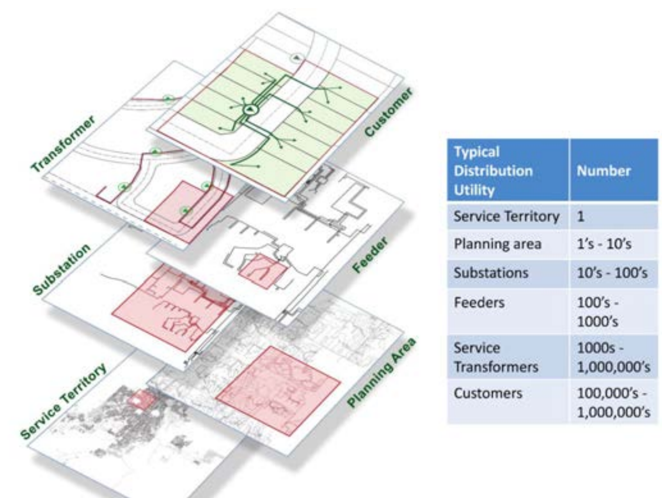
Utility Challenges

An entire distribution service territory often consists of multiple large planning areas where substations and feeders have widely varying design and control parameters. As portrayed in Figure 3, within each planning area, utilities may have tens to hundreds of substations that connect and deliver energy from the transmission system to serve hundreds to thousands of different distribution feeders. Each of these feeders are outfitted with equipment for providing both voltage control and system protection with custom settings to enable the utility to serve all customers in an efficient and reliable manner.

Within each service territory there may be thousands to millions of service transformers that deliver power from the medium voltage down to a more usable, low-voltage service level. These transformers distribute this service through multiple secondary systems that connect each service transformer to individual residences, commercial buildings, and industrial complexes.

Therefore, located at the very "edge" of the grid – the typical distribution utility can have from hundreds of thousands to millions of customers– all served by a vast and diverse number of feeders, substations, planning areas, and ultimately an entire distribution service territory. Planning for and integrating large amounts of DER located near the "edge" of the grid, as a result, can be quite a challenge

Throughout a service territory, utilities may or may not have distribution feeder models of the system. In some cases, distribution



Typical Distribution Utility	Number
Service Territory	1
Planning area	1's - 10's
Substations	10's - 100's
Feeders	100's - 1000's
Service Transformers	1000s - 1,000,000's
Customers	100,000's - 1,000,000's

Distribution diagrams courtesy of Salt River Project

Figure 3 – Characteristics of a Typical Distribution Service Territory

feeder models have not necessarily been required for traditional planning purposes where there is only one-way power flow. In such cases, it is not uncommon for utilities to rely on other means for planning that do not require detailed load flow and take advantage of experience combined with other data repositories such as GIS, asset documentation, and customer information systems.

In some cases only a limited number of distribution models are available. This typically occurs as a result of model development on an as-needed basis. Model development can be a time-consuming exercise. Utilities are now in the process of documenting the system in a more detailed fashion in light of the need to study DER interconnections.

With growing penetration of DER, more detailed models are required. While traditional rules of thumb have proven quite effective through the years, with the proliferation of DER, non-model based techniques of system analysis are no longer sufficient.

Through effective modeling of the distribution system a broad range of benefits can be realized from improved confidence in decision making to increased efficiency of DER impact assessments, visibility into the distribution system, and better utilization of existing assets. Rather than relying on rules-of-thumb, model-based analysis methods enable utilities to more accurately assess DER impacts on the distribution system. Models also allow utilities to better evaluate solutions to accommodate DER and perform value determinations. When models are readily available, utility engineers can also save considerable time assessing the impacts of DER. Variations in grid and DER conditions can be evaluated allowing distribution engineers to consider a wide range of possible conditions by which DER can interact with the grid.

Hosting capacity analysis is a prime example where distribution feeder models are required in order to effectively determine grid impacts due to DER.

Developing and maintaining distribution models that cover the breadth (large number of feeders) and depth (clarity and fidelity through each feeder) allows utilities to better reflect grid assets and performance across the entire distribution system and at the "edge" of the grid. Depending upon where a utility resides on the spectrum of distribution system modeling (breadth and depth), the time it takes can be rather significant (man-months to years) to develop distribution system models with the necessary "breadth" and "depth," and this model expansion will come at an added cost.

As the grid is modernized, available and valid data will become more prevalent but it still remains a difficult and time consuming process to incorporate into planning models. One aspect of this difficulty in modeling will be an abundance of data and knowing what is pertinent to the feeder model. Utilities are in the process of documenting the system in a more detailed fashion and developing accurate system models in the process.

Industry guidance regarding distribution system modeling requirements, gaps, and prioritizations are covered extensively in a recent EPRI report.[9]

9 *Integration of Hosting Capacity Analysis into Distribution Planning Tools.* EPRI, Palo Alto, CA: 2016. 3002005793.

Feeder Models and Associated Data

The vast majority of data needed to perform the hosting capacity analysis are based on "typical" distribution feeder models which distribution planners use today. Valid electrical feeder models will need to include feeder medium voltage lines and regulation equipment, customer loads modeled as they are in the field (location and phase), and substation equivalent impedance. Additional data that may or may not be readily available include non-peak solutions for the feeders as well as accurate models of regulation equipment (settings, etc).

In order to perform this type of analysis across an entire distribution system, a large amount of validated data is required. Since not all utilities have models of their entire distribution system, filling this data gap is a priority to utilizing a hosting capacity method. In NY, the main challenges are to populate the utility tools with data that has not been previously tracked, data that may be kept on paper, and current operating conditions that may have changed.

Another consideration is the type of system being modeled. In New York, there are both radial and network systems. Radial systems employ a hub and spoke configuration to transfer power from high-voltage lines to low voltage customer premises while network systems maybe designed to suffer two failures (hence the designation as designed to a N-2 contingency) without interrupting loads as depicted in Figure 4. The result is reliability up to two orders of magnitude better than can be achieved with radial systems. Due to the different designs of these systems, the modelling needs are different.

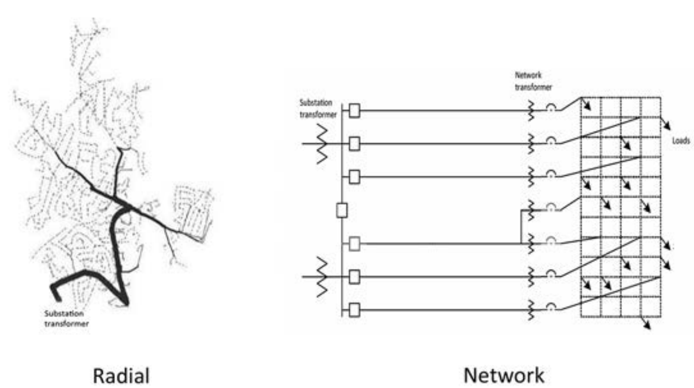


Figure 4 – A typical radial distribution feeder and network distribution system

Over time, distribution feeders change due to new customer interconnections, planned upgrades, maintenance, outage restoration, etc. Additionally, new DER is being added on an ongoing basis. Maintaining system models is an ongoing process. Capturing the existing "status" of DER in addition to the traditional distribution assets will be key to creating valid distribution models. This requires new processes be established to track this data and incorporate it into planning models. A refresh cycle must also be established that provides a timeline for regular updates to the existing approved and installed DER. One example of the importance of this step is illustrated in Figure 5 with the continued growth in PV penetration across the NY utilities. The number of systems, size of systems, and location of systems in the queue must be considered as part of any hosting capacity assessment.

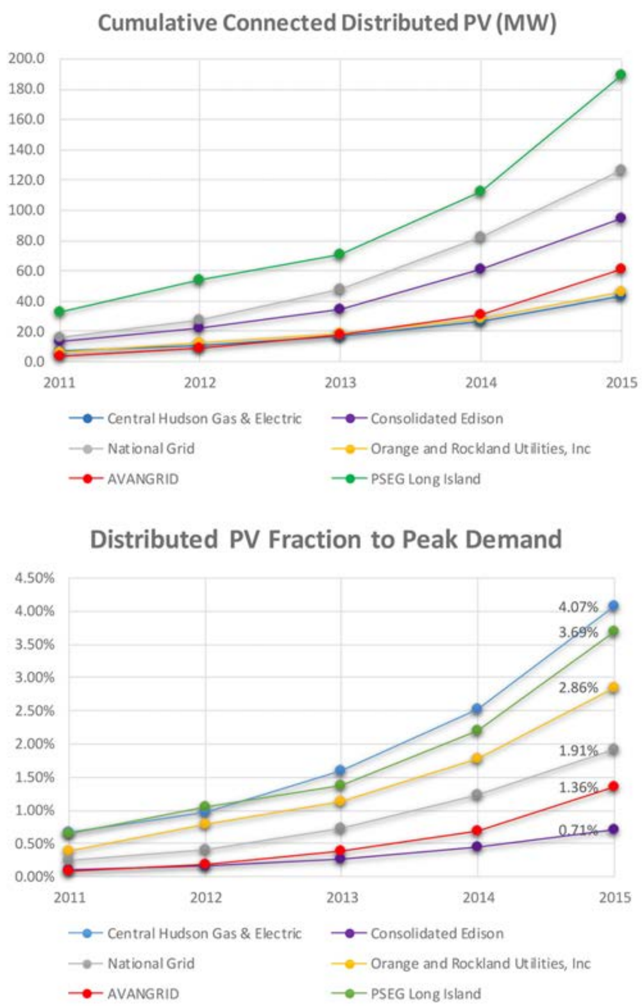


Figure 5 – Installed DER in NY State (Cumulative and Fraction of Peak Demand)

Hosting Capacity and Load Levels

With the introduction of DER, it is essential to consider non-peak load conditions as a distribution feeder hosting capacity changes throughout the day as load varies. With solar PV, for example, the most limiting constraint may occur during low-load conditions when the load is at or near minimum values. This can be quantified by examining DER impacts with feeders at minimum daytime load. However, utility planning methods have traditionally focused on optimizing system design for peak loading conditions. As a result, the toolsets and data sources will need to be adopted to consider non-peak solutions as well.

Distribution Planning Tools

Utilities currently use load flow analysis tools from several vendors for planning purposes. This core functionality needed to perform hosting capacity analysis (load flow and short-circuit analysis) is available within these tools. Rather than retooling, the hosting capacity method can be an add-on that can work within existing distribution planning tools. Using tools distribution planners are familiar with today, the method can also leverage the existing available data set to provide a much needed new functionality. Distribution planners are enabled to use this tool on an as-needed or regular basis to analyze individual feeders or the entire distribution system. This analysis can be done in conjunction with traditional distribution planning and grid modernization assessments. By utilizing this tool, the translation of models between platforms is alleviated and improves data management and upkeep in the process.

Integration of the hosting capacity method into the common planning tools is currently underway with the expectation that most planning tools will have the ability to perform hosting capacity analysis in the next 2–3 years. EPRI is releasing the methodology in 2016 such that it is compatible with the most commonly utilized planning tools and one vendor is adopting the methodology with the planned release of 2016 as well.

10 *Distribution Modeling Guidelines: Executive Summary, Recommendations for System and Asset Modeling for Distributed Energy Resource Assessments.* EPRI, Palo Alto, CA: 2016. 3002008894.

Phase 1 – Indicator Assessment

Recognizing that a true hosting capacity assessment requires distribution feeder models and not all utilities have the present tools and data to model their entire system, distribution indicators will be used to provide information to identify areas where DER can be accommodated on distribution feeders fed from each substation. Possible indicators would include such items as estimated level at which substation backfeed may occur, feeder voltage class, radial vs. networked, etc. Indicators will vary by utility based on the data that is available. Utilities are currently making "red zone" maps available based on these indicators to help provide visibility into locations where there may be a cost to connect.

These indicators will allow developers to consider the type of constraints that may exist in different areas they are considering installations. Locations along feeders where specific limitations may reside are not considered. Feeder-level hosting capacity, where actual calculations will be performed at the feeder-level will be considered in Phase 2.

Phase 2 – Hosting Capacity

In Phase 2, there is a need to ensure a certain level of standardization across the utilities in how they plan and develop hosting capacity requirements. As described in Figure 6, it is key that the hosting capacity method must provide enough granularity such that it can distinguish the important factors: location, feeder design and operation, and DER technology. The method must be scalable in order to analyze entire distribution systems but also repeatable to consider individual feeder modifications. Transparent and proven (i.e., validated) methods should also be used in order to gain confidence in the results obtained through hosting capacity analysis. Lastly, the method must be available such that readily accessible data and distribution planning tools can be utilized.

Granular	• Capture unique feeder-specific responses
Repeatable	• As distribution feeders change
Scalable	• System-wide assessment
Transparent	• Clear and open methods for analysis
Proven	• Validated techniques
Available	• Utilize readily available utility data and tools

Figure 6 – Fundamental Requirements for Hosting Capacity Method

Impact Factors that Contribute to Hosting Capacity

The main factors that drive the amount of DER that can be hosted are: 1) DER location, 2) DER technology, and 3) feeder design and operation. These factors act as inputs to the hosting capacity method and impact the output of the method.

DER Location – The hosting capacity for any feeder is not one single value but a range of values that depend upon a number of factors, mainly DER location. An effective method must consider all possible single, centralized locations along a feeder as well as the aggregate impacts of highly distributed DER. Also inherent to DER location is the consideration of phasing of the feeder at that location, i.e., connected to the three-phase main trunk or a single-phase lateral.

EPRI research has shown that significant levels of small DER spread throughout a single distribution feeder can have a considerable adverse impact on the distribution system performance. This is often neglected in many studies. Likewise, the impact of large centralized DER has been shown to have a significant but widely varying impact depending upon where it is located along the distribution system.[10]

The amount and location of existing DER that are already interconnected can greatly impact the hosting capacity of any given feeder and therefore must be taken into consideration as well.

DER Technology – The type of DER is another critical component since variable DER such as solar and wind have a vastly different distribution impact when compared to other forms of dispatchable DER such as energy storage. The differences primarily emanate from the ability, or lack thereof, to control the DER and when the DER is available. Care must be taken when considering specific technologies and how they interact with the grid as shown in Figure 7.

Variable generation such as solar and wind are similar in that they are for the most part non-dispatchable resources. Even though they are both an intermittent resource their impact to the system is dependent on the time of day they provide power. The impact of inverter-based technologies can change when advanced inverters that have additional grid support functionality are used. In some cases, this functionality can help reduce the impact of the intermittent resource by providing voltage support. However, advanced inverters may not always reduce impact. Identifying the appropriate settings for operation is critical.

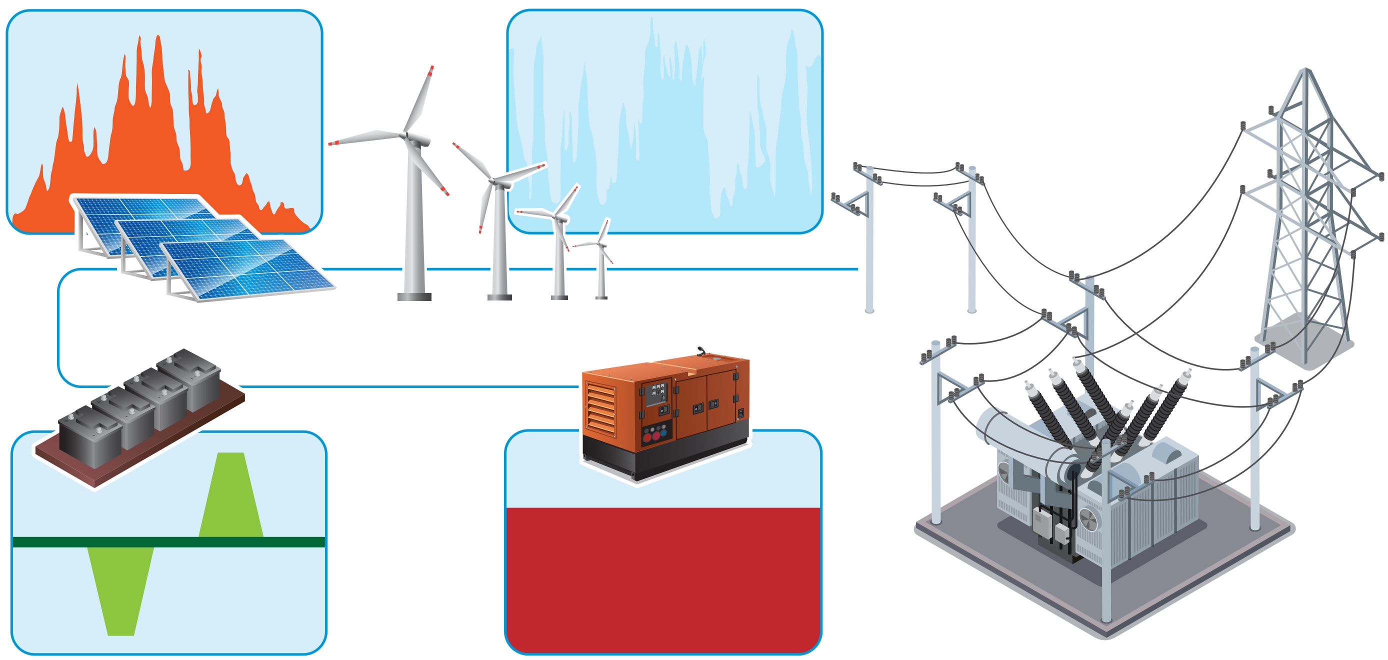


Figure 7 – The Technology

The Hosting Capacity method should be technology neutral and be able to consider any type of DER by inputting various load shapes. The specific technology determines how the analysis is setup to properly quantify the unique impacts of the particular resource. PV is the most prominent technology being installed currently and the near term focus of efforts in NY.

Feeder Design and Operation – Distribution feeder characteristics also determine how much DER can be hosted. Voltage class, feeder topology, and load location are just some of the factors that determine what level can be accommodated and where. Additionally, the operation of the system, like voltage control schemes and radial/network topology, can have an impact on the amount of DER that can be accommodated and where. As load varies over time, the amount of DER that can be integrated is impacted as well. For example, with solar PV the most limiting load level often occurs during midday when some feeders are at their minimum load levels.

The Hosting Capacity method must consider the actual feeder design and operation. These characteristics result in a dynamic interaction that must be examined in the power flow solution of the complete feeder model. Figure 8 summarizes hosting capacity results on 28 different feeders. Each has a unique hosting capacity based on the factors described above when looking at PV.

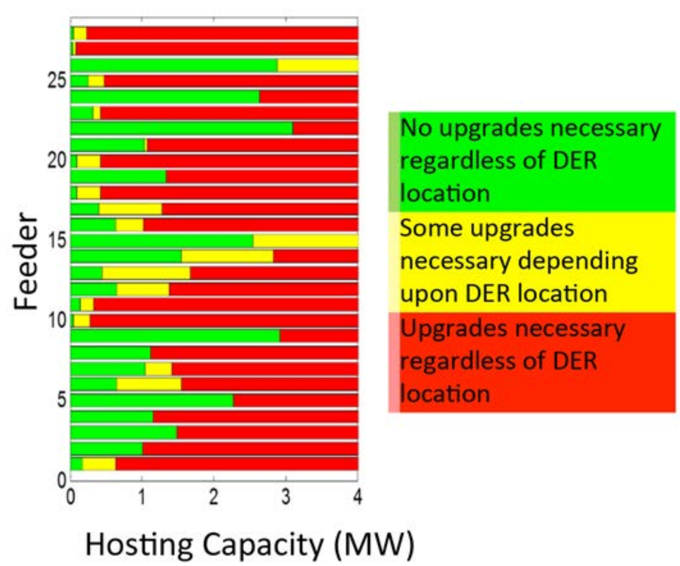


Figure 8 – The Feeder

Necessary Criteria for an Effective Method

Using these items as inputs, there are a range of different outputs that result from the analysis of each impact shown in Figure 9. Utilizing these outputs, the distribution utility can make a decision not only about interconnection impact, but also about how the operation of the feeder may be impacted in the future as penetrations increase.

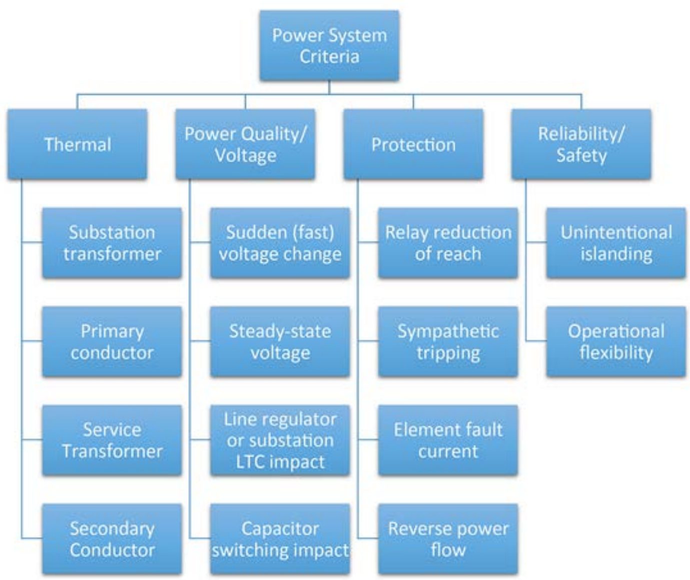


Figure 9 – Power System Criteria for Determining Hosting Capacity

A summary of the various criteria that can impact hosting capacity includes:

Voltage: The hosting capacity on a particular feeder will be dependent on the planning criteria used for the calculation. Operating conditions such as conservation voltage reduction (CVR) could reduce the hosting capacity. These feeders may have additional headroom before reaching the ANSI voltage limits, but the operating strategy may dictate the voltages be kept at lower levels. In addition to overvoltage, the hosting capacity can also be limited by how much the DER changes the voltage. Voltage changes (deviations) may not have a strict ANSI threshold; however, they could cause voltages to suddenly swing above/below operating limits. In addition, this can cause additional control (regulator/capacitor) operations or tripping of sensitive equipment and impact the power quality for existing distribution customers.

Thermal Overload: Distribution assets such as lines and transformers have certain capacity ratings that should not be exceeded or the asset may violate a safety standard (e.g., overhead line clearance), undergo shortened life and/or experience an unexpected failure. While DER can in many cases reduce the thermal loading on lines and transformers, increased levels of generation that cause backfeed (reverse power flow) can reach and/or exceed the thermal limits of assets. This type of condition can occur if the DER produces energy during low-load periods or if the DER is located remotely from the local feeder load.

Protection: As mentioned previously, system protection is another critical aspect that can determine hosting capacity. Utilities must retain the ability to detect and isolate faults as well as provide service restoration to all customers in a timely fashion. The addition of DER can affect the utility's ability to perform these functions, and therefore must be considered when determining hosting capacity as well. Common impacts from integration of DER s include: nuisance fuse blowing, misoperation of equipment, increased short-circuit current, unintentional islanding, and sympathetic tripping of the feeder.

While the fault contribution from inverter-based generation can be short in duration due to fast acting controls, other forms of machine-based DER that utilize synchronous or induction machines can yield much higher fault currents. The type of DER and its associated fault current response must be appropriately quantified and considered. Standard fault current analysis can be used to compare the fault response with and without the DERs to evaluate the potential impact on system protection.

Reliability/Safety: Anti-islanding remains a concern even with the presence of inverter destabilization controls that are constantly searching for the islanded condition. An issue with these destabilization controls is that conflicting objectives between various brands of inverters can potentially delay or miss the detection of an island before automatic feeder control devices try to reclose on the island. Using a direct transfer trip or ensuring there is an active and reactive power mismatch are the most definite ways to prevent an unintentional island but would either add significant cost or could severely limit the amount of DER on the feeder.

Additionally, operational flexibility must be considered to accurately capture the impact of DER. Distribution planners regularly reconfigure the system due to load growth changes, system maintenance, and system contingencies. As the distribution operator reconfigures the distribution system, the hosting capacity of the feeder(s) can vary considerable.[11] These conditions must be included to capture the hosting capacity for each of the scenarios. If not considered, reconfiguration capability (operational flexibility) could be limited.

Applying an Analytical Framework

Given the requirements of the hosting capacity method defined above as inputs and outputs, the analytical approach required to perform this type of analysis can be identified. An illustrative example of how hosting capacity calculations are performed is shown in Figure 10.

Utilizing the hosting capacity method, the distribution feeder model can be analyzed with a series of loadflow and fault studies. The loadflow study provides voltages, element loading, load allocation, and connectivity of the model, while the fault study provides impedance/resistance/reactance data. A baseline feeder performance is established based upon feeder voltages, thermal loadings, and short-circuit response. This should include any existing DER on the feeder as well as in the queue.

Once the baseline feeder response is determined, locations along the feeder are examined. At each electrical "node"[12] in the model, the DER capacity at that location is increased. The impact of that location and capacity of DER is then examined by comparing feeder response to the power system criteria (Figure 9). The DER capacity is then increased until one of the several power system criteria is violated or some other system constraint is found.

The DER assessments are also then performed by applying various DER "scenarios."

These scenarios make up the basis of the DER impact analysis. Each scenario results in a node-specific hosting capacity for DER at a specific location.

An effective hosting capacity method should consider a wide range of scenarios are considered in the overall analysis, including both centralized DER (e.g., ground-mounted solar PV) as well as highly-

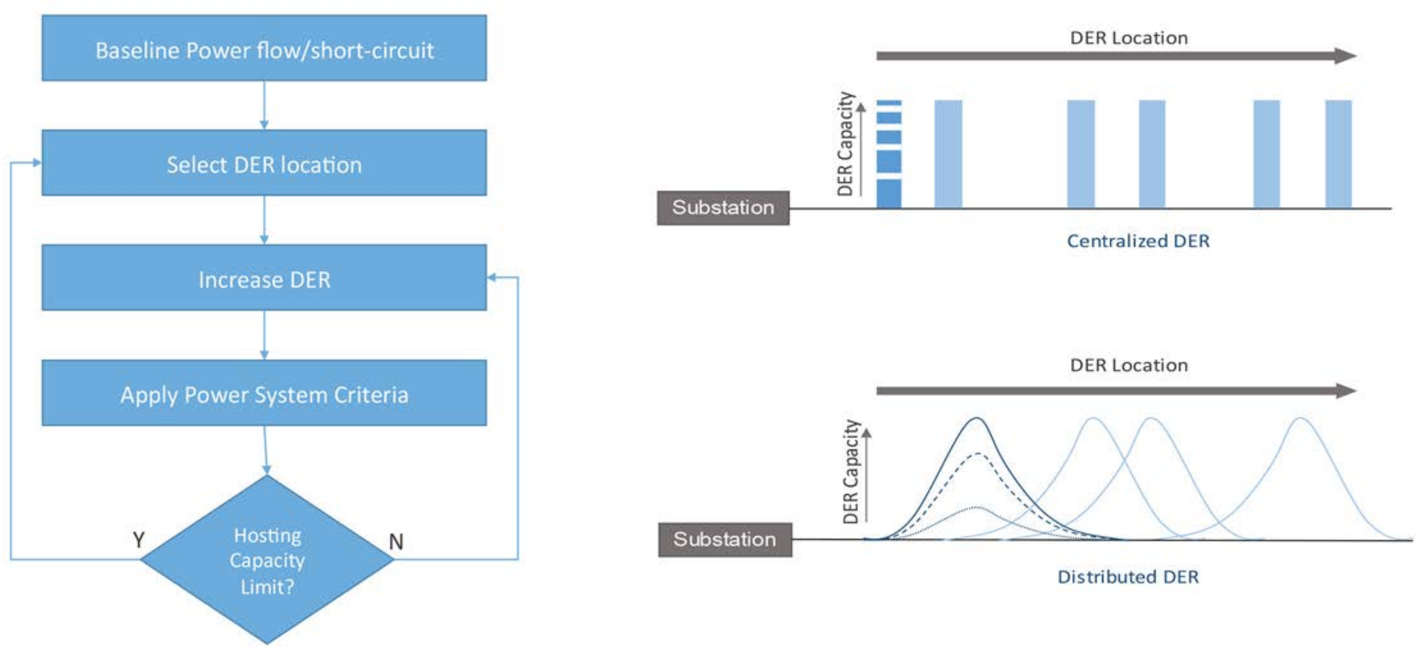


Figure 10 – Example of Streamlined Hosting Capacity Analysis Method

11 *Distributed Photovoltaic Feeder Analysis: Preliminary Findings from Hosting Capacity Analysis of 18 Distribution Feeders.* EPRI, Palo Alto, CA: 2013. 3002001245.

12 Feeder Reconfiguration under High-Penetration PV Conditions. EPRI, 13 The node is a point on the feeder between two line sections. Depending on the model, this may resemble locations in the field where the feeder branches, locations of power poles, or impedance sections within the model.

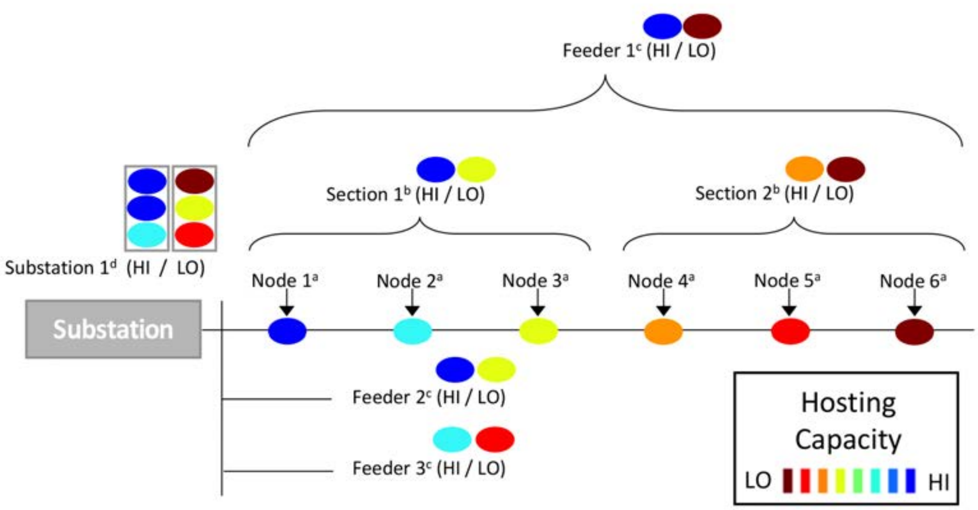
distributed (e.g., customer-based rooftop) systems. For Centralized DER, a scenario's hosting capacity is based on DER at that location and does not consider DER at any other location on the feeder. For Distributed DER, a scenario's hosting capacity is depicted at the node where the DER is "centered" on the feeder and only considers DER at other locations based on the applied DER distribution. For both Centralized and Distributed DER, there are as many scenarios simulated as there are nodes on the feeder. Each scenario results in a hosting capacity value and therefore there are two hosting capacities at each node – one based on Distributed DER and another based on Centralized DER. As such, a single feeder can have thousands of possible hosting capacity values.

When completed, thousands of scenarios are examined on all potential locations, or "nodes", on the distribution feeder.

A simple feeder example in Figure 11 illustrates hosting capacity at the node, section, feeder, and substation. In this example, one distribution impact is considered for centralized DER. The six nodes are each independently examined for the amount of DER that can be accommodated at that location. The colors indicate the resulting hosting capacity. The section hosting capacity is then the range in node hosting capacity on that section. Again, the section's HI/LO range is based on DER only at a single node along that section. Any DER on other sections will change the resulting hosting capacity. Similarly, the feeder hosting capacity is the range in node hosting capacity on the entire feeder. It is important to note that the feeder and section hosting capacity IS NOT the summation of individual node hosting capacities.

Each feeder can then be analyzed independently to determine its feeder hosting capacities. Aggregating further to the substation, one could determine the substation's overall ability to accommodate DER. At the substation, the hosting capacity may be less than the summation of individual feeder hosting capacities. In some cases, there may exist an upstream constraint at either the substation and/or transmission level that may constrain the aggregate feeder-level hosting capacity for feeders fed from a specific substation. This is addressed in Phase 3 described later.

One of the most effective methods to convey results is through visualization. Maps illustrating hosting capacity will be created using the load flow models in the planning tools.. Reference Figure 12 as an illustration of hosting capacity limits for centralized DER based on three different distribution criteria impacts. The hosting capacity is shown at the node, thus the color at the node depicts the amount of DER that could be accommodated at that location and nowhere else on the feeder. Each distribution criterion can have a significantly different hosting capacity result.



[a] Node Hosting Capacity is dependent on DER at other nodes. That shown above is based on DER only at the specified Node.
[b] Section Hosting Capacity is the HI/LO range in Node Hosting Capacity on that section.
[c] Feeder Hosting Capacity is the HI/LO range in Node Hosting Capacity on the feeder.
[d] Substation Hosting Capacity is the HI/LO range representing the summation of HI and LO Feeder Hosting Capacities.

Figure 11 – Example of Node, Feeder, Section, and Substation Hosting Capacity for Centralized DER and one Distribution Impact

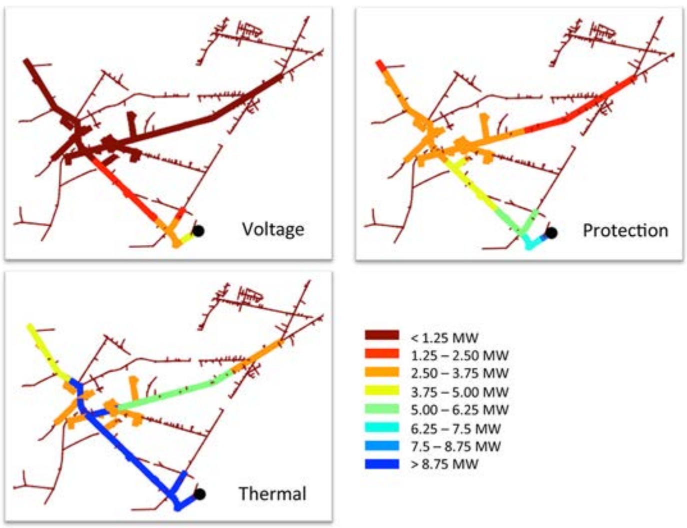


Figure 12 – Node Hosting Capacity for Three Distribution Impacts

The node hosting capacity is ultimately the lowest value at which a planning threshold violation is calculated based on all distribution criteria. Figure 13-C shows an example where the node-level hosting capacity reflects all issues chosen in the analysis for Centralized DER. The feeder hosting capacity then depicts the lowest hosting capacity from the node-based results. The entire feeder is shaded the same color to portray that DER penetration above that level may be problematic at some locations on the feeder (Figure 13-B). There are many locations shown in the node-based results (Figure 13-C) that can accommodate higher levels of DER, but any penetration less should have no adverse impact.

Feeders served from the same substation transformer can have many different hosting capacities as shown in the feeder hosting capacity results (Figure 13-B). Out of seven feeders served from the substation transformer, one falls into the highest hosting capacity range while two fall into the lowest. In this case, the substation hosting capacity is the summation of all the individual feeder hosting capacities, as there were no substation constraints that limited the aggregate DER into the substation. All feeders served from the substation transformer are shaded the same color to represent the substations ability to accommodate DER (Figure 13-A). Again, the value shown in the example depicts the worst-case scenario that occurs on all feeders served. Alternatively, the best-case scenario can be portrayed for feeder and substation hosting capacity.

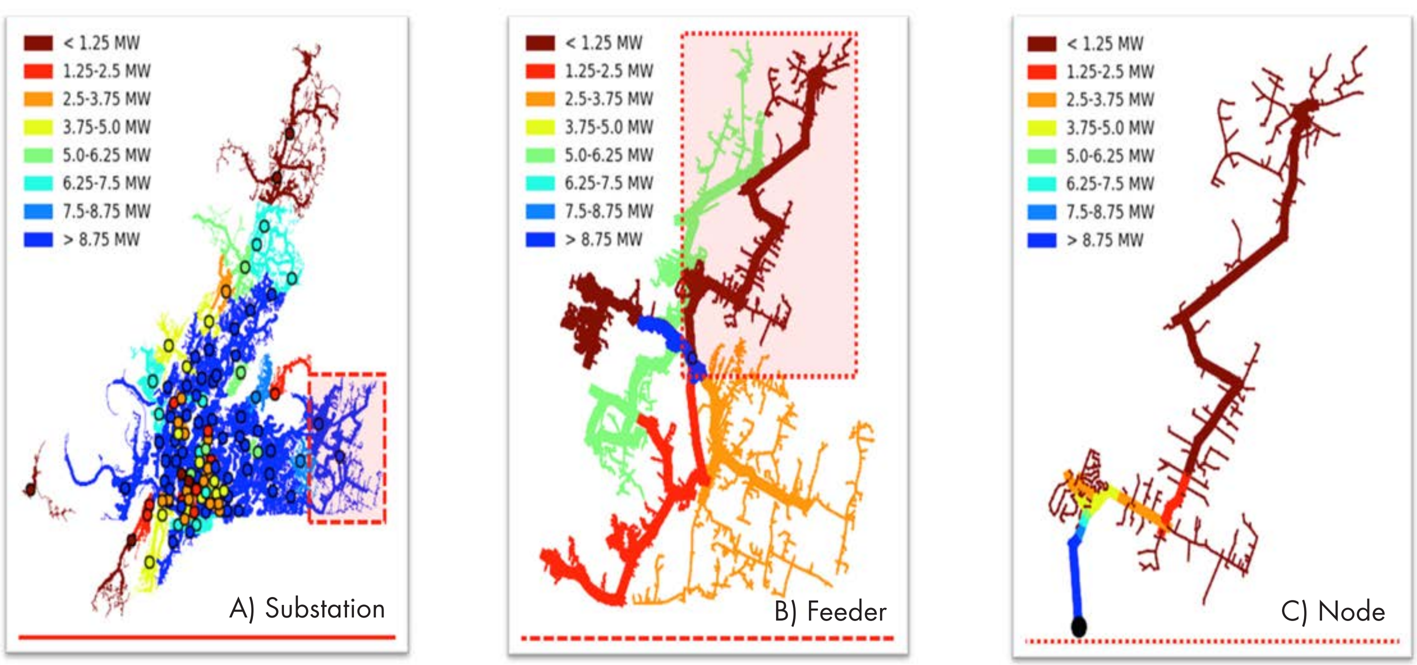


Figure 13 – Substation (A), Feeder (B), and Node (C) Level Hosting Capacity Example Illustration for Centralized DER

Phase 3 – Advanced Hosting Capacity Evaluations

The distribution system is dynamic and regularly reconfigured due to load growth changes over time, system maintenance, and system contingencies (unplanned outages). In order to maintain reliability for all customers, it is paramount that the distribution system remains flexible in order to reconfigure as needed.

DER interconnected to one feeder at a specific location may have no adverse impact to the grid or other customers; however, if the need arises for that portion of the feeder to be served from another feeder, voltage and/or protection issues due to the DER could prevent the operator from performing the switch. As a result, there is the need to consider what is referred to as operational flexibility in a hosting capacity analysis as shown in Figure 14. In some cases, operational flexibility could limit the amount of DER that can be connected to the distribution system at a specific location. This type of analysis requires hosting capacity to be determined for multiple feeder conditions, and presently these switching operations are not modeled/analyzed extensively throughout a distribution system. As the distribution system changes over time to meet new and changing loads, this requires frequent model updates and reanalysis.

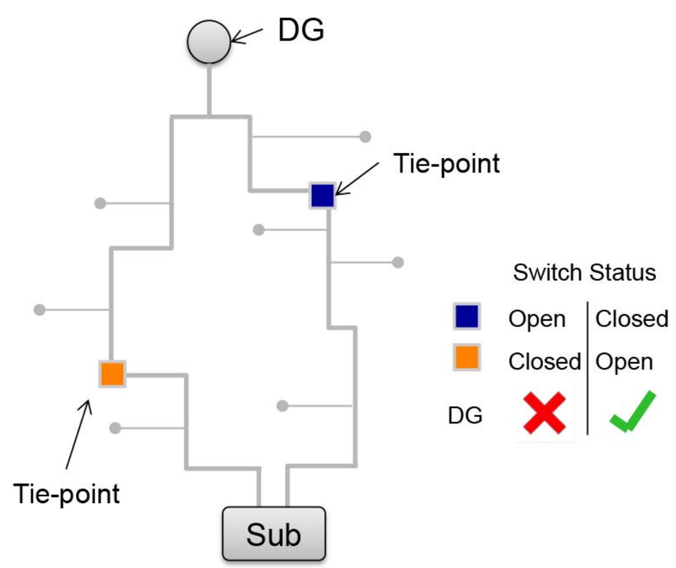


Figure 14 – Need for Consideration of Distribution Operational Flexibility

In addition, as higher penetration levels of DER are realized on the distribution system, the distribution feeder is not the only consideration that must be made. Additional analysis that captures the substation-level impact of aggregate DER across multiple feeders into the substation ensures proper operation of all feeders in the area. In some cases, a substation-level backfeed or sub-transmission/transmission constraint may exist that needs to be taken into account as well.

Including items such as this require additional modeling and coordination with substation/transmission engineering. As the overall grid becomes more integrated, such considerations are paramount.

Phase 4 – Fully Integrated Value and Hosting Evaluations

The capabilities in Phase 4 extend beyond the formal definition of hosting capacity analysis. Phase 4 builds on the foundation of hosting capacity to perform fully integrated value assessments. REV emphasizes the increased integration of distributed energy resources as part of strategies to make the power system more flexible, interconnected, and resilient. Central to this is the ability for utilities to evaluate the locational value of DER on the grid. Just as hosting capacity analysis identifies locations where minimal impact will occur for DER capacities up to given amounts, it will also be able to help identify locations where benefits from DER can be maximized without incurring new costs.

In this final phase, the hosting capacity method enables value assessments that consider the potential to utilize DER to defer or avoid planned capital upgrades, improve system efficiency, and enhance power quality, reliability, and resiliency. However, in this stage an increased level of detail and more comprehensive data set is needed. The data requirements beyond Phases 1-3 include more details on distribution constraints, asset performance, and DER performance metrics. This data enables better analysis of the impacts and ability to fully integrate DER, as well as how to increase hosting capacity through technologies such as energy storage and smart inverters

Advanced hosting capacity will allow benefits and costs to be characterized at both the local level and the aggregated level. The assessment provides insight into impacts and takes into consideration the dependency on specific characteristics of the distribution system (design and equipment), location and type of DER, characteristics of existing loads, and time variation of loads and distributed energy resources. The result is a comprehensive hosting capacity and DER value assessment considering both distribution and transmission.

Summary and Key Takeaways

Effective and efficient means for evaluating the impact of DER is a necessary aspect of distribution planning today. Instead of requiring specialized analysis and skillsets, methods being incorporated into existing distribution planning tool can be used to improve many aspects of DER integration.

This paper defines an effective hosting capacity analysis method for New York State. In the future it will be foundational to considering DER on both radial and network systems, planning distribution systems, interconnection processing and targeting new operational measures to handle higher penetration of DER.

Existing planning tools used by utilities today can be modified and improved to include hosting capacity analysis. In order for this to be available, vendors and utilities must work together to adopt this method as part of their existing solution. With this implementation, distribution utilities will apply these methods using existing tools, available and needed data, and operational strategies.

As the implementation phases unfold, there is an increased need for a more complete and validated data set. Distribution utilities must begin building a more complete data set. Table 1 provides an overview of the considerations in each phase, the data requirements, as well as the outcome and outputs of the analysis method. Implementing these new methods will require time and resources to obtain the data needed, validate the output, and educate developers and the public on how it can be used.

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Table 1 – Implementation Plan - Phases, Data Requirements, Outcome, and Outputs

Phase	Consideration	Data Requirements	Outcome	Possible Outputs
1 Indicator Assessment	Possible indicators such as – Estimated Minimum load levels – Voltage class – Substations over a MW threshold typically indicative of substation backfeed	– Currently available data – Understanding the interconnection queue	– Provides an indication where certain substations/feeders may have high costs associated with interconnecting DER	– Maps indicating where interconnection costs may be higher
2 Hosting Capacity Evaluations – Radial Systems	– All feeders modeled in service territory with periodic updates for existing DER and queued DER mapped into planning models	– All feeders modeled in service territory with periodic updates for existing DER & queued DER mapped into planning models	– Feeder-level hosting capacity determinations	– Maps indicating feeder-level hosting capacity
3 Advanced Hosting Capacity Evaluations	– Substation and transmission assessments and mapping of distribution-level impacts to substation and transmission – Normal and reconfigured system models	– Substation and transmission assessments and mapping of distribution-level impacts to substation and transmission – Normal and reconfigured system models	– Refined hosting capacity evaluations that take into account additional criteria	– Maps indicating node/section-level hosting capacity
4 Fully Integrated DER Value Assessments	– Increased level of detail regarding distribution constraints, asset performance, and DER performance metrics – Models of emerging technologies, such as energy storage	– Increased level of detail regarding distribution constraints, asset performance, and DER performance metrics – Models of emerging technologies, such as energy storage	– Comprehensive hosting capacity and DER value assessments considering both distribution and transmission – Ability to increase hosting capacity	– Maps indicating hosting capacity along with areas where DER can bring additional value to the grid

EPRI Resources

Jeff Smith, *Program Manager*
865.218.8069, jsmith@epri.com

Lindsey Rogers, *Technical Leader*
865.218.8092, lirogers@epri.com

Matt Rylander, *Technical Leader*
512.351.9938, mrylander@epri.com

Integration of Distributed Energy Resources

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

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Appendix F Central Hudson AMI Benefit Cost Study

Benefit Cost Study for Advanced Metering Infrastructure

June 2016

Prepared for
Central Hudson Gas & Electric

Prepared by
Josh Bode, M.P.P., Vice President
Alana Lemarchand, Senior Consultant
Shannon Hees, Project Analyst
Nexant, Inc.

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Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
BCA	Benefit-Cost Analysis
Commission	New York State Department of Public Service Commission
DA	Distribution Automation
DSIP	Distributed System Implementation Plan
MW	Megawatt(s)
T&D	Transmission and Distribution
VVO	Volt/VAR Optimization

1 Executive Summary

Central Hudson Gas & Electric (hereafter referred to as Central Hudson) has investigated the benefits and costs of implementing an Advanced Metering Infrastructure (AMI), pursuant to the *Order Adopting Distributed System Implementation Plan Guidance* and in accordance with the *Order Establishing the Benefit Cost Analysis Framework.* [1]. AMI can support REV goals by empowering customers, through new tools and information, to effectively manage and reduce usage. However, analysis from three perspectives, societal, utility, and ratepayer, and of two deployment scenarios—full and partial deployment, have shown that AMI would be cost-ineffective for customers under all perspectives and scenarios investigated. Therefore, Central Hudson will not be proposing implementation of AMI. As part of the study, we separately analyzed benefits and costs related to operations and to AMI enabled rates and programs. This distinction was made because implementation of AMI enabled rates and programs would require regulatory change and/or modifications to current law.

While AMI has the potential to offer customers, market participants, and utilities increased visibility and resolution with regard to energy usage and flow, this increased visibility comes at a cost. The cost to integrate AMI systems with new and existing applications and devices to improve analytical capabilities and customer tools would be cost prohibitive, given the characteristics of Central Hudson's territory and operations. Moreover, many of the benefits that could be accorded to AMI will already be captured through Central Hudson's implementation of electronic meters and Distribution Automation (DA).

1.1 Results

This analysis assessed two scenarios for deployment of AMI in the Central Hudson territory: full deployment and targeted partial deployment. A full AMI deployment would mean installing AMI to support the roughly 285,000 electric and 78,000 gas meters practically reachable by remote communications in the Central Hudson territory. This deployment would begin in 2020, be completed over 5 years, and be supported by a wireless mesh communication system.

A partial AMI deployment would mean installing AMI to support the roughly 12,000 demand electric meters (essentially all demand customers not currently subject to the provisions of hourly pricing) in Central Hudson's territory, which accounts for approximately 4% of meters, 12% of system demand, and 27% of total energy usage and consumption. This deployment would begin in 2020,be completed over 2 years, and would be supported by cellular communications, as this communications platform is more cost efficient for smaller deployments. Deployment would largely affect the mid-size commercial customers with measured demand between below 300 kW and would not include the approximately three hundred large commercial and industrial customers that are currently interval metered.

For both scenarios, deployment could not be extended to all meters, because a small portion of meters are located in remote terrain, often deep into the Catskill Mountains, and could not be practically accessed via wireless mesh or cellular communications.

[1] CASE 14-M-0101 - Order Establishing the Benefit Cost Analysis Framework, Issued and Effective January 21, 2016; Order Adopting Distributed System Implementation Plan Guidance, Issued and Effective April 20, 2016.

Benefits and costs for both deployment scenarios were evaluated from the three perspectives specified in the BCA framework order:

- Societal Cost Test (SCT): Do the benefits, including externalities, exceed the costs?
- Utility Cost Test (UCT): Is the investment or program self-funding or are additional funds needed?
- Ratepayer Impact Measure (RIM): How does the investment affect customer rates (both delivery and supply)?

Operational benefits include operational utility cost savings[2] and customer fairness benefits[3]. Costs related to deployment of AMI include meter equipment and installation, network equipment and installation (for a wireless mesh deployment), meter data management system and other IT costs, and project management costs.

1.1.1 Full deployment BCA results

Table 1-1 summarizes the net benefits[4] and the benefit cost ratio[5] for the operational business case from the three perspectives relevant to the BCA order. Note that the operational business case includes operational and customer fairness benefits but excludes AMI enabled rates and programs, because such programs would require regulatory change and/or modifications to current law.

The societal cost test for the operational business case shows total benefits of $57.7 million and total costs of $116.5 million, resulting in a net benefits gap of about $58.8 million and a benefit cost ratio of 0.50. Either incremental benefits or cost savings of about $60 million would be needed to close this gap and make full AMI deployment cost effective. The utility cost test gave similar results, with a benefit cost ratio of 0.43.

The ratepayer impact test also includes customer fairness benefits from reduced energy theft and improved meter accuracy that result in a more equitable allocation of costs across customers. Technically, this is a transfer from typical customers to customers who were not paying an appropriate amount for their electricity use (due to theft of slow or failed meters). This transfer does not change the amount of revenue collected through rates, but it leads to a lower cost per kWh for over 98% of customers. From a ratepayer perspective, benefits are $63.9 million and the costs are $106.4 million, resulting in a net benefit gap of $42.6 million and a benefit cost ratio of 0.60, indicating that AMI deployment under this scenario and perspective is still cost-ineffective.

Table 1-2 summarizes the net benefits and the benefit cost ratio for the AMI enabled rates and programs incremental to and exclusive of operational benefits and costs.

[2] avoided meter replacements, avoided meter reading costs, avoided outage management costs and avoided field operations costs

[3] reduced energy theft and improved meter accuracy

[4] total benefits minus total costs

[5] total benefits divided by total costs

Table 1-3 summarizes the net benefits and the benefit cost ratio for the operational business case plus AMI enabled rates and programs.

As demonstrated by these summaries, full AMI deployment would not be cost effective for Central Hudson customers from any of the three benefit-cost perspectives, regardless of the inclusion of AMI enabled rates and programs.

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

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	$106,436.9	$106,436.9
Net Benefits	($58,796.6)	($60,815.2)	($42,557.5)
B/C Ratio	0.50	0.43	0.60

Table 1-2: Benefit and Cost Summary, Full Deployment, AMI Enabled Rates and Programs (Incremental to Operational Business Case)

AMI Enabled Program	Metric	Societal Test	Utility Costs Tests	Rate Payer Impact
Opt-in Time Varying Pricing	Benefits	$19,403.1	$16,025.8	$16,025.8
	Costs	$21,475.8	$18,540.7	$18,546.9
	Net Benefits	($2,072.7)	($2,514.9)	($2,521.1)
	B/C Ratio	0.90	0.86	0.86
Pre-payment program	Benefits	$26,537.6	$18,191.0	$18,191.0
	Costs	$10,622.5	$8,792.6	$23,075.1
	Net Benefits	$15,915.1	$9,398.4	($4,884.1)
	B/C Ratio	2.50	2.07	0.79

Table 1-3: Benefit and Cost Summary, Full Deployment, Operational Business Case + AMI Enabled Rates and Programs

Benefit Cost Analysis (20 year NPV, 2016 $000)	Societal Test	Utility Tests	Rate Payer Impact
Benefits	$103,594.6	$79,838.6	$98,096.3
Costs	$148,548.9	$133,770.3	$148,059.0
Net Benefits	($44,954.2)	($53,931.7)	($49,962.7)
B/C Ratio	0.70	0.60	0.66

1.1.2 Partial deployment BCA results

Table 1-4 summarizes the net benefits[6] and the benefit cost ratio[7] for the operational business case from the three perspectives listed in the BCA order. Note that the operational business case includes operational and customer fairness benefits but excludes AMI enabled rates and programs, because such programs would require regulatory change and/or changes to current law.

The societal cost test for the operational business case shows total benefits of $2.0 million and total costs of $28.2 million, resulting in net benefits gap of about $26.3 million and a benefit cost ratio of 0.07. Either incremental benefits or cost savings of about $26 million would be needed to close this gap and make partial AMI deployment cost effective. The utility cost test gave similar results, with a benefit cost ratio of 0.06.

The ratepayer impact test also includes customer fairness benefits from reduced energy theft that result in a more equitable allocation of costs across customers. Unlike the full deployment scenario, improved meter accuracy is not included because this benefit is already realized by electronic demand meters. Therefore, the ratepayer benefits are $5.3 million and the costs are $25.2 million, but there remains a net benefit gap of $19.9 million and a benefit cost ratio of 0.21, indicative that AMI deployment under this scenario and perspective is still cost-ineffective.

Table 1-5 summarizes the net benefits and the benefit cost ratio for the AMI enabled rates and programs incremental to and exclusive of operational benefits and costs. A pre-payment program does not apply to demand metered business customers and, hence, only the impacts of time varying pricing are included.

Table 1-6 summarizes the net benefits and the benefit cost ratio for the operational business case plus AMI enabled rates and programs[8].

As demonstrated by these summaries, partial AMI deployment would not be cost effective for Central Hudson customers from any of the three benefit-cost perspectives and regardless of the inclusion of AMI enabled rates and programs.

Table 1-4: Benefit and Cost Summary, Partial Deployment, Operational Business Case

Benefit Cost Analysis (20 year NPV, 2016 $000)	Societal Test	Utility 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

[6] total benefits minus total costs

[7] total benefits divided by total costs

[8] For the full deployment scenario, both prepayment program and time-varying rates were included. For the partial deployment scenario, only time varying rates were included, because prepayment programs typically only apply to residential customers

Table 1-5: Benefit and Cost Summary, Partial Deployment, AMI Enabled Rates (Incremental to Operational Business Case)

Benefit Cost Analysis (000s, 2016$)	Societal Test	Utility Costs Tests	Rate Payer Impact
Benefits	$10,947.0	$9,315.4	$9,315.4
Costs	$7,401.9	$6,308.7	$6,314.8
Net Benefits	$3,545.0	$3,006.6	$3,000.6
B/C Ratio	1.48	1.48	1.48

Table 1-6: Benefit and Cost Summary, Partial Deployment, Operational Business Case + AMI Enabled Rates and Programs

Benefit Cost Analysis (20 year NPV, 2016 $000)	Societal Test	Utility Tests	Rate Payer Impact
Benefits	$12,903.2	$10,809.5	$14,599.5
Costs	$35,645.1	$31,460.4	$31,466.5
Net Benefits	($22,741.9)	($20,651.0)	($16,866.9)
B/C Ratio	0.36	0.34	0.46

1.2 Why AMI is not cost effective for Central Hudson

A potential deployment of AMI within Central Hudson territory was assessed from various perspectives (societal, utility, ratepayer) and scenarios (full and partial). The analysis approach taken was the same used by Nexant for various other AMI business cases, many of which resulted in positive business cases that ultimately lead to AMI deployments. However, in the case of Central Hudson, AMI is not cost-effective.

As described in Section 2.3 on the current Central Hudson landscape, the substantial gap between operational AMI benefits and costs is explained by the following Central Hudson characteristics:

- The approved deployment of distribution automation will capture a substantial portion of benefits in the form of Volt/Var Optimization (VVO) and outage location identification, limiting incremental benefits from AMI.[9]
- 50% of customer meters are electronic with Advanced Meter Reading (AMR). By 2020, when AMI deployment would begin, about 60% of customer meters will have electronic meters with AMR. 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 lower than those of utilities which read meters on a monthly basis.

[9] Distribution automation also enables a substantial share of avoided customer outage cost benefits which were hence not quantified.

- 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.

Partial AMI deployment to all demand meters practically reachable by remote communications is also not cost-effective, by an even greater margin than with full deployment. In addition to the characteristics of the current Central Hudson landscape which 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)

2 Introduction

Central Hudson Gas & Electric (hereafter referred to as Central Hudson) has investigated the benefits and costs of implementing an Advanced Metering Infrastructure (AMI) pursuant to the *Order Adopting Distributed System Implementation Plan Guidance* and in accordance with the *Order Establishing the Benefit Cost Analysis Framework*[10]. AMI was considered as a possible tool for supporting REV goals to empower customers through new tools and information and to effectively manage and reduce usage. However, analysis from three perspectives, societal, utility, and ratepayer, and of two deployment scenarios—full and partial deployment, have shown that AMI would be cost-ineffective under all perspectives and scenarios investigated. Therefore, Central Hudson will not be proposing implementation of AMI.

While AMI has the potential to offer customers, market participants, and utilities increased visibility and resolution with regard to energy usage and flow, this increased visibility comes at substantial cost. The cost to integrate AMI systems with new and existing applications and devices to improve analytical capabilities and customer tools would be cost prohibitive. Moreover, many of the benefits that could be accorded to AMI will already be captured through Central Hudson's implementation of electronic meters and Distribution Automation (DA).[11]

2.1 U.S. Smart Meter Overview

According to the Energy Information Agency[12], by 2014 some form of electronic metering[13] had been deployed to 73% of U.S. utility customers but AMI had only been deployed to slightly over half of these customers.

Figure 2-1 shows the AMI deployment levels across states, highlighting that AMI deployment has surpassed 80% in five states, has surpassed 60% in another 6, and remains below 20% in most of the remaining states.

Figure 2-2, which shows deployment levels for AMR, demonstrates that there is again wide variation in deployment rates of AMR versus AMI. Though electronic metering technologies have been available for over 20 years, there are still many regions, for various economic or policy reasons, where AMI has not been deployed to a substantial portion of utility customers. At the same time, AMR is a substantial portion of electronic meter deployment in many of these same states throughout the north, midwest, southeast, and northeast.

[10] CASE 14-M-0101 - Order Establishing the Benefit Cost Analysis Framework, Issued and Effective January 21, 2016; Order Adopting Distributed System Implementation Plan Guidance, Issued and Effective April 20, 2016.

[11] Including avoided customer outage cost benefits which were hence not quantified.

[12] Source: https://www.eia.gov/electricity/data/eia861/

[13] Includes both Automatic Meter Reading (AMR) and AMI

Figure 2-1: AMI deployment rates by state

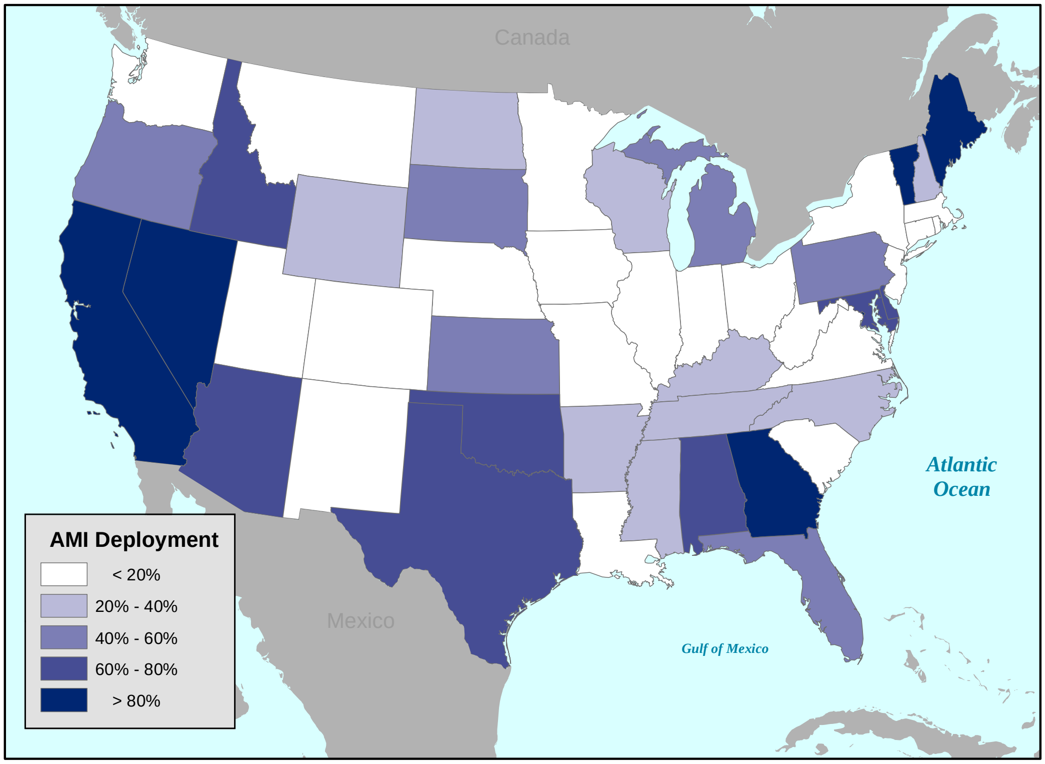
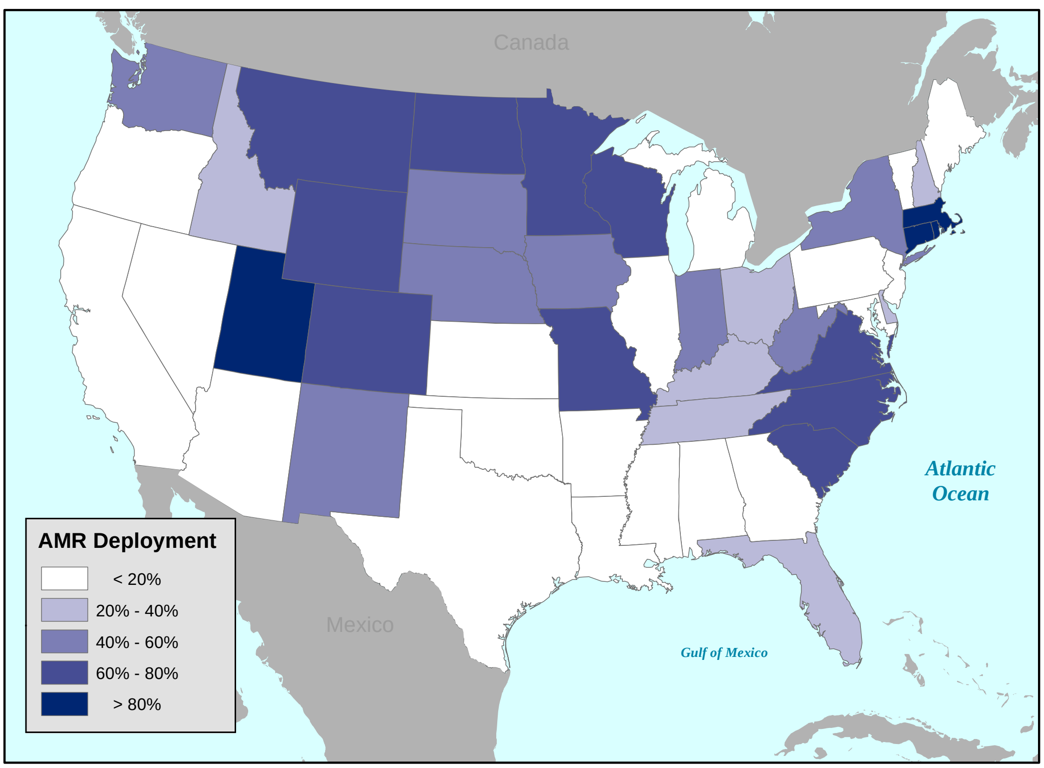


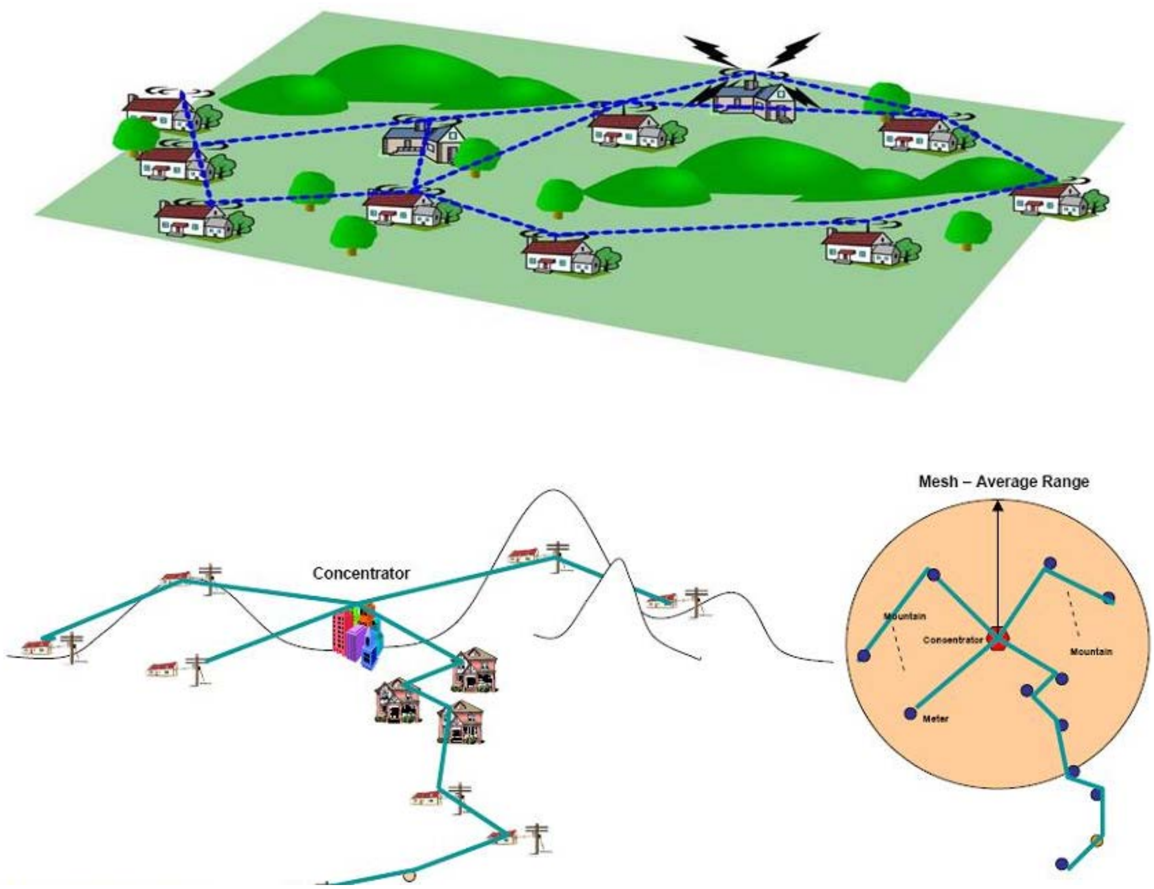
Figure 2-2: Electronic meter (AMR) deployment rates by state



2.2 AMI System Overview

Central Hudson evaluated both a full scale and a partial deployment scenario. Figure 2-3 depicts the components necessary for each scenario. A full scale AMI deployment project would include installation of two-way communicating meters (both electric and gas), supporting wireless mesh communications network and IT infrastructure, and software applications to process data and interact with field devices. The communications network would leverage and build upon the infrastructure already planned as part of the DA deployment. For reasons described in the following section, it would be cost-prohibitive to use the mesh network to communicate with a small portion of meters. For some of these, communication could be established using third party cellular networks; for others, no remote communication could be established without substantial additional cost. However, there is a point beyond which adding additional network hardware simply becomes impractical as it would be more cost-efficient to continue relying on manual (walk by or drive by) meter reading. Such remote areas are deemed not practically reachable by remote communications.

Figure 2-3: System components under full and partial deployment



A partial scale AMI deployment project would include installation of two-way communicating meters (electric only) for demand metered customers falling under the 300kW threshold currently in place for Central Hudson's mandatory hourly pricing program. This accounts for roughly 4% of electric meters.[14] Because the demand meters are distributed throughout the territory, if a wireless mesh network were used to support these meters, a substantial portion of the costs assumed for full deployment would still be necessary to support communications. However, this capital cost would be spread over a much smaller number of meters, leading to a much higher average cost per meter. Because of this, communications for the partial deployment scenario would instead be supported entirely by third party cellular communications. Also, as described above, no remote communication could be established with a small portion of demand meters, even via cellular communications. Additionally, the partial deployment would still necessitate IT infrastructure and software applications to process data and interact with field devices, and this foundational investment would be the same regardless of the scope of the AMI deployment.

Figure 2-4: Average Cost per Meter by Meter Technology and Number of Meters

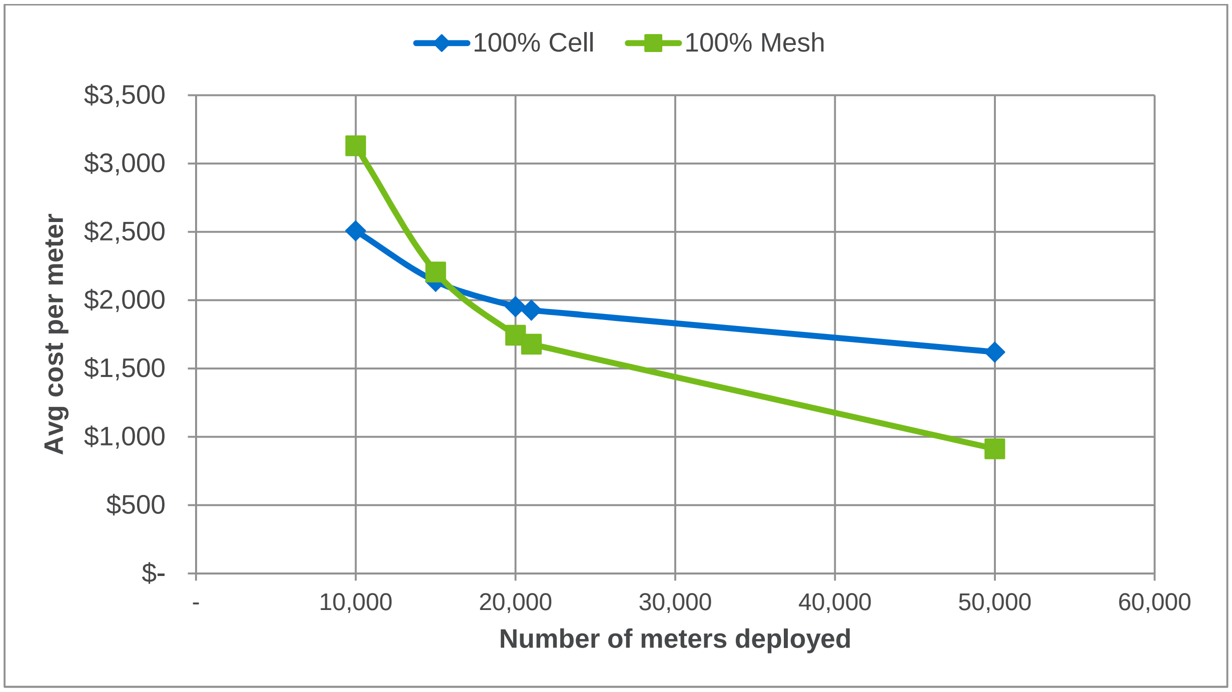


Figure 2-4 demonstrates why cellular meters would be preferred to mesh meters for a partial deployment. The green line shows how the average, all-in deployment cost per meter[15] for a mesh deployment changes as more meters are deployed—assuming utility hosted meter data management. The blue line represents the same for a deployment of cellular meters only—assuming vendor hosted meter data management. Essentially, costs for a cellular deployment are more scalable with the number of meters, because costs such as communications and meter data management are incurred on a per meter basis, whereas analogous costs for a utility hosted mesh system require more upfront,

[14] About 12 thousand of the roughly 380 thousand accounts in Central Hudson territory (counting gas and electric separately)

[15] Total deployment cost (including all the system components described above) divided by number of meters deployed

foundational investment that does not scale as much with the number of meters. Based on this assessment, at least 21,000 meters would need to be deployed for the mesh deployment option with utility meter data management to be less costly than the cellular option with vendor hosted meter data management. Because the partial deployment scenario only involved about 12,000 meters, a cellular deployment would be less costly.

2.3 Central Hudson Current Landscape

Central Hudson serves a diverse territory with unique characteristics that influence the incremental benefits achievable and costs incurred through AMI deployment. These include:

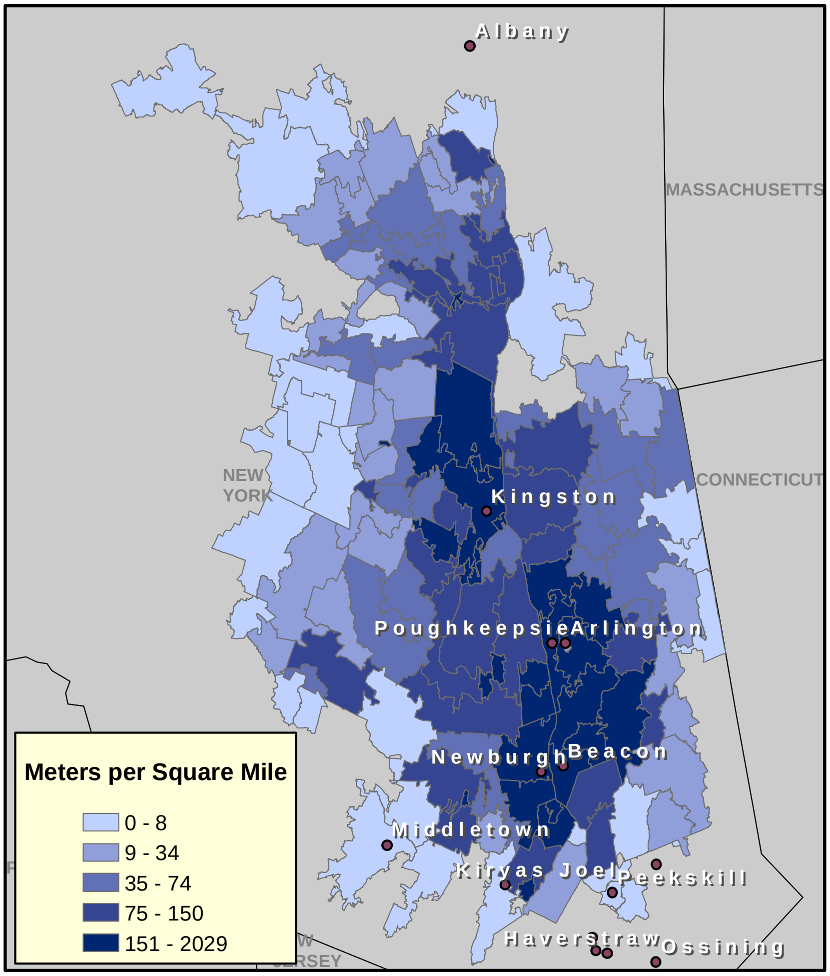
- Factors that reduce the potential for operational cost savings, such as reductions in meter reading costs and utility outage management costs (thereby reducing AMI benefits),

- Factors that reduce the incremental investment needed to support AMI (thereby reducing AMI costs).

One primary operational benefit often realized through AMI deployment is the meter reading cost savings made possible by the automated two-way communication. Some characteristics of the Central Hudson territory impact the meter reading costs the Company faces today, as well as the costs savings that could be expected through AMI. Central Hudson currently reads most meters on a bi-monthly schedule. This means that the vast majority of meters are read every other month, leading to variable meter reading costs that are roughly half what they otherwise would be if most meters were read every month, or twice as often. By extension, this means that the potential for reductions in variable meter reading costs are roughly half of what they would be if Central Hudson read meters on a monthly schedule.

The geography of the Central Hudson territory includes some areas which are rural, remote and with mountainous terrain. Central Hudson has roughly 300 thousand electric and 79 thousand gas customer meters. The service territory covers 2,600 square miles stretching from 25 miles north of New York City to 10 miles south of Albany. However, these meters are not evenly dispersed throughout the territory. As seen in Figure 2-5 the concentration of meters ranges from the large towns of Kingston and Poughkeepsie, where meter density ranges from about 150 to over 2000 meters per square mile, to the mostly rural northern and western portion of the territory, which reaches into the Catskill Mountains, where meter density ranges 8 meters or fewer per square mile. As alluded to above, the communications necessary to support remote meter reading cannot be established in anon-negligible portion of these areas, even via a cellular network. This means that a portion of meter reading costs could not be avoided by deploying AMI throughout the territory, because of these remote areas that could not be practically served by AMI. Central Hudson would need to retain a portion of its meter reading workforce and equipment to read meters in these areas, representing a floor to the achievable reduction in meter reading costs. Further, while a subset of the meters in remote areas could be reached via cellular communication, the additional hardware and recurring communications fees necessary for cellular meters would result in a higher cost per meter than would be the case for meters served by a wireless mesh network. Finally, gas meters will need to be automated in order to produce meter reading savings, which will increase costs, but do not contribute to the various other operational savings.

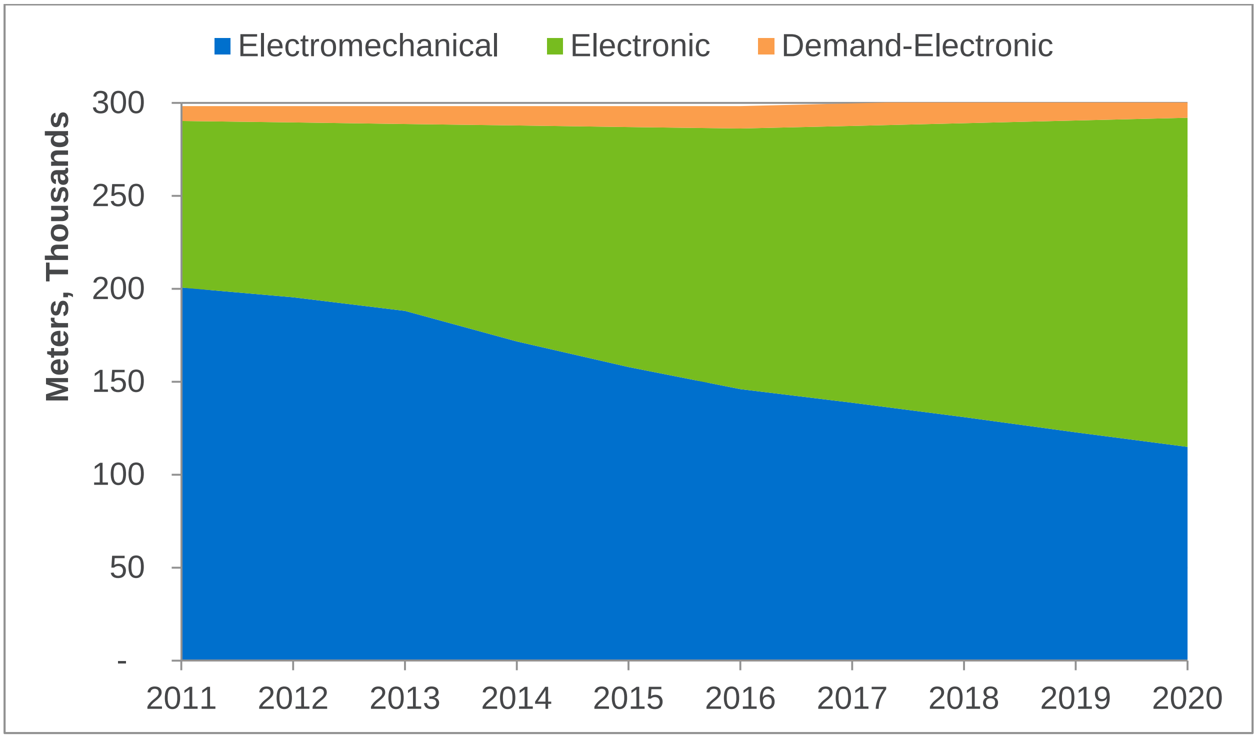
Figure 2-5: Meter density in Central Hudson territory



Another characteristic of Central Hudson operations impacting achievable benefits is the ongoing deployment of electronic AMR meters. Figure 2-6 shows the changing meter population mix over time, demonstrating the recent pace at which Central Hudson has been replacing electromechanical meters with electronic AMR meters. Currently about 50% of meters are electronic AMR meters[16], and at the current pace of change, almost 60% of meters will be AMR capable by 2020. Electronic meters are capable of the one-way communication needed to support walk by or drive by automated meter reading. This has several implications which reduce achievable benefits associated with AMI. First, walk by or drive by meter reading already represents cost savings with respect to electromechanical meters for which meter reading requires physical access and manual reading and recording of usage. This means that the potential for meter reading cost savings from converting electronic meters to AMI is lower than it would be for converting electromechanical meters directly to AMI. In addition, nearly half of meter reading is performed through sub-contracting, which represents a relatively flexible cost.

[16] Including Electronic and Demand-electronic

Figure 2-6: Electric meter population in Central Hudson territory



Another potential operational benefit is avoided future meter replacement costs. Essentially, when an old meter that would have eventually been replaced (e.g. due to failure) is replaced with a new meter, this avoids the future expected replacement of the old meter. However, a majority of Central Hudson meters will be electronic by the time AMI meters would be deployed. These relatively new electronic meters are not expected to fail for several years and avoided replacement costs due to failed meters are therefore lower than they would be if the AMI meters were to replace older electromechanical meters. This is an example of a benefit which is only incremental to electromechanical meters, meaning that no benefits accrue when electronic meters are replaced by AMI meters. Similarly, improvements in metering accuracy are only realized when replacing electromechanical meters. However, it should be noted that these benefits accrue to customer fairness—rather than cost savings for utility operations.

Finally, the New York Public Service Commission has approved Central Hudson's plan for Distribution Automation, and Central Hudson will be deploying Distribution Automation over the next few years. Among other things, this deployment will require investment in data concentrators and wireless radios needed to support wireless mesh communication between Distribution Automation hardware and control centers. This is an investment that will also deliver operational benefits to Central Hudson, including Volt/Var Optimization (VVO). On the one hand, this lowers the communications network investment necessary to support AMI communications; on the other hand, VVO provides benefits which could have been at least partially supported using AMI. However, there will be little incremental VVO benefit delivered by AMI over the benefit already delivered by Distribution Automation. In addition, Distribution Automation and AMI also offer benefits such as reduced utility outage costs, but the incremental benefits for AMI over and above Distribution Automation are also low.

Together, the existing bi-monthly meter reading schedule, the unique geography, the ongoing electronic meter deployment, and the impending deployment of Distribution Automation are factors at play in the Central Hudson territory which would impact both the achievable benefits and costs for deploying AMI. These impacts will be quantified in the results section.

2.4 Report Structure

The remainder of this report is organized as follows. Section 1 summarizes the BCA evaluation approach used for the operational business case, including defining the cost tests evaluated and enumerating and defining the benefits and costs quantified. Section 1 summarizes the benefit cost results for the full deployment scenario. Section 5 summarizes the benefit cost results for the partial deployment scenario. Section 0 provides a summary conclusion for both scenarios.

3 Methodology

3.1 BCA Evaluation Approach

Cost-effectiveness analysis is critical for comparing different resource options and for optimizing investments in generation, transmission and distribution. When done correctly, it allows for comparisons across resource options and provides a basis for prioritizing investments. A key goal of cost-effectiveness analysis is to provide factual insights, make tradeoffs transparent, improve the planning process and help maximize value. Cost-effectiveness analysis is generally applied on a forward looking basis to investments that typically have large upfront costs but have benefits that accrue over multiple years. It also requires a pre-specified perspective, since two different parties can view the same outcome differently. While policies and programs can lead to winners and losers, cost-effectiveness analysis focuses on the broader question of whether the overall policy is beneficial.

The BCA framework order[17] specified that benefit-cost estimates be developed based on three perspectives:

- Societal Cost Test (SCT): Do the benefits, including externalities, exceed the costs?
- Utility Cost Test (UCT): Is the investment or program self-funding or are additional funds needed?
- Ratepayer Impact Measure (RIM): How does the investment affect rates?

The societal test not only counts operational benefits to a utility, but it also includes benefits experienced by customers, reductions in resource requirements (e.g., generation capacity, energy use) and reductions in externalities such as carbon emissions. It does not treat transfers between parties as costs. On the other hand, the UCT does not include benefits experienced by customers or externalities but counts as costs things such as customer incentives, since money to fund programs and incentive payments must be collected. The RIM test focusses exclusively on rates. In some cases, resources that reduce energy consumption, such as energy efficiency and conservation voltage reduction, can lead to lower bills but higher rates, because the revenue for capital infrastructure investments is collected from fewer energy sales. Of these three perspectives, the societal test is the most important from a public policy perspective and is the primary focus in this report.

When estimating the net benefits of an investment over time, the costs and benefits must be compared in present value terms since they occur at different times (with most of the costs typically incurred in the early years, while benefits often continue for many years beyond when major expenditures end).

The primary focus in the following sections is the societal test. From a policy perspective, this is the most important indicator of whether or not AMI should be deployed in Central Hudson's service territory. If net benefits are positive from a societal perspective, it means that society as a whole would be better off by implementing AMI, even if some societal members might gain while others lose. However, if net benefits are negative from a societal perspective, society as a whole would not be better off because the costs to implement AMI would outweigh the benefits derived from AMI.

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[17] CASE 14-M-0101 - Order Establishing the Benefit Cost Analysis Framework, Issued and Effective January 21, 2016

All of the separate analyses summarized below are based on a common set of inputs and assumptions. Among the most important are:

- Meter and network deployment begins in 2020 and occurs over a five year period (ending in 2024) for the full deployment scenario and over a two year period (ending in 2021) for the partial deployment scenario. Meter deployment is assumed to be evenly distributed across each deployment year.
- Each AMI meter is assumed to have a 20 year life. As such, meters deployed in 2021 are assumed to produce benefits tied to meter deployment through 2040 and so on. The analysis period goes from 2020 through 2039.
- The discount rate used for present value calculations is the Weighted Average Cost of Capital (WACC) for Central Hudson. Since taxes are considered income transfers, which are excluded from the societal test, the after-tax WACC is used for the societal test (6.62%), whereas the pre-tax WACC is used for the UCT and RIM tests (9.43%). As directed by the BCA order, carbon reductions are discounted using a societal discount rate of 3%. These differences in discount rates have a very substantial impact on the net benefits and should be kept in mind when comparing the societal, UCT and RIM tests.
- All present value calculations are reported in 2016 dollars by adjusting for 2.1% annual inflation.
- The annual growth in the Central Hudson customer population is assumed to equal 0.5%.

3.2 AMI Benefits

Several benefits can stem from installation of AMI. For this analysis these benefits were classified into three categories: operational utility cost savings, customer fairness benefits, and benefits from AMI enabled rates and programs.

Table 3-1 details the elements included in each benefit category and sub-category along with their applicability to each cost test evaluated.

Operational savings is the largest category of benefits from AMI implementation and includes reduced meter reading costs, meter replacement costs, reductions in storm related costs due to better visibility into outage locations and reestablishment of service, and reduced field service visits associated with connections and disconnections.

Deployment of AMI can also address fairness issues by reducing or eliminating revenue losses from various sources that are currently socialized to all ratepayers. AMI helps direct costs to customers who are responsible for them and reduces the socialization of energy thefts and meter inaccuracies, resulting in more equitable distribution of revenue collection.

Finally, AMI can also enable rates and programs that can lead to more economically efficient use of energy which, in turn, can reduce the need for new generation, transmission and distribution capacity and lower energy use and carbon emissions associated with energy production. In addition, these programs can provide customers with the information to help lower their energy bills. Unlike benefits from the other two categories, these benefits have not been included in the core business case because the AMI enabled programs and rates analyzed would require regulatory change in order to be implemented.

3.2.1 *Operational Benefits*

There are four categories of operational benefits which would directly result in avoided utility costs. These are avoided meter replacements, avoided meter reading costs, avoided outage management costs and avoided field operations costs.

Avoided Meter Replacements (electric meters)

The expected useful life of electronic and electromechanical meters for planning purposes is 30 years, after which the need for meter replacements due to failures or performance issues tends to increase substantially. A substantial portion of Central Hudson meters will reach the end of this useful life during the benefit period analyzed and would be replaced either as part of the ongoing deployment of electronic meters or due to concerns about age and performance. With AMI deployment, this replacement work will no longer be necessary.

With a partial deployment, only planned replacements of demand electric meters would be avoided.

Avoided Meter Reading Costs

A substantial portion but not all of meter reading costs currently incurred by Central Hudson could be avoided by deploying AMI. As alluded to in Section 2, the limitations to these operational cost savings are two-fold:

1. About 5% of meters are located in outlying areas unreachable by wireless or cellular communications. These costs cannot be avoided and also represent a higher than average cost per meter since the geographic dispersion means longer drive time between meters.

2. About half of meter reading is subcontracted and could be entirely avoided by a full AMI deployment. However, a portion of labor hours spent by employee meter readers is spent doing other tasks; this portion of labor hours could not be avoided.

Full deployment of AMI to the 95% of the territory practically reachable by remote communications would lead to the avoidance of all contract labor and a portion of employee meter reading labor. Deployment of AMI to demand meters only would result in some contract labor savings thanks to the elimination of most reader routes associated with demand meters, a small portion of total routes.

Table 3-1: Summary of Benefit Categories and Components

Category	Sub category	Detail	Applicability to cost tests		
			SCT	UCT	RIM
Benefits					
Operational	Avoided Meter Replacements	Electronic	X	X	X
		Demand Electronic	X	X	X
	Avoided Meter Reading Costs	Labor costs	X	X	X
		Vehicle Costs	X	X	X
		Fuel Costs	X	X	X
	Avoided Outage Management Costs	Faster restoration times for storm outages	X	X	X
		Faster outage location time	X	X	X
		Avoided truck rolls for customer side "outages"	X	X	X
	Avoided Field Operations Costs	Avoided connect / disconnect (non-collection)	X	X	X
		Avoided read overs	X	X	X
		Avoided reconnects (collection related)	X	X	X
Customer fairness	Avoided Theft of Service				X
	Improved Meter Accuracy				X
AMI enabled rates & programs	Prepayment program	Capacity reductions and energy savings	X	X	X
		Reduced CO2 compliance cost	X		
	Time varying rates	Avoided capacity costs and energy savings	X	X	X

Avoided Outage Management Costs

AMI systems with two-way communications can be used to "ping" a meter to see if it is connected to the system, thereby establishing the location of an outage and to confirm whether service has been restored. Benefits from this capability fall into three categories:

1. Faster restoration times for storm related outages: Outage detection capabilities can also help reduce outage duration and restoration costs during wide scale outages by detecting whether or not power has been successfully restored everywhere while crews are still in the field, thus avoiding crew re-dispatch.
2. Faster outage location time: AMI systems can be used to identify the location of the outage, reducing patrol time to identify the source of the outage. A substantial portion of this benefit will come through distribution automation, which will allow identification of the circuit experiencing the outage. AMI systems will provide a small incremental benefit of helping locate the exact customer end point of the outage.
3. Avoided truck rolls due to customer side "outages": when a customer calls regarding an outage it can sometimes be determined whether or not the outage is on the customer's side of the meter, thus avoiding the dispatch of field crews if it is.

Avoided Field Operations Costs

Remote connect / disconnect functionality in AMI meters will significantly reduce the need to dispatch field crews to disconnect and reconnect the power when customers move or to read meters when they are transferred from one account to another (called read overs). They can also be used as a means for restoring service more quickly to customers for whom service has been disconnected for collection related reasons. While the use of remote disconnect for collection related purposes is limited in New York State by the requirements of the Home Energy Fair Practices Act (HEFPA), the only limitation to remote connect is for gas services, and this is a result of Company practice and customer safety concerns. The ability for a customer service representative to remotely restore electric service to a customer once a collection is made would benefit customers who would otherwise need to wait for a field representative to be dispatched.

Savings for account transfer related connects, disconnects, and read overs would be avoided under both full and partial AMI deployment roughly proportionately to the number of meters deployed. However, since collection related disconnections are very uncommon among the medium sized commercial customers who are typically demand metered, this cost would not be avoided by the deployment to demand meters only.

3.2.2 Customer fairness benefits

In addition to the operational benefits described above, deployment of AMI can also address fairness issues by reducing or eliminating revenue losses from various sources that are currently socialized to all ratepayers. AMI helps direct costs to customers who are responsible for those costs and reduces the socialization of certain kinds of costs from particular kinds of customers to the overall customer population.

In this analysis these fairness issues have been addressed by quantifying how socialization of costs might be reduced through implementation of AMI, and by quantifying the extent of that socialization reduction as a rate reduction impact rather than a societal benefit. Basically, customers who today have accurate meters, who pay their bills, and who pay for all the electricity they receive will see their bills go down. Because of this, these customer fairness benefits are only applied to the ratepayer impact test and do not factor into the societal cost test.

Two kinds of socialized costs that AMI can address were evaluated:

- Theft of Service: While it is difficult to quantify, there is undoubtedly some theft of service in the Company's service territory, and the revenue that would have been collected from individuals responsible for the theft, is effectively socialized and collected from customers who pay for the service they receive. AMI provides tamper alarms and produces granular usage data at the customer level that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service.
- Meter Inaccuracy: Not all meters are 100% accurate, and some of the existing electromechanical meters in the service territory don't measure all the electricity that is delivered to customers. Typically, electromechanical meters slow down with age and meters that are 20 years old might be under-registering usage by up to 1 percent. Customers with these "slow" meters do not pay for all the service they receive and the revenue shortfall from these customers is socialized to the rest of the customer base. In addition to slow electro-mechanical meters, revenue losses can occur from certain types of meter failures. For example, a three-phase meter might not measure all three phases correctly and, as a result, may under-charge a customer for the service they receive. Finally, it is well-known that new electronic meters have the ability to measure lower starting loads than electromechanical meters. As a result, customers that use proportionately more electricity at lower load levels may not be charged for all the electricity they use.[18] Again, the extent to which this under-registration of low-load demand results in the socialization of usage costs to the rest of the customer population is uncertain but with a new population of AMI meters, the accuracy and meter malfunction problems would be reduced.

In practice it is difficult to know the extent to which theft, inaccurate meters, and malfunctioning meters result in socialization of costs from small groups of customers to the broader customer population. However, these two benefits were still quantified because empirical evidence has indicated that some amount of theft does occur on all systems and that electronic meters are more accurate than electromechanical meters. To some extent, these benefits may be observed as a reduction of the system loss factor.

3.2.3 AMI enabled programs

In addition to the operational and customer fairness benefits described above, AMI can also enable rates and programs that would produce benefits for the utility and for society. Two AMI enabled rates and programs were evaluated, Prepayment programs and Time-varying rates. However, because regulatory

[18] An electronic meter can sense lower loads than an electromechanical meter, and thus register usage that an electro mechanical meter would not notice.

changes would be needed to allow for these rates and programs, their incremental benefits and costs were quantified but kept distinct from the operational business case, resulting in two analyses: one excluding AMI benefits and one including them.

Prepayment program

AMI meters with remote connect / disconnect capability enable prepayment programs and are useful for customers interested in managing their bill to a specific amount (much like pre-pay phones). At least half a dozen utilities have implemented prepayment programs and have demonstrated that prepayment programs consistently deliver participant energy savings of about 12%. These savings are likely due in large part to the behavioral impact on customers of receiving frequent communications about their energy usage and remaining balance.

However, prepayment programs require using remote disconnection as part of program operations. Therefore, the ability to capture the benefits of an AMI enabled prepayment program would be contingent upon regulatory changes and approvals.

Time varying rates

AMI also enables the deployment of time varying rates either on an opt-in or default basis, which allows different prices for different time periods and different locations. This benefit will vary depending on the strategy (default or opt-in), customer targeting (e.g. of customers with higher usage), the ratio of peak time rates to off-peak rates, and the magnitude of avoided T&D and generation capacity costs. The benefits of time-varying rates under multiple strategies have been quantified but not included in the core operational business case because of uncertainty regarding how these would be implemented and because implementation would be reliant on regulatory changes.

3.3 AMI Costs

This section discusses the costs of deploying AMI across the Central Hudson service territory. This discussion is organized into two sub-sections: AMI deployment costs and costs associated with AMI enabled rates and programs. Table 3-2 summarizes the components included in each cost category and sub-category along with their applicability to each cost test evaluated. The rest of this section describes each component, and the Itemized breakdowns of cost assumptions for each component can be found in the appendix.

Note that stranded meter assets were not included as a cost in Central Hudson's analysis, consistent with past Commission decisions. However, as Central Hudson prudently incurred expenditures for its existing meter infrastructure, the Company anticipates that it will recover the cost of the stranded meter assets.

In the case of ConEd, the Commission noted, "[t]here is no basis presented [in the ConEd AMI proceeding] to conclude that the investment in the old meter technology should not have been made at the time the investments were approved by the Commission and the Company's management. Therefore …there is no showing here that inefficient management or poor planning resulted in these costs being stranded."[19]

With more time, Central Hudson would have issued a Request for Information or Request for Proposal and cost estimates would have been based on the competitive bids collected. In the absence of this, cost estimates were based on the internal knowledge of Central Hudson staff where costs would be internal labor and materials[20], a handful of existing technology vendor bids, and on the industry knowledge of Nexant, which has extensive knowledge of AMI deployments, having built multiple business cases over the years.[21]

3.3.1 AMI deployment costs

Costs related to deployment of AMI have been grouped into five categories for this analysis: meter equipment and installation, network equipment and installation (for a wireless mesh deployment), meter data management system and other IT costs, meter and network operations and maintenance, and project management costs.

Meter Equipment, Installation Costs

Meter equipment costs include the capital cost of meters themselves as well as the various ancillary materials needed for some installations, such as panel repairs, adapters for older panels, and tamper proof locking rings and meter seals. Costs assumptions for the meters themselves were differentiated by mesh versus cell, and simple versus complex.[22] Installation labor also includes the incremental labor necessary for these ancillary materials a fraction of the time, as well as time for testing the meters and time for processing each meter in the IT system.

For electric meters the entire meter needs to be replaced; for gas meters a retrofit of the existing meter will usually suffice, though a small portion of installations may require a complete replacement or may pose complexities to the installer for various other reasons.

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[19] CASE 15-E-0050, et al. ORDER APPROVING ADVANCED METERING INFRASTRUCTURE BUSINESS PLAN SUBJECT TO CONDITIONS, March 17, 2016, page 48

[20] The IT budget was developed internally with a team that included IT staff members familiar with the unique needs of Central Hudson's IT system

[21] Working on behalf of both utilities and Public Commissions, Nexant's team has written or contributed to over a half dozen AMI business cases for utilities in the West (e.g. PG&E) as well as in the northeast including utilities in Vermont and New York state (ConEd, NYSEG, RG&E)

[22] Including demand meters and polyphase meters

Table 3-2: Summary of Cost Categories and Components

Category	Sub category	Detail	Applicability to cost tests		
			SCT	UCT	RIM
Costs					
AMI deployment costs	Meter Equipment, Installation Costs	Mesh Meters	X	X	X
		Cell Meters	X	X	X
		Gas Modules	X	X	X
	Network Equipment, Installation Costs	Radio retrofit of existing concentrators	X	X	X
		Incremental concentrators w/ radio	X	X	X
	Meter Data Management System and other IT Costs	MDMS Hardware and Software	X	X	X
		One time IT costs (Billing system & integration)	X	X	X
		MDMS Hardware and Software O&M Costs	X	X	X
		IT O&M Costs	X	X	X
	Meter & Network Operations & maintenance	Meter related maintenance	X	X	X
		Network related maintenance	X	X	X
		Cell Meter Communication	X	X	X
		Meter data management	X	X	X
	Project management		X	X	X
AMI enabled rates & programs	Prepayment program	Program administration & IT costs	X	X	X
		Other program costs	X	X	X
		Lost revenue			X
	Time varying rates	Program administration & IT costs	X	X	X
		Other program costs	X	X	X
		Lost revenue			X

Network Equipment, Installation Costs

Network costs only apply to the deployment of AMI to all meters across Central Hudson territory reachable by remote communication. These costs would essentially consist of the extension and reinforcement of the wireless mesh network that will already be deployed as part of the planned distribution automation deployment. Two components would need to be expanded to support communication with the wireless mesh communicating AMI meters. The first is wireless radios, which send and receive communications to and from meters in vicinity. The second is data concentrators, which are usually collocated with the wireless radios and manage data transfer to and from data collectors, which in turn manage the communications link to central utility control centers. To sufficiently reinforce the wireless mesh network, it will be necessary to add wireless radios to many data concentrators already installed for distribution automation. It will likely also be necessary to install a few additional concentrators[23] to ensure sufficient coverage for all mesh AMI meters.

Meter Data Management System and other IT Costs

The volumes of data collected from AMI meters is managed via a meter data management (MDM) system, which is connected through a meter data head end system that is in turn 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. The cost structure for these two options is substantially different. It presents a substantial investment in both hardware and software licenses[24] for a utility to set up these systems. This investment would not scale with the number of AMI meters deployed. In contrast, vendor hosted systems are generally priced on a per meter basis. As described in Section 2.4, this means that for smaller deployments (e.g. to fewer meters) the vendor hosted option will make more economic sense, but after a certain volume of meters, the utility hosted option will be less costly because foundational fixed costs are spread over more meters, resulting in a lower average deployment cost per meter. For this analysis a utility hosted MDM was assumed for the full deployment of AMI to the roughly 360 thousand meters practically reachable by remote communications, while a vendor hosted MDM was assumed for the 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 outage management system (OMS) and the customer information system (CIS). These costs include an upfront investment as well as an ongoing cost. These costs also include a budget allocation for a permanent position at Central Hudson for managing meter data.

Meter and Network, Operations and Maintenance

The MDM and IT costs described above have associated recurring operations and maintenance costs described in detail in the appendix under the IT cost section. There are also ongoing costs associated with maintaining the AMI meters and communications. Meter maintenance costs were analyzed using typical equipment warranties and failure rates for both meters and mesh network equipment (e.g., radios and concentrators for the mesh network in the full deployment scenario). Other meter related operations and

[23] Also fitted with wireless radios

[24] And recurring maintenance thereof

maintenance costs included a recurring per meter cost for managing meter data as well as the annual per meter cost paid to a cellular provider to support communications for cellular meters. This latter cost would apply to all meters in the partial deployment scenario but for the full deployment scenario it would only apply to the handful of meters that would be too remote to connect practically to the wireless mesh network but could still be reached through a cellular network.

Project management

Central Hudson would need the support of incremental staff resources during the AMI implementation period. These resources range from various engineering positions, communications and network experts, meter testers, project management, and customer service representatives to handle incoming calls and questions. These resources would be needed for roughly the duration of the deployment.[25]

The need for internal resources would be in addition to vendor services which would include network integration, in the case of a full deployment, with wireless mesh and meter integration support.

3.3.2 Costs for AMI enabled rates and programs

AMI would enable rates and programs that could deliver substantial benefits, but these incremental benefits would come at a cost.

Prepayment program

AMI would enable the remote connect and disconnect capabilities required to support a prepayment program. However, there would also be program and IT costs necessary to support and administer the program. These include IT setup and maintenance costs, participant set up costs (e.g. entry into the IT system as a participant), annual participant communications, and program administration (e.g. staff to manage the program).

Time-varying pricing

Support for time varying rates would necessitate IT hardware, software license, and setup costs including interfaces between a new rate engine and various IT systems (e.g. CIS). Recurring costs would include license maintenance and cyber security testing. A portion of these costs would scale with the number of accounts supported, so the costs would be somewhat lower for a partial deployment.

[25] For a full deployment lasting 5 years (60 months), these resources would be needed for 66 months. Fewer resources would be needed for a smaller scale deployment to demand meters and they would only be needed for about the two year (24 month) duration of the deployment.

4 Benefit Cost Analysis: Full Deployment Scenario

This chapter lays out the cost benefit analysis results from three different perspectives for the full deployment scenario, both for the operational business case and then with AMI enabled rates and programs. Also included is a supplementary analysis detailing the sensitivity of results to each assumption. Detailed assumptions can be found in the appendix.

A full AMI deployment would mean installing AMI to support the electric and gas meters in Central Hudson territory that could be practically accessed via wireless mesh or cellular communications. All analyses and perspectives for the full deployment scenario share the following common assumption:

- The meter population at the beginning of 2016 was as follows:
  - ✓ Electromechanical: 161,151
  - ✓ Electronic: 123,652
  - ✓ Demand metered electronic: 12,023
  - ✓ Gas meters: 82,206
- The meter population is assumed to grow at 0.5% annually.
- The conversion of electromechanical meters to electronic meters will continue until 2020 at its current pace.
- The AMI deployment period consists of the five years from 2020 through 2024.
- The achievable AMI deployment rate for all meter types is 95%, meaning that wireless communication (cellular or wireless mesh) cannot be practically established with about 5% of meters due to their remote locations.
- Of these 95% of meters, about 2% will be too remote for practical use of wireless mesh communication and will require cellular communications.
- Costs and benefit assumptions are given in 2016 dollars and assumed to inflate at a rate of 2.10% per year for both labor and non-labor values.
- The analysis period for determining value is the 20 year period from 2020 through 2039.
- To determine net present value over the analysis period, discount rates were used in accordance with Appendix A, Table A-1 of the BCA Handbook, which has been filed as an appendix to the DSIP. A discount rate of 6.62% (Central Hudson's post-tax WACC) was used for the societal cost test and a rate of 9.43% (Central Hudson's pre-tax WACC) was used for the utility cost and ratepayer impact test. For all tests, carbon was discounted at a rate of 3.00% annually.

4.1 Benefit Cost Analysis Results

Table 4-1 summarizes the net benefits[26] and the benefit cost ratio[27] for the operational business case from the three perspectives relevant to the BCA order. Note that the operational business case includes operational and customer fairness benefits but excludes AMI enabled rates and programs because such programs would require regulatory change and approval.

Table 4-1: Benefit and Cost Summary
Full Deployment Operational Business Case

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

The societal cost test for the operational business case shows total benefits of $57.7 million and total costs of $116.5 million, resulting in net benefits gap of about $58.8 million and a benefit cost ratio of 0.50. Either incremental benefits or cost savings of about $60 million would be needed to close this gap and make full AMI deployment cost effective. The utility cost test gave similar results, with a benefit cost ratio of 0.43.

The ratepayer impact test also includes customer fairness benefits from reduced energy theft and improved meter accuracy that result in a more equitable allocation of costs across customers. This is more of a transfer between customers and comes at no incremental cost. Therefore, the ratepayer benefits are $63.9 million and the costs are $106.4 million, but there remains a net benefit gap of $42.6 million and a benefit cost ratio of 0.60, indicative that AMI deployment under this scenario and perspective is still cost-ineffective. The detailed breakdown of benefits and costs can be found in Table 4-2[28].

As demonstrated by these summaries, full AMI deployment would not be cost effective for Central Hudson from any of the three benefit-cost perspectives and regardless of the inclusion of AMI enabled rates and programs.

Figure 4-1 shows the high level 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. The

[26] total benefits minus total costs

[27] total benefits divided by total costs

[28] Central Hudson's s post-tax WACC (6.62%) is the discount rate used for the societal cost test because taxes are considered to be a transfer for that test; Central Hudson's pre-tax WACC (9.43%) is the discount rate is used for the other two tests.

portion of this cost which is upfront meter cost (equipment and installation only) corresponds to an average cost per installed meter of about $143, in line with other recent business cases (see Appendix A). The second largest cost category is 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 4-1: Operational Business Case Societal Benefit and Cost Details, Full Deployment

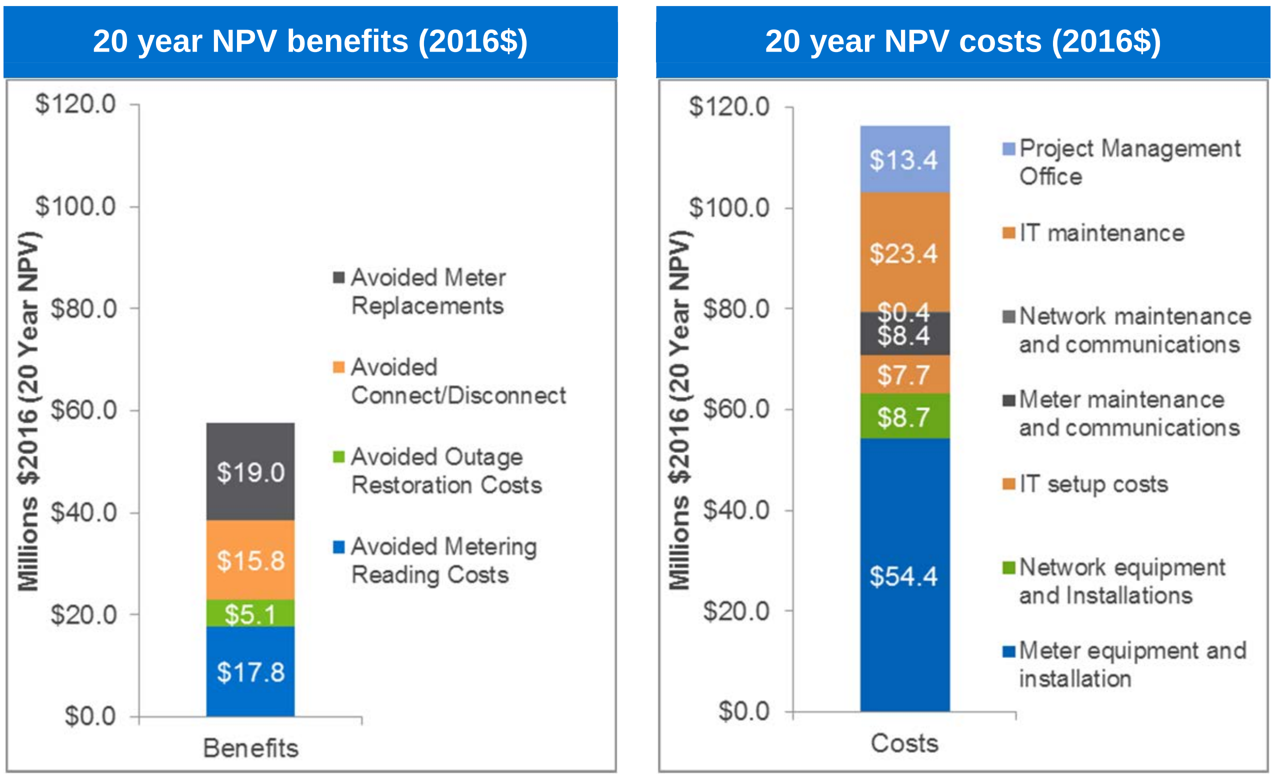


Table 4-2: Benefit and Cost Details, Full Deployment Scenario

Category	Sub category	Detail	Benefit/Cost Test			20 year NPV (2016 $000)	
			Societal	Utility	Ratepayer	Pre-tax Discount Rate (Utility and Ratepayer tests)	Post tax discount rate (Societal test)
Benefits							
Operational	Avoided Meter Replacements	Electronic	X	X	X	$14,775.7	$18,417.0
		Demand Electronic	X	X	X	$429.1	$586.2
	Avoided Meter Reading Costs	Labor costs	X	X	X	$12,224.8	$15,562.3
		Vehicle Costs	X	X	X	$1,327.6	$1,722.7
		Fuel Costs	X	X	X	$409.8	$531.8
	Avoided Outage Management Costs	Faster restoration times for storm outages	X	X	X	$1,950.8	$2,470.0
		Faster outage location time	X	X	X	$658.0	$833.2
		Avoided truck rolls for customer side "outages"	X	X	X	$1,394.4	$1,765.5
	Avoided Field Operations Costs	Avoided connect / disconnect (non-collection)	X	X	X	$9,526.0	$12,061.4
		Avoided read overs	X	X	X	$643.3	$814.5
		Avoided reconnects (collection related)	X	X	X	$2,282.1	$2,889.5
Customer fairness	Avoided Theft of Service				X	$8,336.7	$10,512.8
	Improved Meter Accuracy				X	$9,921.0	$12,510.5
AMI enabled rates & programs	Prepayment program	Avoided capacity costs and energy savings	X	X	X	$18,191.0	$22,976.4
		Reduced CO2 compliance cost*	X			$3,561.1	$3,561.1
	Time varying rates	Avoided capacity costs and energy savings	X	X	X	$16,025.8	$19,403.1

Category	Sub category	Detail	Benefit/Cost Test			20 year NPV (2016 $000)	
			Societal	Utility	Ratepayer	Pre-tax Discount Rate (Utility and Ratepayer tests)	Post tax discount rate (Societal test)
Costs							
AMI deployment costs	Meter Equipment, Installation Costs	Mesh Meters	X	X	X	$43,642.9	$46,256.2
		Cell Meters	X	X	X	$1,647.5	$1,746.1
		Gas Modules	X	X	X	$6,082.0	$6,388.1
	Network Equipment, Installation Costs	Radio retrofit of existing concentrators	X	X	X	$6,000.0	$6,000.0
		Incremental concentrators w/ radio	X	X	X	$2,700.0	$2,700.0
	Meter Data Management System and other IT Costs	MDMS Hardware and Software	X	X	X	$5,392.0	$5,392.0
		One time IT costs (Billing system & integration)	X	X	X	$2,342.4	$2,342.4
		MDMS Hardware and Software O&M Costs	X	X	X	$12,076.0	$14,741.8
		IT O&M Costs	X	X	X	$8,807.0	$10,751.2
	Meter & Network Operations & maintenance	Meter related maintenance	X	X	X	$2,029.5	$2,587.4
		Network related maintenance	X	X	X	$302.0	$383.6
		Cell Meter Communication	X	X	X	$1,023.7	$1,289.9
		Meter data management	X	X	X	$3,549.2	$4,483.5
	Project management office (PMO)		X	X	X	$10,842.6	$11,388.3
AMI enabled rates & programs	Prepayment program	Program administration & IT costs	X	X	X	$3,650.7	$4,479.0
		Other program costs	X	X	X	$5,142.0	$6,143.5
		Lost revenue			X	$14,282.5	$17,996.3
	Time varying rates	Other program costs	X	X	X	$3,217.5	$3,579.2
		Program administration & IT costs	X	X	X	$15,323.2	$17,896.6
		Lost revenue			X	$6.2	$7.5

4.2 Key cost-effectiveness drivers (Sensitivity analysis)

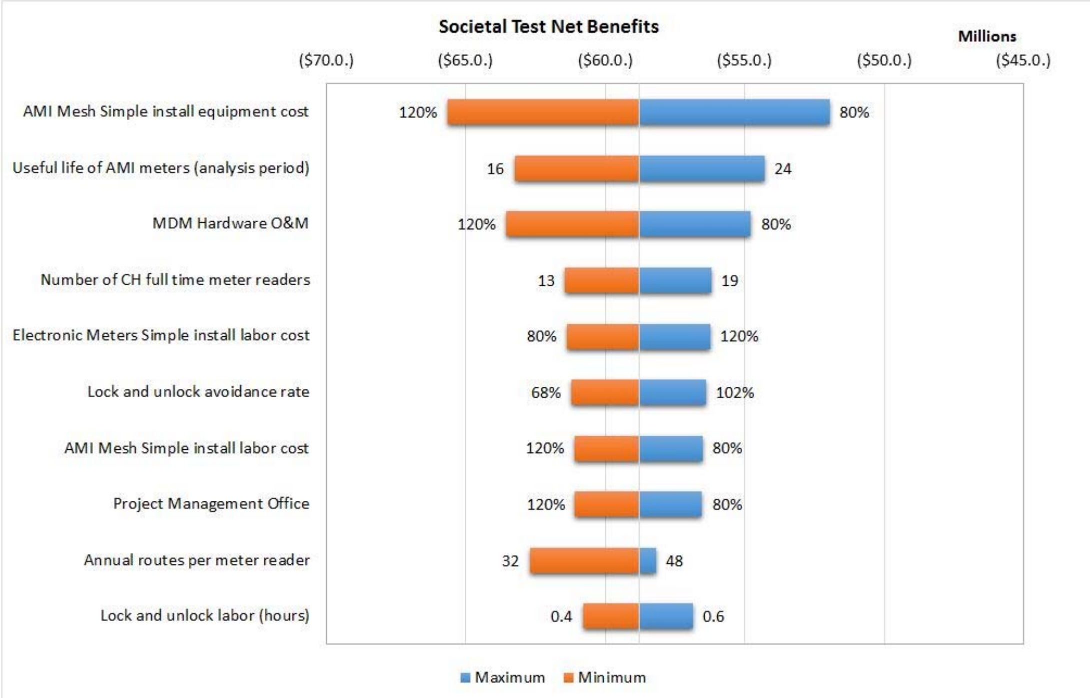
Key drivers of cost-effectiveness were analyzed through a systematic sensitivity analysis designed to identify the inputs that contribute most to net benefits. This is accomplished by varying each component by 20% while holding all other inputs constant. The goal is to identify which inputs have the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

Figure 4-2 shows the sensitivity results for the assumption inputs with the greatest impact on the societal cost test. The top ten assumptions can be said to be the top ten drivers of the result. The mid-point where the blue and orange lines meet is the societal test net benefit of roughly negative $59 million. The orange line representing the resulting incremental net benefit downside from varying each input by 20%, while the blue line represents the resulting incremental net benefit upside. The number labels on each bar represents the alternate assumption used. Many of the top drivers consisted of multi-part inputs which were varied together using a multiplier. This includes mesh meter equipment cost for simple / typical installations (the top driver) and mesh meter labor cost for simple / typical installations (fourth from the top)[29]. Other inputs, such as useful life of AMI meters (the analysis period) were varied directly.

The key finding from the sensitivity analysis is that each individual input has only a small impact on the result. A 20% variation in the top driver, mesh meter equipment cost for simple / typical installations, only results in a net benefit change of roughly plus or minus $6.5 million. This is equivalent to about plus or minus 10% in net benefits or plus or minus 0.06 to the benefit cost ratio. Independently varying each of the next nine key drivers only results in a net benefit change of about plus or minus $2.5 million for each driver. This is equivalent to about plus or minus 5% in net benefits or plus or minus 0.03 to the benefit cost ratio.

[29] See Section 3.3.1 and the appendix for details on the various components included in meter installation equipment and labor costs. For the sensitivity analysis the aggregate value was varied by use of a multiplier in lieu of varying each cost assumption individually.

Figure 4-2: Top Ten Drivers of Full Deployment Societal Benefit Cost Results



4.3 BCA Results: AMI Enabled Rates and Programs

AMI also enables the deployment of time varying rates either on an opt-in or default basis, which allows different prices for different time periods and different locations. These rates enable customers to save money not only by reducing energy use, but by changing when they use power. AMI also enables programs, such as pre-payment options that provide customers with alternative ways to buy electricity. The benefits of AMI enabled rates and programs were quantified but not included in the core operational business case, because of uncertainty regarding how these would be implemented and because implementation would be reliant on regulatory changes.

4.3.1 Time Varying Rates

Figure 4-3 demonstrates how the benefits provided by time-varying rates can vary substantially depending on the strategy (default or opt-in), customer targeting (e.g. customers with higher usage), the ratio of peak time rates to off-peak rates, and the magnitude of avoided T&D and generation capacity costs. Each bar represents total incremental benefits (in blue) and costs (in green) for the different residential enrollment strategies considered. In all four scenarios presented in figure 4-3, non-residential customers are assumed to be defaulted onto time-of-use rates, but the residential strategies vary in accordance with the applicable label. For example, the blue bar on the far left shows that there would be about $19.4 million in benefits when it is assumed that non-residential customers are defaulted onto a time-of-use rate and residential customers are presented with an opt-in TOU-CPP[30] rate, which would be targeted at the top 80% of residential customers by usage. This type of strategy requires continuous recruitment of customers, enrolls fewer customers (15% of targeted customers), but also leads to larger

[30] Time Of Use rate plus a Critical Peak Pricing adder on the days with greatest demand

peak reductions per customer (19.2%).[31] In contrast, the blue bar on the far right shows that there would be about $35.5 million in benefits for a TOU-CPP[32] rate onto which residential customers would be defaulted[33] (but could still opt-out of) and which would be targeted at the top 60% of residential customers by usage and where non-residential customers are defaulted onto time-of-use rates. Despite having a positive net benefit this strategy, as well as the most aggressive strategy of default TOU-CPP for all customers, still results in the AMI business case proving to be cost-ineffective. Additionally, when considering the impacts of implementing time varying rates, it is important to consider the ability that customers have to switch to an Energy Service Company (ESCO). While the switching of customers may not be easily quantifiable, it is important to at least note that customers may have the option to avoid time varying pricing by obtaining their energy supply from a company other than the utility.

The smaller variation in costs shown in Figure 4-3 also demonstrates that the costs associated with time varying rates are influenced by strategy and targeting to a far smaller degree than are benefits. This is largely because the majority of costs associated with time-varying rates come from IT enablement of complex rates. Central Hudson's current Customer Information System would require significant redesign and changes to enable time varying rates for all sectors.

The rate option used for the benefit cost test elsewhere in the full deployment analysis is the opt-in TOU-CPP strategy for residential customers combined with the default TOU for non-residential customers shown on the far left of Figure 4-3. This is because a default time-varying rate would represent a stark shift in rate policy for the state of New York and would therefore require strong support from the Public Service Commission. Currently, California is the only state where residential customers will be defaulted onto time varying rates in the future[34]. Also in the case of California, the default rate will be a TOU rate and will not include a CPP component. Therefore, while the potential default TOU-CPP benefits are included below, the opt-in TOU-CPP results are used for this analysis because that is the most realistically achievable rate design for Central Hudson.

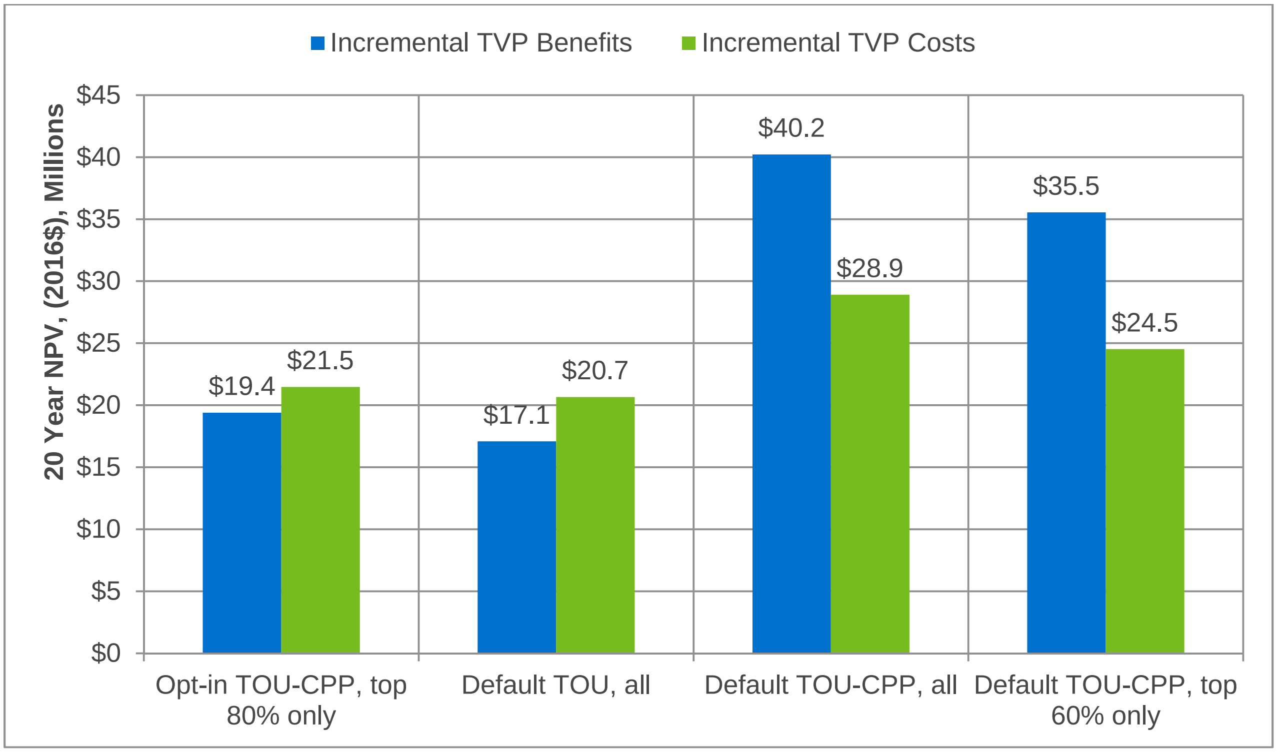
[31] Estimated residential impacts were based on prototypical rates, load data, and price elasticities from the Connecticut Light & Power pricing pilot.

[32] Time Of Use rate plus a Critical Peak Pricing adder on the days with greatest demand

[33] Meaning customers would be placed automatically on the rate but that anyone could chose to opt-out of the rate

[34] Pursuant to an order by the California Public Utilities Commission, residential customers of California IOUs will be defaulted in 2019

Figure 4-3: Incremental benefits and costs for time varying pricing by residential enrollment strategy[35]



4.3.2 Pre-payment Programs

Prepayment programs enable goal-setting with daily feedback to customers. Customers report a greater sense of control and ability to avoid surprise bills and achieve key benefits. A common analogy for prepayment programs is buying gasoline for vehicles (another essential good). The fuel is purchased in advance and the customer receives continuous feedback regarding how much fuel is left and the pace at which they are using it up. They are responsible for moderating their use and for refilling it. AMI enables prepayment programs both by providing a means to communicate to the customer and also by enabling remote disconnect. A zero balance can result in disconnection or higher rates. Prepayment programs have delivered energy savings between 11% and 13% (not including interrupted service) due to behavioral response. In utilities with well-established pre-payment programs, such as Salt River Project, 12% of customers have elected pre-payment.

Setting up a pre-payment programs would cost roughly $1M, most of which is for adapting the IT systems to enable prepayment programs. Once running, annual costs for administration would cost roughly $290k per year ($2016). There are various designs for prepayment programs to enable them to be self-funding.

The analysis reflects that prepayment programs can be cost-effective. Over the course of 20 years, the NPV of benefits and costs total $26.5M and $10.6M, respectively, yielding net benefits of $15.9M.

[35] Non-residential customers are defaulted onto time-of-use rates in all enrollment scenarios

4.4 BCA Results: Operational and AMI enabled benefits and costs

Table 4-3 summarizes from all three cost perspectives the net benefits and the benefit cost ratio for the AMI enabled rate and programs incremental to and exclusive of operational benefits and costs. Table 4-4 summarizes the net benefits and the benefit cost ratio for the operational business case plus AMI enabled rates and programs.

Table 4-3: Benefit and Cost Summary, Full Deployment, AMI Enabled Rates and Programs (Incremental to Operational Business Case)

AMI Enabled Program	Metric	Societal Test	Utility Costs Tests	Rate Payer Impact
Opt-in Time Varying Pricing	Benefits	$19,403.1	$16,025.8	$16,025.8
	Costs	$21,475.8	$18,540.7	$18,546.9
	Net Benefits	($2,072.7)	($2,514.9)	($2,521.1)
	B/C Ratio	0.90	0.86	0.86
Pre-payment program	Benefits	$26,537.6	$18,191.0	$18,191.0
	Costs	$10,622.5	$8,792.6	$23,075.1
	Net Benefits	$15,915.1	$9,398.4	($4,884.1)
	B/C Ratio	2.50	2.07	0.79

Table 4-4: Benefit and Cost Summary, Full Deployment, Operational Business Case + AMI Enabled Rates and Programs

Benefit Cost Analysis (000s, 2016$)	Societal Test	Utility Costs Tests	Rate Payer Impact
Benefits	$103,594.6	$79,838.6	$98,096.3
Costs	$148,548.9	$133,770.3	$148,059.0
Net Benefits	($44,954.2)	($53,931.7)	($49,962.7)
B/C Ratio	0.70	0.60	0.66

Results for the societal test show a 0.70 benefit cost ratio after benefits from AMI enabled rates and programs are added to the operational business case. This is somewhat higher than the 0.60 ratio from the utility cost test, due primarily to the different discount rates used for each test. There is also a fractional difference due to the inclusion of a small amount of carbon benefits[36] in the societal cost test.

[36] Carbon savings result from the energy saved by the prepayment program. Energy savings and therefore carbon savings are negligible for time varying pricing.

The societal cost test shows total benefits of $103.6M and total costs of $148.6M, resulting in a net loss for utility customers of about $45.0 million. As shown in Table 4-3, the AMI enabled rates and programs evaluated contribute a negligible amount of net benefits and therefore do not measurably help close the net benefit gap of about $60 million identified in the operational business case. Even with AMI enabled rates and programs, full deployment of AMI is not cost effective for Central Hudson customers.

5 Benefit Cost Analysis: Partial Deployment Scenario

This chapter lays out the cost benefit analysis results from three different perspectives for the partial deployment scenario, both for the operational business case and then with AMI enabled rates and programs. Detailed assumptions can be found in the appendix.

A partial AMI deployment would mean installing AMI to support the roughly 12,000 electric demand meters in Central Hudson territory, which account for approximately 4% of accounts, 12% of system demand, and 27% of total energy usage and consumption. AMI would replace the electric demand meters in Central Hudson territory so that meters could be practically accessed via wireless mesh or cellular communications. It would largely affect the mid-size commercial customers with demand less than 300 kW and would not include the three hundred or so large commercial and industrial customers that are currently interval metered. All analyses and perspectives for the partial deployment scenario share the following common assumption:

- The relevant meter population at the beginning of 2016 was 12,023.
- The meter population is assumed to grow at 0.5% annually.
- The conversion of electromechanical meters to electronic meters will continue until 2020 at its current pace.
- The AMI deployment period consists of the two years from 2020 to 2021.
- The achievable AMI deployment rate for all demand meters is 95%, meaning that remote communication (cellular or wireless mesh) cannot be practically established with about 5% of meters due to their remote locations.
- Of these 95% of demand meters, about 2% will be too remote for practical use of wireless mesh communication and will require cellular communications.
- Costs and benefit assumptions are given in 2016 dollars and assumed to inflate at a rate of 2.10% per year for both labor and non-labor values.
- The analysis period for determining value is the 20 year period from 2020 through 2039.
- To determine net present value over the analysis period a discount rate of 6.62% (Central Hudson's post-tax WACC) was used for the societal cost test and a rate of 9.43% (Central Hudson's pre-tax WACC) was used for the utility cost and ratepayer impact test. For all tests, carbon was discounted at a rate of 3.00% annually.

5.1 BCA Results

Table 5-1 summarizes the net benefits[37] and the benefit cost ratio[38] for the operational business case from the three perspectives relevant to the BCA framework. Note that the operational business case includes operational and customer fairness benefits but excludes AMI enabled rates and programs because such programs would require regulatory involvement and changes to implement.

The societal cost test for the operational business case shows total benefits of $2.0 million and total costs of $28.2 million, resulting in net benefits gap of about $26.3 million and a benefit cost ratio of 0.07. Either incremental benefits or cost savings of about $26 million would be needed to close this gap and make partial AMI deployment cost effective. The utility cost test gave similar results, with a benefit cost ratio of 0.06.

The ratepayer impact test also includes customer fairness benefits from reduced energy theft that result in a more equitable allocation of costs across customers. Unlike the full deployment scenario, improved meter accuracy is not included because this benefit does not apply to electronic demand meters. The reduced energy theft is more of a transfer between customers and comes at no incremental cost. Therefore, the ratepayer benefits are $5.3 million and the costs are$25.2 million, but there remains a net benefit gap of $19.9 million and a benefit cost ratio of 0.21, indicative that AMI deployment under this scenario and perspective is still cost-ineffective. The detailed breakdown of benefits and costs can be found in Table 5-2[39].

As demonstrated by these summaries, partial AMI deployment would not be cost effective for Central Hudson from any of the three benefit-cost perspectives and regardless of the inclusion of AMI enabled rates and programs.

Figure 5-1 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 ($8.8 million), followed closely by meter equipment and installation ($8.7 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.

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[37] total benefits minus total costs

[38] total benefits divided by total costs

[39] Central Hudson's s post-tax WACC (6.62%) is the discount rate used for the societal cost test because taxes are considered to be a transfer for that test; the Central Hudson's pre-tax WACC (9.43%) is the discount rate is used for the other two tests.

Table 5-1: 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 5-1: Operational Business Case Societal Benefit and Cost Details, Partial Deployment

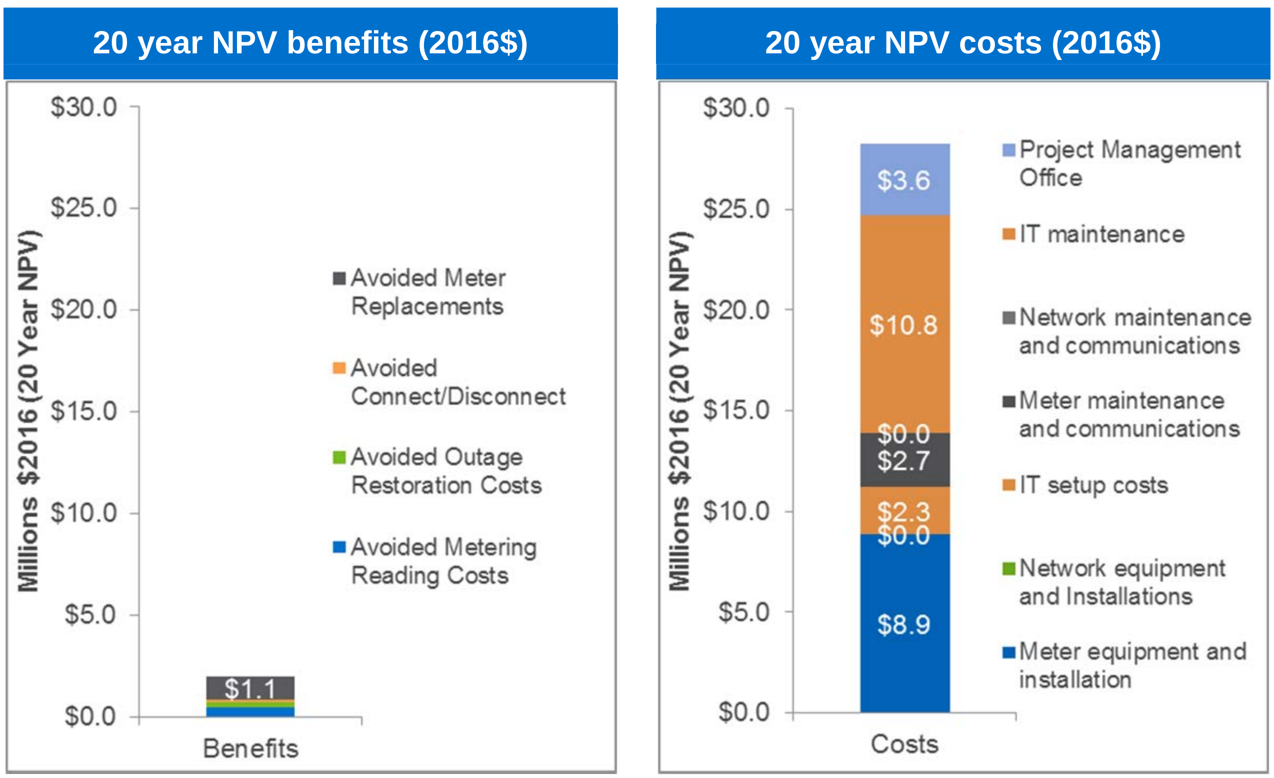


Table 5-2: Benefit and Cost Details, Partial Deployment Scenario

Category	Sub category	Detail	Benefit/Cost Test			20 year NPV (2016 $000)	
			Societal	Utility	Ratepayer	Pre-tax Discount Rate (Utility and Ratepayer tests)	Post tax discount rate (Societal test)
Benefits							
Operational	Avoided Meter Replacements	Electronic	X	X	X	$0.0	$0.0
		Demand Electronic	X	X	X	$804.9	$1,099.5
	Avoided Meter Reading Costs	Labor costs	X	X	X	$385.4	$479.9
		Vehicle Costs	X	X	X	$0.0	$0.0
		Fuel Costs	X	X	X	$0.0	$0.0
	Avoided Outage Management Costs	Faster restoration times for storm outages	X	X	X	$83.2	$103.2
		Faster outage location time	X	X	X	$28.1	$34.8
		Avoided truck rolls for customer side “outages”	X	X	X	$55.7	$69.1
	Avoided Field Operations Costs	Avoided connect / disconnect (non-collection)	X	X	X	$128.2	$159.0
		Avoided read overs	X	X	X	$8.7	$10.7
		Avoided reconnects (collection related)	X	X	X	$0.0	$0.0
Customer fairness	Avoided Theft of Service				X	$3,790.1	$4,672.0
	Improved Meter Accuracy				X	$0.0	$0.0
AMI enabled rates & programs	Prepayment program	Avoided capacity costs and energy savings	X	X	X	$0.0	$0.0
		Reduced CO2	X			$0.0	$0.0
	Time varying rates	Avoided capacity costs and energy savings	X	X	X	$9,315.4	$10,947.0

* A 3% discount rate is applied to CO2 costs per the BCA order

Category	Sub category	Detail	Benefit/Cost Test			20 year NPV (2016 $000)	
			Societal	Utility	Ratepayer	Pre-tax Discount Rate (Utility and Ratepayer tests)	Post tax discount rate (Societal test)
Costs							
AMI deployment costs	Meter Equipment, Installation Costs	Mesh Meters	X	X	X	$0.0	$0.0
		Cell Meters	X	X	X	$8,653.2	$8,868.2
		Gas Modules	X	X	X	$0.0	$0.0
	Network Equipment, Installation Costs	Radio retrofit of existing concentrators	X	X	X	$0.0	$0.0
		Incremental concentrators w/ radio	X	X	X	$0.0	$0.0
	Meter Data Management System and other IT Costs	MDMS Hardware and Software	X	X	X	$0.0	$0.0
		One time IT costs (Billing system & integration)	X	X	X	$2,342.4	$2,342.4
		MDMS Hardware and Software O&M Costs	X	X	X	$1,710.4	$2,113.8
		IT O&M Costs	X	X	X	$7,127.3	$8,700.7
	Meter & Network Operations & maintenance	Meter related maintenance	X	X	X	$296.1	$376.2
		Network related maintenance	X	X	X	$0.0	$0.0
		Cell Meter Communication	X	X	X	$1,860.5	$2,290.4
		Meter data management	X	X	X	$0.0	$0.0
	Project management office (PMO)		X	X	X	$3,161.8	$3,551.4
AMI enabled rates & programs	Prepayment program	Program administration & IT costs	X	X	X	$0.0	$0.0
		Other program costs	X	X	X	$0.0	$0.0
		Lost revenue			X	$0.0	$0.0
	Time varying rates	Other program costs	X	X	X	$256.3	$284.1
		Program administration & IT costs	X	X	X	$6,052.4	$7,117.8
		Lost revenue			X	$6.0	$7.0

5.2 BCA Results: Operational and AMI enabled benefits and costs

Benefits and costs were also assessed for AMI enabled time varying rates. Prepayment programs are not included because they are generally only targeted at residential customers and, therefore, are not relevant for demand metered customers who are typically mid-size commercial.

Table 5-3 summarizes the net benefits, 3.5M, and the benefit cost ratio, 1.48, for the AMI enabled rates incremental to operational benefits and costs., The benefits are based on the implementation of default TOU rates for demand customers[40] (with the customer option to opt out) and assume a modest energy reduction of 2% during peak period. The evidence of peak reduction in response to TOU rates comes from California's recent transition of over 1 million small and medium businesses to mandatory time of use rates. Difference between peak and off peak prices were minimal, but still yielded peak reduction between 2.4% and 3.5%. To be conservative, the analysis assumed peak reductions of 2% among customers who remained on the rate. The cost of implementing time varying rates for demand metered customers is lower because marketing to recruit customers can be avoided and, more importantly, because an IT solution can be designed for demand metered customers at a substantially lower cost than a full deployment where any customer can opt-in to time varying prices.

Table 5-4 summarizes the net benefits and the benefit cost ratio for the operational business case plus AMI enabled rates and programs. Because the AMI enabled time varying rates evaluated contribute $3.5M in net benefits, adding this improves the operational business case. However, even with AMI enabled rates and programs, partial deployment of AMI is not cost effective for Central Hudson customers and would lead to net losses of $22.7M.

Table 5-3: Benefit and Cost Summary, Partial Deployment, AMI Enabled Rates and Programs (Incremental to Operational Business Case)

Benefit Cost Analysis (000s, 2016$)	Societal Test	Utility Costs Tests	Rate Payer Impact
Benefits	$10,947.0	$9,315.4	$9,315.4
Costs	$7,401.9	$6,308.7	$6,314.8
Net Benefits	$3,545.0	$3,006.6	$3,000.6
B/C Ratio	1.48	1.48	1.48

Table 5-4: Benefit and Cost Summary, Partial Deployment, Operational Business Case + AMI Enabled Rates and Programs

Benefit Cost Analysis (000s, 2016$)	Societal Test	Utility Costs Tests	Rate Payer Impact
Benefits	$12,903.2	$10,809.5	$14,599.5
Costs	$35,645.1	$31,460.4	$31,466.5
Net Benefits	($22,741.9)	($20,651.0)	($16,866.9)
B/C Ratio	0.36	0.34	0.46

[40] For both the full and partial deployment scenarios, non-residential customers are assumed to be defaulted onto TOU rates. The primary difference is that the full deployment scenario also includes opt-in TOU-CPP for residential customers.

6 Conclusion

A potential deployment of AMI within Central Hudson territory 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 analysis approach taken was the same used by Nexant for various other AMI business cases, many of which resulted in positive business cases that ultimately lead to AMI deployments. However, in the case of Central Hudson, AMI is not cost-effective for the reasons reiterated below.

6.1 Full deployment

Full AMI deployment to all meters practically reachable by remote communications is not cost-effective. Regardless of whether incremental benefits (and costs) for AMI enabled rates and programs are considered in addition to operational costs and benefits, costs outweigh benefits from both the societal perspective and the utility perspective. From the ratepayer perspective, the same holds true; AMI is not cost-effective regardless of whether incremental benefits (and costs) for AMI enabled rates and programs are considered.

As described in Section 2.3 on the current Central Hudson landscape, the substantial gap between operational AMI benefits and costs is explained by the following Central Hudson characteristics:

- The approved deployment of distribution automation will capture a substantial portion of benefits in the form of Volt/Var Optimization (VVO) and outage location identification, leaving little incremental benefits from AMI.[41]
- 50% of customer meters are electronic with Advanced Meter Reading (AMR). By 2020, when AMI deployment would begin, about 60% of customer meters will have electronic meters with AMR. 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 increase the cost of AMI installation necessary to avoid meter reading costs 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.

6.2 Partial deployment

Partial AMI deployment to all demand meters practically reachable by remote communications is also not cost-effective, by an even greater margin than with full deployment. Regardless of whether incremental benefits (and costs) for AMI enabled rates and programs are considered in addition to operational costs and benefits, costs outweigh benefits from all perspectives.

[41] Distribution automation also enables a substantial share of avoided customer outage cost benefits which were hence not quantified.

In addition to the characteristics of the current Central Hudson landscape which 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)

Appendix A Comparison to ConEd AMI Business Plan

In an effort to provide some degree of external validation for the benefit and cost estimates derived for Central Hudson, Nexant compared the results of the Central Hudson analysis to the results contained in the AMI business plan recently filed by Consolidated Edison (ConEd). Table A - 1 shows how definitions were carefully reviewed to identify how to make a like to like comparison of benefits and costs between the two companies. Except for gas meters and VVO, the items excluded from the Central Hudson analysis were largely deemed to have negligible savings after initial qualitative evaluation. Instead, the analysis focused on the elements most likely to provide measurable quantifiable benefits.

Table A - 1: Comparison of benefit descriptions for ConEd and Central Hudson

ConEd Benefit Description	Central Hudson Benefit Description
Excluded	AMI enabled: Prepayment program
Interval Metering	Excluded
Gas Meters	Excluded because gas meters will be retrofit not replaced
Call Center Labor	Excluded
Distribution System Capital Expenditure Reductions	Excluded
Billing Improvements	Excluded
Distribution Transformers O&M Savings	Excluded
Solar Support	Excluded
Conservation Voltage Optimization	Excluded due to planned Distribution Automation implementation
Demand Side Management Expansion	AMI enabled: Time-varying rates
Inactive Meter/Unoccupied Premises	Excluded
Meter Capital + System Retirement	Replacement of failing meters - Electric
Meter Reading Labor	Meter reading labor
Field operations	Connection / Disconnections and read overs (not collection related)
Meter Accuracy/Irregular Meter Conditions	Meter Accuracy
Revenue Protection	Theft of Service
Contractor and Company Outage Management Labor	Outage management
Bad Debt (remote locks)	Collection reconnects (remote unlocks)
Meter Reading Support Systems	Meter reading vehicles & fuel

Figure A - 1 is a comparison of ratepayer benefits common to both companies, excluding the AMI enabled benefits not included in the operational business case. Each specific benefit is shown as a percent of total benefit to enable a like to like comparison. This shows that the relative share each benefit contributes is relatively comparable between the two companies. Those that vary the most are energy theft and meter accuracy, both contributing about 50% greater share to the ConEd business case (e.g. the 24% share contributed by meter accuracy to the ConEd case is 50% higher than the 16% contributed to the Central

Hudson case). This can largely be explained by the higher wholesale energy prices faced by ConEd in New York City. Meter reading labor also contributes a somewhat higher share for ConEd, perhaps in part due to the Central Hudson characteristics which lead to costs being relatively low today (e.g. bi-monthly meter reading).

Figure A - 1: Comparison of common operational AMI benefits for ConEd and Central Hudson

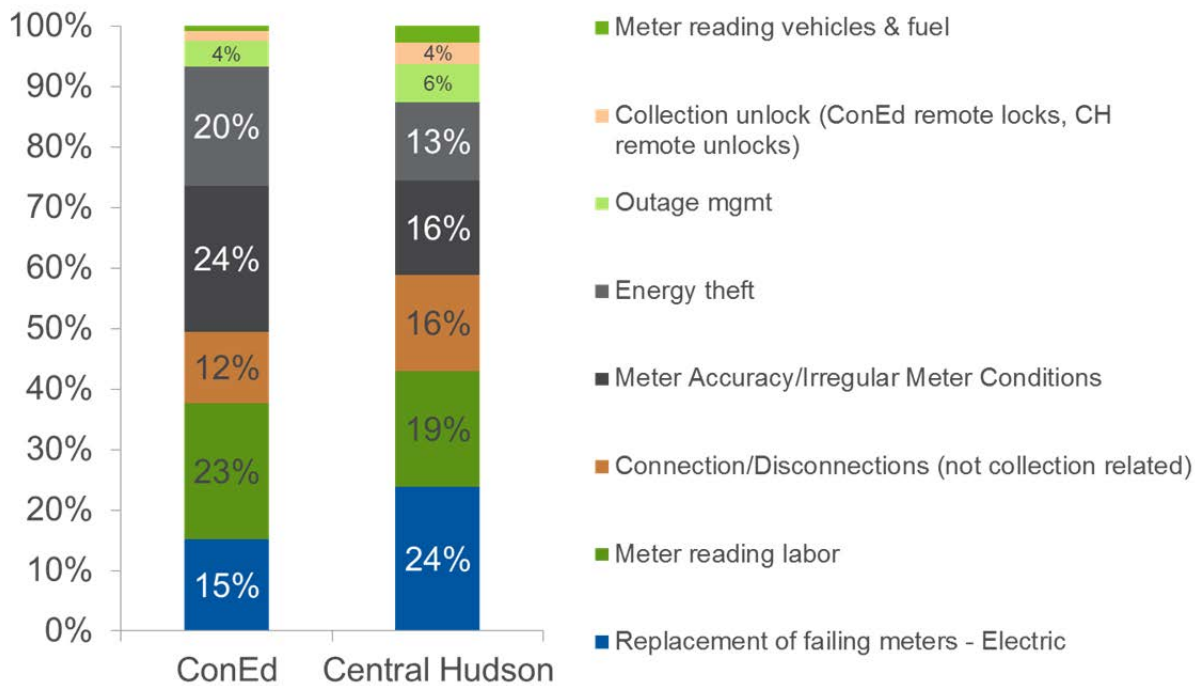
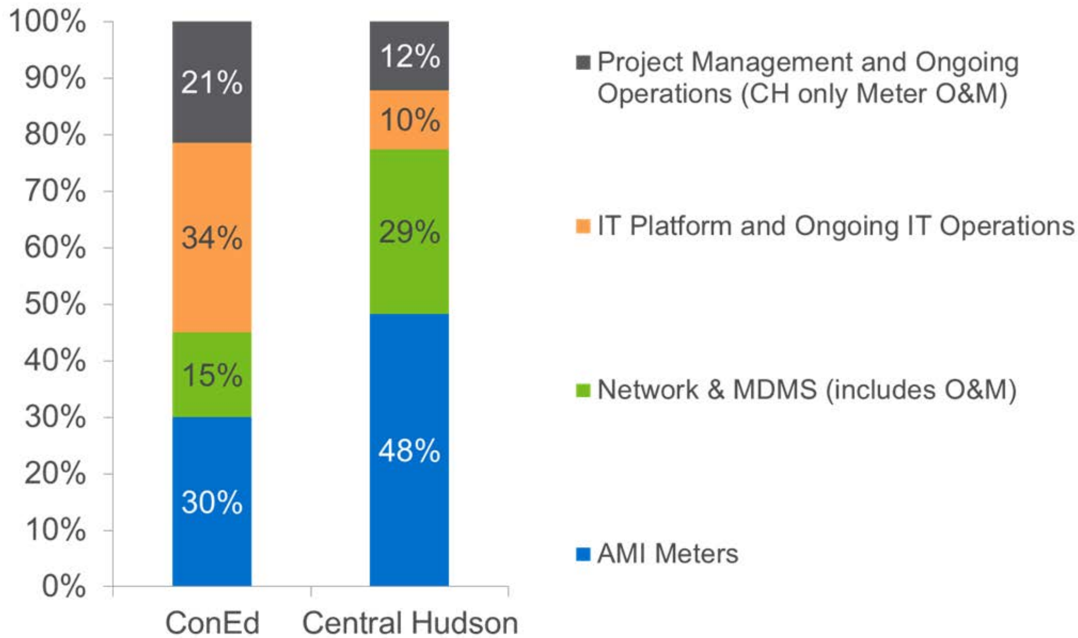


Figure A - 2 shows the relative cost comparison for ConEd and Central Hudson. The two cost categories with the greatest discrepancy are IT costs and AMI meters cost. However, when comparing only the upfront meter cost (equipment and installation only) for ConEd and Central Hudson meter costs are relatively close.[42] This means that difference in IT costs is likely the greatest source of discrepancy. While a detailed comparison of IT costs is not possible with the information provided in the ConEd business plan, this high level comparison suggests that the IT cost estimates used in the Central Hudson analysis are, if anything, not likely to be overestimated. This is a key point because one important reason why AMI proved to be cost ineffective in this analysis is that there are relatively few meters across which to spread foundational IT costs. The ConEd comparison suggests that this does not mean that the IT costs are high as compared to other utilities, rather that there are simply too few meters for AMI benefits to outweigh the cost of AMI.

[42] Total meter cost in the ConEd business case was $777 million for 3.55 million meters, or $162 per meter. The average cost for Central Hudson is $143.

Figure A - 2: Comparison of Common AMI costs for ConEd and Central Hudson



Appendix B AMI Business Case Assumptions: Full Deployment

B.1 General analysis assumptions

Meter population and deployment rates

METER VOLUME	Electro-mechanical	Electronic Meters	Multi Phase Meters	Gas Meters
Units (starting)	161,151	123,652	12,023	82,546
Achievable AMI deployment rate	95%	95%	95%	95%
Percent of AMI meters that will be cell	2%	2%	2%	2%
Population growth (%)	0.50%	0.50%	0.50%	0.50%

Deployment scenario

Deployment scenario	Full
AMI deployment starting in...	2020
Years of Deployment	5

Net present value

Net Present Value assumptions	
Analysis Period (in years)	20
Discount Rate (Pre tax WACC)	9.43%
Discount Rate (Post tax WACC)	6.62%
Discount Rate (Carbon)	3.00%
General Inflation Rate	2.10%
Labor Cost Escalation Rate	2.10%

B.2 Benefit assumptions

B.2.1 Meter reading

Inputs

AVOIDED COST - Meter Readings (2016$)	Employee	Contractor	Contractor or Employee
FTE (starting)	16	15	
Annual FTE Salary Costs (including benefits)	$51,376	$50,072	
Vehicle Costs - excluding fuel (hourly)	$7.71		
Fuel Costs (hourly)	$2.38		
% of Meter Reading Costs Avoided	70%	100%	
Routes per reader per year			40
Hours per reader per year (for applying vehicle & fuel costs)			2,000
Meters per day per reader (before deployment)			306
Meters per day per reader (after full deployment)			150

Assumptions

- Inputs provided by CH staff
- Salary includes benefits for employees, vehicle costs for contractors
- $Meters\ per\ day_{baseline} = \frac{meter\ population}{FTEs\ {*}routes\ per\ FTE}$
- Meters / day/ reader much lower after full deployment due to dispersed, rural non-AMI meter population

B.2.2 Outage management

Inputs

AVOIDED COSTS - Faster restoration times (2016$)	Storm - Base	Storm - OT	Trouble orders - OT
Budget - expense	$1,276,856	$1,124,787	$1,153,172
% of costs eliminated	10.0%	10.0%	0.0%

AVOIDED COSTS - Outage location time (2016$)	Storm	Non storm
Number of outages (annual avg, 2010-2015)	2,720	6,079
Average time to locate an outage (hours)	1.1	1.1
Reduction in outage location time due to AMI (%)	0.0%	10.0%
Hourly labor cost	$150	$100
Hourly equipment cost	$22	$22

AVOIDED COSTS - Truckrolls due to customer side "outages" (2016$)	Storm	Non storm
Number of customer calls	6,854	3,125
Share of customer calls causing truckroll	20.0%	20.0%
Share of customer truckrolls avoided	80.0%	80.0%
Labor Cost per truck roll	$79	$79
Equipment Cost per truck roll	$29	$29

Assumptions

- Inputs provided by CH staff; equipment costs assume service truck / bucket truck class
- Cost reductions allocated on a yearly basis proportionately to AMI meter population
- Outage costs based on 5 year historical (2011-2015) average total costs across all eight districts

B.2.3 Field operations (remote connect / disconnect, read over)

Inputs

AVOIDED COSTS - Field operations connect / disconnect (2016$)	Lock/unlock	Read overs	Collection unlock
Average annual volume	25,551	1,800	10,663
Avoidance rate (electric meters only)	85%	100%	85%
Labor & vehicle hours saved per operation	0.5	0.5	0.5
Hourly labor rate	$79.00	$79.00	$55.00
Hourly vehicle rate	$9.00	$9.00	$7.00
Locking collar unit cost	$10.00		

Assumptions

- Inputs provided by CH staff
- Only locks / unlocks with no gas are avoided
- Only Collection related remote locks are explicitly disallowed so unlock may be permissible

B.2.4 Replacement of failing meters

Inputs

METER COSTS (2016$)	Electronic
Meter useful life	30
Meter cost - simple (includes tax)	$ 40.00
Install cost - simple	$ 89.00
Meter testing simple	$ 1.18
Meter cost - complex / polyphase / demand (incl	$ 170.00
Install cost - complex / polyphase / demand	$ 89.00
Meter testing complex / polyphase / demand	$ 6.25
% complex / polyphase / demand installs	2.8%
Meter IT processing (CSR labor)	$ 9.23

Assumptions

- Meters are replaced at the end of useful life
- Meter age distribution based on install date of existing stock
- Only applied to meters replaced earlier due to AMI

B.2.5 Energy Theft and Meter accuracy

Inputs

Transfer/Equity - Unaccounted for energy (2016$)	Electromech	Electronic	Demand AMR
Average annual usage per meter (kWh)	5,634	7,520	100,972
Unbilled kWh %	1.0%	1.0%	1.0%
Theft avoidance rate	25.0%	25.0%	25.0%
Recovery improvement from meter accuracy	1.0%	0.0%	0.0%

Assumptions

- Benefits are not operational, but rather transfers between ratepayers (leading to more fair allocation of costs across rates) so only apply to RIM test
- Benefit is delivery charge + wholesale avoided energy charge (LBMP) for both avoided theft and improved meter accuracy
- Meter accuracy only applies to replaced electro mechanical meters

B.3 Cost assumptions

B.3.1 AMI meter cost

Inputs

METER COSTS (2016$)	AMI - Mesh	AMI - Cell	Gas Meter / Module
Meter useful life	20	20	30
Meter cost - simple (includes tax)	$ 103.64	$ 238.70	$ 58.51
Install cost - simple	$ 25.00	$ 25.00	$ 27.66
Meter testing simple	$ 0.52	$ 0.52	$ 1.18
Meter cost - complex / polyphase / demand (includes	$ 211.58	$ 596.75	$ 95.66
Install cost - complex / polyphase / demand	$ 75.00	$ 97.50	$ 100.85
Meter testing complex / polyphase / demand	$ 6.25	$ 6.25	$ 6.25
% complex / polyphase / demand installs	2.8%	2.8%	2.8%
Meter IT processing (CSR labor)	$ 9.23	$ 9.23	$ 9.23
Panel repair equipment cost	$ 400.00	$ 400.00	
Panel repair labor cost	$ 200.00	$ 200.00	
% installs needing panel repair	2.5%	2.5%	
Adapters (Old panels)	$ 90.00	$ 90.00	
Adapter installation labor cost	$ 25.00	$ 25.00	
% of sites requiring adapters	5%	5%	
Locking Rings (Tamper proofing)	$ 3.00	$ 3.00	
Meter Seals (Tamper proofing)	$ 1.00	$ 1.00	

Assumptions

- Inputs based on knowledge of industry costs, including Itron quote provided to Central Hudson

B.3.2 Network & software cost

Inputs

AMI NETWORK COSTS (2016$)	Radio only	Concentrator + radio
Number of concentrators planned (DA)	3,000	
Incremental units to support AMI (Full deployment)	100%	10%
Install / retrofit cost	$ 1,000	$ 4,000
Equipment cost	$ 1,000	$ 5,000

METER DATA MGMT & OTHER IT COSTS (2016$)	Initial Costs	Annual O&M
Head End and MDM hardware (utility hosted)	$ 3,392,000	$ 678,400
Software licensing fees (utility hosted only)	$ 2,000,000	$ 400,000
Central Hudson IT costs (Billing system & integration)	$ 2,342,382	$ 636,476
Other Central Hudson labor (1 meter shop FTE for MDM)		$ 150,000

Assumptions

- Network cost inputs based on industry knowledge plus staff discussions of DA deployment plan
- MDMS inputs based on knowledge of industry costs, including Itron quote provided to Central Hudson
- O&M assumed to be a percent of initial cost:
  - MDMS hardware: 20%
  - IT integration: 20%

B.3.3 O&M cost

Inputs

AMI NETWORK O&M COSTS (2016$)	Meter (Cell & Mesh)	Mesh Network
Equipment warranty period (years)	2.0	2.0
Failure rate after warranty	0.5%	0.5%
Communication ($/unit-year) (cell meters)	$ 15.00	$ -
Meter data management ($/meter-year)	$ 1.00	

Assumptions

- Inputs based on knowledge of industry costs, including Itron quote provided to Central Hudson
- O&M assumed to be a percentage of initial cost:
  - MDMS hardware: 20%
  - IT integration: 10%

B.3.4 PMO: Project Management & Central Hudson Labor

Item Description	Cost	FTE's	Units	Unit Type	Total Cost	Internal	External	Total
Customer engagement consultant to run customer engagement process	$ 57.69	-	66	Months	$ -		$ -	$ -
Customer engagement radio interference issues	$ 57.69	0	66	Months	$ 164,683	$ 164,683		$ 164,683
Customer Engagement internal management	$ 57.69	0	66	Months	$ 164,683	$ 164,683		$ 164,683
Director	$ 57.69	1	66	Months	$ 658,731	$ 658,731		$ 658,731
Assoc Director IT Lead	$ 57.69	1	66	Months	$ 658,731	$ 658,731		$ 658,731
Administration	$ 57.69	-	66	Months	$ -	$ -		$ -
Budget/Contracts	$ 57.69	-	66	Months	$ -	$ -		$ -
Customer Communication	$ 57.69	-	66	Months	$ -	$ -		$ -
OT AMI Lead	$ 57.69	-	66	Months	$ -	$ -		$ -
Network Lead	$ 57.69	-	66	Months	$ -		$ -	$ -
Legal and Regulatory	$ 57.69	1	66	Months	$ 329,365		$ 329,365	$ 329,365
Implementation Lead	$ 57.69	-	66	Months	$ -	$ -		$ -
Process Change/Exceptions Management Lead	$ 57.69	-	66	Months	$ -	$ -		$ -
Exception Management	$ 57.69	2	66	Months	$ 1,317,462	$ 1,317,462		$ 1,317,462
Exception Management Support (CSRs)1	$ 51.50	3	66	Months	$ 1,764,218		$ 1,764,218	$ 1,764,218
Expenses (office space, travel, lodging,)			66	Months	$ -			$ -
AMI Vendor Services (setup & integration services for Mesh Network)					$ 5,691,000		$ 5,691,000	$ 5,691,000
Meter Tester[2]	$ 57.69	1	66	Months	$ 658,704			$ 658,704
Real Estate	$ 57.69	-	66	Months	$ -		$ -	$ -
Meter Lead	$ 57.69	-	66	Months	$ -	$ -		$ -
Procurement	$ 57.69	-	66	Months	$ -	$ -		$ -
Cyber Security lead	$ 57.69	1	66	Months	$ 658,731	$ 658,731		$ 658,731
Staff Support for Training	$ 57.69	1	66	Months	$ 329,365	$ 329,365		$ 329,365
Total					**$ 12,395,672**	**$ 3,952,385**	**$ 7,784,583**	**$ 12,395,672**

Appendix C AMI Business Case Assumptions: Partial Deployment

C.1 General analysis assumptions

Meter population and deployment rates

METER VOLUME	Demand Meters
Units (starting)	12,023
Achievable AMI deployment rate	95%
Percent of AMI meters that will be cell	100%
Population growth (%)	0.50%

Deployment scenario

Deployment scenario	Partial
AMI deployment starting in...	2020
Years of Deployment	2

Net present value

Net Present Value assumptions	
Analysis Period (in years)	20
Discount Rate (Pre tax WACC)	9.43%
Discount Rate (Post tax WACC)	6.62%
Discount Rate (Carbon)	3.00%
General Inflation Rate	2.10%
Labor Cost Escalation Rate	2.10%

C.2 Benefit assumptions

C.2.1 Meter reading

Inputs

AVOIDED COST - Meter Readings (2016$)	Employees	Contractor	Contractor or Employee
FTE (starting)	16	15	
Annual FTE Salary Costs (including benefits)	$51,376	$50,072	
Vehicle Costs - excluding fuel (hourly)	$7.71		
Fuel Costs (hourly)	$2.30		
% of Meter Reading Costs Avoided	70%	100%	
Routes per reader per year			40
Hours per reader per year (for applying vehicle & fuel costs)			2,000
Meters per day per reader (before deployment)			306

Assumptions

- Inputs provided by CH staff
- Salary includes vehicle costs for contractors
- $Meters\ per\ day_{baseline} = \frac{meter\ population}{FTEs * routes\ per\ FTE}$
- Few routes are eliminated so only contract labor is avoided

C.2.2 Outage management

Inputs

AVOIDED COSTS - Faster restoration times (2016$)	Storm - Base	Storm - OT	Trouble orders - OT
Budget - expense	$1,276,856	$1,124,787	$1,153,172
% of costs eliminated	10.0%	10.0%	0.0%

AVOIDED COSTS - Outage location time (2016$)	Storm	Non storm
Number of outages (annual avg, 2010-2015)	2,720	6,079
Average time to locate an outage (hours)	1.1	1.1
Reduction in outage location time due to AMI (%)	0.0%	10.0%
Hourly labor cost	$150	$100
Hourly equipment cost	$22	$22

AVOIDED COSTS - Truckrolls due to customer side "outages" (2016$)	Storm	Non storm	Demand meter portion
Number of customer calls	6,854	3,125	10%
Share of customer calls causing truckroll	20.0%	20.0%	95.0%
Share of customer truckrolls avoided	80.0%	80.0%	5.0%
Equipment Cost per truck roll	$29	$29	

Assumptions

- Inputs provided by CH staff; equipment costs assume service truck / bucket truck class
- Cost reductions allocated on a yearly basis proportionately to AMI meter population
- Outage costs based on 5 year historical (2011-2015) average total costs across all eight districts

C.2.3 Field operations (remote connect / disconnect, read over)

Inputs

AVOIDED COSTS - Field operations connect / disconnect (2016$)	Lock/unlock	Read overs	Collection unlock
Average annual volume	25,551	1,800	10,663
Avoidance rate (single phase demand meters)	85%	100%	0%
Labor & vehicle hours saved per operation	0.5	0.5	0.5
Hourly labor rate	$79.00	$79.00	$55.00
Hourly vehicle rate	$9.00	$9.00	$7.00
Locking collar unit cost	$10.00		
Percent demand which are single phase (only single phase avoided)	31.6%		

Assumptions

- Inputs provided by CH staff
- Only locks / unlocks with no gas are avoided
- Collection related remote locks are not applicable to demand meters
- Annual volume is for all Central Hudson, assumed to be proportional to number of meters (only portion allocated to single phase demand meters is avoidable)

C.2.4 Replacement of failing meters

Inputs

METER COSTS (2016$)	Electronic
Meter useful life	30
Meter cost - complex / polyphase / demand (includes tax)	$ 170.00
Install cost - complex / polyphase / demand	$ 89.00
Meter testing complex / polyphase / demand	$ 6.25
% complex / polyphase / demand installs	100.0%
Meter IT processing (CSR labor)	$ 9.23

Assumptions

- Meters are replaced at the end of useful life
- Meter age distribution based on install date of existing stock
- Only applied to meters replaced earlier due to AMI

C.2.5 Energy Theft and Meter accuracy

Inputs

Transfer/Equity - Unaccounted for energy (2016$)	Electromech	Electronic	Demand AMR
Average annual usage per meter (kWh)	5,634	7,520	100,972
Unbilled kWh %	1.0%	1.0%	1.0%
Theft avoidance rate	25.0%	25.0%	25.0%
Recovery improvement from meter accuracy	1.0%	0.0%	0.0%

Assumptions

- Benefits are not operational, but rather transfers between ratepayers (leading to more fair allocation of costs across rates) so only apply to RIM test
- Benefit is delivery charge + wholesale avoided energy charge (LBMP) for both avoided theft and improved meter accuracy
- Meter accuracy improvement does NOT apply to demand meters

C.3 Cost assumptions

C.3.1 AMI meter cost

Inputs

METER COSTS (2016$)	AMI - Cell
Meter useful life	20
Meter cost - complex / polyphase / demand (includes tax)	$ 596.75
Install cost - complex / polyphase / demand	$ 97.50
Meter testing complex / polyphase / demand	$ 6.25
% complex / polyphase / demand installs	2.8%
Meter IT processing (CSR labor)	$ 9.23
Panel repair equipment cost	$ 400.00
Panel repair labor cost	$ 200.00
% installs needing panel repair	2.5%
Adapters (Old panels)	$ 90.00
Adapter installation labor cost	$ 25.00
% of sites requiring adapters	5%
Locking Rings (Tamper proofing)	$ 3.00
Meter Seals (Tamper proofing)	$ 1.00

Assumptions

- Inputs based on knowledge of industry costs, including Itron quote provided to Central Hudson

C.3.2 Network & software cost

Inputs

METER DATA MGMT & OTHER IT COSTS (2016$)	Initial Costs	Annual O&M
Vendor Hosted Head End & MDM option (O&M per cell meter)		$13.20
Central Hudson IT costs (Billing system & integration)	$ 2,342,382	$ 636,476
Other Central Hudson labor (1 meter shop FTE for MDM)		$ 150,000

Assumptions

- Zero network costs due to 100% cell deployment
- MDMS inputs based on knowledge of industry costs, including Itron quote provided to Central Hudson
- O&M assumed to be a percentage of initial cost:
  - MDMS hardware: 20%
  - IT integration: 20%

C.3.3 O&M cost

Inputs

AMI NETWORK O&M COSTS (2016$)	Meter (Cell & Mesh)	Mesh Network
Equipment warranty period (years)	2.0	2.0
Failure rate after warranty	0.5%	0.5%
Communication ($/unit-year) (cell meters)	$ 15.00	$ -

Assumptions

- Inputs based on knowledge of industry costs, including Itron quote provided to Central Hudson

C.3.4 PMO: Project Management & Central Hudson Labor

Item Description	Cost	Partial Deplo	Units	Unit Type	Total Cost	Internal	External	Total
Customer engagement consultant to run customer engagement process	$ 57.69	-	24	Months	$ -		$ -	$ -
Customer engagement radio interference issues	$ 57.69	-	24	Months	$ -	$ -		$ -
Customer Engagement internal management	$ 57.69	0.25	24	Months	$ 59,885	$ 59,885		$ 59,885
Director	$ 57.69	-	24	Months	$ -	$ -		$ -
Assoc Director IT Lead	$ 57.69	-	24	Months	$ -	$ -		$ -
Administration	$ 57.69	1.00	24	Months	$ 239,538	$ 239,538		$ 239,538
Budget/Contracts	$ 57.69	-	24	Months	$ -	$ -		$ -
Customer Communication	$ 57.69	-	24	Months	$ -	$ -		$ -
OT AMI Lead	$ 57.69	-	24	Months	$ -	$ -		$ -
Network Lead	$ 57.69	-	24	Months	$ -		$ -	$ -
Legal and Regulatory	$ 57.69	0.25	24	Months	$ 59,885		$ 59,885	$ 59,885
Implementation Lead	$ 57.69	-	24	Months	$ -	$ -		$ -
Process Change/Exceptions Management Lead	$ 57.69	-	24	Months	$ -	$ -		$ -
Exception Management	$ 57.69	0.50	24	Months	$ 119,769	$ 119,769		$ 119,769
Exception Management Support (CSRs)1	$ 51.50	0.50	24	Months	$ 106,922		$ 106,922	$ 106,922
Expenses (office space, travel, lodging,)			24	Months	$ -			$ -
AMI Vendor Services (setup for hosted MDM option)					$ 648,007		$ 648,007	$ 648,007
Meter Tester[2]	$ 57.69	1.00	24	Months	$ 239,529			$ 239,529
Real Estate	$ 57.69	-	24	Months	$ -		$ -	$ -
Meter Lead	$ 57.69	-	24	Months	$ -	$ -		$ -
Procurement	$ 57.69	-	24	Months	$ -	$ -		$ -
Cyber Security lead	$ 57.69	0.25	24	Months	$ 59,885	$ 59,885		$ 59,885
Staff Support for Training	$ 57.69	-	24	Months	$ -	$ -		$ -
Total					**$ 1,533,420**	**$ 479,077**	**$ 814,814**	**$ 1,533,420**

Appendix D AMI Enabled Rates and Programs

D.1 Prepayment program

Benefit needing regulatory change - Prepayment program (2016$)	Electromech	Electronic
Savings per participant (% of kWh, per lit review, also applied to kW)	12.0%	12.0%
Participation rate (per lit review)	12.0%	12.0%
Avg summer peak reference load (kW), all customers	1.7	1.7
Program annual O&M per participant (1 touch per year)	$10	$10
Setup cost, e.g. 30 min FTE (per participant)	$20	$20
Program set up costs (marketing, program design, website, etc)	$300,000	
Program set up cost (IT)	$702,714	
Program annual overhead cost (IT)	$140,543	
Program annual overhead cost (admin)	$150,000	
lbs CO2 per MWh (baseload upstate NY, EPA EGrid)	408.8	
Carbon value ($/2000 lbs - EPA Social Cost of Carbon)	$36	

D.2 Time varying pricing

Benefit needing regulatory change - Time varying pri	Res, Non-demand	Non-Res, Non-demand	Demand
TVP rate type (only TOU for non-res)	TOU-CPP	TOU	TOU
Customer recruitment target (by usage	Top 80%	All	All
non-res combined)	232,110		12,023
Enrollment option	Optin	Default	Default
Enrollment level	Medium	Medium	Medium
Annual attrition rate (same for all	7%		
Enrollment rate (among target)	15.0%	90.0%	90.0%
Participation rate (enrollment % * target %)	12.0%	90.0%	90.0%
Avg summer peak reference load (kW)	2.0	0.7	22.7
Avg summer peak % reductions (kW)	19.2%	2.0%	2.0%
Avg summer peak kW demand reduction	0.37	0.01	0.45
Avg annual kWh savings per participant	0.2	72.3	1,405.1
Recruitment cost per participant (variable)	$62.84	$9.98	$9.98
Annual O&M per participant (variable)	$7.88	$2.18	$2.18

TVP IT and Program costs	CH IT (full)	CH IT (partial)	Rate design, website
Program setup (fixed)	$4,050,000	$1,000,000	$322,000
Annual O&M (fixed)	$706,000	$96,000	$335,000

Appendix G Capital Prioritization Process Guidelines

Capital Prioritization Process Guidelines

Last Major Revision: May 2015

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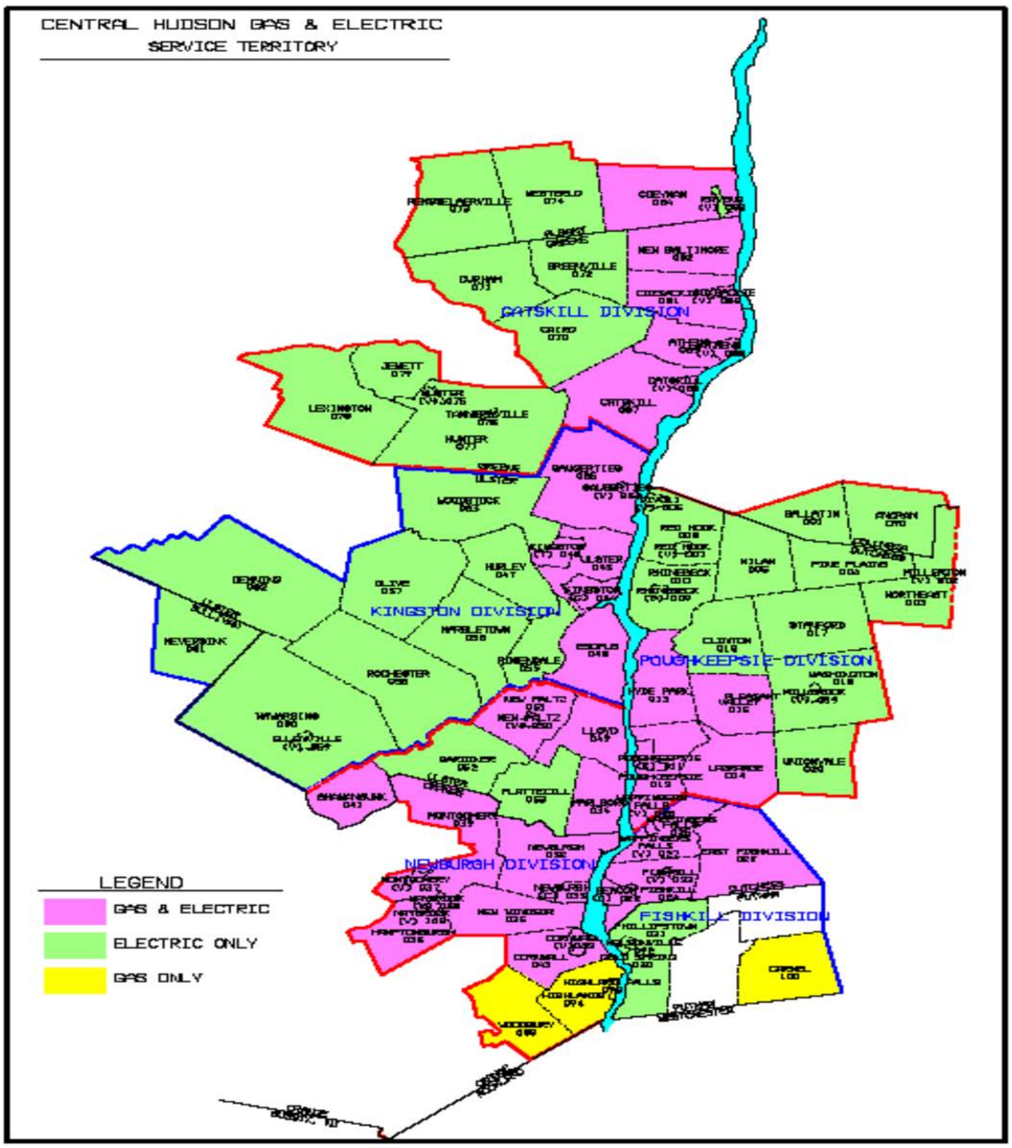
<u>Appendices</u>

1. Introduction

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving approximately 300,000 electric customers and 78,000 natural gas customers in New York State's Mid-Hudson River Valley. Central Hudson delivers natural gas and electricity in a defined service territory that extends from the suburbs of metropolitan New York City north to the Capital District at Albany. Central Hudson is a leader in promoting regional economic growth, improving system reliability, and effective cost management.



Central Hudson owns approximately 81 substations having an aggregate transformer capacity of 5,400 MVA. Central Hudson's electric transmission system consists of 629 pole miles of line. The electric distribution system consists of 7,300 pole miles of overhead lines and 1,400 trench miles of underground lines, as well as customer service lines and meters. Central Hudson's natural gas system consists of 164 miles of transmission pipelines and 1,193 miles of distribution pipelines, as well as customer service lines and meters.

This document provides guidelines for the development and prioritization of the various capital projects and programs that constitute the annual, five year, and ten year capital expenditure budget and forecast to maintain and improve the electric and gas system and operate the business. The output of this process is compiled into a 5 Year Corporate Capital Forecast, which is produced each year. This document is broken down into eight sections subsequent to the Introduction:

(2) Mission, Vision, Strategy, and Goals – provides an overview of these corporate attributes and committees related to Capital Prioritization

(3) Project Categorization – describes our business segments as well as the various methodologies by which capital projects and programs are categorized and analyzed

(4) Corporate Framework for Project Development and Assessment – describes costs and benefits of capital projects and programs and how alternatives are evaluated

(5) Electric – describes the project and program development process and the various prioritization methods specific to the Electric Budget

(6) Gas – describes the project and program development process and the various prioritization methods specific to the Gas Budget

(7) Common (Future Use)

(8) Corporate Capital Budget/Forecast – describes how the Electric, Gas, and Common capital budgets and forecasts are aggregated and the interplay between the budgets

(9) Conclusion

2. Mission, Vision, Strategy, and Goals

2.1 Corporate Mission, Vision, and Strategy

Mission Statement

Central Hudson's mission is to deliver electricity and natural gas to an expanding customer base in a safe, reliable, courteous and affordable manner; to produce growing financial returns for shareholders; to foster a culture that encourages employees to reach their full potential; and to be a good corporate citizen.

Our Vision

We will be recognized as the best energy provider by customers, investors, and employees.

Strategy Statement

Provide exceptional value to Central Hudson customers by:

- Practicing continuous improvement in everything we do.
- Investing in T&D infrastructure to enhance reliability, improve customer satisfaction, and reduce risk.
- Moderating cost pressures that increase customer bill levels and variability.
- Advocating on behalf of customers and other stakeholders.
- Investing in the development of employees to meet the business needs of today and the future.

2.2 Alignment of Capital Prioritization with Goals

As Central Hudson progresses through the Corporate Planning Cycle the Business Plans are developed. Central Hudson's Business Plan is designed to balance the needs of customers and shareholders by balancing operating and financial performance. The Business Plan process includes both top-down and bottom-up planning. The Business Planning Process establishes team goals that align with the corporate strategy, as well as prioritization of major corporate initiatives, including the development of the Capital forecast and Budget. The development and alignment of corporate, team, and individual goals enables the development and proposal of capital projects and programs to reach to these goals. These capital projects and programs are then prioritized through the process described in these guidelines.

2.3 Committees

The following committees support the prioritization and implementation of the capital plan:

2.3.1 Capital Asset Review and Evaluation (CARE)

The CARE Committee provides ongoing monitoring and management of the Company's capital expenditures, separate from the initial Capital Prioritization process. It serves as a governance function for the Central Hudson Board of Directors regarding the company's capital planning and expenditures. The CARE Committee is responsible for providing oversight for the development of the Five Year Capital Plan consistent with the Company's long range strategic business plans and initiatives. The CARE Committee is responsible for evaluating and recommending expenditures of funding for all capital budget categories in the Corporate Annual Capital Budget prior to submission to the Strategic Planning Committee.

Two significant project management roles of the CARE Committee include:

- Review and approval of proposed projects, ensuring each recommended project or program is justified or still justified based on the most current conditions, and has a designated project manager, along with an effective plan, budget, schedule and process for monitoring performance.

- Overall monitoring of key performance indicators of projects and their respective portfolios.

Additional information on the CARE Committee can be found in the *"Capital Asset Review & Evaluation Committee (CARE) Charter:"*

2.3.2 Information Technology Steering Committee (ITSC)

The Mission of the Information Technology Steering Committee is to:

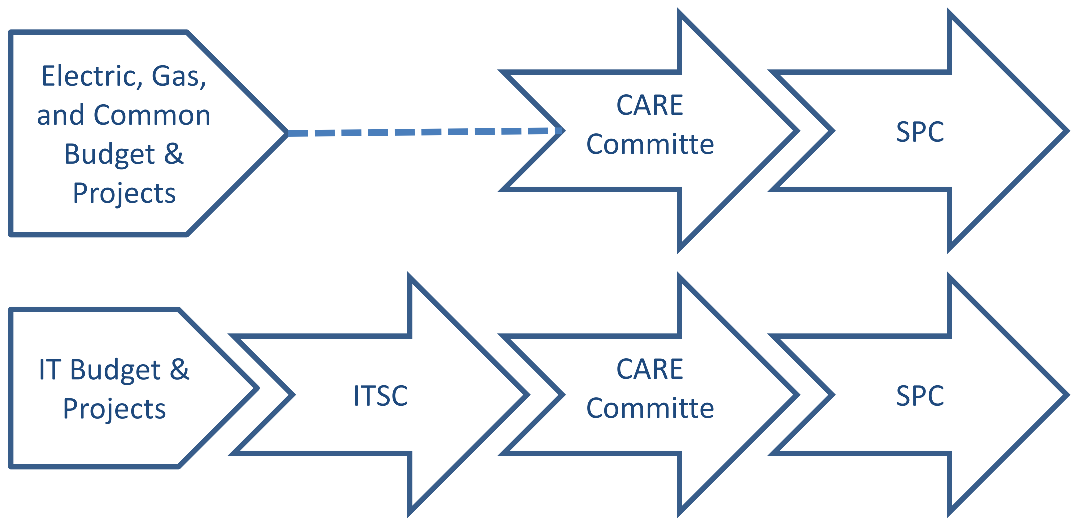
1. Oversee the preparation and monitoring of IT strategies and plans to ensure they align with business strategies. The strategy and plans will be reviewed annually and developed based on a 5 year time horizon.
2. Establish a governance framework and supervise the procurement, delivery, and use of information technology assets across the Central Hudson organization, regardless of the area initiating, delivering, managing, or using the technology asset. This charge will fulfill the committee's obligation to assist the Central Hudson Gas and Electric Board of Directors with their responsibilities for IT governance.
3. Establish a risk assessment methodology to assess, measure, and mitigate risks that threaten our organization's information assets and associated information technology resources. This charge will protect and preserve our assets, privacy of stakeholders, legal standing of the organization and public image of the organization.

The IT Steering Committee will review and recommend approval of all new initiatives (hardware and/or software), changes in IT operating budgets, and IT operational and maintenance activities that exceed $75,000. IT capital projects that meet the thresholds for review of both the ITSC and the CARE committee must be reviewed and approved by both committees.

2.3.3 Strategic Planning Committee (SPC)

The Strategic Planning Committee's purpose is to develop and frequently update and refine a comprehensive long-term strategy for review and approval by the Strategy and Finance Committee and the Board of Directors. The Committee has responsibility for developing corporate objectives that are consistent with and further the strategic direction of the Company, and overseeing their implementation. The Committee's value is realized through the application of its collective industry expertise, organizational leadership, strategic insights, and tactical experience. The Committee's ultimate objective is to position CH Energy Group to meet or exceed shareholder expectations and balance the needs of all stakeholders over the long-term.

The SPC reviews and approves the 5 year Capital Forecast and the following year's Capital Budget on an annual basis and provides insight into major initiatives prior to Fortis and Central Hudson Board of Directors (BOD) review. It also reviews the 10 year forecast and provided strategic input and alignment. The BOD as part of the annual business plan approved process approves the total level of corporate capital expenditures for the following year; including a contingency budget, which is typically 5%. This authorization does not specify project expenditures or specific limits within the electric, gas, and common programs, enabling the BOD to exercise their fiduciary responsibilities while providing the Company flexibility to adapt to changing conditions.



3. Project Categorization

3.1 Introduction

Capital budget projects and programs are categorized in several different ways to meet regulatory and accounting requirements, to assist in analyzing the capital forecast and budget on a summary basis, and to measure and analyze performance against corporate or regulatory targets. This section describes the different methods by which budget projects must be categorized.

3.2 Business Segments

3.2.1 Electric, Gas, Common

Central Hudson Gas & Electric's two primary businesses are electric and gas energy delivery. Capital projects typically impact only one business segment and are budgeted and charged to a budget group within that segment. In addition, independent budgeting and work order development will occur for projects that can be clearly split between the two segments. This includes most field projects involving electric or gas infrastructure.

In addition to these specific electric or gas capital projects or programs, there are some projects that benefit both the electric and gas businesses. These include projects in areas such as Land and Buildings, Information Technology, Office Equipment, and Transportation. These projects are budgeted within the Common Area, with costs allocated to the gas and electric businesses as agreed to in the current rate plan.

3.2.2 Budget Category

Within the Electric, Gas, and Common programs, the budget is subdivided into smaller groups representing each major category within Electric, Gas, and Common. The following is a list of Budget Categories and numbers:

ELECTRIC PROGRAM

- 11 – Hydro & Gas Turbines
- 12 – Transmission
- 13 – Substations
- 14 – New Business
- 15 – Distribution Improvements
- 16 – Transformers
- 17 – Meters

GAS PROGRAM

22 – Transmission
23 – Regulator Stations
24 – New Business
25 – Distribution Improvements
27 – Meters

COMMON PROGRAM

41 – Buildings
42 – Office Equipment (including Software, Hardware, and Security)
43 – Tools
44 – Communication
45 – Transportation

3.3 Expenditure Categorization

3.3.1 Summary Categories

Capital forecasts and expenditures Company have been historically defined into three major 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.

3.3.1.1 Non-Discretionary

Non-discretionary projects and programs are those which are necessary to meet the minimum standards of service or compliance with Public Service Law. Examples of projects that may fall into this category are projects which restore service, enable mandated new business (tariff-based), complete safety repairs, rebuild highways, and facilitate compliance.

3.3.1.2 Maintain System Standards

Maintaining System Standards projects and programs are those which are required to maintain our current level of service reliability and safety or to meet obligations set through the rate proceedings. Examples of projects that may fall into this category are projects which replace equipment based upon condition or planned cycles or correct existing planning or design violations (such as thermal overload or undersized infrastructure).

3.3.1.3 *System Enhancement*

System Enhancement projects and programs are those which are aimed at improving our level of service reliability, reducing risk, or reducing operating costs. While projects that are Non-Discretionary or proposed to Maintain System Standards are required projects needed to continue to provide the existing levels of service quality and reliability, System Enhancement projects have more discretion, require a more in-depth prioritization process, and often provide an opportunity to improve Key Performance Indicators. Examples of projects that fit within this category are projects that improve service quality, provide a net financial customer benefit, or reduce risk. System enhancement projects or programs can be further compartmentalized into the following categories:

- **Projects with a Net Financial Benefit**
  - Projects revenue requirement of the capital investment is lower than the net benefit (e.g. cost savings)
  - Reduces customer bills in the long term

- **Projects that Reduce Risk**
  - Reduces the risk of a system failure that would:
    - Reduce potential public safety risk
    - Result in a widespread incident, impacting system integrity
    - Spur significant punitive regulatory action or reputational risk

- **Projects that Improve Reliability**
  - Improves reliability at a cost that that the Company assesses customers would be willing to pay
  - Demonstrates that increased cost is warranted by the improvement in service quality (benchmark and compare cost per customer outage avoided).

- **Other Projects**
  - Projects that do not clearly fit in the other three categories, but can be justified for other reasons
  - Requires a detailed individual business case

- Demonstrates a clear strategic rationale
- Shows financial projections (customer bill impact and earnings impact)
- Assesses risk (regulatory disallowance, etc.)

3.3.2 Investment Categories

In addition to the Summary Categories, 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, 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 and Gas Engineering Guidelines 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. The benefits and costs of project alternatives are discussed in Section 4.

  For some future projects, the Capital Forecast may include a placeholder capital project while the wires and non-wires alternatives are being analyzed.

- **Infrastructure** - The Electric System Planning Guides and Gas Operating and Maintenance Procedures 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 or G.L. Essentials (gas). 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 projects under Category 14 (Electric) and Category 24 (Gas) 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
    - Cast Iron Undermines
    - Storm-related replacements
    - Third party damage

4. Corporate Framework for Project Development and Assessment

The capital prioritization process includes two major steps: development and selection of project and project alternatives, and prioritization of the selected project alternatives. This section focuses on the development and selection of project and project alternatives by identifying costs and benefits for each project and project alternative and completing an alternatives analysis, with the prioritization of selected project alternatives described in later sections.

4.1 Costs

To properly evaluate project and project alternatives, the project cost estimates need to be prepared consistently. The cost estimates must include all project costs including capital and expense costs. The cost estimates for project alternatives being compared should be prepared to a similar level of accuracy. Finally, the project alternatives must be compared on a consistent basis, with costs brought to the same year basis and with the same levels of overhead applied.

Project costs are estimated and refined at various points in the Project Life Cycle. As a project evolves through the Life Cycle, project cost elements will become better defined and more detailed. Therefore, the project's cost estimate should also evolve and become more accurate. Most projects will be estimated to the Conceptual Estimate level for the purposes of the capital forecast and capital budget. The costs of major projects should be refined as the construction date comes closer, even within the capital budgeting and prioritization process. The cost estimate and contingency should be appropriate for where the project sits within its life cycle. During the evaluation of project alternatives, any risks should be identified for consideration. See Central Hudson's Project Management Manual: Procedures & Best Practices for additional information on Cost Estimates and Contingency

AFUDC, or "allowance for funds used during construction", is the component representing the cost of borrowed funds (interest) used during the construction period. AFUDC applies to all construction projects with a duration in excess of one month and costs of $50,000 or more. The cost estimator must include AFUDC as part of the project cost estimate, as it is a monthly charge to the project. AFUDC does not apply to IT projects.

4.1.1 Capital

Capital costs are all costs associated with the installation or retirement of plant on Central Hudson's system. Examples of equipment include poles, wire, pipe, vehicles, buildings, software and tools. The capital costs can include not only the equipment costs, but also the engineering, permitting, property and easement procurement, initial vegetation removal and site preparation, labor to install or remove capital equipment, contracted labor, drafting, and all of the associated overheads including AFUDC. The Company earns a regulated rate of return on the average book value of the asset class, accounting for the capital depreciated over the life of the asset. The decision whether or not a cost can be capitalized can be complex. The Accounting department can assist whenever there is any ambiguity.

4.1.2 Expense

Expenses include any charges associated with items that do not become assets on the Company's balance sheet. In addition, carrying costs of assets such as Operations and Maintenance (O&M), Property Taxes, and Depreciation are all expense items.

4.1.2.1 Project One Time Expense

A project One Time Expense is an expense that occurs with the initial startup of a project, and is expected to be an isolated expense that is not likely to occur again for the life of the project. An example of a one-time expense would be the transfer of existing equipment from an old facility to a new facility, such as the transfer of the customer's service from the old pole to the new pole.

4.1.2.2 Annual Reoccurring Cost

An annual recurring cost is an expense that is incurred for the life of the asset once it is placed into service. Examples of recurring costs would be rental expense on towers for communication system or additional O&M costs associated with the installation of a new regulator station.

4.2 Benefits

While estimating the cost of a project is important, the benefits are just as critical to understand the need and priority of a project. Benefits can be financial or non-financial and can also be either quantitative or qualitative. While some projects have an easily identified and measureable (quantifiable) financial benefit, the vast majority do not because the data and analytics are not available today. However, the qualitative benefits must be clearly identified so that Engineering judgment and experience can be applied to the prioritization process.

Benefits are classified into three categories: economic, service improvement, and risk reduction, and are described as follows:

4.2.1 Economic

Many capital projects can generate monetary savings or revenue that benefits Central Hudson and its customers. A measurable financial effect, such as reduced operating and maintenance costs, provides a direct economic benefit to Central Hudson. Indirect economic benefits as a result of capital improvement projects are financial cost savings that do not directly benefit Central Hudson yet have a positive impact on society. **Care must be taken not to mix direct and indirect benefits in a cost-benefit analysis.**

4.2.1.1 Direct

Direct economic benefits are the reduction in operation and maintenance (O&M) expenses to Central Hudson customers achieved by the replacement of aging infrastructure and the application of new technologies. While not all projects are driven by aging infrastructure, benefits will be accrued any time infrastructure is replaced with new materials that are less likely to experience failures that result in unplanned emergency work due to service outages and leaks, and may offer an opportunity to reduce maintenance and inspection frequency.

New and stronger infrastructure will also decrease the duration and the number of Company forces or mutual aid crews needed during a storm restoration or gas emergency.

Area growth, new construction standards, and rules and regulations typically dictate that an in-kind infrastructure replacement is not sufficient. Capital projects are designed and built with stronger facilities that can withstand more outside forces and/or superior equipment that can provide more capacity. In addition, the facilities and equipment may be relocated during the project from a remote right-of-way to a travelled road providing better access and quicker restoration during emergencies.

These projects typically result in higher expenditures than a replacement in kind project; however, these higher upfront costs reduce total life cycle costs, including future routine maintenance costs associated with inspections, tree trimming, and storm restorations.

In addition to the direct economic savings associated with a capital project, there are also direct economic savings with the avoidance of another capital or operating expenditure. In some instances, there is not a "do nothing" alternative, so another direct economic benefit of the project can also be quantified as the avoided costs of the minimum required alternative.

4.2.1.2 Indirect

Indirect economic benefits are nonmonetary savings for Central Hudson but provide beneficial impacts to society, the community, and/or the customer (not directly through rates). While these benefits should not be comingled with direct economic benefits in a net present value analysis, they should be considered in the Engineering judgment used to prioritize projects in a customer-centric environment.

Electric capital projects that include automation components and switched voltage control devices enhance the real time data available and enable higher penetration of distributed energy resources. The ability to reduce voltage through the control of these devices may result in reduced losses, and reduced kWh usage, reducing the energy supply component of the bill for all impacted customers. Reducing the energy supply requirements also reduces transmission congestion, which will reduce the NYISO's Locational Based Marginal Price (LBMP) and lower the cost of energy for customers.

During emergencies Central Hudson requires the assistance of Fire and Police Departments to evacuate buildings, close roads, and secure emergency areas. Reducing the number of risky pipelines and failing poles will reduce the number of emergencies and time duration emergency personnel are needed. In addition, reliability improvements can provide financial benefits to Central Hudson customers. The US Department of Energy has developed an Interruption Cost Estimate (ICE) Calculator that continues to evolve to estimate these costs.[1]

4.2.2 Service Improvement

Central Hudson Gas and Electric's mission is to safely plan, design, construct, operate, and maintain a reliable and affordable natural gas and electric transmission and distribution system that optimizes value for all stakeholders. The capital investments will maintain regulatory compliance, enhance reliability, improve customer satisfaction and reduce risk. Capital Projects also allow Central Hudson to identify and implement process improvements that enable the Company to continuously improve the way in which we fulfill our mission and moderate cost pressures that impact customer bills. Central Hudson's Engineering department has identified metrics that measure the capital program's contribution to Central Hudson's overall strategy.

Contribution of some projects to service benefits can be directly measured, whereas others must be described qualitatively using Engineering judgment and experience.

4.2.2.1 Reliability

Category 15 (Electric Distribution) projects that are driven by reliability indicators are prioritized using the following metrics:

System Average Interruption Frequency Index (SAIFI) is the frequency of electrical outages with a duration of 5 minutes or more per customer.

Electric Distribution Projects with reliability utilize the $/Customer Outage Avoided ($/COA) has a component of the project selection and prioritization process. This is calculated by dividing the cost of the project by the non-storm 5 year average number of customers experiencing outages. Only outages that will no longer be experienced upon completion of the project should be included in the calculation. For example, if a section of line is moved on-road, only outages that occurred in that section of line should be included in the COA.

[1] www.icecalculator.com

Customer Average Interruption Duration Index (CAIDI) measures the average duration of all customer outages within the year.

Operating based projects utilize the $/Customer Minute Avoided ($/CMA) as a component of the project selection and prioritization process. This is calculated by dividing the cost of the project by the 5-year average non-storm customer minutes experienced by the outage that exceed 2 hours. For example, a project that costs $360,000 and enables switching for an outage that averages 5 hours impacting 1,000 customers will have a $/CMA of $360,000/(1,000 customers * (60 minutes/hour * (5 hours – 2 hours))) = $2/CMA.

Storm interruption reduction benefits are captured as resiliency benefits.

4.2.2.2 Gas Safety

Gas Safety metrics track performance and monitor the risk of the gas system as a whole. Category 25's (Distribution Improvement) project proposals use the following metrics to as guidance to set the level of capital replacement spending as well as prioritize main replacement projects and other capital programs:

Y/E Leak Backlog is the number of active gas leaks at year end. A sub-set of the Y/E Leak backlog is **Repairable Leak Backlog**, which is the number of active Type 2 or 2A gas leaks at year end. Type 2 or 2A are leaks that due to their severity or proximity to buildings, require more frequent surveillance and prompt scheduled repairs. In addition, already repaired leaks are also considered in the project development and prioritization process.

Leak Prone Pipe is cast iron, wrought iron, or steel pipe without cathodic protection (corrosion protection) typically installed before 1971.

Pressure Service Replacement is the gas Capital Expenditures related to the replacement of steel services where the system pressures exceeds 2 psig and the regulators and meters are located inside of the dwelling or business.

Metallic Services Replaced is the annual number of services comprised of material other than plastic that were replaced. Their replacement is usually associated with a main replacement or leak repair.

4.2.2.3 Customer Satisfaction

Investing in capital projects that improve gas and electric infrastructure enhance reliability and reduce risk, thus improve customer satisfaction. The following indicators are measured to ensure Central Hudson is providing safe, reliable and affordable service to their customers. Although they cannot be directly measured, projects which contribute to improvement in these factors should still be noted and these factors weighed in the priority assessment.

PSC Complaints- The number of chargeable customer complaints received by the Public Service Commission related to Central Hudson per month per 100,000 customers

Customer Service Index – The customer satisfaction measure derived from our "How Are We Doing Survey?" reported to the PSC.

JD Powers- Customer Satisfaction Index as determined in the annual JD Power and Associates Electric Utility Residential Customer Satisfaction Study.

4.2.2.4 Thermal, Pressure, and Voltage, and Power Quality

Projects that allow the Company to maintain standard thermal, pressure and voltage on the electric and gas system are projects which are Non-Discretionary or Required to Maintain System Standards. However, prioritization of the projects will depend upon the expected or actual deficiency in these areas. Large projects involving new or rebuilt substations, transmission line rebuilds, or gas regulator stations are often developed and prioritized within an Electric or Gas Planning study. These projects are then added to the appropriate capital budget year and do not need to be reprioritized within the capital budgeting process.

Gas Pressure – Gas distribution systems must be designed to provide adequate service to all customer at all times. New York Codes, Rules and Regulations (NYCRR) Part 255.623 specifies the minimum delivery pressure for customers on low pressure systems. Central Hudson's Gas Distribution System Estimating Manual and Gas Distribution System Planning Guide specify the pressure requirements of medium and high pressure systems.

Electric Design and Thermal Limitations –
The Costs, Rates & Forecasts Division provides annual system demand forecasts. These forecasts are provided for a normal peak (i.e., 50-50 forecast) and an extreme peak (i.e., approximately a 95-5 forecast).

The summer and winter ratings of equipment on the electric system must be compared with the summer and winter peak loads. These limitations are described in the Electric System Planning Guides and Electric Distribution Engineering Guides.

Electric Voltage and Power Quality – The ANSI 84.1 Standard describes the voltage which must be maintained on the Electric System. In addition, the Electric Safety Standards Order adopted in PSC Case 04-M-0159 requires mitigation of stray voltages on the system. Some customers are sensitive to momentary interruptions or voltage sags and swells, which also must be considered.

Electric Load Serving Capability
The load serving capability (LSC) of Central Hudson's transmission system is its import capability plus the available internal generation. Central Hudson determines the amount of load that can be served by the electric transmission system without violating a thermal or voltage limit for the contingencies defined in the Transmission Planning Guidelines and identifies transmission reinforcement projects as required.

4.2.3 Risk Reduction

The replacement of infrastructure with new and stronger materials and better construction practices reduces the risk of an incident occurring on Central Hudson owned facilities. This inherently provides a safer environment, more compliant system, and stronger and more resilient infrastructure for Central Hudson employees, customers, and the public.

4.2.3.1 Safety

Central Hudson is very focused on the safety of their customers and employees. Currently employee safety metrics measure the number of occurrences and the severity of certain incidents that have occurred. While this metric is quantifiable, capital projects can also provide many indirect benefits that may not be captured by the safety metrics. Below are some examples of what Capital Projects can do to improve the health and livelihood of employees and the public:

- Improve accessibility by relocating electric and gas facilities closer to travelled road. (less off road walking, less carrying of material, less climbing of poles, less chance of insect bites, easier to ground)
- Correct an existing condition that is non-compliant with new regulations (line clearances, depth of cover, etc.)
- Strengthen infrastructure with more robust construction materials that can withstand outside forces such as storms and motor vehicles (less pole breakage, less digging holes and hauling of poles during storm conditions)
- Remove antiquated equipment and facilities such as oil switches, cast iron pipelines, below grade transmission valves and regulator stations (reduced work practices to operate or repair, squeeze versus bagging, confined entry practices, extended switching orders to avoid operating older equipment)
- Eliminate potential hazardous materials such as PCBs, lead, asbestos (reduced work practices, use of respirators, potential environmental releases)

All of the above mentioned benefits can lead to improved working conditions, allowing employees to perform more valuable work with more efficiency throughout a typical work day. In addition to our employees' safety, the safety of the general public is improved with new infrastructure built to our current construction standards.

4.2.3.2 Compliance

Central Hudson Gas and Electric complies with federal, state, and local codes and laws to maintain safe and reliable gas and electric facilities. New York State Public Service Law requires Central Hudson to collect and capture several metrics listed in the "Service" section.

Complying with code and laws ensures Central Hudson is safely and adequately operating and maintaining their gas and electric systems. Eliminating grandfathered facilities provides an opportunity to reduce exposure to the company and ensure compliance. Public service law and federal code regulations also require additional inspections when operating with antiquated facilities. For example, every winter, cast iron pipelines must be continuously surveyed for leaks and the severity of existing leaks monitored.

Various regulatory bodies including Public Service Commission (PSC), North American Electric Reliability Corporation (NERC), and US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHSMA) can audit Central Hudson for code compliance. These governing bodies can also apply penalties to Central Hudson if there is a failure to comply with codes and compliance standards whether or not the compliance failure resulted in an incident.

Per our franchise agreements, Central Hudson has the right to install and maintain pipelines and distribution poles within the road taking. The agreements also require Central Hudson to comply and participate with the municipalities or the New York State and county DOT during any road rebuilds. In addition, Central Hudson is obligated to "make ready" utility poles for any additional attachments. For "make ready" projects, the fiber or cable companies requesting the work are responsible for any of the system improvement costs. These projects are difficult to forecast since they are announced as emergent work, but can provide benefits.

4.2.3.3 *Infrastructure*

Replacing aging facilities either in kind or with more robust materials and current construction standards improves the system. It is in Central Hudson's and the customer's best economic interest to operate and maintain equipment and infrastructure to the end of it useful life. Condition-based assessments are completed whenever feasible.

However, it is not always feasible with the asset management tools that currently exist to accurately predict the end of an asset's useful life. This is where including the asset's age, as a proxy for useful life can be beneficial in the prioritization process. Replacing facilities prior to failure allows engineering and operations to plan, design, and construct a substantial replacement project rather than responding to an emergency or trouble order that usually results in a costly fix during unfavorable conditions. It is therefore frequently beneficial to pursue proactive replacement of major equipment, even where direct economic benefits or reliability improvements cannot alone justify it. Three metrics for prioritization of infrastructure projects identified within Distribution Improvement Project Submittals are:

Three metrics for prioritization of infrastructure projects identified within Distribution Improvement Project Submittals are:

- Average age of major infrastructure (poles, wires, pipes, etc.)
- % infrastructure requires replacement due to inspection findings
- Identified equipment types with abnormal failure rates (cast iron pipes, unprotected steel, leak prone pipe miles replaced)

4.2.3.4 *Resilience*

Central Hudson's gas and electric construction standards specify the proper installation method of facilities to ensure the system can operate under normal condition and operate well when under stress during emergencies.

Gas pipelines and fittings are constructed and rated to operate during extreme conditions. These conditions can be a result of weather, third party occurrences, and equipment failure resulting in low or high pressure. Gas replacement projects allow engineering and operations to design and construct a pipeline that allows for the improvement of the network configuration by installing additional valves and pipelines that can help mitigate the impact to customers during emergency shut downs. Cast iron and steel pipelines are replaced with plastic pipelines and fittings that are expected to have a longer useful life, operate at pressures up to 120 psig, and are easier to operate. The new pipelines are also tested for very high pressures for extended periods of time to ensure there are no anomalies before the pipeline is put into service.

During electric replacement projects, the poles and hardware are now designed and built with to meet a Grade B construction rating. (Grade C is the minimum requirement for all areas except railroad crossings). Grade B construction results in the replacement of a Class 4 or smaller pole with a Class 2 or larger pole, which is significantly less susceptible to wind, tree, and ice damage (see the Long Range Electric System Plan for more information). New hardware installed on the utility poles is also more resilience than existing hardware. Strengthening of the poles and hardware increases the storm resiliency and lowers the total life cycle costs of Central Hudson's facilities.

4.3 Project Alternative Analysis and Selection

4.3.1 Alternative Analysis

To evaluate project alternatives, a net present value analysis is completed that includes all monetized benefits and costs to the Company (no indirect economic benefits). The net present value, or NPV, is the present value computed by using Central Hudson's after tax weighted average cost of capital ("WACC") as the discount rate of cash inflows, minus the present value of cash outflows, including the initial investment. Present value is a future amount of money that has been discounted to reflect its current value, as if it was spent today. The goal of the net present value analysis is to put the costs and benefits on a common basis to compare the net project costs among the alternatives. The goal of the net present value analysis is not to strive for a positive net value for all projects.

In some business cases, it is necessary to consider the customer, rather than the Company perspective. In this case, the pre-tax WACC should be applied, and the application of indirect benefits may be appropriate.

However, the decision does not end with a quantitative analysis. Many of the service, risk reduction, and even economic benefits cannot be quantified at this time, but should be weighted in using experience and judgment. Non-wired and other non-traditional alternatives shall be considered as well. In addition, the following key component should be identified and considered in identifying an alternative, and later in the prioritization with other projects:

4.3.1.1 Main Project Driver

Because projects have many benefits and costs, the primary benefit that drove the assessment of a project need shall carry the most weight in project alternative selection and project prioritization.

4.3.2 Selected Project for Prioritization

A "Project Submittal Form" (See Appendix 1 and 2) should be developed for the project selected for prioritization with a single cost that includes the following factors:

4.3.2.1 Comparable Cost Basis

In order to prioritize projects appropriately, Capital costs should be listed in common year dollars as should one-time expenses. Annual expenses should be in net present value form. All of these project costs should be evaluated on a net present value basis.

4.3.2.2 Current Year Capital Cost Basis

The Company's Capital Budget and Five Year Capital Forecast are prepared on an annual basis. All projects are listed and prioritized using first year dollars so that the project cost is set in time. This is helpful when prioritization of projects is being considered so that projects can be prioritized by year within the five year capital forecast.

5. Electric

5.1 Introduction

To support the corporate mission and strategy, Electric Engineering Services, with the support of the Operations Services, System Operations and Transmission and Distribution Operations divisions, seeks to safely plan, design, construct, operate, and maintain a reliable and affordable electric transmission and distribution system that optimizes value for all stakeholders. It develops prudent capital investments intended to enhance reliability, improve customer satisfaction and reduce risk. These divisions also identify and implement process improvements that enable Central Hudson to continually improve the way in which we fulfill our mission and moderate cost pressures that impact customer bills.

The Electric Engineering Services division accomplishes its mission by setting challenging service reliability goals, while meeting compliance obligations (i.e. non-discretionary items described in Section 3).

Reliability goals are focused on SAIFI (frequency) and CAIDI (duration), and are established within the Central Hudson Gas & Electric Business Plan. The NYS Public Service Commission establishes targets with penalty mechanisms for each of these metrics. As of 2015, the target for SAIFI = 1.3, and the target for CAIDI = 2.5. Central Hudson sets more aggressive internal targets for SAIFI as customer tolerance for outages has declined and technology has reduced the expenditures required to avoid outages.

Many other costs and benefits are considered during the proposal and prioritization of projects. While some of these benefits can be monetized as direct economic benefits, most cannot and require engineering judgment to be able to value the impacts of the project. For this reason, the communication and discussion of projects becomes as important as the measurable impacts. The following is a timeline of the key written and verbal communication points regarding electric project development and prioritization:

Electric Capital Forecast Development Timeline

October

Operations Services issues the Transformer Watch List →
- Electric Planning
- Electric System Design

November

December

January

Engineering Section Leaders/Directors Meet to discuss major budget items

February

EOEs submit projects for review for Category 15

Transmission/ Substation Section Leaders develop budgets for Category 12 & 13

March

Engineering/ Operations SME Meetings for Categories 12, 13, 15

Directors submit forecasts to Manager, Electric Engineering Services and Vice President, Engineering & System Operations for approval

April

Director, Electric Distribution submits draft list to T&D Operations & Estimating (Category 15)

Transmission/ Substation Section Leaders develop budgets for Category 12 & 13

May

Director, Electric System Design submits draft list to T&D Operations (Category 12) & Operations Services (Category 13)

June

Director, Electric Distribution submits final list to T&D Operations & Estimating (Category 15)

July

Manager, Electric Engineering Services develops 5 Year Capital Forecast book for the following 5 years

In addition, there are several on-going activities:

- Project Ideas: Transmission and Distribution (T&D) Operations submits ideas to the Electric Operations Engineer for review and potential development into a project for the following budget cycle via Appendix 4. New project ideas deemed critical are discussed between Director, T&D Operations and Director, Electric Distribution & Standards and added to the work plan.
- Meetings:
  - Category 12 (Led by Section Leader, Electric Transmission Design) – monthly
  - Category 13 (Led by Section Leader, Electric System Design) – monthly
  - Category 15 (Led by Director, Electric Distribution & Standards or Section Leader, Electric Operations Engineering) – bi-monthly

The prioritization process comprehensively considers many factors, and is initiated by the completion of the form in Appendix 1 for every major project or program category (any work not completed under Blanket or Local work orders as defined in PM-02, Work Order Authorizations, Revisions and Management)**.** Some of the benefit, cost, and risk factors are quantitative in nature, but many are qualitative and require Engineering Judgment as described in the remainder of this section. Appendix 1 provides all of these factors that are considered. In addition, Operations may propose an idea for evaluation by completing Appendix 4. The remaining content in Section 5 provides examples of the types of programs and drivers within each budget category of the Electric section.

5.2 Growth Scenario Development

One overarching driver of major capital investment is load growth that may cause equipment to exceed its thermal or operating ratings or load serving capabilities. As described in more detail in Section 2 of the Electric Planning Guides, the Costs, Rates & Forecasts Division provides annual system demand forecasts. These forecasts are provided for a normal peak (i.e., 50-50 forecast) and an extreme peak (i.e., approximately a 95-5 forecast). To appropriately distribute the system demand growth forecasted by the Costs, Rates & Forecasts Division, the Electric Planning & Reliability team has divided the system load among 10 planning areas.

Allocating the load among the 10 groups, Substation Loading forecasts are developed for the low, base, and high case scenarios. Distribution substation transformers projected to operate above their design ratings within 7 years are placed in an Area Study work plan, which includes an in-depth analysis and evaluation of alternatives using Net Present Value, and where practical, cost/benefit analysis described in Section 4 of this document.

More information on Area Study development is available within Section 4.4 of the Electric Planning Guides, and the resulting long-range plan is described in Section 7 of the Long Range Electric System Plan.

The 115/69 kV transmission network is evaluated using Load Serving Capability ("LSC") analysis as well as additional constraints which are more complex in nature and described in Section 3 of the Electric Planning Guides. Depending on the LSC of an area as compared to the projected load over the next 10 years, long-term system enhancements may be developed, as demonstrated in Section 6 of the Long Range Electric System Plan.

5.3 Electric Transmission

For budgeting purposes, electric transmission includes all lines and equipment that operate at voltages of 69 kV and above (except Substations described in Section 5.4). All electric transmission work is budgeted under Category 12.

5.3.1 Inputs and Project Submittal

Electric Transmission Capital Projects stem from regulatory compliance, system and area studies, and inspection data. NERC Standards apply to the NPCC Bulk Electric System (BES) which includes Central Hudson's 345 kV system and the majority of the 115 kV system.

Electric Transmission Planning performs the system and area studies to develop recommendations for new or upgraded transmission system facilities on the basis of anticipated loading, infrastructure needs (as determined by transmission line inspections) or business opportunities. Non-wires alternatives will be evaluated for growth-related projects where feasible.

Electric Transmission Design addresses the condition assessment from inspections which are described in Section 5.2 of the Electric Planning Guides.

The transmission inspection data along with the age and known issues are used to assess the condition of the line. Central Hudson prepared a detailed report in response to the New York State Energy Plan Condition Assessment of New York State's Electric Transmission and Distribution Infrastructure that also includes the Company's plans to address the aging infrastructure.

Conceptual estimates of projects are developed prior to the prioritization process.

5.3.2 Prioritization Process

The following are the types of projects that fall within each investment category:

Non-Discretionary Project Category – Non-discretionary projects typically are required by structure failures, storm damage, code, law or other authority having jurisdiction. It should be noted that when a non-discretionary project is proposed, synergies always are sought with existing projects and plans.

Transmission Design along with T&D Operations prioritizes maintenance of Central Hudson's transmission lines by following the New York Public Service Commission's Orders Instituting Safety Standards, which are described in Section 5.2.1 of the Electric Planning Guides.

Based on the transmission line inspections data, several Transmission Line Programs have been developed to address systemic issues.

High Priority Replacement (HPR)
High Priority Replacements are based upon the results of the transmission line inspections. Depending on the solution needed to resolve the deficiency found in the inspection, solution may be capital (replacement), expense (repair), or a combination of both. Currently, there is a placeholder item in the Category 12 Capital Budget for the high priority replacement program to provide funding to respond to severe conditions, and other structures needing replacement found during transmission line inspections (i.e., Emerging Work).

System Wide Sag Analysis Screening Program
The National Electric Safety Codes (NESC) identifies design criteria for Transmission Lines including the minimum required clearance from ground for specified conductor loading conditions. The minimum clearance required also is dependent on whether the area below the conductor is accessible by pedestrians only or is a roadway.

Recent inspections suggest that, in some instances, existing conditions may be inconsistent with the assumptions used for the original design. Some examples of conditions that may have changed over time include:

- Change in ground profile (i.e., filling)
- Change in usage under conductor (i.e., addition of parking lot)
- Encroachment (i.e., addition of swimming pool)
- Conductor creep (i.e., due to aging)

- Pole/structure repair/replacement (i.e., not in-kind)

A Sag Mitigation Plan was instituted to mitigate all spans that have potential pedestrian or roadway clearance issues. Projects within the program are prioritized based on condition and risk.

Maintain System Standards Category – Many transmission projects fall under the category of maintaining system standards, which also increase the system and/or area load serving capability and improve reliability. Alternatives are evaluated and the timing of the projects is prioritized.

ACSR Conductor Replacement

Due to ACSR conductor failures, older ACSR phase wires were evaluated by NEETRAC[2]. NEETRAC performed a series of tests including visual inspection of the conductor condition, tensile/elongation testing, and mandrel testing to access the coating of the strands to estimate total remaining conductor strength. Based on the NEETRAC analysis, Electric Transmission Design has instituted an ACSR Replacement Program. Electric Transmission Planning may perform a study to determine appropriate area needs (e.g., upgrade operating voltage) and appropriate conductor size to anticipate load growth.

New Transmission Lines and Transmission Rebuilds

New transmission lines and transmission rebuilds take several years to design, permit and construct. The target in-service date is based on the projected year of the need or adjusted to a reasonable timeframe to complete the project. Some unexpected factors may impact the project schedule such as:

- Regulatory Requirements

  Depending on the length and voltage of the proposed transmission line or transmission line rebuild, the project may be subject to New York State Public Service Law Part 102C or Article VII. There is uncertainty associated with obtaining permitting. Permitting for projects that initially may seem relatively straightforward can

[2] National Electric Energy Testing Research and Applications Center

quickly become entangled in the process as unforeseen stakeholders emerge.

- Right of Way / Property Acquisition

  Right of Way / Property Acquisition is susceptible to NIMBY[3] opposition.

System Enhancement Category – There are not a significant number of transmission programs that are primarily initiated by a need to provide System Enhancements, however, specialized cases to improve resiliency have become programs in this category. Appendix 1 should be completed for all projects that fall in this category. Some current examples follow:

Operating Projects
Operating projects are developed with the primary goal of reducing the duration of outages. Typical projects involve installing disconnect switches to allow isolation and supply from another transmission line.

Resiliency Projects
Resiliency projects may be PSC mandated (and fall under non-discretionary), or be proactive based on our experiences in storm situations and prioritized as system enhancements based upon the factors in Appendix 1 and Engineering judgment. Typical projects involve cable terminations in flood zones.

Additional Equipment Installation
Identified trends from inspection or trip out reports may demonstrate a need to increase reliability. Typical projects involve installing lightning arrestors on the line.

Customer Beneficiary Projects
Central Hudson may propose projects to lower capacity and energy costs by alleviating transmission constraints. Such projects typically would involve construction or modification of Bulk Power System facilities.

[3] NIMBY: Not In My Backyard

5.3.3 Outputs

The output of the prioritization process is a 5-year forecast by investment category within Category 12 developed by the Section Leader, Electric Transmission Design. This is submitted to the Director, Electric System Design for approval. Following approval by the Manager, Electric Engineering Services and Vice President, Engineering and System Operations, a detailed list of projects, project details and work plan is submitted to the Manager, T&D Operations. As highlighted in Section 5.1 and described in Section 5.7, there is collaboration across Engineering and Operations along the way to ensure impacts to permitting and workforce constraints are considered.

5.4 Substation

Substations may contain transformers to transfer voltage from transmission or subtransmission lines that run longer distances, to lower voltage levels that connect to more localized transmission lines, or lines that run at distribution voltage levels; substations also may connect transmission lines of the same voltage. Substations may contain switches, breakers, and devices associated with protection and control, as well as the bus work to connect it together. All work associated with electric substations is budgeted under Category 13.

5.4.1 Inputs and Project Submittal

Electric Substation capital projects primarily are a mix of compliance, Infrastructure and area load growth projects. These projects may be identified through several methods.

An area or system study performed by Electric Distribution or Transmission Planning analyzes area load, load forecast and existing substation infrastructure, may recommend a substation project. Project recommendations may include building a new substation, rebuilding a substation, expanding an existing substation, uprating equipment or replacing aging infrastructure. Non-wires alternatives will be evaluated for growth-related projects where feasible. Compliance with Standards and Regulatory Requirements also are evaluated.

Electric System Protection, working with Operations Services and Electric System Design, may initiate the replacement and upgrade of protection, metering, and control systems.

Operation Services may initiate equipment replacement based on their inspections and tests[4] or on compliance with NERC Standards. Operations Services and Electric System Design will initiate projects to replace equipment that is failing, unmaintainable, or outside of compliance with NERC Standards, as well as propose programs when identified trends indicate a systemic issue. For projects that would require transformer replacements, the Transmission or Distribution Planning area will review for replacement in-kind, or complete a detailed Area Study and alternatives analysis and recommend a solution.

Conceptual estimates of projects are developed prior to the prioritization process.

5.4.2 Prioritization Process

Substation projects tend to be driven by compliance and maintenance with incorporation of new technologies being made along the way. The following are the types of projects that fall within each summary category:

Non-Discretionary Project Category – Non-discretionary projects typically are required by code, law, or other authority having jurisdiction. It should be noted that when a non-discretionary project is proposed, synergies always are sought with existing projects and plans. Some current examples follow:

NYISO Metering Upgrades
Substation Design develops a memo based upon annual testing to bring metering systems that fall outside of the appropriate tolerance range up to compliance.

Underfrequency Load Shedding Compliance
Electric Transmission Planning issues a memo annually to adjust the capital plan to ensure relaying and other protective equipment is operating in compliance with the most recent Underfrequency Load Shedding requirements dictated by the Northeast Power Coordinating Council (NPCC) and the NERC.

Security Systems
These may be added due to NERC CIP compliance on the Bulk Electric System, or where theft and safety are of particular concern.

[4] Substation equipment is inspected and tested on a regular interval basis based on equipment and voltage class

Maintain System Standards Category – Many substation projects fall under the category of maintaining system standards. Although these projects must be completed, alternatives are explored. Rather than simply replacing equipment in-kind, modern technologies and designs are analyzed and applied, such as microprocessor based relays and Human Machine Interfaces (HMIs). Our Long Range Electric System Plan details this information. With the exception of emergency work, Appendix 1 shall be completed for each proposed project that falls into this category. Some current examples follow:

Substation Blankets/Minors
These are work orders to develop emerging work, and are classified as blankets or minors/locals according to the latest Central Hudson Accounting Rules (see PM-02, Work Order Authorizations, Revisions and Management).

Relay and Carrier Equipment Replacements
Electric System Protection, with assistance from Operations Services, develops a memo to replace failing equipment on a standalone basis, or as a proactive program based upon trends. Enhancements with current technologies are included in the evaluation process. Projects are prioritized based on condition and risk (such as lack of spare parts, thermal limitations, and customer impact), as well as reduction in maintenance costs, and to coincide with other work in a substation where feasible.

Equipment and Infrastructure Replacement Programs
Many equipment and infrastructure replacement programs, such as the Breaker and Circuit Switcher replacement programs, result from a lack of manufacturer maintenance and support. The cost of a program is estimated in a memo, prepared by Operations Services, Electric System Design or Electric System Protection, and the total size of the program is weighed with risk factors to determine the number of years to completion. Projects within the program are prioritized based on condition and risk (such as lack of spare parts, thermal limitations, and customer impact) and to coincide with other work in a substation where feasible. Permitting and environmental risk factors also are considered.

Substation Upgrades/New Station construction

Substation upgrades/new stations or retirements generally are driven by two factors: infrastructure assessment or load growth. In either case, Transmission or Distribution Planning would develop an area study that analyzes alternatives, risks, and timing for projects in significant detail. For smaller substation projects or where in-kind infrastructure replacement does not require detailed analysis, Category 15 Distribution Improvement Projects may be developed to integrate the new substation with existing circuitry without a full area study. For larger incremental loads to the system, New Business Services would initiate an Engineering Request, in which an analysis similar to that of an area study would be completed, and the recommended alterative would be added to the capital budget plan (often with customer contribution subject to our Rate Tariffs).

During the prioritization process, expenditures associated with these large projects may need to be levelized to adjust to base workforce constraints.

System Enhancement Category – There are not a significant number of substation programs that are primarily initiated by a need to provide System Enhancements; however, specialized cases to improve resiliency and automation have become programs in this category. Appendix 1 should be completed for all projects that fall in this category. Some current examples follow:

Resiliency Projects
Substations located in flood zones may require that structures be raised. They may be PSC mandated (and fall under non-discretionary), or be proactive based on our experiences in storm situations and prioritized as system enhancements based upon the factors in Appendix 1 and Engineering judgment.

Proactive Relay, Control, and Metering Equipment Replacements
These projects will be driven by equipment that is still operational, but where the maintenance can be reduced, flow of data can be improved or automated, and the system can benefit by the additional information provided by electronic components to decrease restoration times and better manage load. These projects would be driven by an Engineering memo that includes an alternatives analysis and the phasing of the projects.

Distribution Automation Support

This is similar to other proactive relay, control, and metering equipment upgrades. Projects to support the Distribution Automation program will be prioritized as needed to support the Distribution Automation program described in Section 5.5. At the substation level, they primarily will include metering and Load Tap Changer control upgrades. Component replacement projects (such as breakers) also may be implemented where there is a future benefit to the Distribution Automation program, such as simultaneously replacing metering and relaying equipment.

5.4.3 Outputs

The output of the prioritization process is a 5-year forecast by investment category within Category 13 developed by the Section Engineer, Electric System Design. This is submitted to the Director, Electric System Design for approval. Following approval by the Manager, Electric Engineering Services and Vice President, Engineering and System Operations, a detailed list of projects with project details and work plan is submitted to the Manager, Operations Services. As highlighted in Section 5.1 and described in Section 5.7, there is collaboration across Design and Operations along the way to ensure impacts to workforce constraints are considered.

5.5 Distribution (Category 15)

The Category 15 (Distribution Improvement) budget includes all capital projects involving voltages less than 69 kV, including the secondary networks and subtransmission lines operating below this voltage level. However, it does not include Hydro Generation (Category 11), Metering (Category 17), Transformers (Category 16), New Business (Category 14) or Substations (Category 13).

5.5.1 Inputs and Project Submittal

As with Transmission and Substation projects, Distribution projects are initiated from a variety of sources and triggers. Non-wires alternatives will be evaluated for growth-related projects where feasible. While some projects are non-discretionary, many are needed to maintain system standards, while some are considered a system enhancement. The following are the types of projects that fall within each summary category:

Non-Discretionary Project Category – Non-discretionary projects are typically required by code, law, or other authority having jurisdiction. It should be noted that when a non-discretionary project is proposed, synergies are always sought with existing projects and plans. Some current examples follow:

Road Rebuilds

State and local road rebuild often require our electric distribution facilities to be relocated; these relocations must be completed. The New Business or Estimating Supervisor will make the Distribution Engineer aware of any known road projects requiring relocation prior to the budget being developed. In addition, a relocation blanket also is budgeted for unforeseen jobs and is based on trends.

Pole Replacements

As a result of our Distribution Inspections program described in Section 5 of the Electric Planning Guides, defective poles are identified and replaced based on the severity rating of the deficiency. This is similar to the Transmission Inspection process described earlier in this Section.

Projects are evaluated for other incremental system benefits, such as relocating pole on road or designing to NESC Grade B construction as described in the Long Range Electric System Plan. The electric model in ESRI will enhance this evaluation in the future by providing a graphical view of the system and key inspection data. Finally, other equipment may be replaced due to a violation of Central Hudson Electric Construction Standards, NESC, IEEE, and other national and international standards.

Maintain System Standards Category – Many distribution projects fall under the category of maintaining system standards, which alternatives are explored and the timing of the projects is prioritized. Additionally, rather than simply replacing equipment in-kind, modern technologies and designs are analyzed and applied. For example, all new distribution design applies NESC Grade B construction to enhance system resiliency. Our Long Range Electric System Plan details this information. With the exception of emerging work, Appendix 1 shall be completed for each proposed project that falls into this category. Some current examples are as follows:

Distribution Improvement Blankets/Minors

These are work orders to develop newly emerging operational work, and are classified as blankets or minors/locals according to the latest Central Hudson Accounting Rules (see PM-02, Work Order Authorizations, Revisions and Management).

Thermal/Voltage/Conversions

These projects are submitted by the Electric Operating Engineer, often with input from Electric T&D Operations and/or Electric Distribution Planning. In addition to on-going load checks, circuit modeling, and errant voltage analysis, these projects may be triggered by the analysis of various reports and metering data described in Section 4 of the Electric System Planning Guides. Conversion from 4kV to 13.2kV operation often is recommended where customers are experiencing low or errant voltage or a step-down transformer is overloaded. Polyphasing, reconductoring, or building new lines also are examples of projects that could fall under this line item. The % overloading, customers impacted, and ancillary benefits such as customer satisfaction and reliability, are considered in prioritizing these projects.

Project Tied to New Substations or Substation Rebuilds
When a new or expanded/rebuilt substation is required, new circuit exits from the substation are necessary to tie the substation bus to the distribution feeders. Often, load growth or reliability maintenance/enhancement also results in the expansion of the number of circuit exits. As described in Section 5.3, the Distribution Planning Engineer completes an in-depth Area Study to evaluate alternatives, including a Net Present Value analysis. In addition, where circuit exits and ties are complex, the Distribution Planning or Electric Operations Engineer will complete an Integration Study detailing the steps and budgetary cost estimate 1-2 years prior to the project in-service date.

Equipment and Infrastructure Replacement Programs
When Distribution Planning or Construction Standards reports or identified trends demonstrate potential need for investment to maintain reliability, an analysis is completed to determine the benefits and costs of addressing the issue and risks of maintaining *status quo*. It is then determined whether a new program should be developed within the capital budget. The size and scope of the program will determine the level of rigor required. An example of less rigorous analysis is the program to replace hydraulic reclosers with electronic reclosers, development of this program used quantifiable attributes including a decrease in maintenance costs as well as the additional information provided by the electronic controllers and the ability to prevent outages through improved transient protection. On the other hand, analysis that is more rigorous was

necessary for the 14.4kV cable rejuvenation program and secondary network replacement programs; development of these programs involved the study of failure rates, inspection data, and development of models and area studies to create a multi-year plan.

System Enhancement Category – These include programs such as Distribution Automation where the dominant component of the project is discretionary, even though some infrastructure replacement may be required to meet code or maintain system standards. Appendix 1 should be completed for all proposed projects that fall in this category. Some current examples follow:

Reliability

Reliability-based projects usually are championed by the District Electric Operating Engineer, with input from Electric T&D Operations. Currently, projects primarily are prioritized on a 5 year historical average $/COA (customer outage avoided) basis, but ancillary benefits to customer satisfaction and resiliency also are considered. The 5 year average is used to smooth results to account for when a circuit may have been trimmed and for any anomalies. This line item includes projects such as moving circuitry from off-road to on-road, closing gaps (i.e., new circuit ties), and installing electronic reclosers.

Additional reliability-focused line items have been added, such as the 10X program and the Automatic Load Transfer program. The 10X program recognizes that the number of outages a customer experiences is important, in addition to achieving the best bang for the buck ($/COA), and provides funding for projects that target customers experiencing 10 or more outages per year. On the other hand, a lower $/COA is expected from projects in the Automatic Load Transfer switch program, because the root cause of the outage is not being addressed, only the transfer of some customers in the event an outage occurs. Other factors listed in Appendix 1 also are considered, such as customer satisfaction and resilience, as well as reduced maintenance of newer infrastructure.

Operating

Operating projects are developed with the primary goal being of reducing the duration of outages. Typical projects involve developing a tie between feeders, or reconductoring the lines to make the tie stronger so more load can be reenergized through switching. Infrastructure replacement projects that do not drive a specific program also may be captured here, although in the longer term they often are required to maintain system standards. Distribution Engineering has begun using a $/CMA (customer minute avoided) to prioritize these projects, but the metric is challenging to apply as discretely as $/COA and requires judgment based on distance from headquarters and time of day/week of outages, which can have a significant impact on the metric. Other factors listed in Appendix 1 also are considered, such as customer satisfaction and resilience, as well as reduced maintenance of newer infrastructure.

Distribution Automation

Distribution Automation is a broad category that includes restoration of power, optimization of voltage, and improvement of power quality, with remote or autonomous operation. Projects focused solely on reliability benefits are prioritized heavily based on $/COA. The major 5 year company-wide roll-out of Volt-VAR optimization, infrastructure improvements, and automated restoration, will rely on many of the prioritization factors described in Section 4, and significant Engineering Judgment to weigh the many benefits of the projects and determine which will be included. In terms of project timing, the geographic areas for deployment will follow the network communications strategy roll-out described in the 2015-2019 Corporate Capital Forecast. Additional prioritization factors unique to this project are anticipated through a separate Distribution Planning memo.

Resiliency

All projects include a component of resiliency since newer infrastructure is built to a higher grade design and construction. Projects primarily driven by resiliency, however, may include components such as microgrids and accelerated pole replacements that do not stand solely based upon reliability impacts. These projects may significantly contribute toward reducing customer impact during storms, either by reducing the number of customers impacted, number of critical customers impacted, number of sensitivity customers impacted or duration of the impact. Microgrids also may be applied as an alternative to a transmission or distribution infrastructure upgrade where $/COA are lower.

Conceptual estimates of projects are developed prior to the prioritization process.

5.5.2 Prioritization Process

The prioritization process varies depending upon the source of the project. Currently, a budget is assigned to each line item, such as Reliability, based upon trends. In addition, new line items may be identified as described in Section 5.5.1. Projects related to substation upgrades and new programs are added based upon the analysis of the Engineer who champions the program or project. Thermal and voltage projects use the % overload of step-down transformers as a key prioritization factor, although ancillary benefits, costs, and risks more likely weigh into the prioritization of those projects. Other projects and line items to maintain system standards generally are broken into multiple phases so that all suitable programs can be incorporated into the budget while maintaining affordability.

The expenditures included in each line item and prioritization within are determined by a number of quantitative and qualitative factors described in Section 4, including Engineering Judgment. For reliability-based projects that are system enhancements, the $/COA (customer outage avoided) is a key driver in the ranking of projects, and $/CMA (customer minute avoided) is becoming a key factor in ranking the operations bucket of projects. For the recloser replacement program, the number of operations is a key driver. Ultimately, Engineering Judgment must be applied to all benefits listed in Appendix 1.

Other constraints also must be factored into the timing and prioritization. For example, projects requiring longer lead times for permitting or equipment procurement are scheduled with sufficient lead time, and the workforce size and mobility also must be considered. While workforce constraints can be alleviated through the use of contractors, there must be experienced supervisors to oversee contractors, as well as a base of employees to manage storms and day-to-day tasks and build a knowledge base.

5.5.3 Outputs

The output of the prioritization process is a 5-year forecast grouped by investment category within Category 15 developed by the Director, Electric Distribution and Standards, with individual projects listed for non-blanket categories where practical (for example, individual locations for recloser, pole, or cutout replacements would not be provided on this summary sheet). Following approval by the Manager, Electric Engineering Services and Vice President, Engineering and System Operations, a detailed list of projects and project details is provided to the Operating Supervisor, Estimating Superintendent and Manager, T&D

Operations. As highlighted in Section 5.1 and described in Section 5.7, there is collaboration across Engineering and Operations along the way to ensure impacts to workforce constraints are considered.

5.6 Other

The budgets for categories outside of Transmission, Substation, and Distribution primarily are driven by compliance, with limited focus on maintaining system standards. The budgets in Categories 14 (New Business), 16 (Meters), and 17 (Transformers) are based upon historical regressions of drivers of load growth and correlation with peak demand. Most meters and transformers are installed due to New Business and System Load growth; Central Hudson's tariff references the obligation to serve these customers. A minor variance in Transformers, which includes regulators and capacitors, also is driven by Distribution Automation.

Category 11 (Hydro/Generation) is driven by the maintenance of our existing plants.

5.7 Prioritization across Categories

5.7.1 Integrated Plans

As described earlier in the section, Categories 12 (Transmission), 13 (Substation), and 15 (Distribution) are the budget categories that exhibit need for discretion. While under development, Directors must meet formally and informally to review the budget and ensure integrated plans are aligned. For projects greater than $5 million, an Integrated Project Plan memo (Appendix 5) is developed by Transmission or Distribution System Planning (depending on the primary driver).

5.7.2 Non-Wires Alternatives

Growth related projects may have opportunity for non-wires alternatives to be considered, such as demand response or distributed generation. Projects may be included in the forecast while these alternatives are explored. Central Hudson is currently proposing a Demand Response demonstration project through the state's Reforming the Energy Vision (REV) proceeding and the Distributed System Implementation Plan (DSIP) has yet to be developed. In addition, the Company was directed to file Dynamic Load Management Program tariffs under Case 14-E-0423. Because the development of these programs in on-going, specific guidance is not incorporated into this document, other than to thoroughly evaluate non-wires alternatives to any growth-related project.

5.7.3 Final Forecast

The Manager, Electric Engineering Services works with the Vice President, Engineering & System Operations, to consider additional corporate constraints and requirements and feedback from the Strategic Planning Committee. The 5 Year Forecast for Electric is then finalized and moves to the process described in Section 8.

6. Gas

6.1 Introduction

The Central Hudson gas system contains over 2,000 miles of pipeline facilities ranging in age from new to over 100 years. It supplies gas service to 78,000 customers along communities near the Hudson River from Woodbury in the south to Coxsackie in the north and ranges from Carmel in the east to as far west as Montgomery.
Gas and Mechanical Engineering and Gas Operations in Customer Services have the combined responsibility to plan, design, construct, operate, and maintain a safe and reliable gas transmission and distribution system. Both departments collaboratively develop prudent capital projects and programs with the goals of enhanced reliability, reduced risk, reduced costs, and improved customer service that enable Central Hudson to continuously improve service while moderating cost pressures that impact customer bills.

Many costs and benefits are considered in the development and prioritization of projects. While some of these can be monetized into direct economic benefits, most cannot and require engineering judgment and experience to value the impact of these benefits. For this reason, the in depth communication and discussion of projects through a strong stakeholder review process becomes as important as the measurable impacts. The following is a timeline of the key written and verbal communication points regarding gas project development and prioritization:

May: Initial SME meeting between Distribution Engineering, Gas Operating Engineer, Gas Operations, and Gas Foremen to discuss various Main Replacement Prioritization (MRP) input criteria to prioritize infrastructure replacements (Category 25).

July: Gas Engineering begins compiling potential regulator station (Category 23) and transmission (Category 24) projects based on developing needs resulting from compliance issues, planning studies, MRP results, and emergent work.

September: Each Director prioritizes “Identified” Capital Project list for their responsible budget categories; Regulators Stations (Category 22), Transmission (Category 23), and Distribution Improvements (Category 25).

October: Directors deliver list of project justifications (compliance related, load growth related, and flow studies recommendations) and budget forecast to the Manager, Gas and Mechanical Engineering

December: Project Design phase begins with Gas Engineering and Gas Operations.

February: Forecast Submitted to Vice President, Engineering and System Operations for approval.

See Section 8 for continuation of timeline involving the Strategic Planning Committee (SPC), Board of Directors, and Fortis.

The prioritization process comprehensively considers many factors, and is initiated by the completion of the form in **Appendix 2** for every major project or program category (any work not completed under Blanket or Local work orders as defined in PM-02, Work Order Authorizations, Revisions and Management)**.** Some of the benefit, cost, and risk factors are quantitative in nature, but many are qualitative and require Engineering Judgment as described in the remainder of this section. Appendix 2 provides all of these factors that are considered. In addition, Operations may propose an idea for evaluation by completing Appendix 4. The remaining content in Section 6 provides examples of the types of programs and drivers within each budget category of the Gas section.

6.2 Growth Scenario Development

A key driver in the gas capital project development that is assessed annually is system load growth. This organic system growth may cause equipment to exceed its load serving capability and result in gas system operating pressures below acceptable limits. Load serving capability is based on system configuration, capacity, design and operating criteria, and the resulting pressures during design day.

For the gas capital forecast, Cost and Rate department provides annual customer growth rate forecasts. Load growth scenarios are developed consistent with these forecasts. Regression analyses for each customer growth scenario are performed to determine projected peak load for each scenario. Peak system loading is based on a design day load (i.e., 70 heating degree forecast).

Central Hudson's gas peak load forecast is allocated into planning areas to identify system capacity needs and the timing of those needs, quantify the risks of the load growth outpacing the Company's ability to serve that load, and assess the alternatives available to meet that load. Gas Engineering uses the design day peak forecast for their planning studies. For each load growth scenario, the needs are identified, the timing determined, and the alternatives developed from planning studies. The forecasted system demand growth is then apportioned among the political districts based on the historical growth over the past 3 to 5 year period. Individual growth rates going forward are then estimated for each political district.

In addition to the organic load growth information assessed in the planning processes, Gas Engineering attends weekly Customer Services New Business and Gas Expansion meetings to be apprised of specific Engineering Requests. Customer Services generate Engineering Requests for customer demands that reach a certain load threshold (specified for each gas pressure system in Gas Distribution Estimating Manual) that result in recommendation from Engineering on how Central Hudson can commit to provide delivery (capacity) of gas. These requests typically specify an expected connected load and demand factor as well as a location for the new facility. In order to respond to an engineering request, a reasonably accurate flow model is necessary to analyze effects the additional load has on the system and properly size the proposed pipeline. In extreme cases, a detailed planning study may be required. Once a planning study is triggered, Engineering will use the large proposed customer load and average annual growth over several years for that particular area in their analysis.

6.3 Gas Transmission

For budgeting purposes, gas transmission includes all pipeline and equipment that operate at 125 psig or above (except Regulator Stations described in Section 6.4). All gas transmission work is budgeted under Category 24.

6.3.1 Inputs and Project Submittal

Capital expenditures in Gas Transmission are primarily a mix of compliance and infrastructure projects. They stem from system-wide load studies or studies performed as part of the gas Transmission Integrity Management Program (TIMP). The studies recommend improvements to valve arrangements (replacing/eliminating no longer functional/useful valves and/or adding valves for enhanced reliability), moisture and overpressure protection schemes, system controllability, and general system operability and maintainability. Compliance-related projects include such issues as the replacement of a main exposed to abnormal stress and the installation of inspection robot launching stations. The remaining gate station and flow station communication and controls upgrades address infrastructure issues that will reduce the risk of system failure, safety incidents, or loss of reliability.

Condition Assessment

The general condition of the entire gas transmission system is assessed several times each year. This is done via various on-foot patrols (road and rail crossing patrols, leak surveys, and cathodic protection surveys) and quarterly aerial patrols where the condition of the pipeline easement is observed by helicopter fly-over. Any condition found that is considered to be a potential threat to the integrity of Central Hudson's gas transmission system is brought to the attention of the IMP team in Gas and Mechanical Engineering. Depending upon the nature or severity of the condition, a Capital Project may be initiated.

Transmission Pipeline Integrity Program

Central Hudson's TIMP focuses on all of the "high consequence" areas along the transmission system. Close-interval testing (referred to as External Corrosion Direct Assessment or ECDA) is done on a schedule that ensures that each identified HCA is visited at least once every five years. This expense activity occasionally reveals improvements that are necessary that must be constructed via the capital budget.

Highway and Railroad Crossing Patrols

This patrol consists of an inspection of transmission line crossings of highways and railroads (which almost always include a casing). Items of particular interest that could generate a capital project include excavation or road construction activity and testing to see if the pipeline could be resting on the casing, shorting the cathodic protection of the pipeline. In addition, an examination for visual signs of gas leakage is performed as well as an inspection with a combustible gas indicating instrument at casing vents.

Leak Survey Patrols

General leak surveys are performed annually. This patrol consists of traveling on foot or in a vehicle over the entire length of the transmission system. In addition, Central Hudson's TIMP requires a second gas leak survey patrol for all Class 3 areas. The right-of-way is carefully examined for evidence of leakage and for conditions such as damaged structures (test stations or line-markers), above-grade facility damage, damaged or leaking valves, construction activity, washouts etc.

Aerial Patrols

Aerial patrols are currently conducted once each quarter, with no interval between patrols exceeding 4.5 months. This patrol consists of a low-altitude, low-velocity helicopter flight over the entire gas transmission system by a qualified employee riding with a licensed pilot. The inspector can make detailed observations regarding surface conditions such as evidence of leakage, evidence of third party construction activity, clearing activity, canopy encroachment, washouts, sufficiency of line markers, and Right-of-Way encroachments. All notable conditions are documented by the TIMP team of Gas and Mechanical Engineering, and some could result in a capital project.

Transmission Valves

Central Hudson inspects all of its transmission system valves once per calendar year. All valve inspections are documented and when inspection results call for follow-up action, repair orders are generated. Depending on the findings from the inspections, a new valve may be necessary or an existing one may need replacement.

Additionally, Central Hudson's gas TIMP team performs evaluations of its line valves. Some of the factors that are taken into consideration are:

- Location: below-grade (within a pit) or above-ground, remotely operable or not, high risk locations
- Valve Type: reduced-port valve, a plug valve, or a full-port valve, etc. (full-port valves are desired for smart-pig or robot inspection applications)
- Condition and Age: information provided from over the line patrol surveys

Central Hudson has recently begun utilizing a robot to perform internal inspections of its gas transmission pipelines. Having valves that are of the full-port design is beneficial for this type of technology. When valves are typically replaced, determining whether a launch-fitting is necessary also is evaluated for future inspection purposes.

Gate & Flow Stations

Central Hudson operates four gate stations at which transfers ownership of the natural gas fuel from the cross-country transporter to Central Hudson. Central Hudson then provides delivery services to firm and interruptible customers within the Hudson Valley.

Central Hudson also owns and operates several flow stations within its territory, typically found where two dissimilar pressure-rated portions of the system meet or where it is beneficial to have a remotely operable valve that can easily control the system. Typically, a remotely operable valve is used to govern the flow of gas between the gas transmission systems.

Both the gate and flow stations are controlled by a series of valves and pressure regulating equipment that communicates continuously with System Operations to ensure reliable and safe transmission of the natural gas into and through the Central Hudson system. It is important that the equipment that monitors and controls these stations is based on the latest, most reliable technology. Based on changes in the industry and regulations, capital upgrades are occasionally required.

6.3.2 Prioritization Process

Capital Projects are categorized into three investment categories (non-discretionary, maintain system standards and system enhancement) as described in Section 3.3.1.

Examples of projects in each category are shown below.

Capital Projects	Categories
Regulatory Compliance	Non-Discretionary
Line Valve/ROV Installations	System Enhancement
Odorant System Improvements	Maintain System Standards
Gate & Flow Station Upgrades/ Automation	System Enhancement

Regulatory Compliance Projects are identified through known or projected compliance requirements and are prioritized based on meeting current regulatory obligations. It should be noted that alternatives were considered before a non-discretionary projects is included in the 5 year capital forecast.

The prioritization process varies depending upon the input source of the project. Projects requiring longer lead times for permitting or equipment procurement are scheduled with sufficient lead time, and the workforce size and mobility also must be considered. While workforce constraints can be alleviated through the use of contractors, there must be experienced supervisors to oversee contractors.

6.3.3 Outputs

The output of the prioritization process is a 5-year forecast by investment category within Category 22 that is developed by the Director of Gas Transmission. See section 6.1 for complete timeline.

6.4 Gas Regulator Stations

Gas Regulator Stations are utilized throughout the Central Hudson territory to maintain pressure of the gas as it travels through the system. Regulators reduce gas pressure from a higher level to a lower level more conducive for distribution. In addition to regulators, the station may contain additional equipment necessary to operate properly; those include above grade piping, filters, valves, meters, and relief valves. All capital work associated with regulator stations are budgeted under Category 23.

6.4.1 Inputs and Project Submittal

Gas Regulator Station Capital Projects are a mix of compliance, infrastructure projects and system load studies. The system load studies provide quantitative information about natural gas usage and capacity needs on the distribution and/or transmission system. They identify equipment within gas regulator stations where current or future demand could change the performance of the station.

Projects also can result from comprehensive reviews that are performed on each regulator station and its associated equipment. These reviews evaluate regulator station needs based on a variety of factors; all of which help to reduce the potential risk of system failure, safety incents and loss of reliability.

Regulator Stations

Regulators & Over Pressure Protection

Natural gas regulator stations serve to protect the pipeline system and ensure it operates safely by reducing the gas pressure as the gas flows further into the system. The primary function of any gas regulator is to match the flow of gas through the regulator to the demand for gas placed upon the system while maintaining the system pressure within the MAOP limits of the line.

To protect the system from exceeding the Maximum Allowable Operating Pressure (MAOP) rating of the line, regulator stations are equipped with a safety device known as a relief valve. Relief valves are designed and sized to protect the system from exceeding beyond a specific percentage over the systems MAOP.

Station and downstream system pressure recording charts are reviewed on a regular cycle to verify station output pressure stability and magnitude. Stations found to have unstable outlet pressures and/or which experience pressure droop during peak flow conditions are candidates for capital project work.

As the demand for natural gas is always changing, Gas & Mechanical Engineering on an on-going basis, verifies the capacity of the regulators in each station to meet the peak design-day demand of the downstream distribution system as well as the over pressure protection settings and capacities. If ever the capacities of the regulator or relief valve are found to be insufficient, a decision is made to correct the deficiency. Depending on the situation, a Capital Project may be necessary.

New Regulator Station Build

System integrity and flow studies are performed to identify and address any maintenance, reliability or operational issues on the system. Typically, these studies identify areas for load growth, known pressure problems, capacity constraints, planned highway relocations and new business requests. As a result, recommendations may include the addition of a new gas regulator station or modifications to existing station components.

Natural Gas Line Heating

The cooling which typically occurs at gas transmission to distribution regulator stations is a concern during the winter heating season. The Bernoulli Effect results in an approximate 7 degrees Fahrenheit decrease in temperature per 100 psi pressure drop. This drop in temperature may result in the condensation and freezing of liquid hydrocarbons/moisture resulting in possible regulator malfunction downstream. The temperature drop may lead to freezing and ground distortion by heaving in the soil around the downstream pipeline which can lead to pipeline and equipment stresses. To prevent these conditions, Central Hudson heats the natural gas upstream of the station regulator. Gas and Mechanical Engineering on an ongoing basis evaluates the amount of energy required for the heating process depending on the pressure drop value, flow characteristics and inlet gas temperatures. This varies from station to station, typically more so on downstream gas demand. In stations with low flow characteristics, having a simple pilot heater is sufficient in keeping the pilots and regulators from freezing. As the transmission gas line heater approaches its useful end of life, performance safety and sizing metrics are evaluated for potential replacement.

Replacing Obsolete/Aging Equipment

Gas and Mechanical Engineering recognizes equipment within its gas regulator stations that have become obsolete and/or replacement parts are scarce or no longer available. Engineering also assesses equipment with excessive maintenance costs, reduced functionality, diminishing reliability and potential safety concerns. As issues arise and Engineering is made aware of operational issues, the prioritization for replacement is evaluated based on the abovementioned conditions. As larger scale work inside an existing station is slated for Capital Replacement, these equipment upgrades also are considered and typically factored into the portfolio.

Cathodic Protection

Cathodic protection, whether galvanic or impressed, prevents the process of corrosion on steel pipelines by causing it to act as the cathode rather than the anode of an electrochemical cell. Annually, the Cathodics Department surveys all test stations and bi-monthly all rectifier cathodic protection levels. Data gathered from the surveys identifies areas where new Test Stations or rectifiers need to be installed or replaced. New installations may require the application of cathodic protection depending on data collected from the field.

6.4.2 Prioritization Process

Capital Projects are categorized into three categories (non-discretionary, maintain system standards and system enhancement) as described in Section 3.3.1. Examples of capital projects in each category are shown below.

Capital Projects	**Categories**
Regulatory Compliance	Non-Discretionary
Regulator Station Rebuilds-Redundancy & Upgrades.	System Enhancement
Regulator & Relief valve replacement/ Automation	System Enhancement
Obsolete/Aging Equipment	Maintain System Standards
Natural Gas Line Heaters	Maintain System Standards
Cathodic Protection	Non-Discretionary

Regulatory Compliance Projects are identified through known or projected compliance issues and are prioritized based on meeting current regulatory obligations. It should be noted that alternatives were considered before a non-discretionary projects is included in the 5 year capital forecast.

The prioritization process varies depending upon the input source of the project. Projects requiring longer lead times for permitting or equipment procurement are scheduled with sufficient lead time, and the workforce size and mobility also must be considered. While workforce constraints can be alleviated through the use of contractors, there must be experienced supervisors to oversee contractors.

6.4.3 Outputs

The output of the prioritization process is a 5-year capital forecast by investment category within Category 23 that is developed by the Director of Gas Transmission.

6.5 Distribution

The gas distribution system operates under 124 psig and delivers gas from the regulator station to customers. Distribution improvement projects (Category 25) include all capital projects involving distribution systems and associated customer service lines. Customer service lines are designated pipelines that deliver the gas from the main to customer.

6.5.1 Inputs and Project Submittal

The development of Gas Distribution Capital Projects originates from the Distribution Integrity Management Program (DIMP), main replacement projects, flow studies, regulatory compliance projects, new business projects, or strategic system expansions.

<u>Distribution Integrity Management Program (DIMP)</u>

There is an on-going initiative to replace leak prone cast iron and bare steel pipes. Central Hudson operates 1,223 miles of distribution main of which approximately 18% is cast iron or unprotected steel. Replacing cast iron and bare steel pipes reduces operating expense, numbers of leaks, corrosion issues, and also improve system reliability. Gas Distribution Engineering currently use the software program Main Replacement Prioritization (MRP) to prioritize cast iron and bare steel replacement projects.

<u>Main Replacement Prioritization (MRP)</u>

MRP uses pipe characteristics, leak history, risk and condition scores, and user-define indicators to prioritize pipe replacement. Once these pipes are scored, the program creates an ordered ranking of pipes to be replaced, project plans designed to use budget money more efficiently, reports detailed replacement strategies and can plot the leak and incident trend.

MRP Inputs

Leak history must be updated to ensure MRP uses the most current conditions with its analysis. Found and closed leaks are mapped and recorded with ArcGIS database .Active leaks may not have been repaired therefore, there is no known failure cause. Therefore, the program assumes that the cause of failure is based on material (e.g., if an active leak is in the vicinity of steel main, MRP automatically assumes the leak was caused by corrosion).

Representing Gas Engineering and Operations, Engineers, Foremen and Gas Mechanics meet annually at May's Subject Matter Expert meeting to discuss MRP inputs and weighting factors. These inputs include:

- Condition- Including Leak History, pipe size, and age
- Risk- Building proximity to pipeline, system pressure
- Flood Plain
- Wall to Wall concrete (Business Districts)
- Cathodic Protection Status

The number of inputs and scoring may change from year to year. ***Meeting minutes and annual MRP input selections can be found in DIMP folder.***

MRP Outputs

The MRP program outputs a list of projects, and the projects are sorted based on total risk scores. Projects identified by the MRP software are prioritized and scheduled for construction as funding allows over a 5-year period. The Gas Distribution Planner organizes the project list into the five operating districts. The Gas Operating Engineer in each district reviews the project list and either confirms or provides additional information as follows:

- The number of services to be replaced and/or swung over to the new main:
- The size of the replacement pipe to be installed.
- The pipe condition by examining the exposed main reports and gas leak history for the sections of main involved.
- The work scope for each project and provide an explanation for any changes made.

- Nearby projects to be combined with each other.
- The conceptual cost estimate for the project.
- The Gas Operating Engineers often have to adjust the conceptual cost estimate for
    - Projects along highways that are concurrent with municipal sewer, water, drainage, and/or repaving work during or shortly after the proposed work tend to be less expensive than historical prices due to less restoration requirements.
    - Projects located on newly paved roadways are frequently cost prohibitive due to municipal requirements to pave curb to curb and frequently are not allowed at all by the permitting agency.
    - Projects located in municipalities that are financially challenged tend to have higher restoration costs and restrictive permitting.

Budget cost estimates are based on historical distribution improvement project costs. ***Additional information on how project costs are estimated can be found in <u>Gas Distribution Engineering Guidelines.</u>***

The Director of Gas Distribution finalizes the MRP project list and prepares it for submittal for review and approval. This step is essentially completed by calculating for each project the ratio of risk score eliminated divided by the estimated conceptual cost and sorting the list from highest to lowest ratio. Projects are ranked by risk eliminated per dollar spent.

<u>Subject Matter Expert (SME) Meetings</u>
The Subject Matter Experts consist of the experienced and knowledgeable individuals from Gas Transmission, Gas Regulators Station, Gas Distribution and Gas Operations. The Gas Department has SME meetings several times a year. There are various topics on the agenda and the corresponding departments attend. Meeting agenda are created and meeting minutes are issued to the meeting participants.

Members of Gas Distribution, Gas Operating Engineers, Gas Operations and the Gas Foreman groups participate in both DIMP's May and July Subject Matter Expert (SME) meetings. The May SME meeting is used to discuss the MRP input as described in Section 6.5.1. The July SME meeting is to review MRP output project list. The Gas Operating Engineer from each operating district prepares a brief problem statement, proposed solution, conceptual cost and benefit, and a map identifying the location for each proposed construction project, including projects identified by the local gas operations personnel that were not recognized by MRP program. Each project is discussed during the meeting. Input from the different departments is considered and the list is prioritizes and placed in the 5 year capital forecast by Gas Engineering.

System Integrity and Flow Studies

System Integrity and Flow studies are performed for gas systems experiencing load growth, known pressure problems, capacity constraints, planned highway relocation and new business requests. These studies are identified through an internal risk methodology based on the type of system, the load growth and the percent of the CH system wide customers on the particular system.

Additional information on how flow and integrity studies are performed can be found in the Gas Distribution Engineering Guidelines.

Proposed capital projects as well as various alternatives are analyzed during a flow study to assure system has adequate capacity. The following projects are emergent work that would not be categorized as Leak prone pipe replacements rather Reinforcements, New Business, and Road Rebuilds.

Regulatory Compliance Projects

Regulatory Compliance Projects include pipeline integrity projects, valve and valve zone projects, highway rebuilds and cast iron undermines. There are limited discretion on project completion and timing. Project alternatives identified and evaluated to determine least cost option.

Central Hudson coordinates with the local municipalities and the Department of Transportation for highway rebuild and road paving projects. The highway rebuilds and road paving projects usually consist of relocation and replacement of existing infrastructure. The infrastructure is optimally designed for both present and projected use through flow and area studies.

New Business or Engineering Request Projects

New Business Projects include new commercial, new resident developments and limited number of upgrades to existing customers. Obligation to serve the customer is less stringent than on the electric side. Projects are economically justified projects, based on a targeted return on equity within three years or projects within the tariff guidelines will proceed. Projects may include developer or customer contribution deposits.

Strategic System Expansion Projects

Projects are identified through planned or potential development opportunities. Business plans are developed for each project and are analyzed based on the return on equity and long term potential revenues.

6.5.2 Prioritization Process

Gas Distribution Capital Projects and Investment Programs are categorized into three categories (non-discretionary, maintain system standards and system enhancement) as described in Section 3.3.1.

Examples of capital projects in each category are shown below.

Capital Projects	Categories
Regulatory Compliance	Non-Discretionary
Highway Rebuild & Road Paving Projects	Non-Discretionary
Leak Prone Pipe Replacement	Non-Discretionary
Reinforcements	Maintain System Standards
Other Main Replacement	Maintain System Standards
Mandatory New Business Projects	Non-Discretionary
System Expansion Projects	System Enhancement

Regulatory Compliance Projects are identified through known or projected compliance issues and are prioritized based on meeting current regulatory obligations. It should be noted that alternatives were considered before a non-discretionary projects is included in the 5 year capital forecast.

The prioritization process varies depending upon the input source of the project. Projects requiring longer lead times for permitting or equipment procurement are scheduled with sufficient lead time, and the workforce size and mobility also must be considered.

6.5.3 Outputs

The output of the prioritization process is a 5-year forecast by investment category within Category 25 that is developed by the Director of Gas Distribution with individual projects listed for non-blanket categories where practical.

6.6 Other

The budgets for categories outside of Transmission, Regulator Stations, and Distribution primarily are driven by compliance, with limited focus on maintaining system standards. The budgets in Categories 24 (New Business) and 27 (Meters) are installed due to New Business and System Load growth; Central Hudson's tariff references the obligation to serve these customers.

6.7 Gas Capital Budget

6.7.1 Prioritization across Categories

While not specifically compared to each other for the purpose of prioritizing one project over the other, Gas Transmission, Regulator Stations, New Business, and Gas Distribution need to coordinate capital projects plans, such as recommendations from distribution planning studies, to ensure the comprehensive plans are aligned and completed in the same timeframe.

6.7.2 Integrated Plans

The Manager of Gas & Mechanical reviews the Gas Capital Budget and ensures that the capital plan is consistent with other corporate work plans and other issues that may not have been considered in the development of the capital projects and programs. For example, some of the capital projects may have an expense component associated with project, which will need to be accounted for in the expense budgets.

6.7.3 Final Budget

A detailed list of projects, along with project details as required in the project development forms and other back-up reports are provided to Estimating and Gas Operations upon approval by the Vice President of Engineering and System Operations.

7. Common (Future Use)

8. Corporate Capital Budget/Forecast

8.1 Introduction

The development of the Corporate Capital Budget/Forecast involves the rigorous processes described in this document, as well as oversight of the key corporate committees detailed in Section 2.3, and final approval by the Board of Directors. It consists of the Electric, Gas, and Common Budgets as inputs. The following is a list of key activities in the process following the development of the Corporate Capital budget:

- February 1 – Initiate Capital Forecast Process
- March 15 – Complete Initial Draft of the Capital Forecast and review with the Capital Asset Review and Evaluation (CARE) Committee
- April – Strategic Planning Committee (SPC) approves the Capital Expenditure forecast
- April – May 15 – Project details refined and input from executive review is integrated. The SPC and Group Heads work together to prioritize key initiatives.
- June/July – Present to the Board for approval the annual capital budget and for review the five year forecast as part of the Business Plan approval
- December – Input approved annual budget into the Company's capital budget system

8.2 Electric, Gas, and Common Inputs

The Electric and Gas budgets are developed independently as described in Sections 5 and 6. The development of the Common budget is also completed independently.

8.3 Prioritization across Categories

Major corporate initiatives (typically greater than $5 million or changes in corporate strategy) across the Electric, Gas, and Common categories are discussed and prioritized between the Group Heads and SPC during a series of meetings in the second quarter of the year. Coupling this Corporate Level prioritization with the rigorous prioritization of all projects within the Business Segments as described in Sections 5 through 7, an overall corporate budget/forecast is developed and submitted to the BOD for review and approval.

8.4 Final Budget

The BOD approves the total level of corporate capital expenditures, typically including a 5% contingency for the subsequent business plan year. They do not typically authorize specific project expenditures or specific limits within the Electric, Gas, or Common programs. This approval process assures consistency with the Company's strategic plan, allows the BOD to exercise its fiduciary responsibility, and provides flexibility to allow for a reasonable level of shifting of resources from one category to another. This flexibility enables the organization to respond to: changing economic conditions, unexpected failures, increasing material costs, and reprioritization of projects required as a result of unforeseen circumstances such as unanticipated DOT relocations, large customer additions, and uncontrollable project delays.

Once approved by the BOD, deviation from the original Electric, Gas, and Common budgets is managed within the CARE committee and the President/CEO will have ongoing review with the Board of Directors.

9. Conclusion

This document serves as a guide for the Capital Prioritization process to optimize the level of capital investments with O&M expenditures, to align capital plans with the Mission, Vision, and Strategy of the Company, and to enable consistency in the process. While these guidelines and templates are utilized as part of the documented process, Engineering and Operating experience and judgment must always be applied in conjunction with these guidelines.

Budget Submittal Form for Electric Projects

Project Name:

Form submitted by:

Budget Group: Select a Budget Group

Summary Category: Select a Category

Investment Category: Select an Investment Category

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Solution

Cost estimate (include AFUDC if appropriate)

Type of estimate: Select Estimate Type

	Total	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Future**
Capital							
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Select Primary Project Objective

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type ____
  - ☐ Current % loaded ____
- ☐ Voltage (Stray, Low, High) ____
- ☐ Power Quality ____

Other ____

Risk Reduction

Safety

- ☐ Employee Safety ____
- ☐ Public Safety ____
- ☐ Other Program Type ____

Compliance

- ☐ Inspections ____
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type ____

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates ____
- ☐ Obsolete/ Unserviceable Equipment ____
- ☐ Condition ____
- ☐ Accessibility (Off Road, underground) ____
- ☐ Strategic Replacement ____
- ☐ Other Program Type ____

Resilience

- ☐ $/COA (with storm) ____
- ☐ $/CMA (with storm) ____
- ☐ Customer Cost of Outage (ICE Calculator) ____
- ☐ Grade B Construction

Other ____

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Gas Projects

Project Name:

Form submitted by:

Recommended In-Service Year:

Budget Group: Select a Budget Group

Summary Category: Select a Category

Investment Category: Select an Investment Category

Number of Customers Affected:

Description of Problem

Gas system:

Gas pressure:

Existing pipe size and material:

Proposed length replacement:

Solution

Proposed size:

Cost estimate (include AFUDC if appropriate):

Type of estimate: Select Estimate Type

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital							
Expense							

Cost Risks

☐ Environmental

Timing/Permitting

Manpower

☐ Other

Primary Project Objective

Select Primary Project Objective

Benefits

Economic

Reduced O&M

☐ Replacement

☐ Reinforcement

☐ Road Rebuild

☐ Other

Service

Reliability

☐ Radial feed

☐ Loop tie

Gas Safety

☐ Pipeline type

☐ Number of closed leaks in past 10 years

☐ Number of hazardous (Class 1, 2A and 2)

☐ Number of active leaks

☐ Length of leak prone pipe eliminated

☐ Number of high pressure service replacement

☐ Number of isolated service replacement

Customer Impact

- [ ] Complaints
- Critical Customers
- [ ] Public Relations Considerations

Other

Risk Reduction

Safety

- [ ] Reduce risk of incident
- [ ] Employee Safety
- [ ] Public Safety
- Other Benefits

Compliance

- [ ] Central Hudson Inspections
- [ ] Elimination of Integrity Related Issues
- Other Program Type

Infrastructure

- Infrastructure year installed
- Number of Services
  - [ ] Indoor meter sets
  - [ ] Metallic
- [ ] Obsolete/ Unserviceable Equipment
- [ ] Strategic Replacement
  - [ ] Flood zone
  - [ ] Main feeder route
  - [ ] Low pressure system
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

APPENDIX 4 – Capital Budget Project Idea Submittal Form

This form gives Central Hudson employees the opportunity to propose new project ideas/scenarios that will be acknowledged and assessed as part of the annual Capital Prioritization review process.

You may be contacted during this process to provide more detailed information and or to clarify different aspects of your proposal.

- Name: __________________
- District: _________________
- Business Segment (circle one): Electric or Gas
- Briefly describe your idea; please be concise and specific:
  ____
  ____
  ____
  ____
- What are the benefits?
  ____
  ____
  ____
  ____
- Project justification and recommended in-service date
  ____
  ____
  ____
  ____
- What are the potential risks?
  ____
  ____

Appendix 5 - Electric Integrated Capital Project Plans Form

As part of the electric planning study recommending an integrated capital project, a recommended in-service date is specified and conceptual cost estimates are developed. Based on the in-service date and the estimated time required to permit and construct the project, the estimated conceptual costs are allocated across multiple years (as necessary) to account for the total time required for project completion.

An Integrated Capital Project Plan requires interaction among many different departments including Transmission & Distribution Planning, Design, Operations, Real Property Services, Environmental Services and Project Management.

The Integrated Capital Project Plan should be a high level summary of the overall project. A template is included on the next page.

Central Hudson Gas & Electric Corporation
Integrated Capital Project Plan

Project:

Needs Assessment:
Completed Studies:

Area growth projections, actuals and capability (include graphs):
Risk Analysis

Alternatives Considered:

Alternatives Evaluation:

Alternative	***Evaluation***	***Cost***

Recommendation:

Projected Costs and Schedule:

Projects	***Category***	***2015***	***2016***	***2017***	***2018***	***2019***	***Future***	***Total***
Filing/Permits								
Right Of Way								
Construction								
Transmission								
Substation/Regulator Station								
Distribution								
Project Management								
Total								

Appendix 6 – Reference List

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- Central Hudson Gas & Electric. “CARE Committee,” http://chwiki.cenhud.com/display/CARE/CARE+Committee

- Central Hudson Gas & Electric. “Information Technology Steering Committee,” http://chwiki.cenhud.com/display/InfTech/IT+Steering+Committee

Appendix H 2017-2021 Capital Forecast and Historical Expenditures

H.1 2017 – 2021 Capital Forecast Budget Package

H.2 2011-2015 Historical Expenditures

CENTRAL HUDSON GAS & ELECTRIC 2017-2021 CORPORATE CAPITAL FORECAST

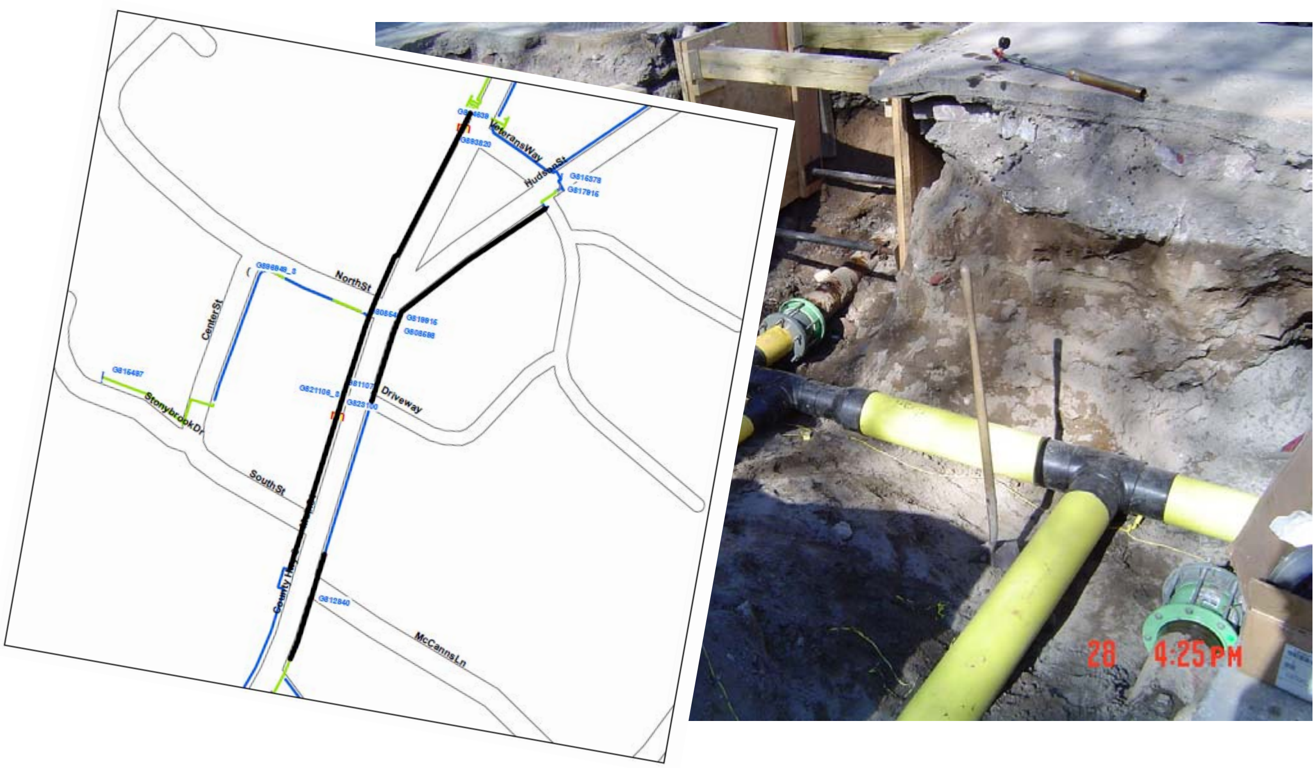


TABLE OF CONTENTS

EXECUTIVE SUMMARY

This document presents the comprehensive Capital Investment Plan for the electric and gas transmission and distribution systems and common program areas of Central Hudson Gas & Electric Corporation (Central Hudson or Company) for the period 2017 through 2021 (Capital Plan). This Capital Plan positions Central Hudson to continue to provide safe and reliable service to customers. This Capital Plan is consistent with the mission of the Company as shown below:

"Central Hudson's mission is to deliver electricity and natural gas to an expanding customer base in a safe, reliable, courteous and affordable manner; to produce growing financial returns for shareholders; to foster a culture that encourages employees to reach their full potential; and to be a good corporate citizen."

This Capital Plan proposes to invest $448 million in the electric delivery system, $284 million in the gas delivery system and $212 million in common program areas over the five - year period. The projects and programs proposed in this Capital Plan are what the Company has determined is needed to deliver safe and reliable service to customers. The Company is continually re-evaluating and reprioritizing projects, and the later years of this Capital Plan will likely change as a result of these reevaluations and assessments. The Capital Plan is developed annually consistent with the Company's Capital Prioritization Process Guidelines.

The 5-Year Capital Plan contains projects that will help achieve the following strategic objectives of Central Hudson:

- Practicing continuous improvement in everything we do
- Investing in electric and gas transmission and distribution infrastructure and common program areas to maintain current levels of customer service;
- Investing capital when justified to reduce risk, enhance reliability, and improve customer satisfaction;
- Advocating regulatory and public policy outcomes that are in the interest of our customers and investors; and
- Moderating cost pressures that increase total customer bill costs and variability.

Capital Forecast – Additions

	2017	2018	2019	2020	2021	TOTAL
ELECTRIC	$ 86,470	$ 87,846	$ 91,925	$ 95,242	$ 86,629	$ 448,113
GAS	47,205	56,752	60,858	59,103	60,121	284,040
COMMON	27,883	43,670	45,031	44,058	51,783	212,426
CORPORATE TOTAL	$ 161,559	$ 188,268	$ 197,815	$ 198,403	$ 198,534	$ 944,579

Capital Forecast – Removal

	2017	2018	2019	2020	2021	TOTAL
ELECTRIC	$ 6,463	$ 6,432	$ 6,595	$ 7,840	$ 7,756	$ 35,085
GAS	2,452	2,470	2,504	2,554	2,625	12,605
COMMON	(81)	(85)	(90)	(98)	(108)	(462)
CORPORATE TOTAL	$ 8,834	$ 8,817	$ 9,009	$ 10,297	$ 10,273	$ 47,229

Introduction

Central Hudson's Corporate Capital Forecast continues to increase at a modest rate and with the addition of several large multi-year capital initiatives being presented this year, the Base Case scenario now totals $945 million in capital expenditures over the five year period 2017-2021. This represents an approximate 10% increase over the prior year's 5-year forecast. While the electric program forecast is showing a modest increase from the prior forecast, the gas program forecast is increasing more significantly as a result of additional Leak Prone Pipe program and gas marketing program expenditures and the common program is increasing due to IT software needs and a planned training facility.

The major changes to the forecast from the prior year's forecast primarily concentrated in the gas and common areas and will be covered in more detailed in the body of this report.

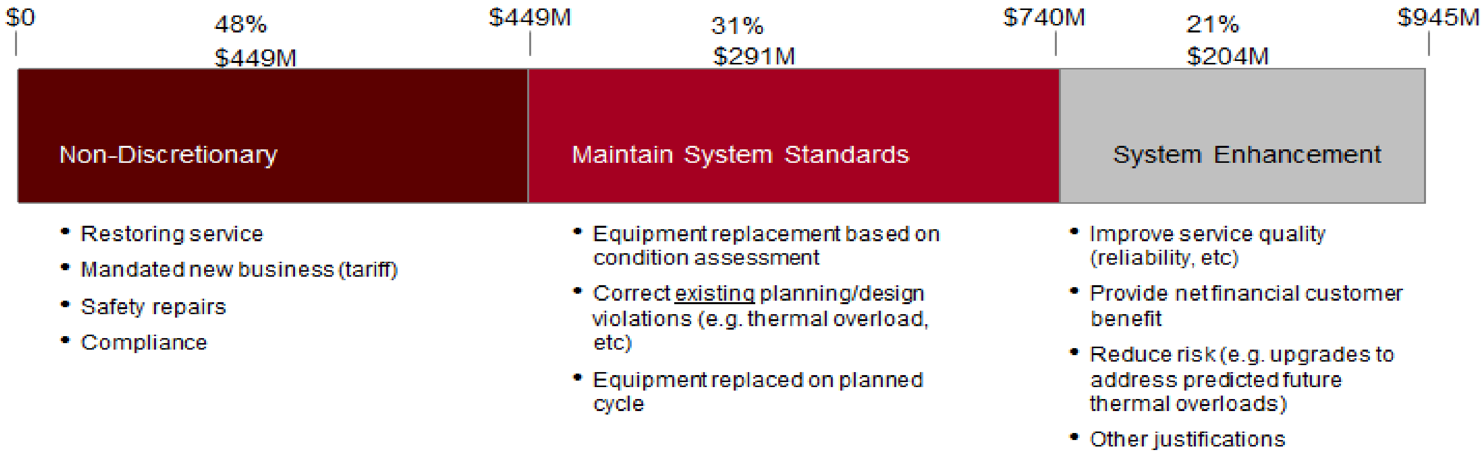
CHG&E Capital Expenditiure Forecast
Comparison of 2016-2020 and 2017-2021
Electric,Gas & Common Forecast

(with inflation & overhead adjustments)

ELECTRIC PROGRAM		
2017-2021 Forecast	$	448,113
2016-2020 Forecast	$	432,423
Change	$	15,690
GAS PROGRAM		
2017-2021 Forecast	$	284,040
2016-2020 Forecast		258,200
Change	$	25,840
COMMON PROGRAM		
2017-2021 Forecast	$	212,426
2016-2020 Forecast		162,500
Change	$	49,926
CORPORATE TOTAL		
2017-2021 Forecast	$	944,579
2016-2020 Forecast		853,122
Change	$	91,456

5-Year Corporate Capital Forecast Summary

A breakdown of the Capital Forecast is shown below indicating the level of spending as we have prioritized the expenditures by their summary categories. Non-discretionary is the level spending that is necessary to meet the minimum standards of service or compliance with Public Service Law. Maintaining System Standards is the level of spending required to maintain our current level of service reliability and safety or to meet obligations set through the rate proceedings. System Enhancement is capital spending aimed at improving our quality of service, reducing risk, or reducing operating costs.



The System Enhancement Capital Spending has been further segregated into the following categories:

- **Projects with a Net Financial Customer Benefit**
  - Projects Revenue requirement of the capital investment is lower than the net benefit (e.g. cost savings) for customers
  - Reduces customer bills in the long term (after next rate case)
  - Increases earnings both short term and long term

- **Projects that Reduce Risk**
  - Investment reduces the risk of a system failure that would:
    - Reduce potential public safety at risk
    - Result in widespread incident, impacting system integrity
    - Spur significant punitive regulatory action

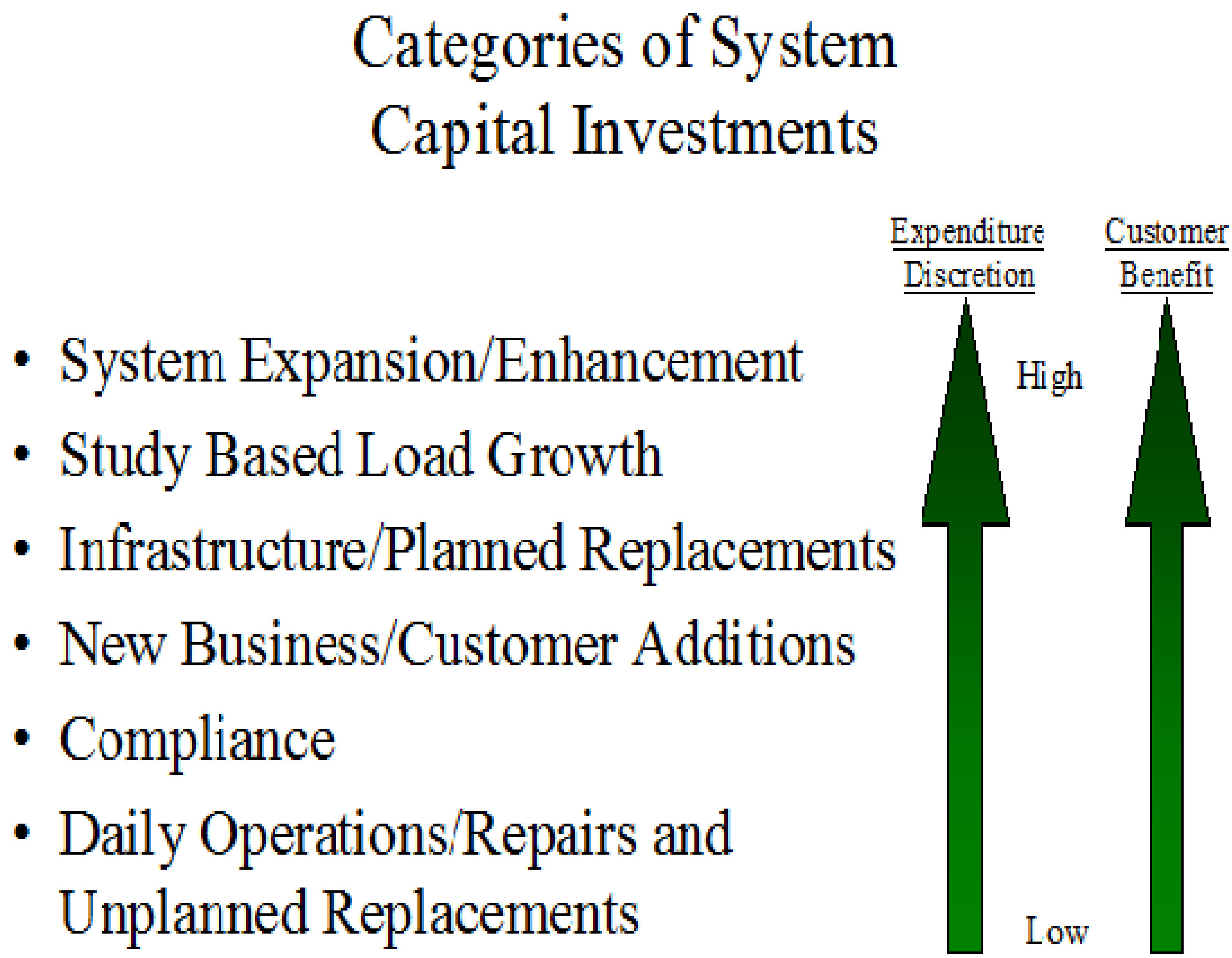
- **Projects that Improve Reliability**
  - Investment improves reliability at a cost that (we believe) customers are willing to pay
  - Demonstrate that increased cost is warranted by the improvement in service quality (benchmark and compare cost per customer outage avoided).

- **Other Projects**
  - Projects that do not clearly fit in the other categories, but can be justified for other reasons
  - Requires detailed individual business case
  - Demonstrate a clear strategic rationale
  - Show financial projections (customer bill impact and earnings impact)
  - Assess risks (regulatory disallowance, etc)

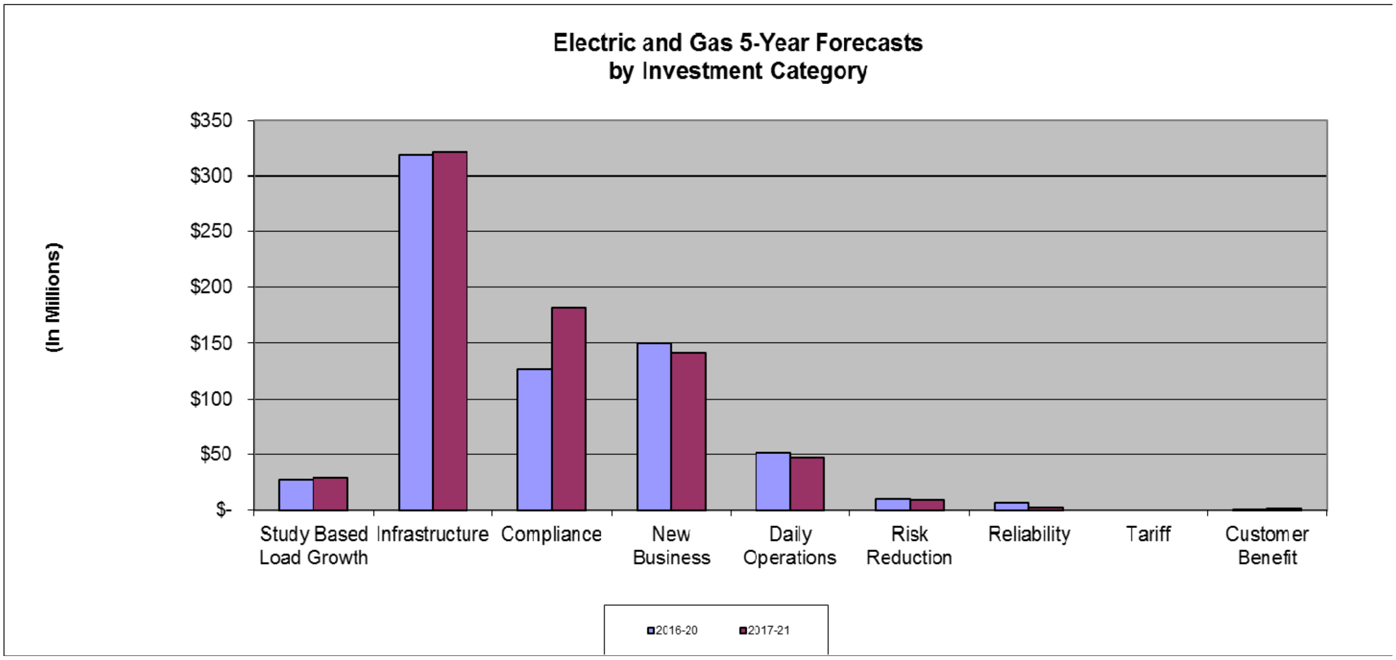
Each year, Central Hudson Gas & Electric Corporation, through its planning and forecasting processes develops a recommended Capital Expenditures Budget for the upcoming fiscal year as well as a forecast for upcoming five-year period.

The corporate capital forecast is developed through a bottom up process where planning studies, infrastructure issues, and compliance requirements, and other corporate initiatives identify specific capital needs. Following the Company's Capital Prioritization Process Guidelines, these needs are prioritized based on the whether the need is non-discretionary (mandated or otherwise not optional), required to maintain the existing level of service or reliability, or a system or service enhancement. In addition to the costs of the projects, the timing of the projects is also analyzed to determine the most appropriate time for the capital investment to be made either due to load growth, risk of failure, or business need.

In addition to the summary categories, the needs are prioritized based on the investment categories shown below. It should be noted that those projects with the least amount of discretion also have the least amount of benefit for customers in terms of improving their level of service quality or reducing operating costs. It is important that we continue to develop sound justifications for the system enhancement projects since they do provide the most benefit to customers.



As can be seen in the comparative graph below load growth related projects represent a very small percentage of the expenditures in the Capital Plan. The major driver of investment continues to be replacing aging assets based on condition with the most significant uptick in expenditures for the Leak Prone Pipe program.



On the electric side, the Distribution Automation Program is a major initiative that has been included in the 5-year forecast. This program will first develop a Distribution Management System to improve reliability, system safety, and system efficiency. After the development of the DMS, there is a large infrastructure improvement aspect of this project which 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 will also be an increased number of Automatic Load Transfer (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, including the additional ALTs, reclosers, and capacitors is $44 million and is estimated to improve reliability by reducing the number of customer outages by 20%. In addition, much of the costs are related to the rebuilding and re-conductoring of electric distribution mainline, some of which would need to be replaced as part of the asset replacement program. Additional benefits would include reduced system losses, improved switching safety, and improved restoration times through the use of manual switching when an ALT is not available.

The single largest component of the gas capital program is the Leak Prone Pipe replacement projects. Central Hudson operates 1208 miles of distribution main of which about 230.6 is cast iron or unprotected steel. Over the last three years (2013 – 2015) an average of 6.4 miles of leak prone pipe has been replaced annually. Expenditures are tracked monthly using the Operations Report. The main replacement projects are identified and prioritized using the GL Main Replacement Program (MRP) which develops a risk 'score' based on pipe and operating characteristics such as material, operating pressure, age, diameter, leak history, location(proximity to buildings, business district, flood prone areas) and, cathodic protection. This risk score measures the relative likelihood and the consequences of a leak associated with each pipeline segment. In addition Subject Matter Expert (SME's) review and planned highway rebuilds are taken into consideration when developing the proposed main replacement project listing.

Accelerating the replacement of leak prone distribution piping is driven by a number of factors, including recent events in the Northeast experienced by utility operators of similar systems receiving nationwide attention and a renewed focus on pipeline safety by government and regulators, coupled with the internal need to meet PSC rate case safety metrics and reduction of operating and maintenance costs associated with leak inventory.

The total for cast iron and unprotected steel main replacement is $155 million in the 5-year forecast (average annual expenditure of $31M). By increasing current annual expenditures on the leak prone pipe with the most risk, the current replacement program can be reduced from a 50 years to approximately 15 years. Further, the replacement of higher risk medium pressure services escalates over the 5-year forecast in order to continue the program to reduce exposure and risk.

The Common Capital Forecast consists of following categories; Land and Buildings, Office Furniture, Tools & Equipment, Transportation, and Information & Technology. Land & Buildings capital forecast comprises primarily of infrastructure replacement projects due to age or equipment failures. The Tools forecast consists of replacements driven by the replacements of the vehicles they are utilized on, obsolescence and incompatibility, decreased reliability, discontinued manufacturer support, and conformance to changing OSHA or other regulations. Transportation capital forecast is built primarily on the replacement of vehicles and equipment base on industry standard replacement criteria. The IT Capital Budget consists of investments for business driven software implementations, upgrades to existing software solutions, and infrastructure or hardware lifecycle upgrades and ongoing extensions resulting from corresponding software updates or implementations.

Resource Needs of Future Program

Central Hudson will face the following opportunities and challenges as we implement this Capital Plan.

On the electric side, the Company will need to continue to develop enhanced competencies in both asset management as well as distribution automation. Improvements are being made to the System Planning Process especially with the need to integrate additional Distributed Energy Resources (DERs) which will encompass both how we determine asset replacements and the methods used to optimize the portfolio of projects and programs as well as better understand how DERs impact system growth. To ensure that the Plan proceeds in the most optimal fashion, the Company will need to reassess the timing and reprioritize projects using both these improved asset management approaches and the understanding of system needs. Planning shall remain as a core competency for the Company.

On the gas side of the business, accelerating the replacement of leak prone distribution piping, enhancements on the transmission system, and regulator station upgrades and replacements will require further detailed project prioritization and system planning. Additionally, engineering design, permitting, estimating and field construction management and oversight resources will be required to maintain the high degree of safety, and quality installations occurring today.

With regard to construction, it is envisioned that the bulk of the incremental electric and gas transmission and distribution construction will be performed by contracted resources. Although there is an increase in the amount of capital construction, it is not so large an increase as to give any concern that contract resources would not be available to complete the work. Consideration for additional field oversight for this construction work will also likely be needed and these resources in the Customer Services Group would charge their labor to capital.

ELECTRIC PROGRAM SUMMARY

Electric System Overview

The Central Hudson electric system serves approximately 300,000 electric customers in New York State's Mid-Hudson River Valley. Central Hudson electric service territory extends from the suburbs of metropolitan New York City north to the Capital District at Albany.

The Central Hudson system is comprised of substations having an aggregate transformer capacity of 5.0 million kilovolt amps, a transmission system consists of 622 circuit miles of line and a distribution system consists of 7,300 pole miles of overhead lines and 1,400 trench miles of underground lines, as well as customer service lines and meters.

The transmission system operates at voltages of 69 kilovolts, 115 kilovolts and 345 kilovolts. The table below provides a more detailed breakdown of the transmission system.

Operating Voltage	Design Voltage	Overhead Circuit Miles	Pipe-Type Cable Circuit Miles	Total Circuit Miles
345 kV	345 kV	76	0	76
115 kV	115 kV	230	3.9	233.9
69 kV	69 kV	272	0	312
	115 kV construction operating at 69 kV	40		
Total		618	3.9	621.9

The distribution system operates at voltages of 4.16 kilovolts, 4.8 kilovolts, 13.2 kilovolts, and 34.5 kilovolts. It also encompasses subtransmission systems that operate at 14.4 kilovolts in three urban areas of our service territory, feeding into secondary networks. The table below provides a more detailed breakdown of the overhead portion of the distribution system.

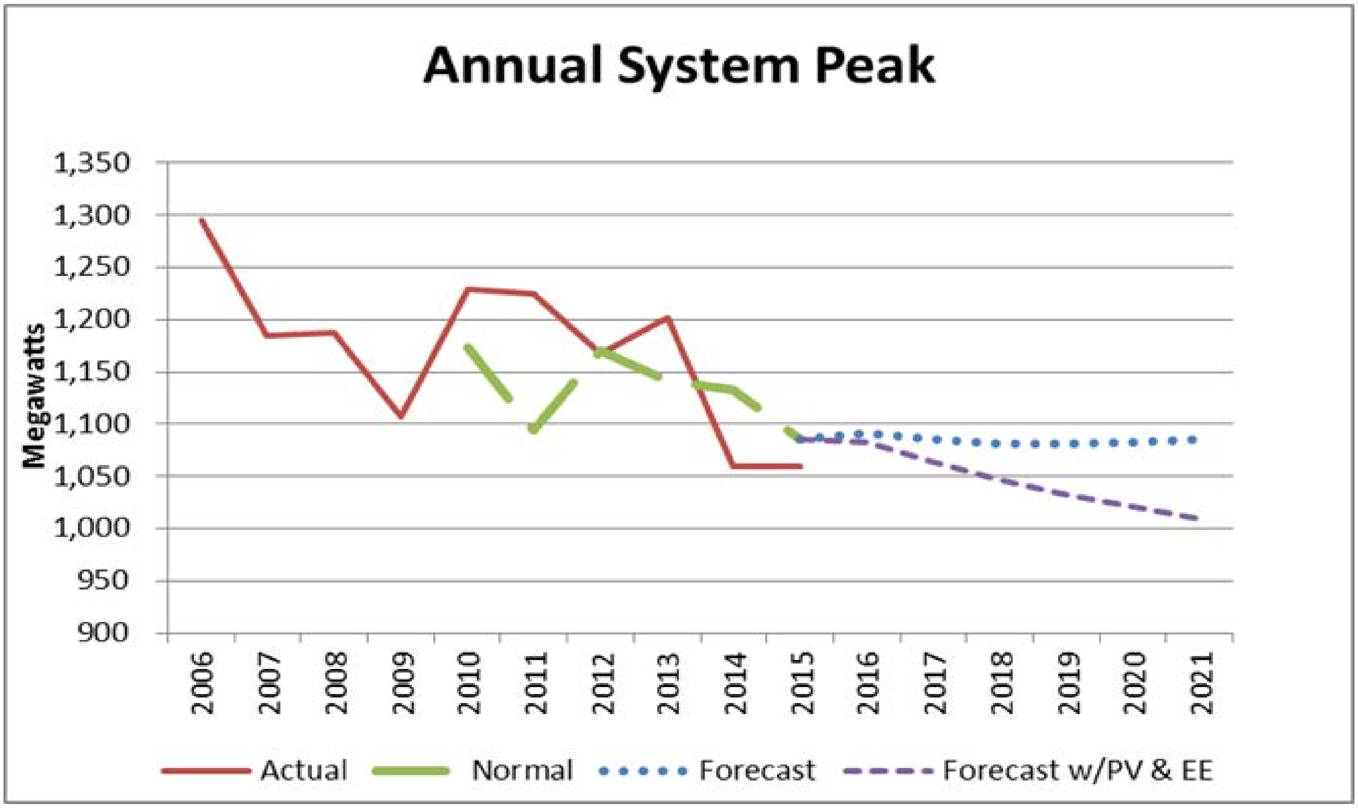
Conductor	Pole Miles of Line
34 kV Overhead	204
13.2 kV Single Phase	4,572
13.2 kV Three Phase	2,380
5 kV or Under	137

Central Hudson's roughly 83 electric substations contain the power transformers that change the voltage from one level to another.

Electric Forecast Overview

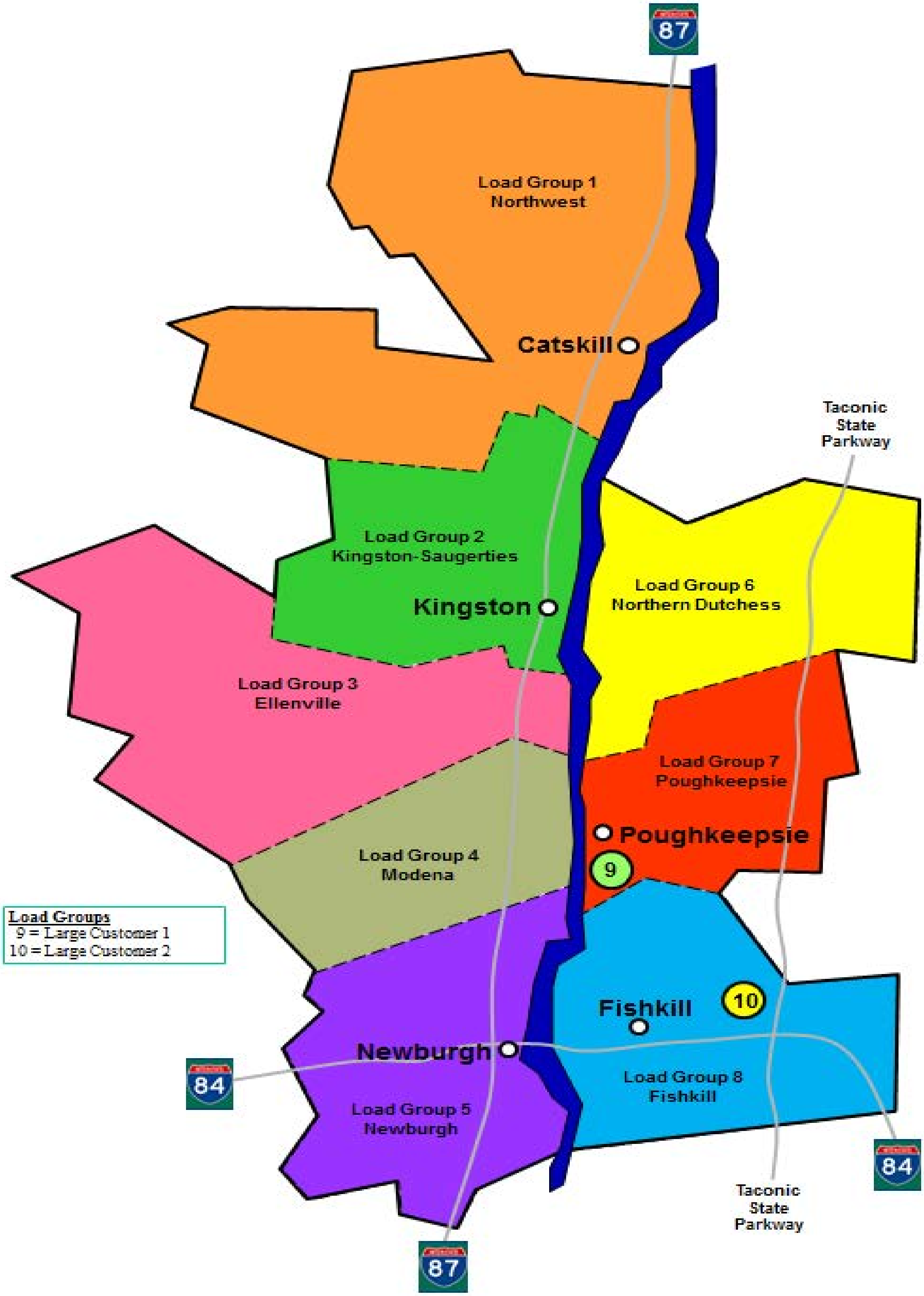
Central Hudson's electric capital forecast for the next 5-year period is developed each year using the most recent planning studies, customer and sales forecasts, corporate load forecasts, and other corporate trends. For the electric capital forecast, an adjusted peak electric demand 1084 MW system load (demand) for 2015 was used as the base year.

The current system peak forecast is shown on the graph below. As can be seen on the graph Central Hudson's peak demand is showing a modest decline based primarily on the regional economy, and the effects of the Company's energy efficiency programs and demand management programs.



In addition, Central Hudson utilizes distribution planning areas to aid in the identification of needs, their timing, the quantification of the risks, and assess the alternatives available to meet those needs. These distribution planning areas largely are based on where the ability exists to transfer load among area substations. The graphic on the next page shows the distribution planning area load groups.

CHGE Franchise Territory by Electric Load Group



Electric Program Detail

The Electric Capital Forecast is developed utilizing guidelines, planning standards and engineering judgment. The forecast is completed for each budget category and integrated into a comprehensive plan. The summaries below provide the annual forecasts for each of the electric program categories.

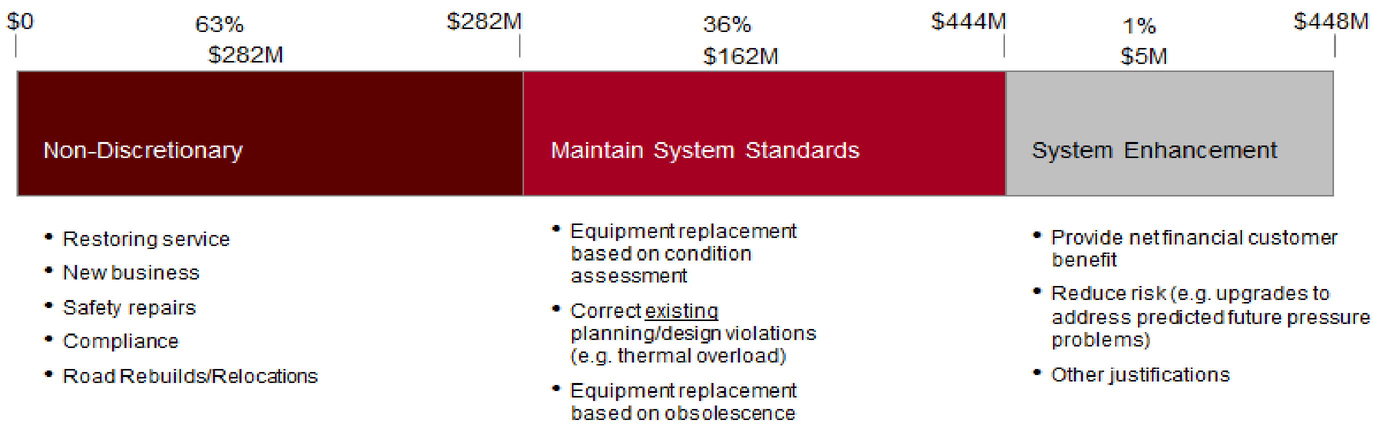
Electric Capital Forecast – Additions

	2017	2018	2019	2020	2021	TOTAL
Production	$ 2,006	$ 2,096	$ 1,559	$ 1,646	$ 1,511	$ 8,817
Transmission	18,920	17,006	19,771	22,096	21,494	99,287
Substation	23,142	21,613	15,306	19,720	16,984	96,766
New Business	4,183	4,497	3,666	3,966	4,193	20,504
Distribution Improvements	30,166	34,380	42,895	38,764	33,085	179,289
Transformers	5,148	5,286	5,698	5,957	6,203	28,292
Meters	2,907	2,968	3,030	3,094	3,159	15,158
Total	$ 86,470	$ 87,846	$ 91,925	$ 95,242	$ 86,629	$ 448,113

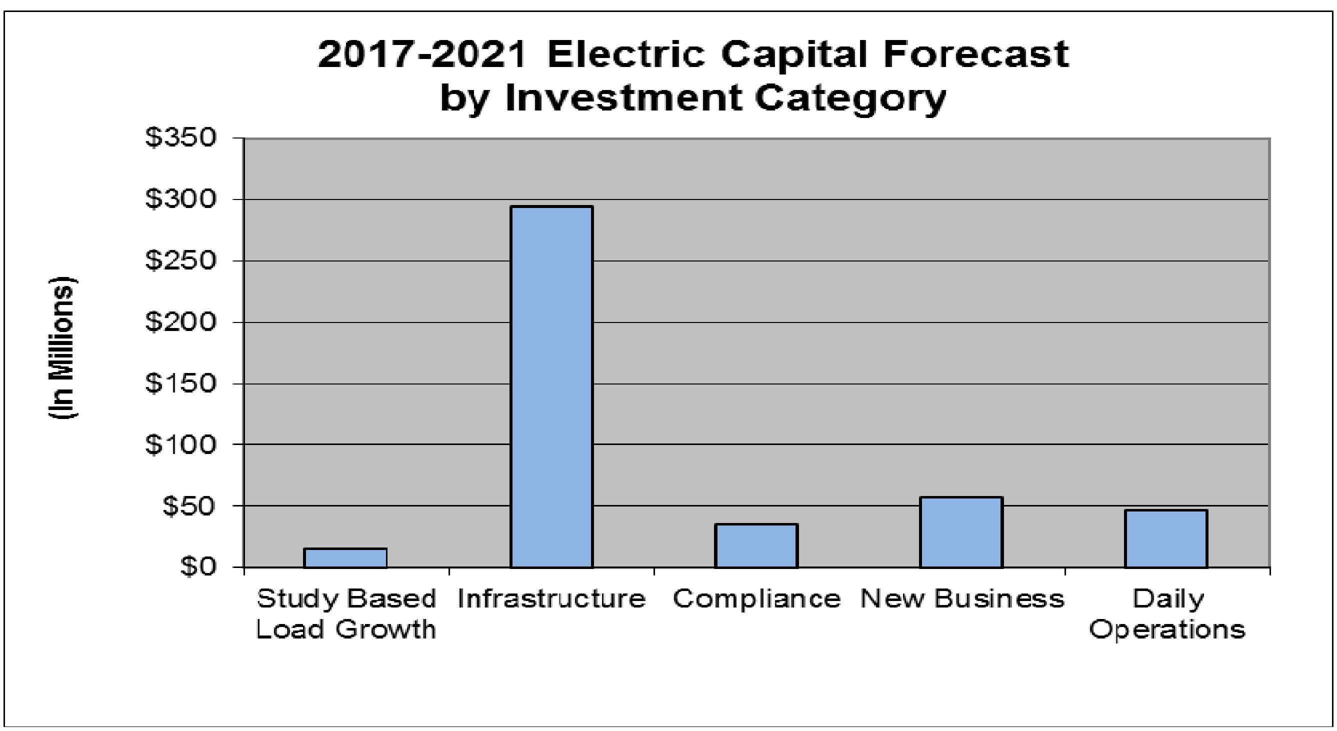
Electric Capital Forecast – Removal

	2017	2018	2019	2020	2021	TOTAL
Production	$ 127	$ 204	$ 130	$ 11	$ 623	$ 1,095
Transmission	1,403	1,551	1,713	2,856	2,306	9,830
Substation	2,038	1,696	1,625	1,786	1,384	8,529
New Business	177	188	184	196	212	956
Distribution Improvements	2,109	2,184	2,303	2,303	2,475	11,374
Transformers	311	311	331	359	398	1,711
Meters	297	297	309	329	357	1,589
Total	$ 6,463	$ 6,432	$ 6,595	$ 7,840	$ 7,756	$ 35,085

A breakdown of the Electric Capital Forecast is shown below indicating the level of spending as we have prioritized the expenditures. Non-discretionary is the level spending that is necessary to meet the minimum standards of service or compliance with public service law. Maintaining System Standards is the level of spending required to maintain our current level of service reliability and to meet obligations set through the rate proceedings. System Enhancement is capital spending aimed at improving our level of service, reducing risk, or reducing operating costs.



In addition, the projects within the Electric Program are categorized by Investment Category as follows: growth, compliance, day-to-day business management, and infrastructure replacement. The bar graph below shows the breakdown of the projects in our current five-year forecast by these Investment Categories.



Electric Transmission

For the Electric Transmission System, the purpose is to serve the expected load by developing a rational program to maintain reliability, avoid unacceptable risks, strive for the most economical reinforcements, and allow for equipment maintenance.

The facilities need to be planned, designed, operated and maintained according to "Good Utility Practice." These are any of the practices, methods or actions required by FERC, NERC, NPCC, NYSRC, NYISO, PSC, applicable law, regulations, or policies and standards, or engaged in or approved by a significant portion of the electric utility industry. Electric Transmission Planning analyses are based on planning criteria where the transmission system is designed and operated to conform to applicable reliability rules: no electric transmission facility should be loaded beyond its normal rating prior to any contingency; no facility to be loaded beyond its applicable emergency rating following any contingency; and fault levels are to be within equipment ratings.

The thermal, voltage, and system stability performance is analyzed under the various customer/load scenarios to assess the load serving capability, identify alternatives to increase load serving capability where needed, and evaluate alternatives.

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 (which adds a 345 kV interconnection to the Catskill District 115kV system), has been deferred due to the Targeted Demand Response (DR) Program; this DR program is expected to delay the Northwest 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 ACSR conductor replacement program. The WH Line was originally constructed in 1932 and this 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 $6.9M. 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 1920's**,** 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 of the line will be retired.

G Line Condition				
		Structures to		
Section	**Miles**	**Replace**	**Repair**	**Probable Replacement Percentage**
Knapps – Lagrangeville	6.6	101	4	69.2
Lagrangeville – Tinkertown	10.1	82	2	67.2
Tinkertown – PV	4.0	16	1	30.2
Totals	20.7	199	7	62.0
Data Based on 1Q 2009 Assessment				

Additionally, rebuilding the KM & TV lines is identified in the 5 year forecast. Inspections have identified 58% and 53%, respectively, of the line's wood pole structures needing replacement. These lines originally were constructed in the 1920's and 1930's.

KM Line Condition				
		Structures to		
Section	**Miles**	**Replace**	**Repair**	**Probable Replacement Percentage**
Knapps Corners – P33581	1.0	10	5	65.2%
P33581 – P33591	0.5	9	5	60.8%
P33591 – P140218	0.35	0	0	0
P140218 - Myers Corners	1.0	9	2	64.7%
Totals	2.85	28	12	58.0%

TV Line Condition				
		Structures to		
Section	**Miles**	**Replace**	**Repair**	**Probable Replacement Percentage**
Myers Corners – P46006	1.0	8	2	58.8%
P46006 – North Chelsea	5.3	42	24	52.4%
Totals	6.3	50	26	53.1%

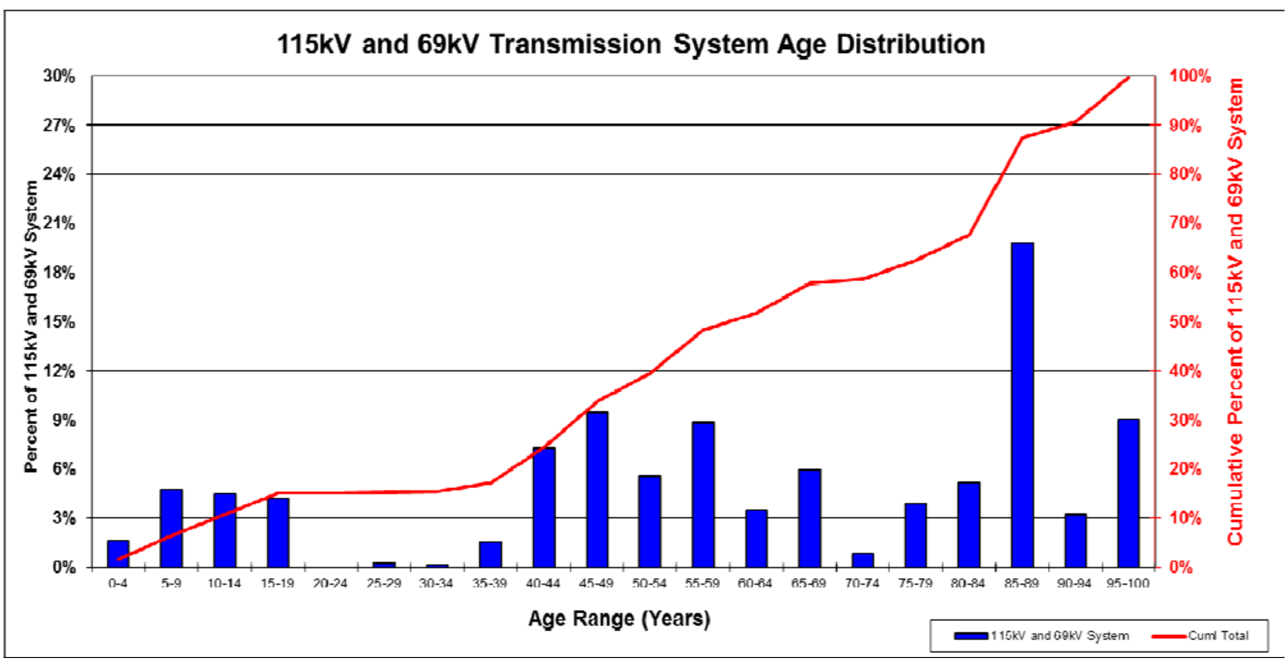
In addition to addressing known infrastructure issues, potential benefits of the KM/TV rebuild include an increase of the transmission supply to the Myers Corners substation. Concerns impacting the rebuild include both numerous right-of-way issues and the proximity to the Dutchess County Airport

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 design reviews that 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 conductor 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.

H & SB Line Condition						
				Structures to		
Line	Section	Miles	# of Structures	Replace/Add mid-span pole	Repair	% of structures that require work
H	Saugerties – N. Catskill	12.061	138	41	66	78%
SB	Hurley Ave. - Saugerties	11.11	118	41	25	56%
	Total	**23.171**	256	82	91	68%

In addition to the above capital expenditures, there are several programs in Electric Transmission designed to reduce risk and improve infrastructure. The “High Priority Replacements (HPR)” 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. The graph directly below 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).



Electric Substation & Distribution

Central Hudson Electric Substation and Distribution capital programs are developed based on our current planning criteria and address load serving capability, infrastructure, compliance and reliability/operating issues. For infrastructure based issues, Central Hudson utilizes its asset management process, including field inspections, condition monitoring, periodic testing and more in-depth analysis and studies to identify trends, equipment issues and ultimately recommend replacement programs. Infrastructure based replacements also will be reviewed to determine whether to replace units in-kind or pursue an alternative solution. Load serving capability problems related to substation equipment or distribution circuits are identified through our planning process. For each area and substation the capacity and operability of the system under the various load forecast scenarios is analyzed. This analysis includes a review of the Substation and Distribution facilities, requiring a full understanding of the limiting components. For any areas or substations where load serving capability has been identified as a potential problem, plans and alternatives by area are evaluated to develop the best solution considering all costs, benefits, and long-range growth potential. The solutions sets for these projects include both traditional utility projects and the use of Non-Wires Alternative solutions to replace or defer the potential capital upgrades.

The planning criteria are based on a combination of economic factors, current industry practice, design and practical considerations, reliability and judgment. Influencing Factors are:

- Current/ thermal limits related to the ability of the facility to withstand load related heating without damage
- Protection requirements – minimum fault current levels need to be maintained to ensure safe operation
- Power Quality - provide adequate voltage to customer premise ANSI C84.1, +/- 5.0% range during normal conditions, +5.8% to – 8.3% under emergency conditions; eliminate stray voltage
- Reliability – proximity of solutions to load and integration of Distribution Automation
- Regulatory Requirements: NESC, NYPSC

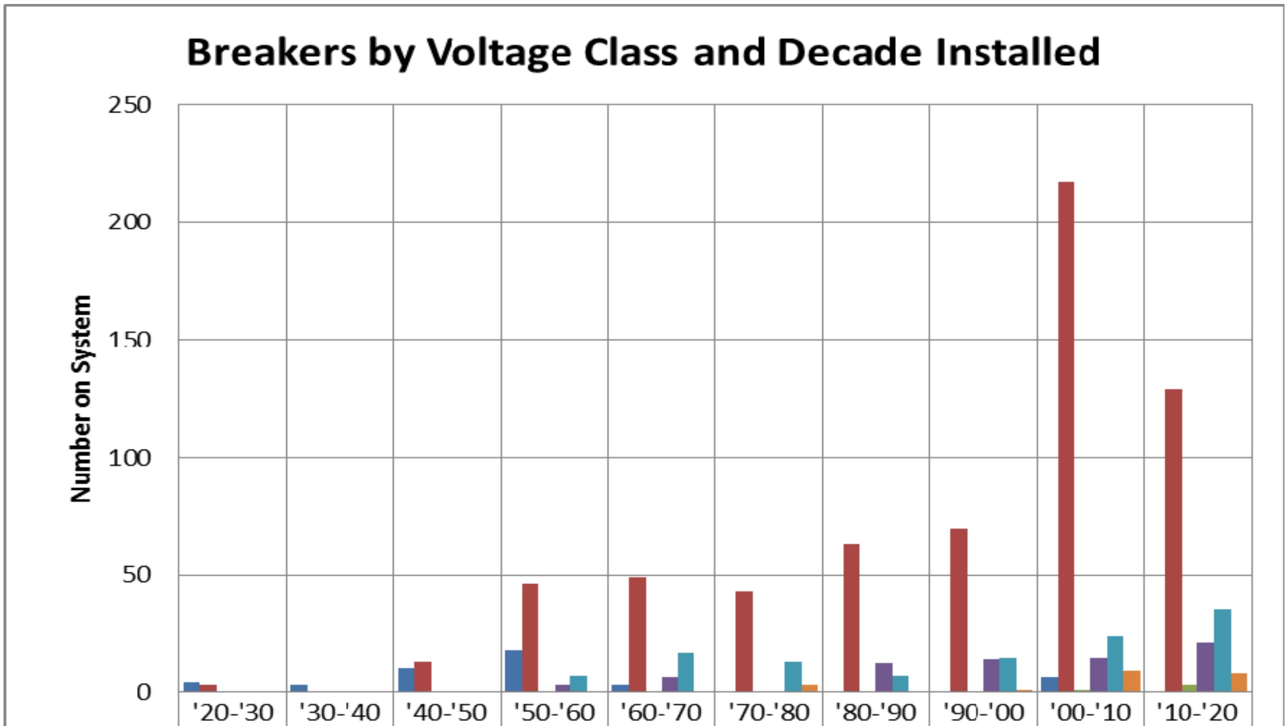
From this process, substation upgrades, equipment replacement programs and projects establishing new substations or the addition of circuits and transformers in existing substations are identified. Due to the projected declining load forecast in the majority of our planning areas, there are a very limited 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 Non-Wires Alternative solutions.

$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 equipment flooding risk reduction and the addition of a second transformer for reliability and operational flexibility at the New Baltimore Substation in addition to avoiding otherwise required Distribution system infrastructure work.

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.

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.

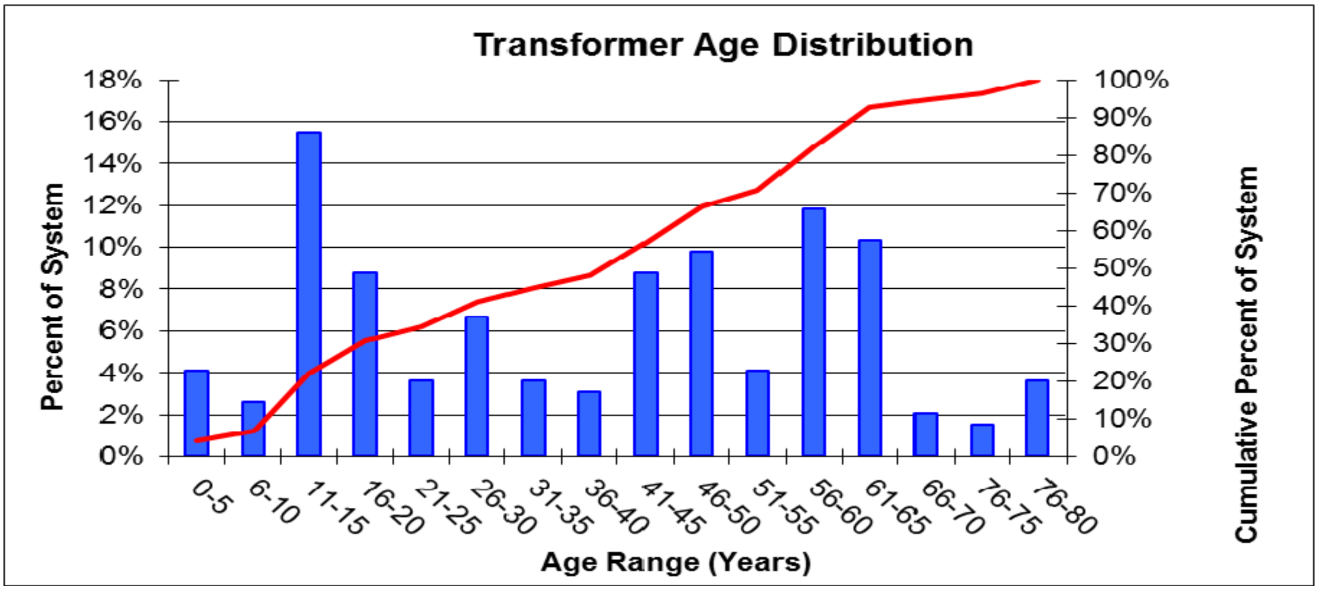


	'20-'30	'30-'40	'40-'50	'50-'60	'60-'70	'70-'80	'80-'90	'90-'00	'00-'10	'10-'20
5kV	4	3	10	18	3	0	0	0	6	0
15kV	3	0	13	46	49	43	63	70	217	129
34.5kV	0	0	0	0	0	0	0	0	1	3
69kV	0	0	0	3	6	0	12	14	15	21
115kV	0	0	0	7	17	13	7	15	24	35
345kV	0	0	0	0	0	3	0	1	9	8

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 (MOS) 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.

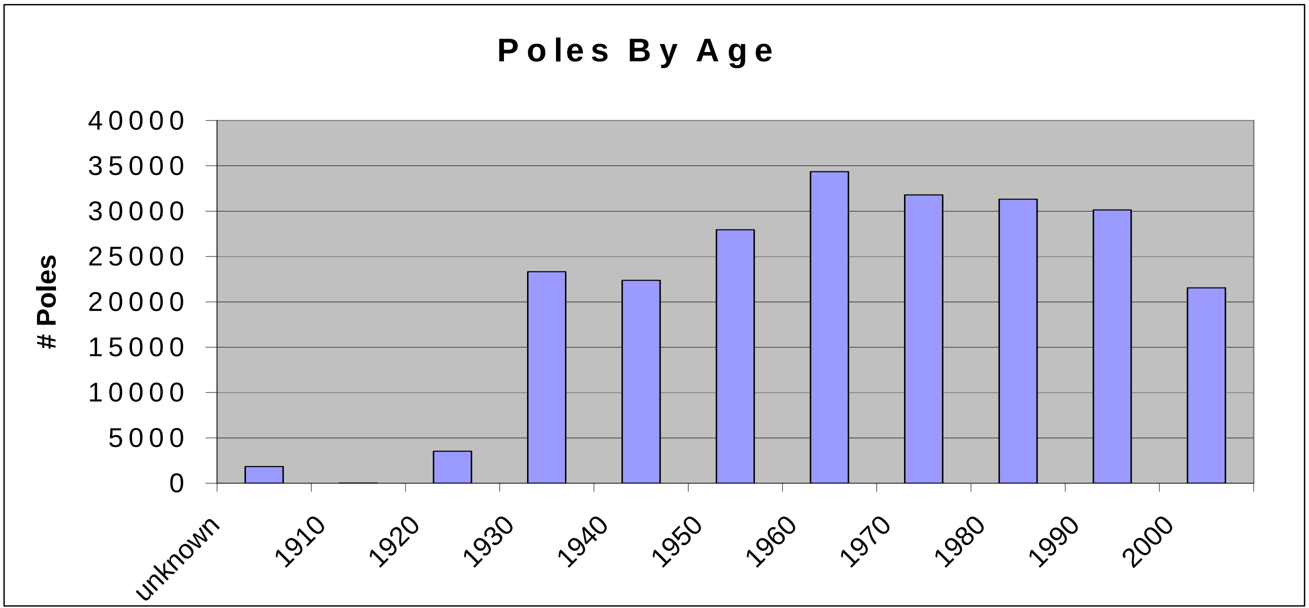
With regard to the Substation Power Transformers, the condition of the power transformers varies and the ability to maintain them is tied closely to their age. The average age of our substation transformers is approximately 40 years old with some transformers more than 80 years old. The transformers 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.



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 distribution poles identified through the inspection program is one of those programs. The graph below provides an overview of the age of the Company's Distribution pole plant. The replacement of porcelain cutouts, prone to failure, is another ongoing capital program.



The Distribution Automation Program is a major initiative that has been included in the 5 year forecast. Central Hudson will continue with the Automatic Load Transfer (ALT) switch and recloser replacement programs. Incremental in the 5 year forecast is advanced distribution automation. This program will develop a Distribution Management System (DMS) to improve reliability, system safety, and system efficiency, enhancing the capability of ALTs to include more complex Fault Location, Isolation and Service Restoration (FLISR), while providing for Volt-VAr Optimization. There also is a large infrastructure improvement aspect of this project which 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 Automatic Load Transfer 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.

New Business, Transformer, and Meters

The remainder of the Electric Capital Budget, the New Business, Transformers, and Meters capital forecast is based on the projected customer growth from the corporate forecast. A regression analysis of the prior 5 years capital expenditures and growth rates is performed for these categories to predict the capital expenditures for the upcoming 5 years given the various growth scenarios. In addition any specifically identified transformer or meter replacement programs are included in the forecast.

GAS PROGRAM SUMMARY

Gas System Overview

The Central Hudson gas system contains well over 2,000 miles of pipeline facilities ranging in age from new to over 100 years of age. It supplies gas service to about 79,000 customers in communities near the Mid-Hudson River Valley from Woodbury in the south to Coxsackie in the north and ranges from Carmel in the east to as far west as Montgomery.

The Company's gas transmission system consists of 165 miles of steel piping ranging from 6-16" in diameter and four gate stations. The Maximum Allowable Operating Pressure (MAOP) is between 512-750 PSIG. The majority (81%) of the transmission system was installed during the 1950's and 1960's. The MPI and MPR transmission lines were the last to be installed (1990's) and account for 12.8% of the total transmission pipeline inventory. Three of the four gate stations date to the 1950's and early 1960's. The last gate station, Pleasant Valley, was constructed in the early 1990's to take gas from the then new Iroquois gas transmission line.

A total of 152 gas regulators stations are utilized to supply the distribution system. The stations either reduce transmission pressure to distribution pressure (66) or further reduce distribution pressure to a lower pressure (86).

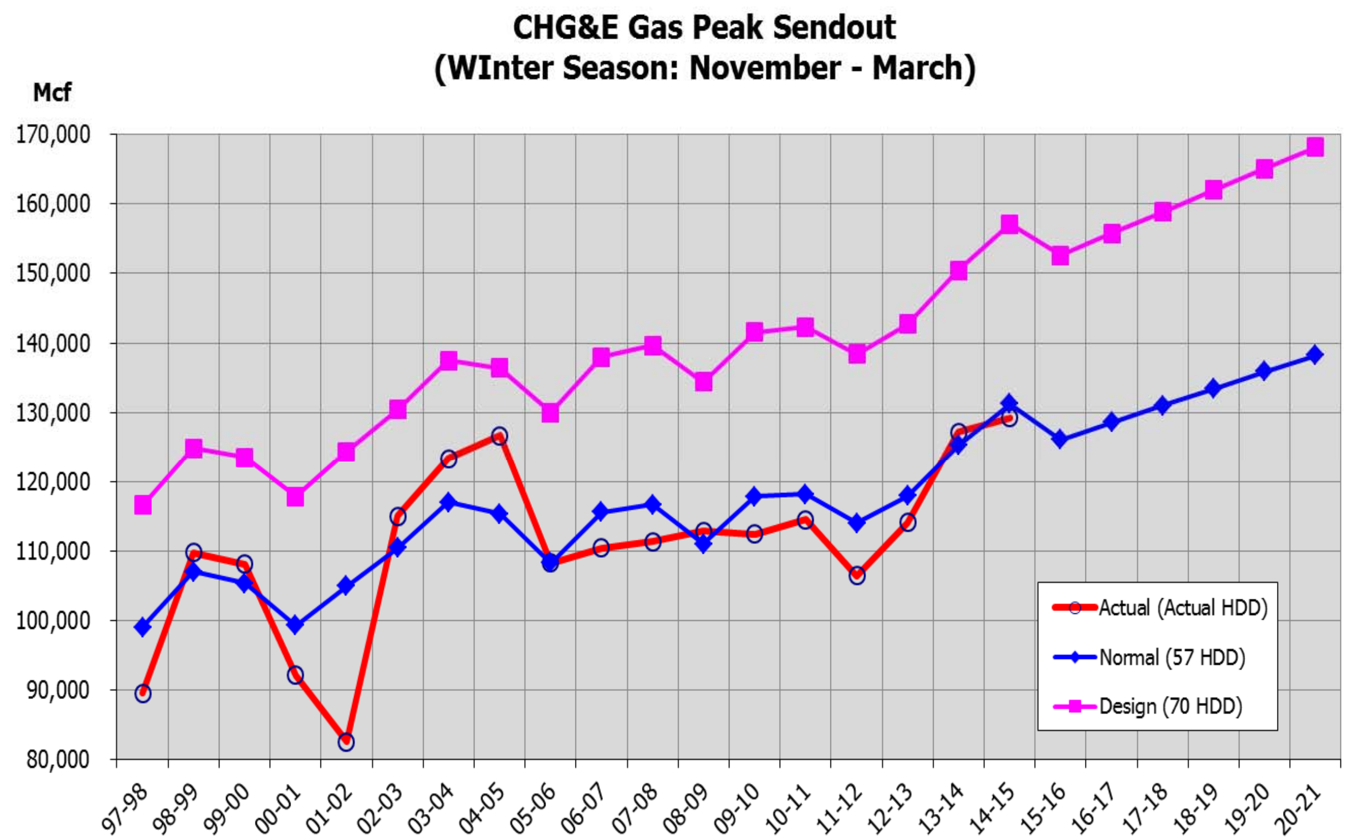
The gas distribution system is comprised of 1,248 miles of distribution main that operates at pressures from utilization (inches of water column) up to 120 psig. Nominal pipe diameters range from ½" to 16 inch in size and comprised of plastic, steel, wrought iron, and cast iron. The predominant material is plastic which makes up 667 miles of the total inventory and cathodically protected steel which accounts for an additional 363 miles. Currently Central Hudson defines leak prone pipe (LPP) as cast iron, wrought iron and unprotected steel. This represents a total of 218 miles or 17% of the total distribution main inventory. The Company's gas service inventory totals 62,320 services of which 39,937 are plastic and 8,383 are protected steel. The remainder, excluding 77 copper services, are considered leak prone.

Low pressure systems exist in each of the larger Cities of Beacon, Newburgh, Poughkeepsie, Kingston, Saugerties, and Catskill. Construction on these systems started in the early 1900s and piping has been added and replaced regularly since that time. These systems contain significant lengths of cast iron, universal, bare steel, and wrought iron piping. Portions of the piping must be replaced in order to maintain a manageable leak inventory. These older communities have transformed from residential/ commercial and industrial centers into primarily residential, light commercial and governmental centers and gas loads have generally stabilized or slightly declined over the years.

Gas Forecast Overview

Central Hudson's gas capital forecast for the next 5-year period is developed each year using a number of inputs such as planning studies, econometric forecasts, corporate load forecasts, facility inspection results, integrity recommendations, field operations feedback as well as others.

Central Hudson's gas peak load forecast is allocated into planning areas to identify system capacity needs and the timing of those needs, quantify the risks of the load growth outpacing our ability to serve that load, and assess the alternatives available to meet that load. As a result of these efforts, the needs are identified, the timing determined, and the alternatives developed from planning studies.



The New Business and Meters capital forecast is based on the projected customer growth from the corporate forecast. A regression analysis of the prior 5 years capital expenditures and growth rates is performed for these categories to predict the capital expenditures for the upcoming 5 years given the various growth scenarios.

For the Gas System, the primary evaluation criteria for area studies are load serving capability, based on system configuration, capacity, and the resulting pressures during design day. The planning criteria are based on AGA Engineering Practices. The minimum operating pressures which are allowed under these planning criteria are 50% of design pressure. Pressures below 50% could result in loss of gas and a significant public safety issue.

The planning criterion is single contingency with no unreserved load. The planning process evaluates the risk associated with load growth uncertainties, the risk of pressure falling below minimum required, the number of customers impacted, and the time associated with restoration of service.

The planning process evaluates alternatives to meet capacity needs based on economic analyses of viable alternatives and develops recommendations and timing that meets system needs at the lowest NPV cost.

Gas Program Detail

The Gas Capital forecast is developed utilizing guidelines, planning standard and engineering judgment. The forecast is completed for each budget category and integrated into a comprehensive plan. The following is a summary of the five year capital forecast for each of the categories.

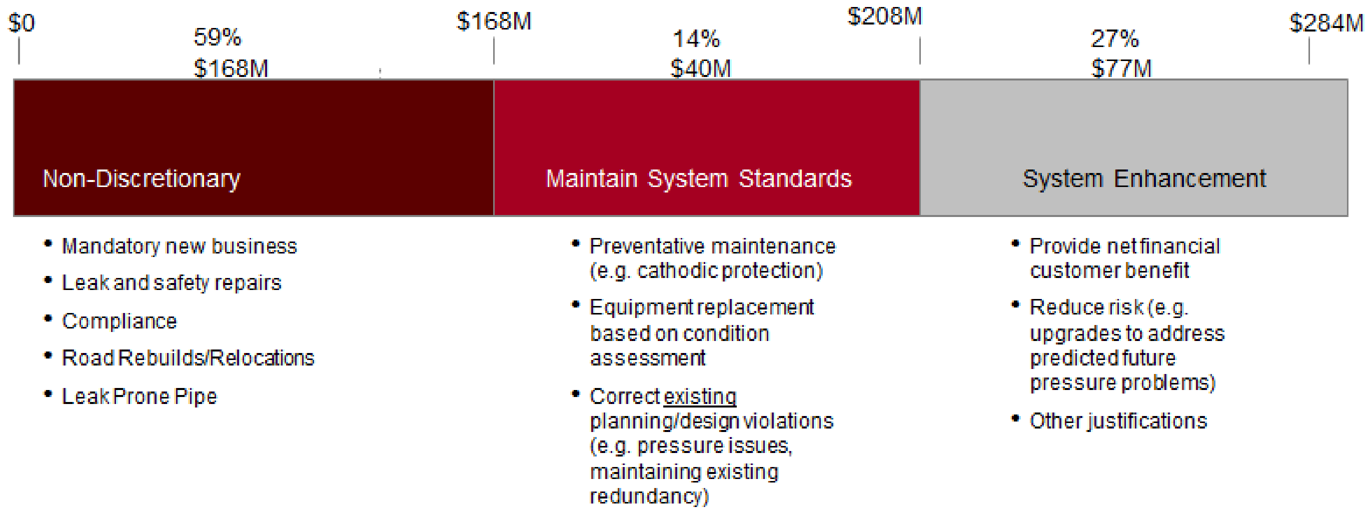
Gas Capital Forecast – Additions

	2017	2018	2019	2020	2021	TOTAL
Production	$ -	$ -	$ -	$ -	$ -	$ -
Transmission	1,678	2,604	6,209	1,684	1,599	13,774
Regulating Stations	1,212	590	1,502	1,571	1,596	6,471
New Business	14,075	14,434	14,293	14,645	14,980	72,427
Distribution Improvements	27,971	36,806	36,489	38,788	39,480	179,534
Meters	2,269	2,317	2,366	2,415	2,466	11,834
Total	$ 47,205	$ 56,752	$ 60,858	$ 59,103	$ 60,121	$ 284,040

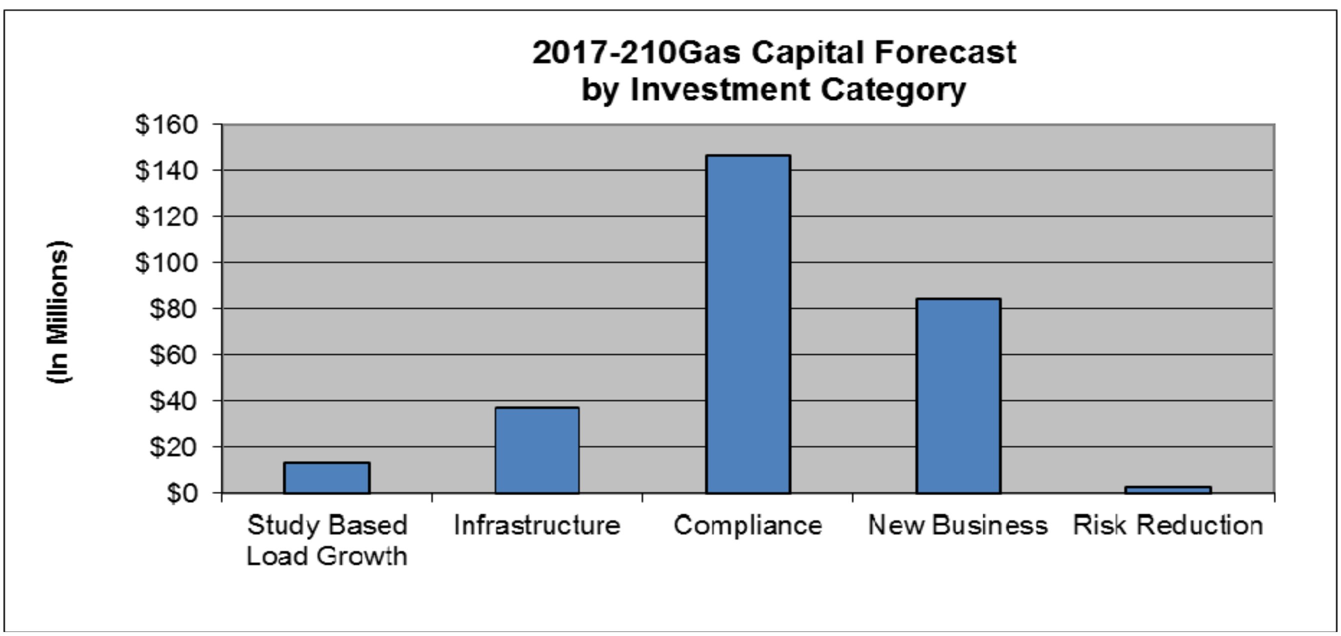
Gas Capital Forecast – Removal

	2017	2018	2019	2020	2021	TOTAL
Production	$ -	$ -	$ -	$ -	$ -	$ -
Transmission	182	191	206	227	256	1,063
Regulating Stations	82	86	91	99	109	467
New Business	1,347	1,342	1,339	1,339	1,338	6,705
Distribution Improvements	837	847	863	885	916	4,349
Meters	4	4	4	4	5	21
Total	$ 2,452	$ 2,470	$ 2,504	$ 2,554	$ 2,625	$ 12,605

A breakdown of the Gas Capital Forecast is shown above indicating the level of spending as we have prioritized the expenditures. Non-discretionary is the level spending that is necessary to meet the minimum standards of service or compliance with public service law. Maintaining System Standards is the level of spending required to maintain our current level of service safety and reliability and to meet obligations set through the rate proceedings. System Enhancement is capital spending aimed at improving our level of service, reducing risk, or reducing operating costs.



In addition, the projects within the Gas Program are categorized by Investment Category as follows: growth, compliance, day-to-day business management, and infrastructure replacement. The bar graph below shows the breakdown of the projects in our current five-year forecast by these Investment Categories.



Gas Transmission

The Gas Transmission category consists of gate station and transmission capital projects. Sample projects may include transmission line replacement/relocations, transmission valve replacements, upgrade/replacement of gate station flow control equipment, etc. The development of the Gas Transmission 5-Year Capital Forecast is derived from the following inputs:

Load Growth
Transmission Integrity Management Program (TIMP)
Regulatory Requirements
Equipment Obsolescence/Performance
Inspection Results
Municipal Projects

The Gas Transmission projects are designed to provide necessary capacity, reduce risk and improve infrastructure. Gas Transmission Capital Projects are primarily a mix of growth, risk reduction and infrastructure. They may stem from System Load Studies or studies performed as part of the Pipeline Integrity Program. These studies result in selected pipeline projects such as casing removals or the installation of remotely operated valves (ROV's). The transmission flow control equipment such as remote terminal units (RTU's) is evaluated to determine useful remaining life. The Gas Transmission 5-Year Capital forecast addresses a number of growth and integrity issues. The remainder of the capital forecast focuses on the following areas for system improvement; TIMP related projects, flow control system upgrades and remote operated valves.

Gas Regulator Stations

The Gas Regulator Station category consists of regulator station capital projects .The projects range from the installation of new stations to the replacement/upgrade of station equipment. The development of the Gas Regulator Station 5-Year Capital Forecast is driven by the following inputs:

Load Growth
Regulatory Requirements
Equipment Obsolescence/Performance
Inspection Results

The Gas Regulator Station projects consist primarily of a mix of capacity, compliance and infrastructure projects. The large scale main replacements associated with the LPP Replacement Program will result in changes in the low and medium pressure system flows. As a result modifications will be made to existing stations as needed to account for increase flow. In some cases stations will be eliminated due to increase main diameters. The remainder of the Gas Regulator Station capital forecast is related to infrastructure and compliance due to regulatory requirements, equipment obsolescence, maintenance issues, improved/remote pressure control, retirements, and relocations. In addition a number of regulator and relief valves have been identified for replacement since they are no longer supported by the manufacturer and are considered obsolete.

Gas Distribution Improvements

The Gas Distribution Improvement category consists primarily of new or replacement main and valve projects as well as service replacements. Projects in this category may include LPP main replacements, main reinforcements, additional valve installations, etc. The development of the Gas Distribution 5 Year Capital Forecast is derived from the following inputs:

Load Growth
Distribution Integrity Management Program (DIMP)
Risk Assessment (including leak history, material type, location, etc.)
Regulatory Updates
Inspection Results
Municipal Projects

The Gas Distribution 5 Year Capital Forecast is driven primarily by the mandated replacement of Leak Prone Pipe (LPP). The table below details the Company's currently approved rate Order which specifies the minimum replacement quantities and the maximum capitalized cost per mile for LPP.

Year	LPP Eliminated (miles)	Cost per Mile (000)
2016	13	$1,400
2017	14	$1,500
2018	15	$1,600

2015 Joint Proposal LPP Replacement Requirements

The LPP replacement projects are identified and prioritized using the GL Main Replacement Program (MRP) which develops a risk 'score' based on pipe and operating characteristics such as material, operating pressure, age, diameter, leak history, location (proximity to buildings, business district, flood prone areas) and, cathodic protection. This risk score measures the relative likelihood and the consequences of a leak associated with each pipeline segment. In addition Subject Matter Expert (SME's) review is taken into consideration when developing the proposed main replacement project listing. Based on industry best practice LPP projects consist of 1- 2 mile 'neighborhood' projects which result in limited disruption to customers and more economical replacement of LPP. While this methodology does result in the replacement of existing short sections (< 100 feet) of plastic and protected steel previously replaced due to undermines or leak repairs the overall efficiencies gained through bypassing and elimination of prolonged customer interruption are significantly more cost effective. The total budget for LPP replacement is $154.9 million in the 5 year forecast.

Included in the Gas Distribution capital budget is funding for main replacements or relocations associated with municipal projects such as road rebuilds. The actual project cost is included when the actual project is known otherwise the budgeted amounts are trended from past year expenditures.

Also included in Gas Distribution Improvements are reinforcements to existing systems based on area studies such as the SM line reinforcement project. This project addresses the current and potential new growth in the Carmel and Mahopac Area. A total of $5.2 million has been identified for this project.

New Business & Meters

The New Business section of the Gas Capital Budget is based primarily on the projected customer growth from the corporate forecast. The forecasted expenditure level is based on historical expenditure levels and historical and forecasted customer growth rates. The Gas New Business has forecast over $63 million over the 5-year period for residential and commercial conversion. An additional $9.8 million has been identified for expansion into new franchise areas and to serve large commercial or industrial customers.

The Gas Meters capital forecast is based on the projected customer growth from the corporate forecast. The forecasted expenditure level is based on historical expenditure levels and historical and forecasted customer growth rates. The meter forecast is based on the annual needs for non-load related meter installations (Meter Testing Program or ERT meter requests) approximately 3000 meters during the forecast period, and the forecast level based on the customer growth, peak, and sales forecast.

COMMON PROGRAM SUMMARY

The Common Capital Forecast consists of the Land and Buildings Capital Budget, the Office Furniture Capital Budget, the Tools & Equipment Capital Budget, the Transportation Capital Budget, and the Information & Technology Capital Budget Forecasts. The following is a summary of the five year capital forecast for each of these categories.

Common Capital Forecast – Additions

	2017	2018	2019	2020	2021	TOTAL
Lands and Buildings	$ 3,947	$ 3,611	$ 5,037	$ 9,191	$ 14,579	$ 36,365
Office Equipment	10,262	23,221	23,819	20,002	23,506	100,810
Tools	1,071	1,630	1,595	1,357	1,280	6,933
Communication	4,648	5,992	4,360	2,882	1,330	19,212
Transportation	7,956	9,216	10,220	10,626	11,088	49,107
Total	$ 27,883	$ 43,670	$ 45,031	$ 44,058	$ 51,783	$ 212,426

Common Capital Forecast – Removal

	2017	2018	2019	2020	2021	TOTAL
Lands and Buildings	$ 243	$ 253	$ 269	$ 292	$ 324	$ 1,380
Office Equipment	1	1	1	1	1	5
Tools	0	0	0	0	0	1
Communication	3	4	4	4	5	20
Transportation	(328)	(342)	(364)	(395)	(438)	(1,867)
Total	$ (81)	$ (85)	$ (90)	$ (98)	$ (108)	$ (462)

Land and Building

The Land & Buildings Capital Budget consists primarily of infrastructure replacement projects due to age or equipment failures. These include roof replacements, paving, HVAC equipment replacements, and electric or plumbing system replacements. In addition to these infrastructure replacement projects, there are several special projects included in the 5-year forecast that are envisioned to improve energy efficiency, productivity, or help fulfill strategic initiatives such as improved security and training. The special projects include a building expansion / upgrades at the Standfordville District Headquarters ($1.5M), renovation and build out of the South Road System Operations area ($625K), creation of disaster recovery center / office space in the Lake Katrine facility ($3M), and a total of $16M for new training facilities and building/renovation at the South Road Campus to address office space needs.

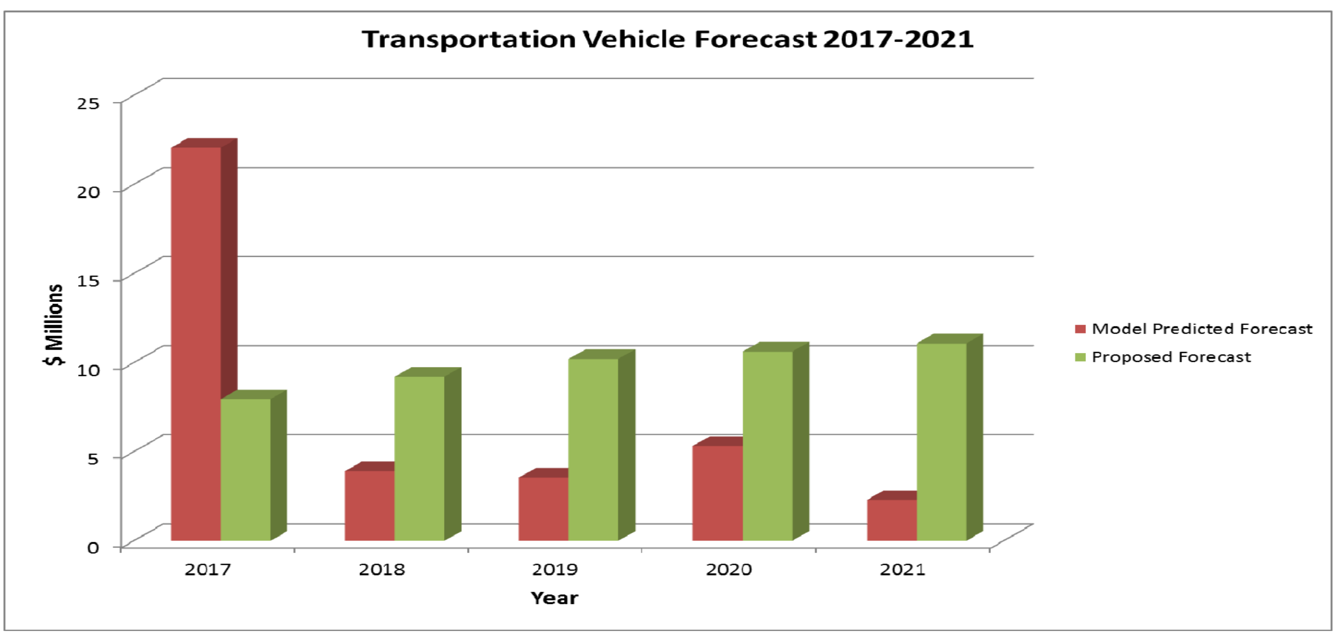
The Office Furniture Capital Budget consists of normal replacements due to wear and tear and those driven by office upgrades or changes requiring additions to meet the new use of the space.

Transportation and Tools

The Tools budget consists of replacements driven by the replacements of the vehicles they are utilized on, obsolescence and incompatibility, decreased reliability, discontinued manufacturer support, and conformance to changing OSHA or other regulations. Specialized tools required to accomplish new tasks or support the application of new techniques, are purchased after a trial use period.

The Transportation Capital Forecast is based primarily on the replacement of equipment. In the past, light duty vehicles were replaced every 10 years/150k miles, medium duty trucks every 12 years/150k miles, and power operated equipment (bucket trucks) every 12 yrs/13,000 engine hours. In 2015 new replacement criteria was implemented based on industry benchmark information for each class of vehicle for a fleet replacement schedule that replaces light/medium duty units at 7 years / 120k miles, and heavy duty units at 10 years / 9,500 engine hours. The changes in criteria were aimed at increasing the reliability of the fleet and controlling expense, operating, and maintenance costs as vehicles and equipment neared the end of their lifecycle. In addition, the expanded capital construction program and in some case type of work (i.e., off-road) were factored into the forecast. Results of the analysis and implementation of new methodology resulted in the following.

- Yielded a $37M spend over 5 years to replace vehicles older than 10 years; heavily weighted to first year ($22M)
- Added $1M / year for replacing non-road equipment
- Added $600K/year for replacing specialized track equipment
- Spend is proposed to be levelized over the next 5 years
- Reduces average fleet age and *"caps"* fleet age at 10 years
- Age is currently main driver of fleet replacement; this budget would "flush" the fleet
- With new mileage and hour tracking systems being installed, fleet can be managed on utilization – most vehicles will be replaced before they reach 10 years old



Information Technology / Communications

The IT Capital Budget consists of investments for business driven software implementations, upgrades to existing software solutions, and infrastructure or hardware lifecycle upgrades and ongoing extensions resulting from corresponding software updates or implementations. For planning purposes, the life cycle of the IT infrastructure is anticipated to be between 5 and 8 years on average, but varies depending upon the type of equipment. The useful life largely depends on usage, environment, technology obsolescence and incompatibility, decreased reliability and discontinued manufacturer support:

Mainframe, peripherals, storage and printers - 8 years
PC & laptops – 5 years
Mobile Computers – 3 years
Network Printers – 3 years
Network devices – 5 years
Telephone systems – 10 to 12 years

Additionally, the IT Capital Forecast includes software applications and upgrades related to providing a net business and customer benefit or reducing corporate risk. For this forecast the major software application projects include further investments into Business Intelligence, Cybersecurity, Enterprise Content Management, Digital (Web/Mobile/Social) Initiatives for Customer Engagement (DICE), Modernization of CIS, Unified Communications / Voice over IP / IVR upgrades, Emergency Management & Mobility, Business Agility with an Enterprise Services Oriented Architecture (SOA) Framework, Increasing the Quality and Speed of Applications Testing, Human Resources System Replacement, Wiki Redesign, GIS extensions, and Financial Application upgrades. These software applications and upgrades are evaluated through the IT Steering Committee with alignment to strategy and financial analysis used as the criteria for approving the project.

Within the communication budget is funding for the Company's Network Strategy project. The Network Strategy project is an enterprise solution to address communication needs among the company's fixed assets. These fixed assets include corporate offices, gas gate and regulator stations, electric substations, electric distribution DA (distribution automation) devices, mobile radio tower and large customer meters, The two-way network is being built with a high speed backbone and medium bandwidth mesh radio network to communicate to more dispersed assets. The five year forecast includes $17M for this project.

SUMMARY SCHEDULES 2017-2021 FORECAST

Appendix H1 2017 – 2021 Capital Forecast Budget Package

2017- 2021 Construction Forecast ($000's)

INSTALLATION W/ AFUDC

(with inflation & OH adjustment)

		Expenditures with AFUDC										
		2016 JP Budget	2017 Proposed Budget (1st Half)	2017 Proposed Budget (2nd Half)	2017 Proposed Budget	2018 Proposed Budget (1st Half)	2018 Proposed Budget (2nd Half)	2018 Proposed Budget	2019 Proposed Budget	2020 Proposed Budget	2021 Proposed Budget	2017-2021 Proposed Budget Total
ELECTRIC PROGRAM												
Hydro & Gas Turbines	**11**	1,067	824	1,182	2,006	1,048	1,048	2,096	1,559	1,646	1,511	8,817
Transmission	**12**	16,866	12,994	5,926	18,920	7,886	9,120	17,006	19,771	22,096	21,494	99,287
Substations	**13**	22,830	10,681	12,461	23,142	8,796	12,817	21,613	15,306	19,720	16,984	96,766
New Business	**14**	2,714	2,091	2,091	4,183	2,249	2,249	4,497	3,666	3,966	4,193	20,504
Dist. Improvements	**15**	30,079	14,696	15,470	30,166	15,243	19,136	34,380	42,895	38,764	33,085	179,289
Transformers	**16**	4,861	2,543	2,605	5,148	2,643	2,643	5,286	5,698	5,957	6,203	28,292
Meters	**17**	2,905	1,744	1,163	2,907	1,484	1,484	2,968	3,030	3,094	3,159	15,158
Total Electric Program		81,321	45,573	40,898	86,470	39,349	48,497	87,846	91,925	95,242	86,629	448,113
GAS PROGRAM												
Production	**21**	-	-	-	-	-	-	-	-	-	-	-
Transmission	**22**	1,823	222	1,456	1,678	593	2,011	2,604	6,209	1,684	1,599	13,774
Regulator Stations	**23**	1,531	663	549	1,212	358	233	590	1,502	1,571	1,596	6,471
New Business	**24**	15,927	7,034	7,041	14,075	7,208	7,226	14,434	14,293	14,645	14,980	72,427
Dist. Improvements	**25**	23,224	9,942	18,029	27,971	10,637	26,169	36,806	36,489	38,788	39,480	179,534
Meters	**27**	2,229	1,135	1,135	2,269	1,159	1,159	2,317	2,366	2,415	2,466	11,834
Total Gas Program		44,734	18,996	28,210	47,205	19,954	36,798	56,752	60,858	59,103	60,121	284,040
COMMON PROGRAM												
Buildings	**41**	3,870	1,974	1,972	3,947	1,805	1,805	3,611	5,037	9,191	14,579	36,365
Buildings Minors		2,324	1,974	1,972	3,947	1,805	1,805	3,611	5,037	9,191	14,579	36,365
UPS		-	-	-	-	-	-	-	-	-	-	-
Fishkill Expansion		-	-	-	-	-	-	-	-	-	-	-
Standfordville Expansion		1,546	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
Office Equipment	**42**	17,225	5,475	4,787	10,262	9,082	14,139	23,221	23,819	20,002	23,506	100,810
General	**421**	173	102	102	204	156	156	312	213	326	222	1,276
EMS	**423**	8,160	1,394	955	2,349	1,754	2,795	4,549	680	1,031	4,489	13,099
EDP	**4222**	1,922	1,574.62	405.95	1,981	2,081	1,096	3,177	3,107	3,127	3,192	14,583
Software	**4220**	6,342	2,133.98	2,962.13	5,096	4,747	9,717	14,465	19,185	14,867	15,005	68,618
Security	**424**	627	270	362	632	344	375	719	633	651	599	3,233
Tools	**43**	816	535	535	1,071	815	815	1,630	1,595	1,357	1,280	6,933
Communication	**44**	4,490	2,324	2,324	4,648	2,475	3,517	5,992	4,360	2,882	1,330	19,212
Transportation	**45**	7,364	3,978	3,978	7,956	4,608	4,608	9,216	10,220	10,626	11,088	49,107
Total Common Program		33,764	14,287	13,597	27,883	18,786	24,884	43,670	45,031	44,058	51,783	212,426
CORPORATE TOTAL		159,819	78,855	82,704	161,559	78,089	110,179	188,268	197,815	198,403	198,534	944,579

Appendix H1 2017 – 2021 Capital Forecast Budget Package

2017- 2021 Construction Forecast ($000's)

REMOVAL

(with inflation)

		Expenditures								
		2016 JP Budget	2017 Proposed Budget (1st Half)	2017 Proposed Budget (2nd Half)	2017 Proposed Budget	2018 Proposed Budget	2019 Proposed Budget	2020 Proposed Budget	2021 Proposed Budget	2017-2021 Proposed Budget Total
ELECTRIC PROGRAM										
Hydro & Gas Turbines	**11**	55	117	10	127	204	130	11	623	1,095
Transmission	**12**	1,723	804	600	1,403	1,551	1,713	2,856	2,306	9,830
Substations	**13**	1,262	787	1,250	2,038	1,696	1,625	1,786	1,384	8,529
New Business	**14**	173	88	88	177	188	184	196	212	956
Dist. Improvements	**15**	1,343	1,055	1,055	2,109	2,184	2,303	2,303	2,475	11,374
Transformers	**16**	299	156	156	311	311	331	359	398	1,711
Meters	**17**	2	149	149	297	297	309	329	357	1,589
Total Electric Program		4,857	3,155	3,307	6,463	6,432	6,595	7,840	7,756	35,085
GAS PROGRAM										
Production	**21**	-	-	-	-	-	-	-	-	-
Transmission	**22**	226	91	91	182	191	206	227	256	1,063
Regulator Stations	**23**	78	41	41	82	86	91	99	109	467
New Business	**24**	302	673	673	1,347	1,342	1,339	1,339	1,338	6,705
Dist. Improvements	**25**	125	419	419	837	847	863	885	916	4,349
Meters	**27**	4	2	2	4	4	4	4	5	21
Total Gas Program		734	1,226	1,226	2,452	2,470	2,504	2,554	2,625	12,605
COMMON PROGRAM										
Buildings	**41**	232	121	121	243	253	269	292	324	1,380
Buildings Minors		232	121	121	243	253	269	292	324	1,380
Fishkill Expansion			-	-	-	-	-	-	-	-
Standfordville Expansion		-	-	-	-	-	-	-	-	-
		-								-
Office Equipment	**42**	1	0	0	1	1	1	1	1	5
General	**421**	-	-	-	-	-	-	-	-	-
EMS	**423**	-	-	-	-	-	-	-	-	-
EDP	**4222**	-	-	-	-	-	-	-	-	-
Software	**4220**	-	-	-	-	-	-	-	-	-
Security	**424**	-	-	-	-	-	-	-	-	-
Tools	**43**	-	0	0	0	0	0	0	0	1
Communication	**44**	4	2	2	3	4	4	4	5	20
Transportation	**45**	(315)	(164)	(164)	(328)	(342)	(364)	(395)	(438)	(1,867)
Total Common Program		(78)	(41)	(41)	(81)	(85)	(90)	(98)	(108)	(462)
CORPORATE TOTAL		5,513	4,341	4,493	8,834	8,817	9,009	10,297	10,273	47,229

ELECTRIC PROGRAM INDIVIDUAL PROJECT SUBMITTAL

Budget Submittal Form for Electric Projects

Project Name: High Priority Repair (HPR) Program

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Non-Discretionary

Investment Category: Compliance

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Transmission lines are inspected on a cyclical basis with varying methods ranging from aerial patrols to comprehensive ground patrols. Inspection results are stored in a searchable database, currently the Wagner NextGrid System. This database contains data recorded from all types of inspection methods including aerial patrol, comprehensive aerial inspection, comprehensive ground inspection, ground line testing and treatment, climbing inspection, corona camera inspection, infrared inspection, and other types of inspection as well. Inspection data is recorded for all transmission assets including poles, insulators, guy wires and anchors, structure hardware, foundations, grounding, conductors, static wires, suspect clearances, and right of ways (including encroachments, vegetation, access, etc). After the completion of each inspection cycle, results are analyzed and condition assessments are assigned to the appropriate component of each structure. These conditions are rated on a scale from "1" to "5" with "5" being in the most need of repair. Components with ratings of either "5" or "4" must be repaired or replaced within 1 and 3 years, respectively, after the date of the inspection.

Solution

There is a need to provide funding to respond to the results of the inspection process described above. In some instances components can simply be replaced while in other instances an entire structure might need to be replaced. The design work is then completed and materials ordered. Aside from emergency replacements, replacements are typically grouped in packages to efficiently utilize field resources.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	15,733,000	3,485,000	3,761,000	3,746,000	2,331,000	2,410,000	2,030,000
Expense							

Cost Risks

- ☑ Environmental: Matting may be needed for equipment access in swampy areas
- ☑ Timing/Permitting: Long Lead time permitting may prolong the project
- ☐ Manpower
- ☐ Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [x] Inspections: Repair of conditions within the proper timeframes
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [x] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ___ years
- [x] Failure Rates: Reduce the risk of increased failure rates
- [ ] Obsolete/ Unserviceable Equipment
- [x] Condition: Mitigation of aged infastructure
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: P&MK Replacement and Span Correction

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

In January 2006, the MK Line static wire failed mid-span and dropped into the energized phase conductor. This investigation then led to subsequent design reviews and the discovery that many of the structures on the P & MK Lines (Now split into the MK, HK, GK, MG, FK and P Lines) are undersized for current structure loading requirements. The HK, MK, GK, MG, FK and P Lines were evaluated with updated PLS-CADD model data to verify that the lines are compliant with the NESC. The preliminary findings indicate that there are 125 structures requiring mitigation, using an evaluation method based upon now known structure types prone to failure.

Solution

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. The updated LiDAR/PLS-CADD data on the spans in question is being re-analyzed. Study work is under way to determine the most prudent course of action; the design of that solution is currently in progress and will be completed by the end of 2016.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	6,614,000	378,000	1,118,000	2,787,000	2,331,000	0	
Expense							

Cost Risks

- ☑ Environmental: Matting needed for structure access
- ☑ Timing/Permitting: PSC approval may be needed as this is an open article VII project
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☑ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☑ Failure Rates: Reduce failure rates through preemptive replacement
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Target structure types now know to need reinforcement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Structure Analysis Report In-Progress

Or

Project Alternatives Considered

Instead of structure replacement, Engineering examined the use of pole top bayonets to increase the static wire attachment heights and increase static/conductor clearances. This option proved undesirable as it caused an unacceptable increase to existing structure loading.

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: G Line South Rebuild

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The 17.799 mile 69 kV G line from Pleasant Valley to Knapps Corners was built in the 1920's with single pole double cross arm structures. Approximately 27.7% of the structures are in need of replacement due to the aging infrastructure and poor condition. The G line has experienced 50 trips outs over a 14 year period (1998 to 2011). The transmission supply to Meyers Corners Substation currently is limited by the area transmission (North Chelsea 115/69 kV transformer). Myers Corners Substation currently is operating at 69 kV and is designed for 115 kV operation.

Solution

The final strategy for the southern (East – West) section is still under development, however, the current preferred option is to rebuild at 69 kV from Knapps Corners to Meyer's Corners to North Chelsea. The routing and construction type alteratives evaluation is anticipated to be completed by mid-2016. Design and permitting will begin thereafter.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	13,244,000	496,000	1,347,000	5,574,000	5,827,000		
Expense							

Cost Risks

- ☑ Environmental: Potential for Matting and scheduling constraints due to clearing restrictions
- ☑ Timing/Permitting: Local permitting approvals needed to begin work
- ☐ Manpower
- ☑ Other: This project is inter-related with several other CHG&E projects that would need to be completed before work could being. This may affect project schedule and cost.

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections: Mitigate Existing Sev.4 and Sev. 5 HPR Conditions on the Line
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☑ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 90+ years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☑ Condition: Most of the line is of the original vintage and at the end of its service life
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Internal project alternatives analysis in progress

Decision criteria for alternative selection

Central Hudson — A FORTIS COMPANY — People. Power. Possibilities.

Budget Submittal Form for Electric Projects

Project Name: SB Line New 115kV Line Hurley Ave to Saugerties

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The 69 kV H & SB Lines connect the North Catskill, Saugerties & Hurley Avenue Substations. Together, the lines are approximately 23.4 miles in length. The 11.1 mile portion of the line from Hurley Avenue to Saugerties is designated as the SB Line. The majority of structures and conductor on this line were built in 1919 and are close to reaching the end of their useful life. There are also a number of spans identified on this line as part of Central Hudson's SAG Mitigation program.

Solution

To address the aging infrastructure and provide the potential for additional area load serving capability to the Northwest Area, the chosen course of action is to rebuild the SB Line for 115 kV. The 115 kV SB line rebuild and an additional 115 kV reinforcement in the Northwest Area will also help maintain system reliability. The budgetary cost estimates below reflect the conceptual estimates found in the relevant planning memo (EP2015-003) as well as additional adjustments based on similar in-progress article VII actual expenditures.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	18,029,000	198,000	305,000	404,000	8,687,000	8,434,000	7,105,000
Expense							

Cost Risks

- ☑ Environmental: Lead paint containment associated with existing tower removals
- ☑ Timing/Permitting: Permitting completion required before start of project
- ☐ Manpower
- ☐ Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☑ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections: Address existing Sev.4 and Sev.5 Findings
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☑ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure 90+ years
- ☑ Failure Rates: Improve this through preventative replacement
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Optimize structure placement through new design
- ☑ Other Program Type: Address SAG Spans deferred from the 2007 SAG Program

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: EP2015-003

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: H Line New 115kV Saugerties to North Catskill

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The 69 kV H & SB Lines connect the North Catskill, Saugerties & Hurley Avenue Substations. Together, the lines are approximately 23.4 miles in length. The 12.3 mile portion of the line from North Catskill to Saugerties is designated as the H Line. The majority of structures and conductor on this line were built in 1919 and are close to reaching the end of their useful life. There are also a number of spans identified on this line as part of Central Hudson's SAG Mitigation program.

Solution

To address the aging infrastructure and potentially provide additional area load serving capability to the Northwest Area, the chosen course of action is to rebuild the H Line for 115 kV. The 115 kV H line rebuild and an additional 115 kV reinforcement in the Northwest Area will also help maintain system reliability. The budgetary cost estimates below reflect the conceptual estimates found in the relevant planning memo (EP2015-003) as well as additional adjustments based on similar in-progress article VII actual expenditures.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	12,149,000	198,000	305,000	404,000	2,807,000	8,434,000	7,105,000
Expense							

Cost Risks

- [x] Environmental: Lead paint containment associated with existing tower removals
- [x] Timing/Permitting: Permitting completion required before start of project
- [ ] Manpower
- [ ] Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☑ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections: Address existing Sev.4 and Sev.5 Findings
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☑ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure: 90+ years
- ☑ Failure Rates: Improve this through preventative replacement
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Optimize structure placement through new design
- ☑ Other Program Type: Address SAG Spans deferred from the 2007 SAG Program

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: EP2015-003

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Transmission Minor Projects

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Non-Discretionary

Investment Category: Daily Operations

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Minor Transmission projects arise throughout the year. These projects are not large enough to warrant a line item in the capital budget/forecast. Typically these jobs include the need to update/replace equipment installed on a transmission line such as:

Failed/Damaged:

- Insulators
- Conductor
- Poles
- Structure members
- Other Equipment that fails and is beyond repair
- Minor Pole Relocations

Solution

Install new and update existing equipment as required during the course of a year that is not specifically tied to a major project. Budget projections include for (9) basic single pole replacements annually based on historical project data.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	1,399,000	261,000	278,000	276,000	287,000	297,000	228,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [x] Public Safety
- [ ] Other Program Type

Compliance

- [x] Inspections: Addressing high risk findings from the inspection program
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [x] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ___ years
- [x] Failure Rates: Improve this through preventative replacement
- [ ] Obsolete/ Unserviceable Equipment
- [x] Condition: Address conditions indicating imminent failure
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Network Strategy

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: System Enhancement

Investment Category: Daily Operations

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

In 2015, Central Hudson's Network Strategy Group created a comprehensive plan to install various communication systems throughout the service territory. These communication connections would be placed strategically to allow for efficient and secure company communications between various critical facilities.

Solution

The Network Strategy Group has identified several existing transmission lines that provide existing pathways that can be utilized for communication connections as part of the overall system communication plan. Central Hudson will be installing fiber optic communication on these existing electric transmission pole plants over the course of the next 5 years.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$5,133,000	$0	$0	$3,530,000	$664,000	$940,000	$792,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☑ Reduced Customer Bill: Justified by business case
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement
- ☑ Other Program Type: Communication upgrades utilizing existing pole plant

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: ROW Repair Project

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Daily Operations

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Central Hudson had committed voluntarily to obtain additional right of way as follow up to the Northeast Blackout of 2003. The report to the PSC stated that we would identify easements that were deficient from the standard of 100 foot on 69kV and 115kV lines and 150 foot on 345kV lines.

Solution

Central Hudson has identified easement deficiencies along its 69kV, 115kV and 345kV transmission line corridors. The adjacent property owners have been identified and, if haven't already, will be contacted in an attempt to acquire the additional ROW. A vendor will be chosen to provide all of the required work and services to document and obtain additional easement agreements throughout the service territory.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	5,834,000	496,000	508,000	758,000	1,221,000	2,850,000	2,639,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☑ Accessibility (Off Road, underground) Improves Access to Structures
- ☑ Strategic Replacement Acquire ROW essential to maintenance of existing facilities
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: ACSR Replacement Project _ WH 1 and WH 2 Line Rebuild

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

During 2003, samples were taken of the WH1 & WH2 line conductor for testing by NEETRAC; this testing revealed evidence of conductor annealing which can result in clearance issues. During the System-Wide Sag Analysis Screening Program, 36 spans of the WH-1 and WH-2 were identified as spans with potential road clearance violations. See EP #2011-010. Also as of 2015, Inspections findings indicate that (47) structures on the line have conditions warranting repair or replacement.

Solution

As recommended, Central Hudson's portion of the 69 kV WH-1 and WH-2 lines should be rebuilt as a single circuit 69 kV line along the same route with 795 ACSR conductor with OPGW neutral for substation communications. The WH-1/2 line taps to Greenfield Road should be rebuilt as a single circuit 69 kV line along the same route with 795 ACSR conductor & OPGW. The Honk Falls WH-769 Breaker should be replaced per the Breaker Replacement Program.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	7,453,000	7,453,000					
Expense							

Cost Risks

- [x] Environmental: Matting for Access
- [x] Timing/Permitting: Permitting approvals needed for construction start
- [ ] Manpower
- [x] Other: Outage constraints involving the NYC DEP and ability of hydro-generation facilities to operate during critical time periods throughout the year.

Primary Project Objective: Risk Reduction

Benefits

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [x] Critical Customers: NYC Board of Water Supply - Hydro Generation Facilities
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections: Mitigate Existing Sev.4 and Sev. 5 HPR Conditions on the Line
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☑ NESC Codes
- ☑ Other Program Type: SAG Mitigation Program

Infrastructure

- ☑ Average Age of Infrastructure 80+ years
- ☑ Failure Rates: Reduced rate of failure through preemptive replacements
- ☐ Obsolete/ Unserviceable Equipment
- ☑ Condition: Most of the line is of the original vintage and at the end of its service life
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

EP #2011-010

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: G Line North Rebuild - 69kV

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The 17.799 mile 69 kV G line from Pleasant Valley to Knapps Corners was built in the 1920's with single pole double cross arm structures. Approximately 27.7% of the structures are in need of replacement due to the aging infrastructure and poor condition. The G line has experienced 50 trips outs over a 14 year period (1998 to 2011).

Solution

The northern section of the G line will continue to operate at 69 kV with the installation of larger conductor. The northern section of the 69 kV G line would begin at Pleasant Valley, supply Tinkertown and terminate at the Todd Hill Substation. A 115/69 kV transformer will be installed at Todd Hill. The portion of the 7023 circuit that is currently double circuit with the G line will be rebuilt in a underbuild configuration on the new G line structures in that section. See EP2013-017 for Details.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	6,952,000	6,753,000	199,000				
Expense							

Cost Risks

- ☑ Environmental: Matting
- ☑ Timing/Permitting: Permitting needs to be completed prior to construction start.
- ☐ Manpower
- ☐ Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [x] Inspections: Mitigate Existing Sev.4 and Sev. 5 HPR Conditions on the Line
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [x] NESC Codes
- [ ] Other Program Type

Infrastructure

- [x] Average Age of Infrastructure 80+ years
- [x] Failure Rates: reduce failure rates through preemptive replacements
- [ ] Obsolete/ Unserviceable Equipment
- [x] Condition: Most of the line is of the original vintage and at the end of its service life
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: EP#2013-017

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: EF Line Rebuild - 115kV

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

In 2015, a field inspection of the 1.98 mile 115kV "EF" Line (Shenandoah - East Fishkill) showed that 82% of the existing structure plant would require replacement due to component defects. There were also an additional 8% of structures that showed a significant number of minor defects indicating an overall poor structure condition.

Solution

Given the level of replacement needed to repair the identified component defects, it has been proposed to rebuild all 1.98 miles of the existing 115kV "EF" Line. This would include replacement of all structures, conductor and overhead ground wire. The voltage is planned to remain at 115kV. Structures will remain in the same general locations, and the height of the structures are not planned to increase by more than 10 feet. The total number of structures has the potential to decrease as the design is developed. Additional rights-of-way (ROW) are not required for this rebuild and at this time no existing ROW deficiencies have been identified.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	3,601,000	99,000	1,779,000	1,723,000			
Expense							

Cost Risks

- [x] Environmental: Potential need for matting and restrictions on tree clearing
- [x] Timing/Permitting: Outage Restrictions associated with connection into Global Foundaries Facility.
- [ ] Manpower
- [ ] Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [x] Critical Customers: Global Foundries
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [x] Inspections: Mitigate Existing Sev.4 and Sev. 5 HPR Conditions on the Line
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [x] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ___ years
- [x] Failure Rates: Reduce failure rate through preemptive replacement
- [ ] Obsolete/ Unserviceable Equipment
- [x] Condition: Most of the line is of the original vintage and at the end of its service life
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [x] Other Program Type: Driven by HPR Condition findings.

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: Planning Memo in Progress

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: CL Line Rebuild - 69kV

Form submitted by: K.Bragg

Budget Group: 12 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

In 2015, a field inspection of the 11.7 mile 69kV "CL" Line (North Catskill - Lawrenceville - South Cairo) showed that 69% of the existing structure plant would require replacement due to component defects. There were also an additional 23% of structures that showed a significant number of minor defects indicating an overall poor structure condition.

Solution

Given the level of replacement needed to repair the identified component defects, it has been proposed to rebuild 10.16 miles of the existing 11.7 mile line. The 1.54 mile section of line immediately outside of the North Catskill Substation was recently replaced with new steel structures in 2008. The rebuild will include the replacement of all structures, conductors and overhead ground wire in the designated 10.16 mile section of line. The line voltage is planned to remain at 69kV.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	11,672,000	496,000	8,947,000	2,230,000			
Expense							

Cost Risks

- [x] Environmental: Matting for equipment access
- [x] Timing/Permitting: Permitting required prior to construction start
- [ ] Manpower
- [ ] Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections: Mitigate Existing Sev.4 and Sev. 5 HPR Conditions on the Line
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☑ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☑ Failure Rates: Reduce failure rates through preemptive replacement
- ☐ Obsolete/ Unserviceable Equipment
- ☑ Condition: Most of the line is of the original vintage and at the end of its service life
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☑ Other Program Type: Driven by HPR Condition findings.

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: Planning Memo in Progress

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Substation Minor Projects

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Non-Discretionary

Investment Category: Daily Operations

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Minor Substation projects are completed throughout the year based on failures and equipment condition assessments. These are smaller scale projects and typically based on the need to update/replace substation equipment including:
Battery Chargers
Meters
Controls
Communications
Other Equipment that fails and is unrepairable

Solution

Install new and update existing equipment as required during the course of a year that is not specifically tied to a major project upgrade.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,683,000	$658,000	$743,000	$691,000	$707,000	$884,000	$2,500,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure years
- [x] Failure Rates Reviews of history of equipment failure.
- [x] Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.
- [ ] Condition
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: ESP Infrastructure Replacement

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

A variety of equipment exists in Central Hudson substations, including protective relays, meters, reclosers controls, and other control & communications equipment such as Remote Terminal Units (RTUs). Each of these components serves an integral role in contribution to the overall, integrated substation protection, control, and monitoring function.

The need for upgraded infrastructure has been made evident through the inclusion of new substations and through various targeted replacement programs, all in the Category 13 Capital Forecast. These programs include the RTU Retrofit Program, the Breaker Replacement Program, and the Generation 1 Relay Replacement Program. These programs only address a sample of individual concerns without giving consideration to remaining equipment in the station that should be upgraded on an integrated basis. Without an integrated program, the remaining outdated equipment in the substations is replaced through attrition solely: an accelerated replacement schedule is recommended that takes advantage of the savings that can be realized by performing incremental work at the same time as previously identified and justified capital work.

Solution

Install new and update existing equipment as required during the course of a year that is not specifically tied to a major project upgrade. These upgrades, when coupled with existing projects in a location, can take advantage of construction efficiencies to reduce overall costs of performing the work separately.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$14,315,000	$1,868,000	$3,652,000	$2,230,000	$2,986,000	$3,578,000	$7,895,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☑ Failure Rates: Reviews of history of equipment failure.
- ☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Replace equip. in order to supply protection & metering options.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study SR#2011-07

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Generation 1 Relay Replacement Program

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Generation 1 Relays are the first generation of microprocessor based relays installed on our system. These relays are approaching upwards of twenty years old, many are incapable of performing certain functions and are experiencing more extensive age-related failures. Many Generation 1 relays are now unsupported by the manufacturers and have limited or no parts availability for maintenance.

Solution

Program to replace existing Gen 1 relays during the course of a year that are not specifically tied to major project upgrades.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,066,000	$864,000	$203,000	$0	$0	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 20 years
- ☑ Failure Rates: These relays have a higher rate of failure than any other relays.
- ☑ Obsolete/ Unserviceable Equipment: Difficulty finding replacement parts.
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: RTU Replacement Program

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The first and second generation of Remote Terminal Units (RTU's) require more extensive maintenance due to age-related component failures. Many of these RTU's are now unsupported by the manufacturers and have limited or no parts availability for maintenance and repair.

Solution

Planned replacement of first and second generation of RTU's located at Substations, see attached RTU Replacement Table.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,493,000	$218,000	$285,000	$334,000	$324,000	$330,000	$900,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☑ Failure Rates: Reviews of history of equipment failure.
- ☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- ☑ Condition: Reviews of current conditions of RTUs.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: Central Hudson's "RTU Replacement Table"

Or

Project Alternatives Considered

Decision criteria for alternative selection

Substation / Location	Electric/Gas	Man.	RTU Type	Current Protocol	Future Man.	Future Type	Future Protocol	Comments
Coxsackie Substation	Electric	CDC	8890	CDC	SEL	Axion	DNP	Scheduled for 2019
Coldenham Substation	Electric	Harris	D-20	DNP	SEL	Axion	DNP	Scheduled for 2018
High Falls Substation	Electric	Harris	D-20	DNP	SEL	Axion	DNP	Scheduled for 2018
North Catskill Substation	Electric	Harris	D-20	DNP	SEL	Axion	DNP	Scheduled for 2019
Greenfield Rd. Substation	Electric	Harris	M-4000	CDC	SEL	Axion	DNP	Scheduled for 2020 (Substation Project)
Jansen Ave. Substation	Electric	Harris (DU)	M-4000	CDC	SEL	Axion	DNP	Scheduled for 2018
Maybrook Substation	Electric	Harris (DU)	M-4000	DNP	SEL	Axion	DNP	Scheduled for 2018 (Substation Project)
Woodstock Substation	Electric	Harris (DU)	M-4000	CDC	SEL	Axion	DNP	Scheduled for 2018 (Substation Project)
Standfordville Substation	Electric	Harris (DU)	M-4000	CDC	SEL	Axion	DNP	Scheduled for 2019 (Substation Project)
Hunter Substation	Electric	Harris (DU)	M-4000	CDC	SEL	Axion	DNP	Scheduled for 2020
Vinegar Hill Substation	Electric	Harris (DU)	M-4000	CDC	Telvent(DU)	2100	DNP	Scheduled for 2020
Montgomery Substation	Electric	NONE			SEL	Axion	DNP	Scheduled for 2020 (Substation Project)
Converse St. Substation	Electric	NONE						
Merritt Park Substation	Electric	Novatech	BM85	DNP	SEL	Axion	DNP	Scheduled for 2021
Staatsburg Substation	Electric	Novatech	BM85	DNP	SEL	Axion	DNP	Scheduled for 2021
Westerlo Substation	Electric	Novatech	BM85	DNP	SEL	Axion	DNP	Scheduled for 2021
East Kingston Substation	Electric	Novatech	Orion5R	DNP				
Galeville Substation	Electric	Novatech	Orion5R	DNP				
Milan Substation	Electric	Novatech	BM85	DNP				
Modena 115kV Sub	Electric	Novatech	BM85	DNP				
North Chelsea Sub	Electric	Novatech	BM85	DNP				
Spackenkill Substation	Electric	Novatech	Orion5R	DNP				

Updated 6/2/2016

Budget Submittal Form for Electric Projects

Project Name: Circuit Breaker Replacement Program (345 kV)

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Central Hudson has on going condition based circuit breaker replacement program. The 345kV circuit breakers are critical to the reliable operation of the 345kV bulk electric system. As part of the on-going breaker replacement program, the 345kV circuit breakers at the Roseton and Rock Tavern Substation have been replaced in prior years. Based on age and condition, the remaining 345kV circuit breakers (Hurley Avenue Substation) on our system are planned for replacement.

Solution

Selective replacement of specific breakers as specified by the program.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$2,506,000	$0	$1,688,000	$818,000	$0	$0	$0
Expense							

Cost Risks

- [x] Environmental: Replace old oil circuit breakers.
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 40 years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: Central Hudson's "Breaker Replacement Program"

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Circuit Breaker Replacement Program (115, 69, 34.5, 13.8 kV)

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Central Hudson has on going condition based circuit breaker replacement program. The majority of power circuit breakers on the Central Hudson System have been in operation for over 40 years. Some of the breakers are at their duty rating, some have inherent design or operating issues, and others are obsolete and do not have spare parts available for repair or maintenance.

Solution

Selective replacement of specific breakers as specified by the program. (This represents the continuation of our on-going circuit breaker replacement program).

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$7,597,000	$1,433,000	$1,631,000	$1,310,000	$1,239,000	$1,983,000	$5,000,000
Expense							

Cost Risks

- [x] Environmental: Replacement of Old Oil Circuit Breakers.
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [x] Average Age of Infrastructure 40 years
- [x] Failure Rates: Breakers replaced based on failure rates.
- [x] Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- [x] Condition: Breakers replaced based on deteriorated condition.
- [ ] Accessibility (Off Road, underground)
- [x] Strategic Replacement: Breakers replaced based on infrastructure upgrades.
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: Central Hudson's "Breaker Replacement Program"

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: 345 kV Switch Replacement Program

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Problems have been identified with the TTT-7, EA, VR2 and VT-1 style motor operated 345kV air disconnects at the Roseton, Rock Tavern and Hurley Ave substations. Limited to no replacement parts are available for these style switches. These disconnects have reached the end of their useful lives, are problematic, and have resulted in extended time trouble-shooting problems and result in increased callouts. There have been several failures in recent times and due to frequency of operation and general condition

Solution

With the developing trend of problems and consideration given to the criticality of the bulk 345kV system, a multi-year systematic 345kV disconnect replacement program has been developed.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,119,000	$540,000	$659,000	$644,000	$659,000	$617,000	$1,600,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 40 years
- ☑ Failure Rates Reviews of history of equipment failure.
- ☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.
- ☑ Condition Switches replaced based on deteriorated condition.
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement Switches replaced based on infrastructure upgrades.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

E. Schultz: “Operations Services Infrastructure Projects”, May 10, 2013.

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: 115 kV Switch Replacement Program

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Based on condition, age and criticality, Operations Services has identified 115kV disconnect switches as a candidate for targeted replacements.
The 115kV Switch Replacement Program will operate similar to our on-going Breaker Replacement Program. Switches will be identified by condition, criticality, age, use, availability of parts, and maintenance issues in order to create a prioritized list for replacement.

Solution

Development of a 115kV switch replacement program.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,297,000	$51,000	$51,000	$1,038,000	$558,000	$1,598,000	$5,000,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 40 years
- ☑ Failure Rates: Reviews of history of equipment failure.
- ☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- ☑ Condition: Switches replaced based on deteriorated condition.
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Switches replaced based on infrastructure upgrades.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

E. Schultz: "Operations Services Infrastructure Projects", May 10, 2013.

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: DA Program LTC Upgrade

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: System Enhancement

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Central Hudson's current distribution LTC power transformer controls are not equipped with supervisory indication or control of tap position and are limited on the number of steps of voltage reduction. Our distribution automation program includes two-way communication and control of field devices to enable CVR/VVO. The decrease and flattening of customer end use service voltage has been shown to improve end use efficiency with a direct impact or reduction in customer usage. The replacement of substation LTC controls are required for the implementation of our Distribution Automation program.

Solution

Planned replacement / upgrade of Substation transformer LTC controls coordinated with our distribution automation program.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,360,000	$595,000	$765,000	$0	$0	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☑ Reduced Customer Bill: Lowering voltage while maintaining current will aid in lowering customer bills.
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

☐ Thermal/Load Serving Capability

☐ Equipment Type

☐ Current % loaded

☐ Voltage (Stray, Low, High)

☐ Power Quality

Other

Risk Reduction

Safety

☐ Employee Safety

☐ Public Safety

☐ Other Program Type

Compliance

☐ Inspections

☐ Road Rebuild

☐ Joint Facilities/CATV Agreement

☐ NESC Codes

☐ Other Program Type

Infrastructure

☐ Average Age of Infrastructure years

☐ Failure Rates

☐ Obsolete/ Unserviceable Equipment

☐ Condition

☐ Accessibility (Off Road, underground)

☑ Strategic Replacement Install LTC controls that perform desired functions and comm.

☐ Other Program Type

Resilience

☐ $/COA (with storm)

☐ $/CMA (with storm)

☐ Customer Cost of Outage (ICE Calculator)

☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

See below.

Or

Project Alternatives Considered

F. Bruna,"SCADA Requirements for Distributed Automation", E.P. #2013-015, April 15, 2013

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Danskammer Substation Storm Hardening WO# 5560AR (8516AR)

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The Danskammer Substation requires Storm Hardening upgrades to protect the site from the high water levels associated with storm events. The substation experienced flooding in 2012 during hurricane Sandy.

Solution

Protect the Substation from High Water Levels associated with Storm Events. Install an elevated control house and raise the height of the control boxes on the yard equipment.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,227,000	$1,227,000	$0	$0	$0	$0	$0
Expense	$0	$0	$0	$0	$0	$0	$0

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☑ Condition: Prepare the substation for future storms.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Montgomery Street Substation Replace Transformers

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer.
Based on this review and as recommended in E.P. #2010-013, both Montgomery Street transformers should be replaced due to their condition. The transformers are now over 75 years old and are indicating dielectric breakdown.

Solution

Replace existing transformers due to age and condition.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,466,000	$1,466,000	$0	$	$0	$0	$0
Expense	$0	$0	$0	$0	$0	$0	$0

Cost Risks

- [x] Environmental: Oil filled transformers - oil containment.
- [x] Timing/Permitting: Historic Site.
- [ ] Manpower
- [ ] Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☑ Employee Safety: Decrease of risk of current transformers failing.
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 75 years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- ☑ Condition: Increase of negative DGA sample tests.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: See below.

Or

Project Alternatives Considered

P. Harpolis, E.P. #2010-013 "Montgomery Street Substation Breaker Replacement", October 4, 2010.

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Todd Hill 'G' Line Add 115/69 kV Autotransformer

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The 69kV G Line is being reconfigured and rebuilt due to infrastructure issues. The Todd Hill Substation has been determined to be the optimal location to install a 115/69kV source to the area to support the reconfiguration of the 69kV G Line. A 115/69kV autotransformer must be installed at the Todd Hill Substation to provide this source.

Solution

Add a 115/69kV, 50MVA Autotransformer at Todd Hill. The Substation will be expanded to make room for the transformer and G Line structure. The 115kV bus will be extended and the C Line dead end structure will be moved further east. The new 50MVA Autotransformer, G Line dead end structure, 69kV breaker, lightning mast, instrument transformers and disconnect switches will be installed adjacent to Transformer #1 between the C-519 and C-512 switches per EP2014-011.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,466,000	$1,466,000	$0	$0	$0	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ☐ years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Support of the reconfiguration of the G Line.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

See below.

Or

Project Alternatives Considered

R. Chan, H. Swanson, E.P. # 2014-011, "Updated Recommendation to the Rebuild of the Northern Section of the 69 kV G Line" October 13, 2014.

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Union Ave Substation Switchgear Replacement

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Due to asset condition and aging infrastructure it has been determined that the existing outdoor switchgear, control house, and RJ-52 115kV breaker in the lower yard of the Union Ave. Substation are nearing the end of their useful life.

Solution

A new Power Control Center will be installed to replace the aging control house and switchgear. The following breakers are to be replaced with switchgear enclosed in the PCC: TD-(4041-4047),TD-4049, UN-594,UW-1494, C-2551, W-1095, W-837, and C-2552. All associated relaying will be replaced as well with the breakers. The RJ line relaying, transformer protection, and RJ-52 breaker failure relays will be replaced in the PCC as well. The RJ-52 breaker will be replaced with a new SF6 gas breaker as part of the breaker replacement program.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,238,000	$3,188,000	$51,000	$0	$0	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☑ Timing/Permitting: Town Hall approval required to expand fenceline.
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 60 years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- ☑ Condition: Difficulties in the operation of Substation due to outdoor switchgear.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Boulevard Transformer Replacement

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer.

As part of this review, Boulevard Transformer #1 (Phases #1, #2 and #3) was assessed and determined to be in poor and degrading condition. This transformer has been in service since 1954 and located at this station since 1998.

The power factor results for the three single-phase banks have been consistently above acceptable values in all insulation. Results for Phase #3 low-ground insulation increased by 75% from 1998 to 2010. Results for all other insulation in Phases #1, #2 and #3 have been consistently above acceptable values (between 0.5% and 1%) over the testing period. Dissolved gas-in-oil analysis results indicate that the Phase #1 unit has just begun to show signs of cellulose overheating.

In addition, Boulevard Transformer #2 is 76+ years old and has increased power factor readings. Based on the age and condition, this transformer requires repalcement.

Solution

Replace the existing three transformers at Boulevard with two 13.4MVA (12MVA) transformers.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$2,306,000	$2,255,000	$51,000	$0	$0	$0	$0
Expense							

Cost Risks

- ☑ Environmental: Oil filled transformers - oil containment.
- ☑ Timing/Permitting: Permitting required to enforced secondary entrance to install new control house.
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 62 years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.
- ☑ Condition Elevated power factor tests results.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: See below.

Or

Project Alternatives Considered

S. Martino, E.P. # 2014-003, "Boulevard/Jansen Ave./South Wall St./Converse St. Area Study" November 21, 2014.

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Reynolds Hill Substation Transformer Replacements

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer.

As part of this review, as well as the lack of spare parts due to their unique 4-winding configuration, it is recommended that both Reynolds Hill Transformers be replaced based on condition and age.

Solution

Replace selected transformers with new 22.4MVA transformers equipped with LTC and remove the circuit regulators.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,205,000	$2,648,000	$557,000	$0	$0	$0	$0
Expense							

Cost Risks

- ☑ Environmental: Oil filled transformers - oil containment.
- ☑ Timing/Permitting: Permitting required for substation footprint additions for new oil containment.
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 60 years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement Replace unique transformer which has no system spares.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: N. Conza, E.P. # 2012-017, "Reynolds Hill Transformer Study" April 4, 2013.

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Woodstock Substation Switchgear Replacement

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The existing external switchgear and control house switchgear has reached the end of its useful life and replacement parts are difficult to obtain or no longer available. Maintenance issues have been experienced with racking the 1947 vintage breakers in the external switchgear. Replacement parts for the racking mechanisms are no longer available.

The dial up RTU housed inside of the control house switchgear is unreliable, due to space constraints there is no room to add additional equipment or to replace the RTU. The 1972 vintage breakers utilize a puffer with a plastic manifold, this has been a constant maintenance issue.

The external switchgear and control house switchgear have separate DC voltage supplies, a 24 volt and a 48 volt battery system, respectively. There is no room to upgrade either battery system, and maintenance of the system is problematic.

Solution

It is recommended that the external switchgear and control house switchgear be replaced with a new Power Control Center (PCC). The PCC will contain two bus's with a normally open tie breaker, 15kV breakers rated 2000A and 1200A, protective relaying, interconnection cabinet, PT's, station service transformers, RTU, and DC battery system. The PCC will contain provisions for future expansion.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,121,000	$2,057,000	$1,064,000	$0	$0	$0	$0
Expense							

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☑ Employee Safety: Reduction of the risk of an equipment failure and flash over.
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 69 years
- ☑ Failure Rates: RTU is unreliable.
- ☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- ☑ Condition: Current conditions of switchgears make it impossible to upgrade equipment.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Maybrook Substation Upgrades

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Growth

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The Montgomery and Maybrook area has experienced significant growth over the past decade. The Maybrook Substation transformers are approaching their firm ratings, and the four distribution circuits are runnings close to, at, or above their 6 MVA normal design criteria. As the economy is recovering, a number of larger industrial loads are coming on line, and a continued abundance of available land with proximity to I-84 will drive the continued growth of warehouses and the residential housing market in the long-term. This realized and potential growth has triggered the need to address the loading concerns in the area.

Solution

Upgrade the Maybrook Substation by replacing the two 10 MVA transformers with two new 12 MVA (13.4 MVA) 69/13.8 kV transformers. Transfer the 10MVA transformers to the Montgomery Substation.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,562,000	$978,000	$2,584,000	$0	$0	$0	$0
Expense							

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- [x] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [x] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ____ years
- [ ] Failure Rates
- [x] Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- [ ] Condition
- [ ] Accessibility (Off Road, underground)
- [x] Strategic Replacement: Increase of loading conditions.
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: See below.

Or

Project Alternatives Considered

C. Ritacco, E.P. # 2011-012, "Montgomery/Maybrook Area Study" January 13, 2012.

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Knapps Corners Substation

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The existing Knapps Corners Substation was built in 1941 and later expanded in 1953. Based on condition and age, the major substation equipment (power transformers, circuit breakers, disconnect switches, control house, relaying and control equipment) requires replacement.

Solution

Replace the existing Knapps Corners Substation with a new Substation on adjacent property. The existing substation cannot be removed from service during construction and the existing footprint is constrained. This creates difficulties, impacts reliability and increases the cost of rebuilding the substation in the same location. Based on these factors, a new substation will be constructed adjacent to the existing one, and the existing substation will be retired/removed.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$9,952,000	$1,369,000	$ 5,624,000	$2,959,000	$0	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

☐ Thermal/Load Serving Capability

☐ Equipment Type

☐ Current % loaded

☐ Voltage (Stray, Low, High)

☐ Power Quality

Other

Risk Reduction

Safety

☐ Employee Safety

☐ Public Safety

☐ Other Program Type

Compliance

☐ Inspections

☐ Road Rebuild

☐ Joint Facilities/CATV Agreement

☐ NESC Codes

☐ Other Program Type

Infrastructure

☑ Average Age of Infrastructure 60 years

☑ Failure Rates: Reviews of history of equipment failure.

☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.

☑ Condition: Reviews of current conditions of existing substation equipment.

☐ Accessibility (Off Road, underground)

☑ Strategic Replacement: Provisions for the reroute of the G Line South.

☐ Other Program Type

Resilience

☐ $/COA (with storm)

☐ $/CMA (with storm)

☐ Customer Cost of Outage (ICE Calculator)

☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: See below.

Or

Project Alternatives Considered

Loeven, E.A.: "Knapps Corners 15 kV Bus Reconfiguration", S.R.2012-01. June 1, 2012.
Paull, J.: "Knapps Corners Substation Breaker Study", E.P. # 2009-01. December, 2, 2009.

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: North Chelsea Transformer Replacement

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The 69kV G Line is being rebuilt due to asset condition. The routing analysis will determine the optimal solution in regards to both line routing and voltage level (115kV or 69kV) for the rebuild. Pending the results of the routing analysis, a 69kV source may be required at the North Chelsea Substation.

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer.

Based on this assessment, it has been determined that the existing three single phase 115/69kV transformers at North Chelsea have reached the end of their useful life and require replacement.

Solution

Replace existing three 115/69 kV single phase transformers with a three phase 115/69 kV autotransformer.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,446,000	$196,000	$355,000	$896,000	$0	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 69 years
- ☑ Failure Rates Four of thirteen transformers of this vintage have failed.
- ☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.
- ☑ Condition Elevated power factor measurements above acceptable limit.
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement Provisions for the reroute of the G Line South.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

See below.

Or

Project Alternatives Considered

"Central Hudson Gas & Electric Long Range Electric System Plan", October 2013

Decision criteria for alternative selection

Central Hudson — People. Power. Possibilities. — A FORTIS COMPANY

Budget Submittal Form for Electric Projects

Project Name: Stanfordville Substation New Transformer

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer. Based on this assessment, the existing Standfordville Substation transformer has reached the end of its useful life and requires replacement.

Solution

Replace the existing transformer at the Stanfordville Substation with a 12 MVA 69/13.8kV bank.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,787,000	$489,000	$507,000	$792,000	$0	$0	$0
Expense							

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

☐ Thermal/Load Serving Capability

☐ Equipment Type

☐ Current % loaded

☐ Voltage (Stray, Low, High)

☐ Power Quality

Other

Risk Reduction

Safety

☐ Employee Safety

☐ Public Safety

☐ Other Program Type

Compliance

☐ Inspections

☐ Road Rebuild

☐ Joint Facilities/CATV Agreement

☐ NESC Codes

☐ Other Program Type

Infrastructure

☑ Average Age of Infrastructure 61 years

☐ Failure Rates

☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence in the station.

☑ Condition Dissolved Gas Analysis indicating overheating in the transformer insulation.

☐ Accessibility (Off Road, underground)

☑ Strategic Replacement Reinforcement of the Northeast 69 kV area.

☐ Other Program Type

Resilience

☐ $/COA (with storm)

☐ $/CMA (with storm)

☐ Customer Cost of Outage (ICE Calculator)

☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Budget Submittal Form for Electric Projects

Project Name: Coxsackie Substation Transformer Replacement

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer. Based on this assessment, the existing Coxsackie Substation transformer has reached the end of its useful life and requires replacement.

Solution

Replace the existing transformer at the Coxsackie Substation with a 12MVA transformer.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,545,000	$147,000	$507,000	$841,000	$51,000	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [x] Average Age of Infrastructure 59 years
- [ ] Failure Rates
- [x] Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence in the station.
- [x] Condition: Elevated power factor measurements above acceptable limit.
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Kerhonkson Substation Autotransformers

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

The existing Modena Substation115kV/69kV single phase autotransformers have reached the end of their useful life. These units are part of a group of sister transformers installed at the Ohioville, North Chelsea and Modena Substations. Based on condition, age and several failures of these single phase units, these transformers are all planned for replacement. Based on a review of the Ellenville Transmission Area, it is recommended that on the retirement of the Modena 115kV/69kV autotransformers, new autotransformers be installed at the Kerhonkson Substation. This work will need to be completed in conjunction with the upgrade of the P and MK Lines to 115kV operation.

In addition to addressing the infrastructure issues, this work will increase the load serving capability within the Ellenville Area. It is recommended to replace the autotransformers and convert the P and MK lines to 115kV operation by 2020. The majority of the work required for the line conversion has been completed previously based predominately on infrastructure issues (rebuild of the P & MK Lines, rebuild of the High Falls, Galeville, Kerhonkson and Sturgeon Pool Substations).

Solution

Install two new 115/69kV autotransformers at the Kerhonkson Substation and reconfigure the 69kV bus at the Honk Falls Substation.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$5,241,000	$98,000	$507,000	$595,000	$4,042,000	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [x] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure years
- [ ] Failure Rates
- [ ] Obsolete/ Unserviceable Equipment
- [ ] Condition
- [ ] Accessibility (Off Road, underground)
- [x] Strategic Replacement: Part of P & MK area study.
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: Chan, R.: "P & MK Area Study". E.P. #2010-008. May 2, 2011.

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Montgomery Substation Rebuild

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer. Based on this assessment, the existing Montgomery transformer has reached the end of its useful life and requires replacement.

Solution

Remove existing 2 MVA 69/4.16 kV transformer at the Montgomery Substation and install two 10 MVA 69/13.8 kV transformers that were located previously at the Maybrook Substation. This work coincides with the distribution circuits upgrade from 4160 V to 13.8 kV.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,773,000	$244,000	$760,000	$844,000	$1,925,000	$0	$0
Expense							

Cost Risks

☐ Environmental

☐ Timing/Permitting

☐ Manpower

☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.

☐ Reduced Customer Bill

☐ Other

Service

Non-Storm Reliability

☐ $/COA

☐ 5 Year Average # Outages Avoided

Non-Storm Operating

☐ $/CMA

☐ 5 Year Average Duration of Outages

Customer Satisfaction

☐ Complaints

☐ Critical Customers

☐ LSA Customers

☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 62 years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence in the station.
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: See below.

Or

Project Alternatives Considered

C. Ritacco, E.P. # 2011-012, “Montgomery-Maybrook Area Study" January 13, 2012

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Modena Add Additional 115 kV Breaker

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: System Enhancement

Investment Category: Daily Operations

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Based on the projected load growth and load serving capability within the Ellenville Area, it is recommended to convert the P and MK lines to 115kV operation. The majority of the work required for the line conversion has been completed (rebuild of the P & MK Lines, rebuild of the High Falls, Galeville, Kerhonkson and Sturgeon Pool Substations).

The upgrade of the P&MK Lines to 115kV will require the addition of a third 115kV breaker at the Modena Substation to form a ring bus.

Solution

A third 115 kV breaker will be installed at Modena Substation to form a ring bus. Provision for the third 115 kV breaker already has been incorporated in the Modena Substation electrical layout.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$2,437,000	$0	$203,000	$395,000	$1,840,000	$0	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Completes a ring bus at Modena Substation.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Chan, R.: “P & MK Area Study”. E.P. #2010-008. May 2, 2011.

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: New Baltimore Transformer Replacement

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Due to their proximity, the Coxackie and New Baltimore Substations provide reserve capability and operating flexibility between the two substations. The existing distribution infrastructure between the substations is aging, in poor condition and has access limitations due to CSX railroad expansion. To maintain reliability and operating flexibility in this area, the distribution infrastructure requires replacement. A review of the area determined that a more cost effective solution is to install a second transformer and associated circuit positions at the New Baltimore Substation.

Solution

Add an additional 12 MVA transformer and associated distribution feeders to the New Baltimore Substation.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,492,000	$0	$51,000	$273,000	$1,117,000	$51,000	$0
Expense							

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement Provide operational flexibility.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Greenfield Road - Substation Upgrade

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer. Based on this assessment, the existing 69-4.16kV Greenfield Road Substation transformers have reached the end of their useful life and require replacement.

Solution

Retire all of the 4 kV equipment including Transformers #1 and #3 and all other associated equipment. Two existing 69-13.8kV three phase transformers will be utilized (current plans are to use the Modena Substation spare and the retired Kerhonkson Substation transformers).

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,153,000	$98,000	$203,000	$296,000	$505,000	$51,000	$0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

☐ Thermal/Load Serving Capability

☐ Equipment Type

☐ Current % loaded

☐ Voltage (Stray, Low, High)

☐ Power Quality

Other

Risk Reduction

Safety

☐ Employee Safety

☐ Public Safety

☐ Other Program Type

Compliance

☐ Inspections

☐ Road Rebuild

☐ Joint Facilities/CATV Agreement

☐ NESC Codes

☐ Other Program Type

Infrastructure

☑ Average Age of Infrastructure 78 years

☐ Failure Rates

☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.

☑ Condition Elevated power factor measurements above acceptable limit.

☐ Accessibility (Off Road, underground)

☐ Strategic Replacement

☐ Other Program Type

Resilience

☐ $/COA (with storm)

☐ $/CMA (with storm)

☐ Customer Cost of Outage (ICE Calculator)

☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Trap Rock Tap Station

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Based on infrastructure issues determined by inspections and a condition based assessment, the 69kV TR needs to be rebuilt. This line is the sole supply to a quarry limiting the ability to obtain outages during a rebuild of the line. A review has determined that the most economical solution is to build a new substation tapped off of the 115kV SC line to supply the quarry and to retire the TR Line.

Solution

Install a new 115/13.8 kV or 115/69 kV Substation to serve Trap Rock. Additionally, install a new 115 kV breaker at the Sand Dock Substation to limit exposure to IBM resulting from a fault at the new tap on the SC Line.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$5,324,000	$400,000	$253,000	$592,000	$2,021,000	$2,058,000	$50,000
Expense							

Cost Risks

☐ Environmental

☐ Timing/Permitting

☐ Manpower

☐ Other

Primary Project Objective

Service

Benefits

Economic

☐ Reduced O&M

☐ Reduced Customer Bill

☐ Other

Service

Non-Storm Reliability

☐ $/COA

☐ 5 Year Average # Outages Avoided

Non-Storm Operating

☐ $/CMA

☐ 5 Year Average Duration of Outages

Customer Satisfaction

☐ Complaints

☑ Critical Customers: Trap Rock Quarry

☐ LSA Customers

☑ Public Relations Considerations: The line runs through a residential area; its retirement will remove the infrastructure from customers' property.

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

An alternative considered was to rebuild the TR Line in kind. Construction would be costly and lengthy due to the restrictions from the quarry on the allowable outage durations to perform the work.

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Aged Transformer Replacements

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

As part of the ongoing review of the substation power transformer fleet, Operations Services completes a condition-based assessment of those transformers that are 55 years old or greater. This assessment is based on routine testing and monitoring to determine an overall condition and condition-trend of the transformer.

The following power transformers have been identified due to age (55+) and will have their inspection results monitored more closely as a result. Some of the units have exhibited early indications of degradation. In the event that these transformers show deteriorating condition, they will be targeted for replacement pro-actively before risking failure. These transformers include:

North Catskill Transformers # 4 & #5 (115/69 kV Autos); Smithfield Transformer #1 (69/13.8 kV); Dashville Transformer #2 (69/4 kV); Forgebrook Transformers # 1 & #2 (115/13.8 kV); Pulvers Corners Transformer #4 (69/13.8 kV); Union Avenue Transformers # 1 & #2 (115/13.8 kV); Tinkertown Transformers # 1 & #2 (69/13.8 kV); Converse Street Transformer #2 (14/4 kV); East Park Transformer #1 (69/13.8 kV); Grimley Road Transformer #2 (69/13.8 kV); Neversink Transformers # 3 & #6 (69/13.8 kV); Ohioville Transformers # 1 & #2 (115/13.8 kV); South Cairo Transformer #1 (69/13.8 kV)

Solution

Replace transformers and any associated relaying as appropriate.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$9,971,000	$0	$0	$1,332,000	$3,031,000	$5,608,000	$9,963,000
Expense							

Cost Risks

- [x] Environmental: More extensive oil containment is now required.
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- [x] Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- [ ] Reduced Customer Bill
- [ ] Other

Service

Non-Storm Reliability

- [ ] $/COA
- [ ] 5 Year Average # Outages Avoided

Non-Storm Operating

- [ ] $/CMA
- [ ] 5 Year Average Duration of Outages

Customer Satisfaction

- [ ] Complaints
- [ ] Critical Customers
- [ ] LSA Customers
- [ ] Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 55+ years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment Reviews of equipment obsolescence.
- ☑ Condition Varying transformer health.
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement Prioritized replacements.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Aged Switchgear Replacements

Form submitted by: Mason Mullamphy

Budget Group: 13 - Substations

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted

Project ID (District-YYYY-ID)

Description of Problem

Based on condition assessment, several existing switchgears have been identified for replacement due to age and condition. These switchgears are located in the following substations:

Converse Street Substation
Lincoln Park Substation
Sturgeon Pool Generator Breakers Substation
Montgomery Street Substation

Solution

Replace switchgears and any associated relaying as appropriate.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,544,000	$0	$0	$0	$0	$1,544,000	$4,500,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Newer equipment requires less maintenance than existing equipment.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 60 years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment: Reviews of equipment obsolescence.
- ☑ Condition: Switchgear deterioration.
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement: Modernization of relaying equipment.
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Appendix 1

Budget Submittal Form for Electric Projects

Project Name: 14.4kV Cable Rejuvenation Program

Form submitted by: N. Conza

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

The 14.4kV Rejuvenation program was initiated in 2009, with the replacement of the Poughkeepsie PO, PK and PU PILC network feeder main lines, as well as the majority of the WN cable feed to the Montgomery Street substation. The remaining Newburgh 14.4kV feeds to the Montgomery Street Substation are the B, F and R cables. Just as in Poughkeepsie, these cables are in need of replacement due to age and condition. The underground infrastructure, which is nearly 90 years old is also in need of replacement. The final portion of the WN cable is also in need or replacement due to cable age. The infrastructure is nearly 100 years old and all spare conduits have collapsed. The conduits are currently inaccessible due to a library being built over them in 1973.

Solution

Replace the remaining Newburgh 14.4kV cables, as well as their associated infrastructure.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$5,462,000	$488,000	$1,109,000	$1,084,000	$1,365,000	$1,416,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 100 years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☑ Condition Collapsed and abandoned ducts, leaking lead cables over 70 years old.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: E.P. #2011-001

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: 4800V Conversion/Infrastructure Program

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

A large infrastructure concern in the Central Hudson territory is the 4800V circuitry. These 4800V pockets limit the operational as well as the circuit configuration, and load serving capability. The primary concern with the 4800V circuitry is the age. Central Hudson abandoned the practice of installing 4800V circuitry in the 1940s. Much of the area infrastructure is over 70 years old and has exceeded its useful life. Central Hudson has roughly 146 miles of 4800V circuitry.

Solution

A conversion program was developed to the eliminate 4800V aging infrastructure. The program focuses on upgrading 4800V mainline circuitry to 13.2kV operation. A particular focus is placed on developing projects that eliminate overloaded, step-down transformer banks in order mitigate thermal and infrastructure concerns, as well as remove any of the other potential hazards associated with 4800V circuitry.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$11,050,000	$1,331,000	$1,472,000	$1,626,000	$3,222,000	$3,399,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☑ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [x] Thermal/Load Serving Capability
  - [x] Equipment Type
  - [x] Current % loaded
- [x] Voltage (Stray, Low, High)
- [x] Power Quality

Other

Risk Reduction

Safety

- [x] Employee Safety: Upgrading to a 13.2kV Wye system minimizes associated risks
- [x] Public Safety: Upgrading to a 13.2kV Wye system minimizes associated risks
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [x] Average Age of Infrastructure ____ years
- [x] Failure Rates
- [x] Obsolete/ Unserviceable Equipment
- [x] Condition
- [x] Accessibility (Off Road, underground)
- [x] Strategic Replacement
- [ ] Other Program Type

Resilience

- [x] $/COA (with storm)
- [x] $/CMA (with storm)
- [x] Customer Cost of Outage (ICE Calculator)
- [x] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: CEMI / Worst Circuit Reliability Program

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

Central Hudson maximizes its reliability improvement efforts through continuous analysis and planning, but historic data shows that specific circuits and "pockets" of customers tend to experience a significantly higher frequency or duration of outages than average.

Solution

The CEMI (customers experiencing multiple interruptions) and Worst Performing Circuits program have been designed to help identify and develop reliability improvements for these customers. The customers experiencing the poorest of reliability are identified, and improvement projects are developed annually.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$6,176,000	$1,746,000	$1,109,000	$1,084,000	$1,104,000	$1,133,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Service

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☑ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☑ Complaints
- ☑ Critical Customers
- ☑ LSA Customers
- ☑ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure ___ years
- ☑ Failure Rates: The program typically replaces antiquated infrastructure
- ☐ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☑ Accessibility (Off Road, underground): Infrastructure is often made more accessible
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☑ $/COA (with storm)
- ☑ $/CMA (with storm)
- ☑ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Distribution Automation Program

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: System Enhancement

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

An aging infrastructure, an inefficient grid, rising energy costs, increased demand for uninterrupted service, clean energy goals, and increased adoption of technology (i.e. distributed generation and solar), as well as availability of more sophisticated technology, have driven the need for a reformation of the electric distribution system.

Solution

The Electric Distribution Automation program was developed in order to address these growing concerns. Through the implementation of a Distribution Management System (DMS), Central Hudson will be able to implement programs such as Volt-Var optimization (VVO), Conservation Voltage Reduction (CVR), and Fault Location Isolation and Service Restoration (FLISR). Programs such as these are aimed to lower customer energy usage, defer transmission investments, replace aging assets, incorporate modern technology, and improve customer reliability.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$34,402,000	$7,040,000	$9,320,000	$12,291,000	$5,221,000	$530,000	2,500,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower: Extensive work is involved in a new program
- ☐ Other

Primary Project Objective

Service

Benefits

Economic

- ☑ Reduced O&M: Distribution Automation will reduce O&M costs
- ☑ Reduced Customer Bill: Many of the projects are designed to reduce customer bills
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☑ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☑ Complaints
- ☑ Critical Customers
- ☑ LSA Customers
- ☑ Public Relations Considerations

Service Standards

- ☑ Thermal/Load Serving Capability
  - ☑ Equipment Type
  - ☑ Current % loaded
- ☑ Voltage (Stray, Low, High)
- ☑ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☑ Other Program Type: Reforming the Energy Vision (REV)

Infrastructure

- ☑ Average Age of Infrastructure years
- ☑ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☑ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☑ $/COA (with storm)
- ☑ $/CMA (with storm)
- ☑ Customer Cost of Outage (ICE Calculator)
- ☑ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: E.P. #2015-12, E.P. #2016-05

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Distribution Improvement Blankets

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Non-Discretionary

Investment Category: Daily Operations

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

Newly emerging, operational work on the distribution system must be addressed on a routine basis, such as emergency work, and CATV rebuilds and other compliance related issues.

Solution

Develop work orders to address emerging operational work.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$38,291,000	$7,059,000	$6,133,000	$8,203,000	$8,358,000	$8,538,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☑ Timing/Permitting
- ☑ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Distribution improvement projects typically reduce operating and maintenance costs
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☑ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☑ Complaints
- ☑ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections
- ☐ Road Rebuild
- ☑ Joint Facilities/CATV Agreement
- ☑ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ☐ years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment
- ☐ Condition
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☑ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Distribution Improvement Operating/Infrastructure

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID) 1551-0X

Description of Problem

One of the primary focuses of the Category 15 Capital Budget plan is to improve the reliability of the Central Hudson customers. Operational limitations in the distribution circuitry is a primary driver in the overall duration that the average customer experiences.

Solution

Operating projects are developed with the primary goal being of reducing the duration of outages. Typical projects involve developing a tie between feeders, or reconductoring the lines to make the tie stronger so more load can be reenergized through switching. Many of these projects also address aging infrastructure that does not fall under a specific program.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$16,023,000	$2,376,000	$2,001,000	$4,271,000	$3,838,000	$3,538,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective: Service

Benefits

Economic

- ☑ Reduced O&M: Operational improvements can dramatically reduce O&M costs.
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☑ Complaints
- ☑ Critical Customers
- ☑ LSA Customers
- ☑ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☑ Obsolete/ Unserviceable Equipment
- ☑ Condition
- ☑ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☑ $/COA (with storm)
- ☑ $/CMA (with storm)
- ☑ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Distribution Improvement - Reliability

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

One of the primary focuses of the Category 15 Capital Budget plan is to improve the reliability of the Central Hudson customers. The improvement is focused on both the frequency and duration in which a customer is without power.

Solution

Currently, projects are created according to a 5 year historical average $/COA (customer outage avoided) basis, but ancillary benefits to customer satisfaction and resiliency also are considered. Improvement projects include moving circuitry from off-road to on-road, closing gaps (i.e., new circuit ties), installing electronic reclosers, installing automatic load transfer teams, and replacing failure prone equipment.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$12,647,000	$1,573,000	$2,772,000	$2,710,000	$2,760,000	$2,832,000	TBD
Expense							

Cost Risks

- ☑ Environmental: Reliability projects must still protect environmental factors such as vegetation and wildlife
- ☑ Timing/Permitting:
- ☐ Manpower:
- ☐ Other:

Primary Project Objective: Service

Benefits

Economic

- ☑ Reduced O&M: Reliability improvement can dramatically reduce operating and maintenance costs.
- ☐ Reduced Customer Bill:
- ☐ Other:

Service

Non-Storm Reliability

- ☑ $/COA:
- ☑ 5 Year Average # Outages Avoided:

Non-Storm Operating

- ☑ $/CMA:
- ☑ 5 Year Average Duration of Outages:

Customer Satisfaction

- ☑ Complaints:
- ☑ Critical Customers:
- ☑ LSA Customers:
- ☑ Public Relations Considerations:

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☑ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure ____ years
- ☑ Failure Rates: Engineering analysis determines equipment with a high failure rate
- ☑ Obsolete/ Unserviceable Equipment
- ☑ Condition
- ☑ Accessibility (Off Road, underground)
- ☑ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☑ $/COA (with storm)
- ☑ $/CMA (with storm)
- ☑ Customer Cost of Outage (ICE Calculator)
- ☑ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Distribution Improvement - Thermal/Voltage

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Growth

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

Load growth in a particular area may cause equipment to exceed its thermal ratings or load serving capabilities. Additionally, overloaded equipment has a tendency to fail which can be a safety concern and compromises customer reliability.

Solution

Load relief projects are often recommended to mitigate the loading, thermal, and voltage concerns. Polyphasing, reconductoring, or building new lines also are examples of projects that could fall under this line item.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$12,070,000	$2,712,000	$2,716,000	$2,168,000	$2,208,000	$2,266,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☑ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Mitigating loading concerns typically reduces O&M costs
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☑ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [x] Thermal/Load Serving Capability
  - [x] Equipment Type
  - [x] Current % loaded
- [x] Voltage (Stray, Low, High)
- [x] Power Quality

Other

Risk Reduction

Safety

- [x] Employee Safety — Properly sized equipment mitigates safety concerns with overloads
- [x] Public Safety — Properly sized equipment mitigates safety concerns with overloads
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ___ years
- [x] Failure Rates
- [ ] Obsolete/ Unserviceable Equipment
- [ ] Condition
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [x] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: Distribution Pole Replacement Program

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Non-Discretionary

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

Much of the Central Hudson pole plant is antiquated and undersized. Many of the poles have been exposed to rot, woodpeckers, and other weather related decay. As the poles weaken, their likelihood of failure dramatically increases. Weak and failing poles are a key driver in decreasing customer reliability.

Solution

As a result of our Distribution Inspections program, defective poles are identified and replaced based on the severity rating of the deficiency. Projects are evaluated for other incremental system benefits, such as relocating pole on road or designing to NESC Grade B construction. Additionally, other poles may be replaced due to a violation of Central Hudson Electric Construction Standards, NESC, IEEE, and other national and international standards.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$17,398,000	$1,952,000	$2,217,000	$3,252,000	$4,878,000	$5,098,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective: Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: Pro-active replacement of equipment greatly reduces the O&M costs
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☑ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☑ Complaints
- ☑ Critical Customers
- ☑ LSA Customers
- ☑ Public Relations Considerations

Service Standards

- [ ] Thermal/Load Serving Capability
  - [ ] Equipment Type
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [x] Public Safety: Larger, stronger poles decreases public exposure
- [ ] Other Program Type

Compliance

- [x] Inspections: Pole inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [x] NESC Codes
- [ ] Other Program Type

Infrastructure

- [x] Average Age of Infrastructure ___ years
- [x] Failure Rates
- [ ] Obsolete/ Unserviceable Equipment
- [x] Condition: Replaces failure prone poles
- [x] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [x] $/COA (with storm)
- [x] $/CMA (with storm)
- [x] Customer Cost of Outage (ICE Calculator)
- [x] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: New Union Avenue 4049 Circuit

Form submitted by: Angelo Onevelo

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Growth

Number of Customers Affected: 764

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID) N-2017-01

Description of Problem

The Coldenham 4027 circuit has consistently reached or exceeded its 6/9 MVA design criteria. The circuit has historically been classified as a 9/12 MVA circuit, but further review has shown that the circuit only has a design rating of 6/9 MVA. The circuit has peaked over its design criteria in 2013, 2014 and 2015 at 8.62 MVA, 7.28 MVA and 7.10MVA respectively. Load shifting capabilities are severely limited in this area due to the current circuit loading. Due to the expansive load growth in the area of Rt. 17K and Rt. 300, additional load support is needed.

Amerisource (Matrix) is developing a distribution center on Rt. 17K on the east side of I-87. Their demand load is expected to reach 1,450 kVA when the property is completely developed. Currently, the Coldenham 4027 circuit feeds this area. Because of the current circuit loading stated above, the 4027 cannot handle the proposed load from Amerisource.

Solution

Utilization of the former UN or UW breaker positions at the Union Avenue Substation is a possible solution. A new distribution circuit can exit the substation utilizing the UN or UW underground cable path on the back side of the substation as an express feed to Rt. 17K. The circuit should rise on Hillside Ave. and begin heading west as double circuit construction with the Union Ave. 4045 circuit for 0.2 miles. The circuit will then run north along an existing ROW towards the Verizon communications tower for 0.5 miles. A continuation of the ROW will need to be cleared for 0.15 miles to meet up with the existing pole plant on the north side of the Verizon communications tower. The circuit will continue 0.85 miles north along Ellis Ave utilizing an existing pole line. The circuit will then head west along Little Britain Rd. for 0.30 miles as double circuit construction with the Union Ave. 4047 circuit. This new construction will take over the circuitry feeding north on Wisner Ave. and east on 17K to offload the 4027 circuit. A Viper recloser will also be added to the circuit.

The express feed should be comprised of 556 WR ACSR open wire with a 336 Bare ACSR neutral for the entirety of the project. This project will also require 0.8 miles of reconductoring along Rt. 17K. from Wisner Ave. to Dalfonso Rd. The reconductoring will consist of 556 ACSR Bare wire with a 336 Bare ACSR neutral.
See Attachment #1.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	1,115,000	1,115,000					
Expense							

Cost Risks

- ☑ Environmental: Extensive ROW Trimming will be needed.
- ☑ Timing/Permitting: Need to acquire joint pole use through ROW. Network Strategy is working on it.
- ☐ Manpower
- ☐ Other

Primary Project Objective

Service

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [x] Thermal/Load Serving Capability
  - [x] Equipment Type: Conductor (336 Spacer)
  - [x] Current % loaded: 77%
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ____ years
- [ ] Failure Rates
- [ ] Obsolete/ Unserviceable Equipment
- [ ] Condition
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: N-17-06: Extend Circuitry 1.6 Miles Underground Along Rt. 17K

Or

Project Alternatives Considered

Three distribution alternatives were considered and this proposed alternative proved to be the least costly solution.

Decision criteria for alternative selection

1. Survey work as already begun in this area on Rt. 17K. Initial project work has been completed due to the arrival of Amerisource (Matrix Properties) on Rt. 17K.

2. In order for this alternative circuit design to come to fruition, most of the poles from the Union Avenue Substation to Rt. 17K would need to be replaced to accommodate the double circuit construction. Along Union Avenue, the circuitry would be placed in a triple circuit design. This would be placing the vulnerability of the circuits at risk. This alternative project would require 3 circuit miles, which is equal to the ROW option.

3. Reconductoring along Rt. 17K would increase the design criteria of the Coldenham 4027 circuit to 9/12 MVA. This would increase circuit capacity by 1.5 MW. Switching capabilities would still be greatly limited due to the still limited capacity on the circuit. Load growth is still expected in this area.

Budget Submittal Form for Electric Projects

Project Name: Extend Circuitry 1.6 Miles Underground Along Rt. 17K

Form submitted by: Angelo Onevelo

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Growth

Number of Customers Affected: 147

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID) N-2017-06

Description of Problem

The area around Rt. 17K and Rt. 300 in the Town of Newburgh has seen substantial load growth in recent years. The Bethlehem Road 4092 circuit is the primary circuit that feeds this load pocket along Rt. 300. In 2013, the 4092 circuit peaked at 5.37 MVA. Switching options are greatly limited during peak times. The Coldenham 4027 circuit is the circuit that feeds down Rt. 17K on both the east and west sides of I-87. This circuit has consistently peaked over its 6/9 MVA design criteria in 2013, 2014 and 2015 at 8.62 MVA, 7.29 MVA and 7.10 MVA respectively. A budget project currently scheduled for 2017 (N-2017-01) will offload 3 MW from the Coldenham 4027 circuit. Once this work is completed, the 4027 circuit will peak at approximately 4.5 MW. With the additional load from Amerisource (Matrix) in 2017, the circuit will peak at approximately 5.9 MVA. With this additional loading from Amerisource (Matrix), additional load growth will be limited due to available circuit capacity in the area.

Solution

In order to meet the demand of future expected load growth, it is proposed to extend the 4025 circuit from Governor's Drive to the intersection of Rt. 17K and Rt. 300. This circuit extension would be comprised of underground conduit construction and would run for approximately 1.6 miles. This will allow of utilization of the lightly loaded Coldenham 4025 circuit. This will also allow for the development of expected load growth in the Rt. 17K and Rt. 300 area.

This project will fall within the criteria for non-wires alternatives.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	1,600,000	1,600,000					
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Service

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☐ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- [x] Thermal/Load Serving Capability
  - [x] Equipment Type: Conductor
  - [ ] Current % loaded
- [ ] Voltage (Stray, Low, High)
- [ ] Power Quality

Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Road Rebuild
- [ ] Joint Facilities/CATV Agreement
- [ ] NESC Codes
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ___ years
- [ ] Failure Rates
- [ ] Obsolete/ Unserviceable Equipment
- [ ] Condition
- [ ] Accessibility (Off Road, underground)
- [ ] Strategic Replacement
- [ ] Other Program Type

Resilience

- [ ] $/COA (with storm)
- [ ] $/CMA (with storm)
- [ ] Customer Cost of Outage (ICE Calculator)
- [ ] Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: B, F, & R Cables

Form submitted by: N. Conza

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected:

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID) N-2017-08

Description of Problem

The B, F & R cables that feed the Montgomery Street Substation are mostly comprised of PILC cables. Sections of these cables were installed between 1928 and 1956. Numerous repairs have been made to these cables over the years due to leaking lead splices. In 2015, a major repair was performed on 3 simultaneous leaks in the same manhole. The infrastructure is just as old as the cables and is in poor condition. The 4" fiber duct configuration has resulted in the lead cables being stacked on each other in each manhole. A major failure of one of the cables could potentially result in loss of all three cables. Of the 3 spare ducts in this duct bank, only 2 are available due to a collapse and failed cable pull. The structural integrity of these aging fiber ducts cannot and should not be relied on for new cables.

Solution

Construct a new duct bank and replace the B, F & R cables up to I84 between 2018 and 2026. Continuation south of I84 shall be evaluated in 2022 and assigned a new Newburgh project ID number.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$11,750,000	$1,000,000	$1,500,000	$1,000,000	$1,500,000	$1,250,000	$5,500,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☐ $/COA
- ☐ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☐ 5 Year Average Duration of Outages

Customer Satisfaction

- ☐ Complaints
- ☐ Critical Customers
- ☐ LSA Customers
- ☐ Public Relations Considerations

Service Standards

- ☐ Thermal/Load Serving Capability
  - ☐ Equipment Type
  - ☐ Current % loaded
- ☐ Voltage (Stray, Low, High)
- ☐ Power Quality

Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Road Rebuild
- ☐ Joint Facilities/CATV Agreement
- ☐ NESC Codes
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 88 years
- ☐ Failure Rates
- ☐ Obsolete/ Unserviceable Equipment
- ☑ Condition: Cables and ducts are aging and in poor condition. Leaks found during inspections.
- ☐ Accessibility (Off Road, underground)
- ☐ Strategic Replacement
- ☐ Other Program Type

Resilience

- ☐ $/COA (with storm)
- ☐ $/CMA (with storm)
- ☐ Customer Cost of Outage (ICE Calculator)
- ☐ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study: E.P. #2011-001

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Electric Projects

Project Name: URD Replacement

Form submitted by: Chris Ritacco

Budget Group: 15 - Distribution Improvements

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: Varies

For Category 15 only: Budget Year Submitted 2017

Project ID (District-YYYY-ID)

Description of Problem

Many of the aged underground residential developments (URDs) are beginning to experience underground cable failures. When URD faults occur, they are particularly harmful to reliability due to the normally high customer count and extensive repair times.

Solution

Central Hudson continues to pro-actively monitor and address URD replacements on a targeted basis. Aging URDs with higher customer counts are primarily targeted in order to maximize the reliability improvement.

Cost estimate (include AFUDC if appropriate)

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$2,709,000	$0	$532,000	$0	$1,044,000	$1,133,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☑ Other: digging

Primary Project Objective

Service

Benefits

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Service

Non-Storm Reliability

- ☑ $/COA
- ☑ 5 Year Average # Outages Avoided

Non-Storm Operating

- ☑ $/CMA
- ☑ 5 Year Average Duration of Outages

Customer Satisfaction

- ☑ Complaints
- ☑ Critical Customers
- ☑ LSA Customers
- ☑ Public Relations Considerations

Service Standards

☐ Thermal/Load Serving Capability

☐ Equipment Type

☐ Current % loaded

☐ Voltage (Stray, Low, High)

☐ Power Quality

Other

Risk Reduction

Safety

☐ Employee Safety

☐ Public Safety

☐ Other Program Type

Compliance

☐ Inspections

☐ Road Rebuild

☐ Joint Facilities/CATV Agreement

☐ NESC Codes

☐ Other Program Type

Infrastructure

☑ Average Age of Infrastructure years

☑ Failure Rates URD cable is a common equipment failure

☑ Obsolete/ Unserviceable Equipment

☑ Condition replaces failure prone cable

☐ Accessibility (Off Road, underground)

☑ Strategic Replacement

☐ Other Program Type

Resilience

☑ $/COA (with storm)

☑ $/CMA (with storm)

☑ Customer Cost of Outage (ICE Calculator)

☑ Grade B Construction

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

GAS PROGRAM INDIVIDUAL PROJECT SUBMITTAL

Budget Submittal Form for Gas Projects

Project Name: Remote Operated Valves, Project 22-4

Form submitted by: Tera Stoner

Recommended In-Service Year: 2017 through 2021

Budget Group: 22 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: 0

Description of Problem

Gas system: Transmission

Gas pressure: 512 psi through 750 psi

Existing pipe size and material:

Proposed length replacement:

The US Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHSMA) will mandate in the near future operators of natural gas transmission lines to have in-service line valves capable of remote operation to isolate a section of main should there be a rupture. In this way, PHSMA hopes to reduce the response time and contain the situation in a timely manner. Central Hudson only has manually operated valves where a crew must travel to the line valve's location and physically close the valve.

Solution

Proposed size: uncertain

In 2016, there are several aspects of the project to be analyzed. Central Hudson would ideally re-configure or modify current line valves already in-service for remote operation capabilities. First, the location of valves relative to high population densities will be identified to prioritize which valves should be modified and when. Second, the pneumatic devices and actuator shall be chosen. It is hopeful the gear hand wheel can be removed and the new pneumatic actuator can be applied. Third, the RTU and communication strategy shall be chosen. The communication strategy should be in line with Central Hudson's current Network Strategy plans.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$2,474,000	$152,000	$209,000	$434,000	$772,000	$907,000	
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☑ Other: New technology being applied on company equipment for the first time.

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Replacement
- ☐ Reinforcement
- ☐ Road Rebuild
- ☐ Other

Service

Reliability

- ☐ Radial feed
- ☐ Loop tie

Gas Safety

- ☐ Pipeline type
- ☐ Number of closed leaks in past 10 years
  - ☐ Number of hazardous (Class 1, 2A and 2)
- ☐ Number of active leaks
- ☐ Length of leak prone pipe eliminated
- ☐ Number of high pressure service replacement
- ☐ Number of isolated service replacement

Customer Impact

- ☐ Complaints
- ☐ Critical Customers
- ☐ Public Relations Considerations

Other

Risk Reduction

Safety

- ☑ Reduce risk of incident
- ☐ Employee Safety
- ☑ Public Safety
- ☐ Other Benefits

Compliance

- ☑ Central Hudson Inspections
- ☑ Elimination of Integrity Related Issues
- ☐ Other Program Type

Infrastructure

1950 to present Infrastructure year installed

Number of Services

- ☐ Indoor meter sets
- ☐ Metallic

- ☐ Obsolete/ Unserviceable Equipment
- ☐ Strategic Replacement
  - ☐ Flood zone
  - ☐ Main feeder route
  - ☐ Low pressure system
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

It is assumed the current gear box on a line valve can be removed and an actuator applied. However, the TP and the AH Line was installed between 1950 and 1960 and current valve actuator models may not be compatible with valves of this age. In this case, Gas & Mechanical will analyze if a new valve assembly will be required taking advantage of a launch port for internal integrity testing tools. In this case it may cost $300,000 to $400,000 per valve for the manual to remote operated conversion. After analyzing several white papers discussing the issue, Gas & Mechanical Engineering recommends a line valve can only be activated by a System Operator. Other companies are proposing to use line break sensors, which are not feasible for Central Hudson's system which allows

Decision criteria for alternative selection

distribution regulator stations to feed from the transmission main itself.

Budget Submittal Form for Gas Projects

Project Name: Poughkeepsie Receival TP Line Feed, Project 22-7

Form submitted by: Tera Stoner

Recommended In-Service Year: 2018

Budget Group: 22 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: 0

Description of Problem

Gas system: MP Line to TP Line

Gas pressure: 750 psi to 512 psi

Existing pipe size and material: various

Proposed length replacement: uncertain

Currently the line valve controlling pressure between the MP Line and the TP Line is both the pressure controller and the over-pressure monitor. There is a risk that if the control valve fails, there is no over-pressure protection for the TP Line. The risk is low because System Operations usually maintains the transmission system pressure between 400 and 450 psi, which is below the MAOP of the TP Line. The feed to the 60 psi regulators is sourced downstream of the control valve. If System Operations had to close the MP Line valve at Poughkeepsie Receival and the TP Line Valve at the West Shore Flow Station to protect the TP Line River Crossing, the feed to the 60 psi regulators will be stopped. These regulators support a major feed to the PN Line and Poughkeepsie's medium and low pressure distribution systems and cannot undergo an interruption.

Solution

Proposed size: uncertain

A second control valve should be installed to monitor pressure downstream of the current control valve to provide over-pressure protection to the TP Line. In addition the feed to the 60 psi regulators shall be moved to upstream of the control valves. With this relocation, the inlet to the 60 psi regulators will need to be uprated for 750 psi MAOP. At the same time, any upgrades to the field equipment reporting to SCADA will be made. The station's SCADA equipment will receive a battery power supply to provide alternative power during service interruptions.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,178,000		$1,178,000				
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☑ Other: This project will occur in a former MGP Site.

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☐ Reduced O&M
- ☐ Replacement
- ☑ Reinforcement
- ☐ Road Rebuild
- ☐ Other

Service

Reliability

- ☐ Radial feed
- ☐ Loop tie

Gas Safety

- ☐ Pipeline type
- ☐ Number of closed leaks in past 10 years
  - ☐ Number of hazardous (Class 1, 2A and 2)
- ☐ Number of active leaks
- ☐ Length of leak prone pipe eliminated
- ☐ Number of high pressure service replacement
- ☐ Number of isolated service replacement

Customer Impact

- [ ] Complaints
- [ ] Critical Customers
- [ ] Public Relations Considerations

Other

Risk Reduction

Safety

- [ ] Reduce risk of incident
- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Benefits

Compliance

- [ ] Central Hudson Inspections
- [ ] Elimination of Integrity Related Issues
- [ ] Other Program Type

Infrastructure

1969 Infrastructure year installed

Number of Services

- [ ] Indoor meter sets
- [ ] Metallic

- [ ] Obsolete/ Unserviceable Equipment
- [ ] Strategic Replacement
  - [ ] Flood zone
  - [ ] Main feeder route
  - [ ] Low pressure system
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

As this project occurs within a former MGP Site, there is sensitivity working within possible contaminated soils. Gas & Mechanical Engineering will work with Environmental Services to ensure all safety guidelines are met. It may be more cost effective to relocate the station and line valves all together to the top tier of the property where the former Propane-Air Plant was situated to avoid any conflicts with the MGP Remediation work.

Decision criteria for alternative selection

Budget Submittal Form for Gas Projects

Project Name: Pipeline Integrity, Project 22-9

Form submitted by: Tera Stoner

Recommended In-Service Year: 2017 through 2021

Budget Group: 22 - Transmission

Summary Category: Maintain System Standards

Investment Category: Infrastructure

Number of Customers Affected: 0

Description of Problem

Gas system: various

Gas pressure: 512 psi to 750 psi

Existing pipe size and material: various

Proposed length replacement: various

Funds reserved for instances where inspections under the Pipeline Integrity Program may require a pig launch, replacement of pipe, erosion mitigation, ROW security gates, or resolution of easement issues.

Solution

Proposed size: uncertain

For each instance require capital funding for a possible pig launch, replacement of pipe, erosion mitigation, ROW security gates, or resolution of easement issues, all work is analyzed and designed to provide the most cost effective approach. Majority of construction work is competitively bid besides where specialty services may be required such as those provided by Pipetel or TDW Services.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,375,000	$117,000	$209,000	$287,000	$349,000	$413,000	TBD
Expense							

Cost Risks

☐ Environmental

☐ Timing/Permitting

☐ Manpower

☑ Other: Scope may vary greatly for work considering factors such as ROW accessibility, specialized service pricing, length and size of piping affected.

Primary Project Objective

Service

Benefits

Economic

☐ Reduced O&M

☐ Replacement

☐ Reinforcement

☐ Road Rebuild

☐ Other

Service

Reliability

☐ Radial feed

☐ Loop tie

Gas Safety

☐ Pipeline type

☐ Number of closed leaks in past 10 years

☐ Number of hazardous (Class 1, 2A and 2)

☐ Number of active leaks

☐ Length of leak prone pipe eliminated

☐ Number of high pressure service replacement

☐ Number of isolated service replacement

Customer Impact

- [ ] Complaints
- [ ] Critical Customers
- [ ] Public Relations Considerations

Other

Risk Reduction

Safety

- [x] Reduce risk of incident
- [ ] Employee Safety
- [x] Public Safety
- [ ] Other Benefits

Compliance

- [x] Central Hudson Inspections
- [x] Elimination of Integrity Related Issues
- [ ] Other Program Type

Infrastructure

1950-present Infrastructure year installed

Number of Services

- [ ] Indoor meter sets
- [ ] Metallic

- [ ] Obsolete/ Unserviceable Equipment
- [ ] Strategic Replacement
  - [ ] Flood zone
  - [ ] Main feeder route
  - [ ] Low pressure system
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

For each instance require capital funding for a possible pig launch, replacement of pipe, erosion mitigation, ROW security gates, or resolution of easement issues, all work is analyzed and designed to provide the most cost effective approach. Majority of construction work is competitively bid besides where specialty services may be required such as those provided by Pipetel or TDW Services.

Decision criteria for alternative selection

Budget Submittal Form for Gas Projects

Project Name: Poughkeepsie Receival Rebuild, Project 23-10

Form submitted by: Tera Stoner

Recommended In-Service Year: 2018

Budget Group: 23 - Regulator Stations

Summary Category: System Enhancement

Investment Category: Infrastructure

Number of Customers Affected: 0

Description of Problem

Gas system: TP System to PN Line

Gas pressure: 512 psi to 60 psi

Existing pipe size and material: various

Proposed length replacement: various

The rebuild of the MP to TP Line control valve also affects the inlet configuration to the regulator runs where pressure is reduced from transmission level to 60 psi to feed the PN Line, PMP System, and PLP System. This rebuild must also coincide with remediation work of the former MGP site. Initial discussion with Environmental Services may require the station to be relocated to the eastern edge of the gas regulator yard to allow for remediation work to be conducted clear of piping. However, it may be more appropriate to relocate the station completely to the upper tier. Regulator runs shall be reconfigured to upgrade the existing heater, correct flange classifications, upgrade from Axial Flow Valve Regulators to modern fully supported regulators while also meeting the needs of the capacity load adjustments driven by Distribution Improvement Projects.

Solution

Proposed size: uncertain

As studies are completed realizing the effects Distribution Improvement Projects have on station load, piping shall be sized according to these requirements. Likely an 8-inch outlet header will be required following a 6-inch inlet header for the 60 psi pressure control runs. A heater and filter will also be incorporated. The header sizes for the medium pressure regulator runs will likely be 8-inch for the inlet header and 10-inch for the outlet header. The header sizes for the low pressure regulator runs will likely be 8-inch for the inlet header and 16-inch for the outlet header. The pressure control regulators and over pressure monitor devices will be fully supported models.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,291,000	0	0	$528,000	$324,000	$439,000	0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☑ Other: Work scope will be in conjunction with the environmental remediation work for the former MGP site. Piping layout, and scope of work may vary depending on the NYS DEC requirements for the property.

Primary Project Objective

Service

Benefits

Economic

- ☐ Reduced O&M
- ☑ Replacement
- ☐ Reinforcement
- ☐ Road Rebuild
- ☐ Other

Service

Reliability

- ☐ Radial feed
- ☐ Loop tie

Gas Safety

- ☐ Pipeline type
- ☐ Number of closed leaks in past 10 years
  - ☐ Number of hazardous (Class 1, 2A and 2)
- ☐ Number of active leaks
- ☐ Length of leak prone pipe eliminated
- ☐ Number of high pressure service replacement
- ☐ Number of isolated service replacement

Customer Impact

- [ ] Complaints
- [ ] Critical Customers
- [ ] Public Relations Considerations

Other

Risk Reduction

Safety

- [ ] Reduce risk of incident
- [x] Employee Safety
- [x] Public Safety
- [ ] Other Benefits

Compliance

- [ ] Central Hudson Inspections
- [ ] Elimination of Integrity Related Issues
- [ ] Other Program Type

Infrastructure

1969 Infrastructure year installed

Number of Services

- [ ] Indoor meter sets
- [ ] Metallic
- [ ] Obsolete/ Unserviceable Equipment
- [ ] Strategic Replacement
  - [ ] Flood zone
  - [ ] Main feeder route
  - [ ] Low pressure system
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

As the work scope of this project shall be done in conjunction with the former MGP Site Remediation and MP Line - TP Line interconnect adjustment. Station layout and construction sequence will be analyzed to minimize any service interruption to the PN Line.

Decision criteria for alternative selection

Budget Submittal Form for Gas Projects

Project Name: Leak Prone Pipe Replacement Projects

Form submitted by: K. Reer

Recommended In-Service Year: 2017 to 2021

Budget Group: 25 - Distribution Improvements

Summary Category: Non-Discretionary

Investment Category: Compliance

Number of Customers Affected: 77,000

Description of Problem

Gas system: Low, Medium and High Pressure Systems -

Gas pressure: Various

Existing pipe size and material: Program applies to all Bare steel, wrought iron, and cast iron piping materials

Proposed length replacement: 14.0 Miles

Central Hudson has an inventory of approximately 220 miles of gas distribution pipe considered "leak prone". This piping has been identified the the most recent rate case as requiring replacement. The settlement order set aside funding per the following race case order excerpt:

"The Company agrees to capital expenditures for the replacement or elimination of Leak Prone Pipe at a cost of $1.4 million per mile for 2016; $1.5 million per mile for 2017; and $1.6 million per mile for 2018. The Company further agrees to the following targets for the replacement or elimination of Leak Prone Pipe: a) 13 miles for 2016; b) 14 miles for 2017; and c) 15 miles for 2018. The Company shall maintain the 2018 pipe target until such time as it is changed by the Commission."

Applies to Funding Account 2-2580-00-YY

Solution

Proposed size: This funding project is for Neighborhood LPP Project specific work orders.

2017: BN Line Replacement: $4,805 (k), Cornwall - Faculty Row: $867, Bement Avenue: $2,515, Fullerton to Robinson; $3,137, Jefferson Heights: $1,845.

Projects for years 2018 to 2021 have been tentatively identified and required funding detail provided in the spreadsheet.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$107,517,000	$13,169,000	$21,137,000	$21,607,000	$25,494,000	$26,110,000	$323,517,000
Expense	$3,250,000	$750,000	$750,000	$750,000	$750,000	$750,000	$7,200,000

Cost Risks

☐ Environmental

☐ Timing/Permitting

☐ Manpower

☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

☐ Reduced O&M

☑ Replacement — Per rate case orders, elimination of risk and reduction of operating expense

☐ Reinforcement

☐ Road Rebuild

☐ Other

Service

Reliability

☐ Radial feed

☐ Loop tie

Gas Safety

D	Pipeline type
N/A	Number of closed leaks in past 10 years
N/A	Number of hazardous (Class 1, 2A and 2)
100+	Number of active leaks
14.0	Length of leak prone pipe eliminated
0	Number of high pressure service replacement
	Number of isolated service replacement

Customer Impact

- [ ] Complaints
- [ ] Critical Customers
- [ ] Public Relations Considerations

Other

Risk Reduction

Safety

- [x] Reduce risk of incident
- [ ] Employee Safety
- [x] Public Safety
- [ ] Other Benefits

Compliance

- [ ] Central Hudson Inspections
- [x] Elimination of Integrity Related Issues
- [ ] Other Program Type

Infrastructure

1875 + Infrastructure year installed

1000/yr Number of Services

  - [ ] Indoor meter sets
  - [x] Metallic

- [ ] Obsolete/ Unserviceable Equipment
- [ ] Strategic Replacement
  - [ ] Flood zone
  - [x] Main feeder route
  - [x] Low pressure system
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Gas Projects

Project Name: Service Replacement and Minor Projects

Form submitted by: K. Reer

Recommended In-Service Year: 2017 to 2021

Budget Group: 25 - Distribution Improvements

Summary Category: Non-Discretionary

Investment Category: Compliance

Number of Customers Affected: 77,000

Description of Problem

Gas system: Low, Medium and High Pressure Systems -

Gas pressure: Various

Existing pipe size and material: Funding program is for minor main projects and service replacements system-wide

Proposed length replacement: N/A

Central Hudson has approximately 60,000 gas service lines and 1250 miles of gas distribution pipe. Minor property unit replacement projects for mains and service line replacements are performed as a normal part of operations. Significant numbers of service lines are replaced as an integral part of the LPP replacement program, the requirements for which are Set forth in the following excerpt.

"The Company agrees to capital expenditures for the replacement or elimination of Leak Prone Pipe at a cost of $1.4 million per mile for 2016; $1.5 million per mile for 2017; and $1.6 million per mile for 2018. The Company further agrees to the following targets for the replacement or elimination of Leak Prone Pipe: a) 13 miles for 2016; b) 14 miles for 2017; and c) 15 miles for 2018. The Company shall maintain the 2018 pipe target until such time as it is changed by the Commission."

Solution

Proposed size: This funding project is for Blankets and Service Replacement Limited Terms.

2017: Service replacements - normal operational needs: $1,435, Service replacements - associated with pipeline replacement work (LPP): $3,264, Service replacements - isolated steel services; $538, Blanket work orders - minor units; $524. Total 2017 funding; $5,761.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$35,407,000	$5,761,000	$7,782,000	$7,292,000	$7,292,000	$7280,000	$73,000,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective

Risk Reduction

Benefits

Economic

- ☑ Reduced O&M: New pipe reduces leak repair costs
- ☑ Replacement: Per rate case orders, elimination of risk and reduction of operating expense
- ☐ Reinforcement
- ☐ Road Rebuild
- ☐ Other

Service

Reliability

- ☐ Radial feed
- ☐ Loop tie

Gas Safety

D	Pipeline type
N/A	Number of closed leaks in past 10 years
N/A	Number of hazardous (Class 1, 2A and 2)
100+	Number of active leaks
	Length of leak prone pipe eliminated
	Number of high pressure service replacement
	Number of isolated service replacement

Customer Impact

- [ ] Complaints
- [ ] Critical Customers
- [ ] Public Relations Considerations

Other

Risk Reduction

Safety

- [x] Reduce risk of incident
- [ ] Employee Safety
- [x] Public Safety
- [ ] Other Benefits

Compliance

- [ ] Central Hudson Inspections
- [x] Elimination of Integrity Related Issues
- [ ] Other Program Type

Infrastructure

Infrastructure year installed

1000/yr Number of Services

- [ ] Indoor meter sets
- [x] Metallic

- [ ] Obsolete/ Unserviceable Equipment
- [ ] Strategic Replacement
  - [ ] Flood zone
  - [ ] Main feeder route
  - [ ] Low pressure system
- [ ] Other Program Type

Other

Move indoor service lines outdoors wherever possible, install EFVs on pounds pressure service lines, reduce or eliminate the approximately 17000 LPP services in inventory and reduce leak survey and repair costs, reduce risk, improve system capacity.

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

COMMON PROGRAM INDIVIDUAL PROJECT SUBMITTAL

Budget Submittal Form for Common Projects

Project Name: Distribution Management System Phase I and Phase II

Form submitted by: Christine Robertson & Erica Tyler

Budget Group: 4230 - EMS

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

Central Hudson does not currently have the capability to remotely monitor and control its electric distribution system from a central location under a single operating authority. This deficiency precludes the ability to implement applications such as VVO and FLISR. The same applies to the existing gas distribution system where the deficiency precludes the ability to implement pressure control alarming that could provide faster response to rising pressures during peak conditions.

DMS Phase II requires additional work tied to advanced applications and final acceptance payment for the DMS. This was separated out of the initial DMS project per accounting as it is expected that this will not be completed until after the system goes into production.

Solution

Central Hudson is installing a Distribution Management System (DMS) which 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. Additional electric applications including Switch Order Management, Volt Var Optimization (VVO) and Fault Location Isolation and Restoration (FLISR) are possible with this complex system. Central Hudson will also use the data acquisition and supervisory control capabilities of the new DMS to monitor and control its gas distribution system and improve the overall efficiency of its gas distribution operations. By allowing for remotely monitored and controlled system pressures, this reduces the risk of rising above MAOP and therefore reducing associated violation penalties.

The plan for the implementation of the DMS is staged based on opportunities at the several sections of the service territory. Implementation will be focused initially in Lower Hudson following the Distribution Automation and Network Strategy projects to get optimal benefits provided by implementing these applications.

Continuing work on the DMS applications in Phase II will lead up to the final acceptance payment of the DMS. This work includes fine tuning of Fault Location Isolation and Restorations (FLISR) and Volt Var Optimization (VVO) that is expected after system implementation and prior to final acceptance of the system.
This project is consistent with the Grid Modenization Road-map.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Definitive Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,278,000	$1,278,000					
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower: Resource availability due to additional work load and projects.
- ☑ Other: Quality risk due to inaccurate and/or missing GIS data for the Network Model. Communication Risk due to cultural differences, lack of feedback, and\or slow response.

Primary Project Objective: Service

Benefits:

Economic

- ☐ Reduced O&M
- ☑ Reduced Customer Bill: Volt-Var Optimization application to achieve customer energy reduction
- ☑ Other: Reductions in customer outages as FLISR is implemented.

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☑ Other Program Type: Installation of new Hardware

Other

The DMS has five separate environments: Primary Control Center, Backup Control Center, Quality Assurance, Program Development and Operator Training Simulator. The Primary Control Center and Backup Control Center environments are highly reliable, fully redundant, scalable, and contain stringent security features to prevent access by unauthorized personnel.

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Central Hudson issued a request for proposals for the DMS in March 2015 to five vendors.

Decision criteria for alternative selection

The vendor and system evaluation process employed used a systematic top down approach starting with generalized functional requirements, a wide field of potential DMS vendors and based on sound criteria and team scoring, working through to a final selection. In conclusion, the Schneider ADMS solution was the appropriate choice for CHG&E.

Budget Submittal Form for Common Projects

Project Name: EMS Software Upgrade (Non-JUMP)

Form submitted by: Erica Tyler

Budget Group: 4230 - EMS

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

To maintain reliable operations of the Energy Management System (EMS) by upgrade existing aging GE PowerOn Reliance EMS hardware and software or replace existing aging GE system with a new system vendor.

Solution

This is a placeholder for the next required upgrade of the existing EMS system. Decision is dependent upon the direction of the EMS software now that the GE/Alstom merger is complete. Evaluation of possible EMS systems will be completed in 2020 with the system updated or new EMS implemented in 2021.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$4,542,000				$109,000	$4,434,000	
Expense							

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [ ] Manpower
- [x] Other: Depending on the reliability and functionality of the future hybrid GE/Alstom system, CH may choose to move forward with an EMS system replacement. This could impact cost of the project.

Primary Project Objective: Service

Benefits:

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [ ] Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Code Requirement/PSC
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ___ years
- [ ] Failure Rates
- [ ] Obsolete/Unserviceable Equipment
- [ ] Condition
- [ ] Strategic Replacement
- [ ] Other Program Type

Other

Provide a reliable Energy Management System for operations to monitor and operate the Electric and Gas Transmission systems and maintain strict compliance for system security.

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

People. Power. Possibilities. Central Hudson A FORTIS COMPANY

Budget Submittal Form for Common Projects

Project Name: EMS/DMS - Bldg 810 Redesign

Form submitted by: Erica Tyler

Budget Group: 4230 - EMS

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

The Distribution Management System will require a 24/7 Control Operations Center within a secured Physical Security Perimeter. Additionally, current and future staffing levels has exceeded the available work space within the existing secured area that is necessary for these control systems.

Solution

A partial and tentative work order exists for this project and Central Hudson is currently working with a consultant to begin preliminary discussions of this future control center. In 2017 this work will continue with an architect to determine best configuration and begin determination of required budget for the project.

These conceptual place holders were developed using general cost estimates and will require further evaluation.

The following projects are as a result of the redesign of the existing Bldg 810

DMS - DSO work area Bldg 810 S1 - New space for Distribution System Operators
EMS PCC Map-board Replacement (Video Wall) - Replacement of Aging Tile Map-board
EMS DTS Video Wall/Blackboard Software - Operator Training Enhancements - Training enhancement

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	TBD	$357,000	$1,562,000	TBD			
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☑ Other: This work is subject to coordination with system operations.

Primary Project Objective: Service

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☑ Other: Increased situational awareness and coordination between Transmission and Distribution System Operators.

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Analysis is currently being conducted with Bilfinger Mauell.

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Bill Redesign - OT Streamserve

Form submitted by: Surekha Jadhav

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Infrastructure

Description of Problem

Current bill is limited in options to display additional info that customers are requesting.

Solution

Redesign the bill using s/w - the redesigned bill could be given to Kubra or any other print vendor for the paper mailings. Otherwise, based on the need to improve the overall look and flow of the bill coupled with new business models that translate to displaying new information on the bill. Evaluation will be performed against other possible alternatives includinng leveraging Kubra to do the bill redesign.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,530,000	0	$535,000	$658,000	$167,000	$172,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Economic

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Business Intelligence (Cognos)

Form submitted by: Vicki Wheeler

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

The BI program was set up about 5 years ago mainly to address the data silo'd in the mainframe and also provide a solution for numerous reports that required various input sources and therefore were compiled manually into massive spreadsheets. It started out very small with only one full-time resource and an informal project management and request submission process. Now it is a formal program with a defined team and a formal project management process along with IT Steering Committee review and approval of the projects to be undertaken.

Solution

We purchased Cognos and a single Netezza box in December 2011. We hired a skilled contract resource (still on the team today) to start rolling out reports in 2012. Over time, we have built up the team to 3 contract resources and one full time CH PM and a part time Program Manager. in 2016 a second, DR/Test Netezza box was purchased. Many reports and dashboards have been implemented that provide the business areas with way more information than they have ever had before in terms of managing their work and getting visibility into patterns etc; we cannot keep up with the demand for more. The 5 year plan will be established later this year and include rolling some of the reporting up into corporate wide KPIs, pushing data out to mobile devices, creating a enterprise data framework, near real-time data updates and exploring predictive analytics.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$6,158,000	$848,000	$1,278,000	$1,315,000	$1,336,000	$1,380,000	TBD
Expense	$135,000	0	0	$45,000	$45,000	$45,000	TBD

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [x] Manpower: resource availability due to additional workload, changing priorities
- [x] Other: funding availability due to changing priorities/competing projects

Primary Project Objective: Service

Benefits:

Economic

- [x] Reduced O&M
- [ ] Reduced Customer Bill
- [x] Other: improved business processes, data management, visibility

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [x] Inspections: Projects implemented to monitor and manage gas inspections and
- [x] Code Requirement/PSC: Various projects to monitor & manage code & PSC requirements
- [x] Other Program Type: Various projects to monitor & manage operational compliance

Infrastructure

- [ ] Average Age of Infrastructure ____ years
- [ ] Failure Rates
- [ ] Obsolete/Unserviceable Equipment
- [ ] Condition
- [ ] Strategic Replacement
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: CIS / REV Modernization

Form submitted by: Vicki Wheeler

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

The CIS system is a custom built mainframe application that has been in service since 1984. It handles all of the possible interactions with a customer, not just billing, A/R, payments etc. As such it is the hub for just about all other applications in use, both mainframe and otherwise. It has grown in size and complexity over the years, and requires that changes be made by analysts with a significant number of years experience dealing with the system. Most of the original programmers are no longer with Central Hudson and the few remaining are at risk of retiring in the not too distant future. Making changes to CIS can be a long process, mostly in terms of testing through everything to make sure nothing was impacted downstream and unexpectedly.

REV (Reforming the Energy Vision) came into the picture recently, and is changing the utility business. There is more regulatory activity and requirements now than ever before This means the CIS has to change along with it. Due to the points mentioned above, that is not a very agile process and can take more time than we have. For example, our REV demonstration project by the end of 2016 is going to allow customers to choose to have a smart meter installed to provide them with detailed energy analytics. It seems very likely that complex, variable time of use billing rates could come shortly thereafter, in order to allow customers to take full advantage of their new smart meters. With all of the other regulatory requirements that have been stacked up waiting for us to roll out monthly billing on July 1, 2016, it could be some time before we are able to program in house any new complex billing rates.

Solution

For the last year or so, we have been bringing in various vendors to demo their solutions to help us investigate other CIS options that would allow us to increase our CIS billing flexibility:
1. a 'bolt on' rate engine that could calculate a new complex rate value for a meter reading and pass all the info back to the existing CIS. This could include a hosted solution by another Fortis utility.
2. a new billing CIS that could store account data, process all the billing functions for the accounts with those new rates and interface with the existing CIS to pass over any required data to book.
3. a new fully functional CIS that could take certain accounts and perform all CIS processes required for that account - in effect having 2 parallel CIS systems with the assumption that all accounts would eventually over time wind up in the new CIS. At which time the existing CIS would be sunsetted.

All of these options require significant interfacing with the existing CIS so it is still unclear at this point which solution could be the best fit for us. We continue to research and bring various vendors in to perform demo's of their products. At some point in the near future we will likely select one of the vendors to come in and perform a requirements gathering workshop with us to dive more in depth into what solution(s) have the most pros and the least cons for our situation.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$10,543,000	0	$1,758,000	$2,960,000	$2,951,000	$2,874,000	TBD
Expense							

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [x] Manpower: resource availability due to additional workload, changing priorities, retirements
- [x] Other: funding availability due to changing priorities/competing projects

Primary Project Objective: Service

Benefits:

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [x] Other: improved agility & time to market with regulatory and other billing modifications to 32 yr old CIS

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Code Requirement/PSC
- [x] Other Program Type: new rate design requirements from Public Service Commission

Infrastructure

- [ ] Average Age of Infrastructure ____ years
- [ ] Failure Rates
- [ ] Obsolete/Unserviceable Equipment
- [x] Condition: CIS custom software increasingly complex (mainframe HW it runs on very current)
- [x] Strategic Replacement: Aging CIS (1984) will need full/partial replacement eventually
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

so far: Itron's rate engine, Nexant's rate engine, Oracle's CC&B (multiple vendors), hosted solution with TEP, Hansen's Nirvanasoft, an SAP hosted solution (multiple vendors).
Still in progress.

Decision criteria for alternative selection

not laid out yet.

Budget Submittal Form for Common Projects

Project Name: ECM Program

Form submitted by: Vicki Wheeler

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Compliance

Description of Problem

Records Management for electronic documents and email had been a challenge for Central Hudson for some years due to the proliferation of documents on various share drives. In 2012 an RFP was sent out to various software vendors for ECM (Enterprise Content Management) solutions and OpenText was selected. The first phase, to roll out the software to all areas of the company, was guided by the following primary objectives:

1. Increase compliance with Central Hudson's Records Management policy, and
2. Improve the efficiency of the Company's execution of legal and regulatory holds and discovery.

Since then the ECM Program was set up to implement various basic functionality in different Phases, guided by the original objectives and a 5 year plan.

Solution

The ECM Program got underway in 2012 with the purchase of the OpenText Content Server software and related modules. Phases 1-3 were completed by December 31, 2015 to install the basic software, roll it out across the entire company and then start implementing various RM functionality as well as a major software upgrade. Phase IV is scheduled up through Dec 31, 2016. The ECM 5 year plan for 2017-2021 is currently being updated and will include another major software upgrade (to Content Suite 16), Email management, Dispositioning, Physical Objects, Groups & Permissions redesign, new functionality enhancements, etc. Each calendar year is typically another Phase, starting up with Phase V in 2017 (Year 1 below). Our strategic partner for ECM implementations is currently Cognizant, and we have no plans to replace them.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$4,635,00	$973,000	$1,358,000	$1,398,000	$445,000	$460,000	TBD
Expense	$135,000	0	0	$45,000	$45,000	$45,000	TBD

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower: resource availability due to additional workload, changing priorities
- ☑ Other: funding availability due to changing priorities/competing projects

Primary Project Objective: Risk Reduction

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☑ Other: Compliance; improved business processes

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☑ Other Program Type: Records Management

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Wiki/CentralHudson.com Redesign - WCM (Web Content Management)

Form submitted by: Vicki Wheeler

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

The implementation will provide the foundation to extending customer self-services, REV related services, and the REV driven customer portal:
o Provides the foundation for a scalable Wiki and Website
o Enables analytics across our web properties including customer self service
o Combined with Portal solution provides the platform for overall customer engagement growth

This project is directly related to enabling our group mission and supports our strategic imperatives - 'Enrich Customer & Business Partner Experience'.

Solution

Software solution purchased, preliminary planning done in 2015. Incorporates a redesign of the Wiki & CentralHudson.com leveraging a WEB Content Management solution that will provide a single development platform for both Web & Mobile enablement of the Wiki and CentralHudson.com. Intent is to drive personalization and provide the ability to have tracking of usage for channel analytics leveraged to see where employees & customers are transacting, dropping off, etc in order to identify where to focus and to ensure focused employee & customer adoption.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,770,000	0	$447,000	$603,000	$612,000	$287,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower: resource availability due to additional workload, changing priorities
- ☑ Other: funding availability due to changing priorities/competing projects

Primary Project Objective: Service

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☑ Other: improved web presence and visibility into customer/employee use of the web (and wiki)

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections: Projects implemented to monitor and manage gas inspections and
- ☐ Code Requirement/PSC: Various projects to monitor & manage code & PSC requirements
- ☐ Other Program Type: Various projects to monitor & manage operational compliance

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☑ Strategic Replacement: wiki is old; cumbersome; little external website analytics capability
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Increase Quality & Speed of Delivery of Application Testing

Form submitted by: Nicole Tancredi

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

As part of our goal to Increase Quality and Speed of Delivery of Application Testing, in late 2014, we procured HP Application Lifecycle Management (ALM) and Unified Functional Testing (UFT) software tools. These tools will enable us to reduce cycle time, provide consistency in testing and improve the overall end product quality. This project is a continuation of multi-phased application testing scripts, including automation of testing wherever applicable to reduce delivery cycle time and increase quality.

Solution

This level of spend will enable us to complete the scripting and automation, across the portfolio so that benefits can be realized.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$2,371,000	$159,000	$533,000	$548,000	$557,000	$575,000	TBD
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower: Resource Availability due to additional workload and projects.
- ☐ Other

Primary Project Objective: Service

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☑ Other Program Type: Foundational investment - effective, timely, and consistent app delivery.

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Digital Initiatives for Customer Engagement (DICE)

Form submitted by: Nicole Tancredi

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

This project is an initial investment to keep momentum going forward on digital initiatives as prioritized by the Digital Interactive Working Group. Ongoing investment in Digital (Web/Mobile/Social) customer enablement via extending self service capabilities, growing adoption of existing self service offerings, and aligning customer experience across all channels.

Solution

Expanded investment in digital will enable significant progress in development, translating to more customer engagement and satisfaction. Identification of potential productivity and/or hard savings through reductions in costs of other customer touchpoints will need to be estimated and measured.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$8,903,000	$127,000	$1,385,000	$2,412,000	$2,450,000	$2,530,000	TBD
Expense	$1,792,000	0	$118,000	$338,000	$558,000	$778,000	TBD

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower: Resource Availablity due to additional workload and projects.
- ☐ Other

Primary Project Objective: Service

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Business Agility with Enterprise SOA

Form submitted by: Nicole Tancredi

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

The Business Agility with an Enterprise SOA (Service Oriented Architecture) project will establish the foundation and tools to allow Central Hudson to be more agile in business process implementation by exposing core business logic and enabling the integration of key processes and information. SOA will be key to how fast we deliver, how we can leverage existing business functions across our portfolio, and to how we build the foundation for our future with mobile application solutions, cloud, and modernization vs. mass replacement. By making foundational investments, we will enable a flexible, scalable, secure, and reliable environment. This environment will be poised for current and anticipated information and technology demands across the enterprise coupled with a continued focus on digital (web, mobile, social, IVR), self-service oriented offerings to increase overall customer engagement.

Solution

In 2014, the software tools were purchased for Oracle SOA Suite and in 2015, together with our Strategic Partners, we installed and configured these tools. In 2016, we have deployed several services within SOA. The continued investment in SOA is a necessity in order to reduce complexity and costs. It will bring flexibility, interoperability, discoverability, reusability, and shared services, allowing us to leverage new and existing business logic via exposed services.

The investment aims to fully implement SOA across the entire application portfolio. In 2017, we continue with limited incremental progress. The investment in outer years allow us to increase progress through full implementation and continuous extension of portfolio.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Definitive Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$5,189,000	$254,000	$959,000	$1,261,000	$1,336,000	$1,380,000	$1,200,000
Expense							

Cost Risks

- ☐ Environmental
- ☑ Timing/Permitting: Timing with other ongoing IT projects
- ☑ Manpower: Resource Availability due to additional workload and projects.
- ☐ Other

Primary Project Objective: Service

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☑ Other Program Type: Strategic cornerstone of IT future projects & initiatives

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Mainframe Bundled Releases

Form submitted by: Nicole Tancredi

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

This project is to include bundling of minor changes on our mainframe systems into planned releases.

Solution

By bundling mainframe enhancements and improvements into a release, we are able to satisfy the business requirements with minimal impact on our production systems.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,467,000	$140,000	$320,000	$329,000	$334,000	$345,000	$350,000
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower: Resource Availablity due to additional workload and projects.
- ☐ Other

Primary Project Objective: Service

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☐ Strategic Replacement
- ☑ Other Program Type: Keeping systems current and up to date

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: TotalHR Replacement

Form submitted by: Nicole Tancredi

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Daily Operations

Description of Problem

TotalHR system has been upgraded and kept up to date but lacks features such as Performance Management, Employee Self Service portal, etc.

Solution

Replacement of TotalHR with a full featured solution will provide a more robust solution for the HR department and for employees.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$2,144000	0	$533,000	$767,000	$557,000	$287,000	0
Expense							

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [x] Manpower: Resource Availablity due to additional workload and projects.
- [ ] Other

Primary Project Objective: Service

Benefits:

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [ ] Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Code Requirement/PSC
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ___ years
- [ ] Failure Rates
- [ ] Obsolete/Unserviceable Equipment
- [ ] Condition
- [x] Strategic Replacement: Full featured HR system
- [x] Other Program Type: Keeping systems current and up to date

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Emergency Management Software Upgrade

Form submitted by: Surekha Jadhav

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Infrastructure

Description of Problem

The existing EMS s/w is approaching end of life phase where the vendor stop supporting the current version we're on. This will leave us with unsupported version of this critical s/w.

Solution

Various software upgrades, enhancements, and/or other software needs for this domain.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,327,000	0	$320,000	$329,000	$334,000	$345,000	TBD
Expense	$450,000	0	$45,000	$90,000	$135,000	$180,000	TBD

Cost Risks

- [ ] Environmental
- [ ] Timing/Permitting
- [ ] Manpower
- [ ] Other

Primary Project Objective: Service

Benefits:

Economic

- [ ] Reduced O&M
- [ ] Reduced Customer Bill
- [ ] Other

Risk Reduction

Safety

- [ ] Employee Safety
- [ ] Public Safety
- [ ] Other Program Type

Compliance

- [ ] Inspections
- [ ] Code Requirement/PSC
- [ ] Other Program Type

Infrastructure

- [ ] Average Age of Infrastructure ____ years
- [ ] Failure Rates
- [x] Obsolete/Unserviceable Equipment
- [ ] Condition
- [ ] Strategic Replacement
- [ ] Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Mobility Upgrade

Form submitted by: Surekha Jadhav

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Infrastructure

Description of Problem

Current mobility solution - h/w and s/w is aging. The s/w is approaching end of support phase leaving our critical resources with unsupported h/w and s/w.

Solution

Replace aging h/w and upgrade mobility (mobile workforce management) s/w to a more recent version of the s/w.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$1,570,000	$1,132,000	0	$438,000	0	0	0
Expense							

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☑ Other: Need to make sure the scope is controlled

Primary Project Objective: Economic

Benefits:

Economic

- ☑ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ___ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☑ Strategic Replacement
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

People. Power. Possibilities. Central Hudson A FORTIS COMPANY

Budget Submittal Form for Common Projects

Project Name: OMS Replacement

Form submitted by: Surekha Jadhav

Budget Group: 42 - Office Equipment

Summary Category: System Enhancement

Investment Category: Infrastructure

Description of Problem

Existing OMS s/w is approaching end of life phase leaving with an unsupported version of s/w.

Solution

Upgrade/replace OMS.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Conceptual Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$3,028,000	0	$1,164,000	$1,864,000	0	0	TBD
Expense	$1,421,000	0	$164,000	$419,000	$419,000	$419,000	TBD

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☐ Manpower
- ☐ Other

Primary Project Objective Economic

Benefits:

Economic

- ☐ Reduced O&M
- ☐ Reduced Customer Bill
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☐ Average Age of Infrastructure ____ years
- ☐ Failure Rates
- ☐ Obsolete/Unserviceable Equipment
- ☐ Condition
- ☑ Strategic Replacement
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study

Or

Project Alternatives Considered

Decision criteria for alternative selection

Budget Submittal Form for Common Projects

Project Name: Network Strategy Project

Form submitted by: Gary Schmid

Budget Group: 44 - Communication

Summary Category: System Enhancement

Investment Category: Infrastructure

Description of Problem

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 Public Service Commission on June 17, 2015. 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."

Solution

Network Strategy is a well-defined plan to leverage technologies for current and future communication needs. This is a long-term cost effective strategy to establish robust systems that provide reliable and secure communications that we can control, monitor and maintain 24x7x365. The scope of Network Strategy is communication with Central Hudson's fixed assets. Central Hudson's fixed assets included in the scope are corporate offices, gas gate and regulator stations, electric substations, electric system distribution automation equipment, mobile radio towers, and large customer meter installations. 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 distribution automation equipment, electric substations, gas regulator stations and large customer meter installations. Provision would be made available for a future Tier 3 low bandwidth network that could reach further into our territory for future needs.

Cost estimate (include AFUDC if appropriate):

Type of estimate: Preliminary Estimate

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Future
Capital	$16,786,000	$4,444,000	$4,742,000	$3,935,000	$2,556,000	$1,108,000	
Expense	$3,734,000	$472,000	$699,000	$837,000	$854,000	$872,000	TBD

Cost Risks

- ☐ Environmental
- ☐ Timing/Permitting
- ☑ Manpower — Limited manpower has slowed implementation, will increase as operational responsibilities grow
- ☐ Other

Primary Project Objective: Service

Benefits:

Economic

- ☑ Reduced O&M — operational costs are projected to decrease
- ☑ Reduced Customer Bill — This project supports the DMS/DA implementation and resulting reductions.
- ☐ Other

Risk Reduction

Safety

- ☐ Employee Safety
- ☐ Public Safety
- ☐ Other Program Type

Compliance

- ☐ Inspections
- ☐ Code Requirement/PSC
- ☐ Other Program Type

Infrastructure

- ☑ Average Age of Infrastructure 20 years
- ☑ Failure Rates — high failure rates with existing TELCO equipment
- ☑ Obsolete/Unserviceable Equipment — existing equipment obsolete/difficult to maintain
- ☐ Condition
- ☑ Strategic Replacement — New system will provide higher reliability,speed and security
- ☐ Other Program Type

Other

Alternatives Analysis

Reference Report or Study: 2015 Business as Usual vs DA/NS/DMS Cost Justification Analysis

Or

Project Alternatives Considered

Decision criteria for alternative selection

DETAIL SCHEDULES 2017-2021 FORECAST

	ELECTRIC ADDITIONS					W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Growth vs. Sustaining	Discretion Level	Investment Type	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Production	Hydro Minor Projects	G-Sustaining	Maintain Standards	Infrastructure	On-going	111	163	168	173	184	799
Production	GT Minor Projects	G-Sustaining	Maintain Standards	Infrastructure	On-going	111	163	168	173	184	799
Production	Sturgeon Pool Rotor Unit#2	G-Sustaining	Non Discretionary	Daily Operations	12/31/2017	703	0	0	0	0	703
Production	Sturgeon Pool Wet Section Unit#2	G-Sustaining	Non Discretionary	Daily Operations	12/31/2017	1080	0	0	0	0	1080
Production	Sturgeon Pool Wet Section Unit#3	G-Sustaining	Non Discretionary	Daily Operations	12/31/2018	0	1073	0	0	0	1073
Production	Dashvillel Rotor Unit#1	G-Sustaining	Non Discretionary	Daily Operations	12/31/2018	0	704	-6	0	0	698
Production	Dashvillel Rotor Unit#2	G-Sustaining	Non Discretionary	Daily Operations	12/31/2019	0	-6	727	0	0	720
Production	Sturgeon Pool Dam Camara System	G-Sustaining	Non Discretionary	Compliance	12/31/2019	0	0	224	0	0	224
Production	High Falls Facility Camara System	G-Sustaining	Non Discretionary	Daily Operations	12/31/2019	0	0	224	0	0	224
Production	Dashville Facility Camara Suystem	G-Sustaining	Non Discretionary	Daily Operations	12/31/2020	0	0	0	231	0	231
Production	Dashville Rubber Gate Replacement	G-Sustaining	Non Discretionary	Daily Operations	12/31/2020	0	0	56	929	0	985
Production	Hydro SCADA - New Com Link	G-Sustaining	Non Discretionary	Daily Operations	12/31/2020	0	0	0	139	0	139
Production	Dashville Remote Start	G-Sustaining	Non Discretionary	Compliance	12/31/2021	0	0	0	0	301	301
Production	Dashville Window Replacements	G-Sustaining	Maintain Standards	Infrastructure	12/31/2021	0	0	0	0	373	373
Production	Sturgeon Pool Window Replacements	G-Sustaining	Maintain Standards	Infrastructure	12/31/2021	0	0	0	0	469	469
Production	Subtotal - Electric Production					2,006	2,096	1,559	1,646	1,511	8,817
Transmission	NERC Alert (until June 2016) and HPR Combined	T-Sustaining	Non Discretionary	Compliance	On-going	2975	3557	3537	2118	2193	14381
Transmission	Transmission Minor Projects	T-Sustaining	Non Discretionary	Daily Operations	On-going	214	231	228	238	247	1158
Transmission	Network Strategy Projects	T-Sustaining	Maintain Standards	Infrastructure	On-going	0	0	3271	515	855	4640
Transmission	ROW Repair Project (Deficiencies)	T-Sustaining	Maintain Standards	Risk Reduction	On-going	496	508	758	1221	2850	5834
Transmission	ACSR Conductor Replacement Program, WH1 and WH2 Lines - Part 102C: 13.8 miles each	T-Sustaining	Maintain Standards	Infrastructure	06/01/2017	6943	0	0	0	0	6943
Transmission	G Line - North Section - 7.83 miles at 69 kV	T-Sustaining	Maintain Standards	Infrastructure	12/31/2017	6447	199	0	0	0	6646
Transmission	EF Line: 115kV Line Rebuild - East Fishkill -	T-Sustaining	Non Discretionary	Compliance	03/31/2019	99	1626	1567	0	0	3292
Transmission	CL Line: 69kV Line Rebuild - North Catskill - Cairo	T-Sustaining	Non Discretionary	Compliance	12/01/2019	496	8131	2021	0	0	10648
Transmission	P&MK Structure Replacement and Span Correction	T-Sustaining	Maintain Standards	Infrastructure	06/01/2020	347	1016	2527	2118	0	6008
Transmission	69kV G Line South - Knapps to North Chelsea - 102C	T-Sustaining	Maintain Standards	Infrastructure	12/01/2020	496	1118	5053	5295	0	11962
Transmission	TR Line Retirement	T-Sustaining	Maintain Standards	Infrastructure	12/01/2021	0	0	0	212	0	212
Transmission	SB Line: New 115kV Line - Hurley Ave. to Saugerties - Article VII: 11.11 miles	T-Sustaining	Maintain Standards	Infrastructure	12/01/2021	198	305	404	7837	7674	16419
Transmission	H Line: New 115kV Line - Saugerties to N.Catskill - Article VII: 12.25 miles	T-Sustaining	Maintain Standards	Infrastructure	12/01/2022	198	305	404	2542	7674	11124
Transmission	ACSR Conductor Replacement Program, A & C Lines - Article VII: 10.8 miles total	T-Sustaining	Maintain Standards	Infrastructure	06/30/2016	10	10	0	0	0	20
Transmission	Subtotal - Electric Transmission					18,920	17,006	19,771	22,096	21,494	99,287
Substation	Substation Minor Projects	D-Sustaining	Non Discretionary	Daily Operations	On-going	464	549	493	505	515	2526
Substation	ESP Infrastructure Repl. (relays, meters, data transfer equip, etc.).	D-Sustaining	Maintain Standards	Infrastructure	On-going	1691	3297	2022	2694	3236	12941
Substation	Generation 1 Relay Replacement Program	D-Sustaining	Maintain Standards	Infrastructure	On-going	782	203	0	0	0	985
Substation	RTU Replacement Program	D-Sustaining	Maintain Standards	Infrastructure	On-going	208	275	314	303	309	1408
Substation	Breaker Replacement Program (345kV)	D-Sustaining	Maintain Standards	Infrastructure	On-going	0	1520	740	0	0	2260
Substation	Breaker Replacement Program (115kV, 69kV, 13.8kV)	D-Sustaining	Maintain Standards	Infrastructure	On-going	1127	1325	789	707	1441	5390
Substation	Circuit Switcher Replacement Program	D-Sustaining	Maintain Standards	Infrastructure	On-going	261	0	0	0	0	261
Substation	345kV Switch Replacement Program	T-Sustaining	Maintain Standards	Infrastructure	On-going	489	608	592	606	617	2912
Substation	115kV Switch Replacement Program	D-Sustaining	Maintain Standards	Infrastructure	On-going	0	0	986	505	1544	3035
Substation	DA Program LTC Automation	D-Sustaining	System Enhancements	Customer Benefit	On-going	518	765	0	0	0	1283
Substation	Danskammer - Storm Hardening	T-Sustaining	System Enhancements	Risk Reduction	04/01/2017	1227	0	0	0	0	1227
Substation	Montgomery Street - Transformer Replacements	D-Sustaining	Maintain Standards	Infrastructure	06/30/2017	1466	0	0	0	0	1466
Substation	Todd Hill ("G" line 115kV - Add 115/69kV Tr and 69kV Bkr)	D-Sustaining	Maintain Standards	Infrastructure	12/31/2017	1466	0	0	0	0	1466
Substation	Union Ave. - Station Upgrade (New Switchgear)	D-Sustaining	Maintain Standards	Infrastructure	12/01/2017	2933	51	0	0	0	2983
Substation	Boulevard - Transformer Replacements	D-Sustaining	Maintain Standards	Infrastructure	12/01/2017	2102	51	0	0	0	2153

	ELECTRIC ADDITIONS					W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Growth vs. Sustaining	Discretion Level	Investment Type	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Substation	Reynolds Hill - Transformer Replacements	D-Sustaining	Maintain Standards	Infrastructure	12/01/2017	2444	557	0	0	0	3001
Substation	Woodstock - Switchgear Replacement	D-Sustaining	Maintain Standards	Infrastructure	06/01/2018	1955	1013	0	0	0	2968
Substation	Maybrook - Substation Upgrades (2 New 20 MVA 69-13.8kV Transformers)	D-Sustaining	Maintain Standards	Study Based Load G	12/30/2018	978	2533	0	0	0	3511
Substation	Knapps Corners - New Substation	D-Sustaining	Maintain Standards	Infrastructure	06/30/2019	1369	5573	2959	0	0	9901
Substation	North Chelsea - Single Phase Transformers Replacement	T-Sustaining	Maintain Standards	Infrastructure	06/30/2019	196	304	740	0	0	1239
Substation	Stanfordville - New Transformer (12MVA)	D-Sustaining	Maintain Standards	Infrastructure	06/30/2019	489	507	740	0	0	1735
Substation	Coxsackie - Transformer Replacement	D-Sustaining	Maintain Standards	Infrastructure	12/01/2019	147	507	789	51	0	1493
Substation	Kerhonkson Autos (formerly New Honk Falls Sub)	D-Sustaining	Maintain Standards	Infrastructure	03/31/2020	98	507	543	4042	0	5189
Substation	Montgomery - Transformer Replacement (Reuse one 12MVA from Maybrook)	D-Sustaining	Maintain Standards	Infrastructure	06/01/2020	244	760	740	1819	0	3563
Substation	Modena - Add 3rd Bkr to complete 115kV Ring Bus (see P&MK memo)	D-Sustaining	System Enhancements	Reliability	06/01/2020	0	203	395	1819	0	2416
Substation	Terminal upgrade work for 115kV (High Falls, Galeville, and Modena)	D-Sustaining	Maintain Standards	Infrastructure	12/01/2020	0	0	0	101	10	111
Substation	New Baltimore - Transformer Replacement (Reuse a bank tbd)	D-Sustaining	Maintain Standards	Infrastructure	12/01/2020	0	51	247	1010	51	1359
Substation	Greenfield Rd. - Substation Upgrade (Reuse Kerhonkson xfmr)	D-Sustaining	Maintain Standards	Infrastructure	12/01/2020	98	203	296	505	51	1153
Substation	Trap Rock - Tap Station	T-Sustaining	Maintain Standards	Infrastructure	12/31/2021	196	253	592	2021	2058	5120
Substation	Aged Transformer Replacements	D-Sustaining	Maintain Standards	Infrastructure	Future	0	0	1332	3031	5608	9971
Substation	Aged Switchgear Replacements	D-Sustaining	Maintain Standards	Infrastructure	Future	0	0	0	0	1544	1544
Substation	Honk Falls (Work assoc w/ WH line rebld) (see memo)	D-Sustaining	Maintain Standards	Infrastructure	12/01/2016	49	0	0	0	0	49
Substation	Sturgeon Pool	D-Sustaining	Maintain Standards	Infrastructure	12/01/2016	147	0	0	0	0	147
Substation	Subtotal - Electric Substation					23,142	21,613	15,306	19,720	16,984	96,766
New Business	New Business	D-Growth	Non Discretionary	New Business	On-going	1320	1419	1157	1251	1323	6471
New Business	New Business - Blanket OH	D-Growth	Non Discretionary	New Business	On-going	2338	2514	2049	2217	2344	11463
New Business	New Business - Blanket URD Combo	D-Growth	Non Discretionary	New Business	On-going	391	420	342	370	392	1915
New Business	New Business - Blanket URD	D-Growth	Non Discretionary	New Business	On-going	134	144	117	127	134	655
New Business	Subtotal - Electric New Business					4,183	4,497	3,666	3,966	4,193	20,504
Distribution	Distribution Improvement Blankets (15BL-01)	D-Sustaining	Non Discretionary	Daily Operations	On-going	6788	5955	7938	8093	8213	36987
Distribution	Relocation Blankets (15BL-02)	D-Sustaining	Non Discretionary	Compliance	On-going	201	207	205	209	212	1034
Distribution	Distribution Improvement Minors (1511-0X)	D-Sustaining	Non Discretionary	Infrastructure	On-going	603	621	615	627	636	3102
Distribution	Distribution Improvement Conversions (1521-0X)	D-Growth	Non Discretionary	Infrastructure	On-going	302	311	307	313	318	1551
Distribution	Road Rebuild Relocation Projects (1531-0X)	D-Sustaining	Non Discretionary	Compliance	On-going	503	518	512	522	530	2585
Distribution	Distribution Improvement (1551-0X) - Thermal / Voltage	D-Growth	Non Discretionary	Study Based Load G	On-going	2514	2537	2048	2089	2119	11308
Distribution	Distribution Improvement (1551-0X) - Reliability	D-Sustaining	Non Discretionary	Infrastructure	On-going	1458	2589	2561	2611	2649	11868
Distribution	CEMI/Worst Circuit Reliability Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	1619	1036	1024	1044	1060	5783
Distribution	Microgrids	D-Sustaining	Non Discretionary	Infrastructure	On-going	503	518	0	0	0	1021
Distribution	Cutout Replacement Program - lower threshold	D-Sustaining	Non Discretionary	Infrastructure	On-going	251	259	256	261	265	1292
Distribution	Distribution Improvement (1551-0X) - Operating/ Infrastructure	D-Sustaining	Non Discretionary	Infrastructure	On-going	2202	1869	4035	3603	3285	14995
Distribution	5kV Aerial Cable Replacement Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	251	311	461	470	477	1970
Distribution	Overhead Secondary Replacement Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	201	207	205	209	212	1034
Distribution	Distribution Pole Replacement Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	1810	2071	3073	4699	4769	16422
Distribution	Copper Wire Replacement Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	453	466	615	627	636	2796
Distribution	4800 V Conversion/Infrastructure Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	1234	1375	1536	3133	3179	10458
Distribution	14.4 kV Cable Rejuvination	D-Sustaining	Non Discretionary	Infrastructure	On-going	453	1036	1024	1305	1325	5142
Distribution	Oil Switch Replacement	D-Sustaining	Non Discretionary	Infrastructure	On-going	101	104	102	104	106	517
Distribution	CE Mesh / Protector Relays	D-Sustaining	Non Discretionary	Infrastructure	On-going	91	124	92	125	127	559
Distribution	Secondary Network Upgrade Program (All Districts)	D-Sustaining	Non Discretionary	Infrastructure	On-going	302	207	512	261	265	1547
Distribution	URD replacement	D-Sustaining	Non Discretionary	Infrastructure	On-going	0	497	0	1044	1060	2601
Distribution	Maybrook Substation Circuit Exits	D-Sustaining	Non Discretionary	Study Based Load G	06/01/2018	0	621	0	0	0	621

	ELECTRIC ADDITIONS					W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Growth vs. Sustaining	Discretion Level	Investment Type	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Distribution	Montgomery Substation Circuit Exits	D-Sustaining	Non Discretionary	Infrastructure	12/01/2019	0	0	2356	0	0	2356
Distribution	Boulevard Substation Integration	D-Sustaining	Non Discretionary	Infrastructure	12/01/2017	503	0	0	0	0	503
Distribution	Stanfordville Integration	D-Sustaining	Non Discretionary	Infrastructure	12/31/2018	0	621	0	0	0	621
Distribution	Greenfield Road Substation Integration	D-Sustaining	Non Discretionary	Infrastructure	12/01/2020	0	0	0	940	0	940
Distribution	Clinton Avenue Retirement	D-Sustaining	Non Discretionary	Infrastructure	12/01/2021	0	0	0	0	424	424
Distribution	Knapps Corners circuit exits	D-Sustaining	Non Discretionary	Infrastructure	06/30/2018	0	518	0	0	0	518
Distribution	Coxsackie Circuit exits	D-Sustaining	Non Discretionary	Infrastructure	12/31/2019	0	0	512	0	0	512
Distribution	New Baltimore Circuit exits	D-Sustaining	Non Discretionary	Study Based Load G	12/01/2020	0	0	0	313	0	313
Distribution	Greenfield Rd. - Substation Upgrade (Reuse Kerhonkson xfmr)+	D-Sustaining	Non Discretionary	Infrastructure	12/01/2017	256	0	0	0	0	256
Distribution	Distibution Automation - Major Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	7040	9320	12291	5221	530	34402
Distribution	Electronic Recloser Replacement Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	352	362	358	679	689	2441
Distribution	Distribution Automation - ALT Program	D-Sustaining	Non Discretionary	Infrastructure	On-going	175	119	256	261	0	811
Distribution	Subtotal - Electric Distribution Improvements					30,166	34,380	42,895	38,764	33,085	179,289
Transformer	Transformers - New Business	D-Sustaining	Non Discretionary	New Business	On-going	4367	4413	4720	4861	5063	23424
Transformer	Capacitors	D-Sustaining	Non Discretionary	Infrastructure	On-going	42	43	46	47	49	226
Transformer	Regulators	D-Sustaining	Non Discretionary	Infrastructure	On-going	210	235	264	297	310	1316
Transformer	Network Protectors	D-Sustaining	Non Discretionary	Infrastructure	On-going	530	595	668	751	782	3327
Transformer	Subtotal - Electric Transformers					5,148	5,286	5,698	5,957	6,203	28,292
Meter	X041A - Special Meter Installations	D-Sustaining	Non Discretionary	Compliance	On-going	153	156	159	163	166	798
Meter	X042A - Instrument Transformers	D-Sustaining	Non Discretionary	Compliance	On-going	266	272	278	284	290	1389
Meter	X043A - Electric Meters	D-Sustaining	Non Discretionary	New Business	On-going	2487	2540	2593	2648	2703	12971
Meter	Subtotal - Electric Meters					2,907	2,968	3,030	3,094	3,159	15,158
	Total - Electric					86,470	87,846	91,925	95,242	86,629	448,113

	ELECTRIC REMOVALS								
CAT.	Description	Discretion Level	Investment Type	2017	2018	2019	2020	2021	5-Year Total
Production	Hydro Minor Projects	Maintain Standards	Infrastructure	5	5	5	5	5	26
Production	GT Minor Projects	Maintain Standards	Infrastructure	5	5	5	5	0	21
Production	Sturgeon Pool Rotor Unit#2	Non Discretionary	Daily Operations	117	0	0	0	0	117
Production	Sturgeon Pool Wet Section Unit#2	Non Discretionary	Daily Operations	0	0	0	0	5	5
Production	Sturgeon Pool Wet Section Unit#3	Non Discretionary	Daily Operations	0	76	0	0	0	76
Production	Dashvillel Rotor Unit#1	Non Discretionary	Daily Operations	0	0	120	0	0	120
Production	Dashvillel Rotor Unit#2	Non Discretionary	Daily Operations	0	117	0	0	0	117
Production	Dashville Rubber Gate Replacement	Non Discretionary	Daily Operations	0	0	0	0	109	109
Production	Dashville Window Replacements	Maintain Standards	Infrastructure	0	0	0	0	224	224
Production	Sturgeon Pool Window Replacements	Maintain Standards	Infrastructure	0	0	0	0	280	280
Production	Subtotal - Electric Production			127	204	130	11	623	1,095
Transmission	NERC Alert (until June 2016) and HPR Combined	Non Discretionary	Compliance	510	204	208	213	217	1352
Transmission	Transmission Minor Projects	Non Discretionary	Daily Operations	47	47	48	49	50	241
Transmission	Network Strategy Projects	Maintain Standards	Infrastructure	0	0	259	149	85	493
Transmission	ACSR Conductor Replacement Program, WH1 and WH2 Lines - Part 102C: 13.8 miles each	Maintain Standards	Infrastructure	510	0	0	0	0	510
Transmission	G Line - North Section - 7.83 miles at 69 kV	Maintain Standards	Infrastructure	306	0	0	0	0	306
Transmission	EF Line: 115kV Line Rebuild - East Fishkill -	Non Discretionary	Compliance	0	153	156	0	0	309
Transmission	CL Line: 69kV Line Rebuild - North Catskill - Cairo	Non Discretionary	Compliance	0	816	208	0	0	1024
Transmission	Retirement of O & OB Line Section from Dashville Tap to Ohioville	Maintain Standards	Infrastructure	0	0	52	585	0	637
Transmission	P&MK Structure Replacement and Span Correction	Maintain Standards	Infrastructure	31	102	260	213	0	606
Transmission	69kV G Line South - Knapps to North Chelsea - 102C	Maintain Standards	Infrastructure	0	229	521	532	0	1282
Transmission	TR Line Retirement	Maintain Standards	Infrastructure	0	0	0	0	434	434
Transmission	SB Line: New 115kV Line - Hurley Ave. to Saugerties - Article VII: 11.11 miles	Maintain Standards	Infrastructure	0	0	0	851	760	1611
Transmission	H Line: New 115kV Line - Saugerties to N.Catskill - Article VII: 12.25 miles	Maintain Standards	Infrastructure	0	0	0	266	760	1026
Transmission	Subtotal - Electric Transmission			1,403	1,551	1,713	2,856	2,306	9,830
Substation	Substation Minor Projects	Non Discretionary	Daily Operations	194	194	198	202	369	1157
Substation	ESP Infrastructure Repl. (relays, meters, data transfer equip, etc.).	Maintain Standards	Infrastructure	176	355	208	292	342	1374
Substation	Generation 1 Relay Replacement Program	Maintain Standards	Infrastructure	82	0	0	0	0	82
Substation	RTU Replacement Program	Maintain Standards	Infrastructure	10	10	21	21	22	84
Substation	Breaker Replacement Program (345kV)	Maintain Standards	Infrastructure	0	168	78	0	0	246
Substation	Breaker Replacement Program (115kV, 69kV, 13.8kV)	Maintain Standards	Infrastructure	306	306	521	532	543	2207
Substation	Circuit Switcher Replacement Program	Maintain Standards	Infrastructure	25	0	0	0	0	25
Substation	345kV Switch Replacement Program	Maintain Standards	Infrastructure	51	51	52	53	0	207
Substation	115kV Switch Replacement Program	Maintain Standards	Infrastructure	51	51	52	53	54	262
Substation	DA Program LTC Automation	System Enhancements	Customer Benefit	76	0	0	0	0	76
Substation	Union Ave. - Station Upgrade (New Switchgear)	Maintain Standards	Infrastructure	255	0	0	0	0	255
Substation	Boulevard - Transformer Replacements	Maintain Standards	Infrastructure	153	0	0	0	0	153
Substation	Reynolds Hill - Transformer Replacements	Maintain Standards	Infrastructure	204	0	0	0	0	204
Substation	Woodstock - Switchgear Replacement	Maintain Standards	Infrastructure	102	51	0	0	0	153
Substation	Maybrook - Substation Upgrades (2 New 20 MVA 69-13.8kV Transformers)	Maintain Standards	Study Based Load	0	51	0	0	0	51
Substation	Knapps Corners - New Substation	Maintain Standards	Infrastructure	0	51	0	0	0	51
Substation	Knapps Corners - Retire Old Substation	Maintain Standards	Infrastructure	0	204	0	319	0	523
Substation	North Chelsea - Single Phase Transformers Replacement	Maintain Standards	Infrastructure	0	51	156	0	0	207
Substation	Stanfordville - New Transformer (12MVA)	Maintain Standards	Infrastructure	0	0	52	0	0	52
Substation	Coxsackie - Transformer Replacement	Maintain Standards	Infrastructure	0	0	52	0	0	52
Substation	Kerhonkson Autos (formerly New Honk Falls Sub)	Maintain Standards	Infrastructure	0	0	52	0	0	52
Substation	Montgomery - Transformer Replacement (Reuse one 12MVA from Maybrook)	Maintain Standards	Infrastructure	0	0	104	106	0	210
Substation	Modena - Add 3rd Bkr to complete 115kV Ring Bus (see P&MK memo)	System Enhancements	Reliability	0	0	0	21	0	21
Substation	Terminal upgrade work for 115kV (High Falls, Galeville, and Modena)	Maintain Standards	Infrastructure	0	0	0	27	0	27

Appendix H1 2017 – 2021 Capital Forecast Budget Package

	ELECTRIC REMOVALS								
CAT.	Description	Discretion Level	Investment Type	2017	2018	2019	2020	2021	5-Year Total
Substation	New Baltimore - Transformer Replacement (Reuse a bank tbd)	Maintain Standards	Infrastructure	0	0	26	106	0	132
Substation	Trap Rock - Tap Station	Maintain Standards	Infrastructure	204	0	0	0	0	204
Substation	Van Wagner - Retire Substation	0	0	51	0	0	0	0	51
Substation	McKinley Street - Retire Substation	0	0	51	0	0	0	0	51
Substation	Balmville - Retire Substation	0	0	51	0	0	0	0	51
Substation	Maryland Ave - Retire Substation	0	0	0	51	0	0	0	51
Substation	Beacon - Retire Substation	0	0	0	102	0	0	0	102
Substation	Conway - Retire Substation	0	0	0	0	52	53	0	105
Substation	Clinton Ave. - Retire Substation	0	0	0	0	0	0	54	54
Substation	Subtotal - Electric Substation			2,043	1,696	1,625	1,786	1,384	8,534
New Business	New Business	Non Discretionary	New Business	76	79	79	84	91	410
New Business	New Business - Blanket OH	Non Discretionary	New Business	71	74	74	78	85	381
New Business	New Business - Blanket URD Combo	Non Discretionary	New Business	15	16	16	17	18	81
New Business	New Business - Blanket URD	Non Discretionary	New Business	15	16	16	17	18	81
New Business	Subtotal - Electric New Business			177	184	184	196	212	953
Distribution	Distribution Improvement Blankets (15BL-01)	Non Discretionary	Daily Operations	271	178	265	265	325	1304
Distribution	Relocation Blankets (15BL-02)	Non Discretionary	Compliance	16	15	12	12	15	69
Distribution	Distribution Improvement Minors (1511-0X)	Non Discretionary	Infrastructure	47	44	36	36	44	207
Distribution	Distribution Improvement Conversions (1521-0X)	Non Discretionary	Infrastructure	24	22	18	18	22	103
Distribution	Road Rebuild Relocation Projects (1531-0X)	Non Discretionary	Compliance	40	37	30	30	37	172
Distribution	Distribution Improvement (1551-0X) - Thermal / Voltage	Non Discretionary	Study Based Load	198	179	119	119	146	762
Distribution	Distribution Improvement (1551-0X) - Reliability	Non Discretionary	Infrastructure	115	183	149	149	183	779
Distribution	CEMI/Worst Circuit Reliability Program	Non Discretionary	Infrastructure	127	73	60	60	73	393
Distribution	Microgrids	Non Discretionary	Infrastructure	40	37	0	0	0	76
Distribution	Cutout Replacement Program - lower threshold	Non Discretionary	Infrastructure	20	18	15	15	18	86
Distribution	Distribution Improvement (1551-0X) - Operating/ Infrastructure	Non Discretionary	Infrastructure	173	132	235	235	253	1028
Distribution	5kV Aerial Cable Replacement Program	Non Discretionary	Infrastructure	20	22	27	27	33	128
Distribution	Overhead Secondary Replacement Program	Non Discretionary	Infrastructure	16	15	12	12	15	69
Distribution	Distribution Pole Replacement Program	Non Discretionary	Infrastructure	142	146	179	179	329	976
Distribution	Copper Wire Replacement Program	Non Discretionary	Infrastructure	36	33	36	36	44	184
Distribution	4800 V Conversion/Infrastructure Program	Non Discretionary	Infrastructure	97	97	90	90	220	593
Distribution	14.4 kV Cable Rejuvination	Non Discretionary	Infrastructure	36	73	60	60	92	320
Distribution	Oil Switch Replacement	Non Discretionary	Infrastructure	8	7	6	6	7	34
Distribution	CE Mesh / Protector Relays	Non Discretionary	Infrastructure	7	9	5	5	9	35
Distribution	Secondary Network Upgrade Program (All Districts)	Non Discretionary	Infrastructure	24	15	30	30	18	116
Distribution	URD replacement	Non Discretionary	Infrastructure	0	35	0	0	73	108
Distribution	Maybrook Substation Circuit Exits	Non Discretionary	Study Based Load	0	44	0	0	0	44
Distribution	Montgomery Substation Circuit Exits	Non Discretionary	Infrastructure	0	0	137	137	0	275
Distribution	Boulevard Substation Integration	Non Discretionary	Infrastructure	40	0	0	0	0	40
Distribution	Stanfordville Integration	Non Discretionary	Infrastructure	0	44	0	0	0	44
Distribution	Greenfield Road Substation Integration	Non Discretionary	Infrastructure	0	0	0	0	66	66
Distribution	Knapps Corners circuit exits	Non Discretionary	Infrastructure	0	37	0	0	0	37
Distribution	Coxsackie Circuit exits	Non Discretionary	Infrastructure	0	0	30	30	0	60
Distribution	New Baltimore Circuit exits	Non Discretionary	Study Based Load	0	0	0	0	22	22
Distribution	G Line – Rebuild the 7023 circuit as an underbuild under the new G Line	Non Discretionary	Infrastructure	20	0	0	0	0	20
Distribution	Distibution Automation - Major Program	Non Discretionary	Infrastructure	553	658	717	717	366	3011
Distribution	Electronic Recloser Replacement Program	Non Discretionary	Infrastructure	28	26	21	21	48	143
Distribution	Distribution Automation - ALT Program	Non Discretionary	Infrastructure	14	8	15	15	18	70
Distribution	Subtotal - Electric Distribution Improvementa			2,109	2,184	2,303	2,303	2,475	11,374
Transformers	Transformers - New Business	Non Discretionary	New Business	311	311	331	359	398	1711
Transformers	Subtotal - Electric Transformers			311	311	331	359	398	1,711
Meters	X041A - Special Meter Installations	Non Discretionary	Compliance	297	297	309	329	357	1589
Meters	Subtotal - Electric Meters			297	297	309	329	357	1,589
	Total - Electric			6,468	6,428	6,595	7,840	7,756	35,086

	GAS ADDITIONS				W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Discretion Level	Investment Type	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Transmission	Prior Year Projects	Maintain_Standards	Infrastructure	12/01/2017	26	0	0	0	0	26
Transmission	Cathodic Test Stations	Maintain_Standards	Infrastructure	12/01/2017	87	0	0	0	0	87
Transmission	Pipeline Integrity	Maintain_Standards	Infrastructure	12/01/2017	117	0	0	0	0	117
Transmission	West Shore Control Valves Upgrades	System_Enhancements	Infrastructure	12/01/2017	101	0	0	0	0	101
Transmission	West Shore SCADA	System_Enhancements	Reliability	12/01/2017	101	0	0	0	0	101
Transmission	West Shore Over Pressure Protection	System_Enhancements	Risk Reduction	12/01/2017	432	0	0	0	0	432
Transmission	Remote Operated Valves	System_Enhancements	Risk Reduction	12/01/2017	152	0	0	0	0	152
Transmission	TP Line Reroute at Harriman Station	Maintain_Standards	Risk Reduction	12/01/2017	509	0	0	0	0	509
Transmission	Gate Station sourced from HVEX Design	System_Enhancements	Infrastructure	12/01/2017	153	0	0	0	0	153
Transmission	Prior Year Projects	Maintain_Standards	Infrastructure	12/01/2018	0	26	0	0	0	26
Transmission	Cathodic Test Stations	Maintain_Standards	Infrastructure	12/01/2018	0	37	0	0	0	37
Transmission	Pipeline Integrity	Maintain_Standards	Infrastructure	12/01/2018	0	209	0	0	0	209
Transmission	Poughkeepsie Receival Control Valve Rebuild with Over Pressure Protection	System_Enhancements	Risk Reduction	12/01/2018	0	1178	0	0	0	1178
Transmission	Poughkeepsie Receival SCADA and Battery Backup	System_Enhancements	Risk Reduction	12/01/2018	0	105	0	0	0	105
Transmission	Remote Operated Valves	System_Enhancements	Risk Reduction	12/01/2018	0	209	0	0	0	209
Transmission	Gate Station sourced from HVEX Bidding, Initial Construction	System_Enhancements	Infrastructure	12/01/2018	0	525	0	0	0	525
Transmission	Rose Place TP Line Replacement	Maintain_Standards	Infrastructure	12/01/2018	0	314	0	0	0	314
Transmission	Prior Year Projects	Maintain_Standards	Infrastructure	12/01/2019	0	0	27	0	0	27
Transmission	Cathodic Test Stations	Maintain_Standards	Infrastructure	12/01/2019	0	0	38	0	0	38
Transmission	Pipeline Integrity	Maintain_Standards	Infrastructure	12/01/2019	0	0	287	0	0	287
Transmission	Remote Operated Valves	Maintain_Standards	Infrastructure	12/01/2019	0	0	434	0	0	434
Transmission	Gate Station sourced from HVEX Construction	System_Enhancements	Infrastructure	12/01/2019	0	0	5423	0	0	5423
Transmission	Prior Year Projects	Maintain_Standards	Infrastructure	12/01/2020	0	0	0	28	0	28
Transmission	Cathodic Test Stations	Maintain_Standards	Infrastructure	12/01/2020	0	0	0	39	0	39
Transmission	Pipeline Integrity	Maintain_Standards	Infrastructure	12/01/2020	0	0	0	349	0	349
Transmission	Remote Operated Valves	Maintain_Standards	Infrastructure	12/01/2020	0	0	0	772	0	772
Transmission	Mahopac Heater	Maintain_Standards	Infrastructure	12/01/2020	0	0	0	496	0	496
Transmission	Prior Year Projects	Maintain_Standards	Infrastructure	12/01/2021	0	0	0	0	28	28
Transmission	Cathodic Test Stations	Maintain_Standards	Infrastructure	12/01/2021	0	0	0	0	40	40
Transmission	Pipeline Integrity	Maintain_Standards	Infrastructure	12/01/2021	0	0	0	0	413	413
Transmission	Remote Operated Valves	Maintain_Standards	Infrastructure	12/01/2021	0	0	0	0	907	907
Transmission	Tuxedo Gate Station Control Valve Sizing	Maintain_Standards	Infrastructure	12/01/2021	0	0	0	0	153	153
Transmission	Gas Chromatographs	Maintain_Standards	Infrastructure	12/01/2021	0	0	0	0	57	57
Transmission	Subtotal Tranmission				1,678	2,604	6,209	1,684	1,599	13,774
Regulator Stations	Pressure Chart Upgrades	Maintain_Standards	Infrastructure	01/01/2017	51	0	0	0	0	51
Regulator Stations	Station Pressure Stabilization	Maintain_Standards	Infrastructure	01/01/2017	142	0	0	0	0	142
Regulator Stations	Fullerton Regulator Station Rebuild	System_Enhancements	Infrastructure	01/01/2017	188	0	0	0	0	188
Regulator Stations	South Street Regulator Station Rebuild	System_Enhancements	Infrastructure	01/01/2017	284	0	0	0	0	284
Regulator Stations	South Clinton Street Property Purchase	System_Enhancements	Infrastructure	01/01/2017	101	0	0	0	0	101
Regulator Stations	First Street Regulator Station Property Purchase	System_Enhancements	Infrastructure	01/01/2017	101	0	0	0	0	101
Regulator Stations	Coxsackie Regulator Runs and Heater Rebuild	System_Enhancements	Infrastructure	01/01/2017	324	0	0	0	0	324
Regulator Stations	Prior Year Projects	Maintain_Standards	Infrastructure	01/17/2017	20	0	0	0	0	20
Regulator Stations	Pressure Chart Upgrades	Maintain_Standards	Infrastructure	01/01/2018	0	52	0	0	0	52
Regulator Stations	Station Pressure Stabilization	Maintain_Standards	Infrastructure	01/01/2018	0	104	0	0	0	104
Regulator Stations	Prior Year Projects	Maintain_Standards	Infrastructure	01/01/2018	0	21	0	0	0	21
Regulator Stations	South Clinton Street Regulator Station Rebuild	System_Enhancements	Infrastructure	01/01/2018	0	414	0	0	0	414
Regulator Stations	Pressure Chart Upgrades	Maintain_Standards	Infrastructure	01/01/2019	0	0	53	0	0	53
Regulator Stations	Station Pressure Stabilization	Maintain_Standards	Infrastructure	01/01/2019	0	0	212	0	0	212

	GAS ADDITIONS				W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Discretion Level	Investment Type	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Regulator Stations	Prior Year Projects	Maintain_Standards	Infrastructure	01/01/2019	0	0	21	0	0	21
Regulator Stations	Poughkeepsie Receival Rebuild 60 psig regulators/ heater/ filter	System_Enhancements	Infrastructure	01/01/2019	0	0	528	0	0	528
Regulator Stations	Regulator Station SCADA implemenation	System_Enhancements	Infrastructure	01/01/2019	0	0	211	0	0	211
Regulator Stations	First Street Regulator Station Rebuild	System_Enhancements	Infrastructure	01/01/2019	0	0	476	0	0	476
Regulator Stations	Pressure Chart Upgrades	Maintain_Standards	Infrastructure	01/01/2020	0	0	0	54	0	54
Regulator Stations	Station Pressure Stabilization	Maintain_Standards	Infrastructure	01/01/2020	0	0	0	216	0	216
Regulator Stations	Prior Year Projects	Maintain_Standards	Infrastructure	01/01/2020	0	0	0	22	0	22
Regulator Stations	Regulator Station SCADA implemenation	System_Enhancements	Infrastructure	01/01/2020	0	0	0	216	0	216
Regulator Stations	Union Ave. Regulator Station Rebuild	System_Enhancements	Infrastructure	01/01/2020	0	0	0	416	0	416
Regulator Stations	Catskill Heater Replacement	System_Enhancements	Infrastructure	01/01/2020	0	0	0	324	0	324
Regulator Stations	Poughkeepsie Receival Medium Pressure Rebuild	System_Enhancements	Infrastructure	01/01/2020	0	0	0	324	0	324
Regulator Stations	Pressure Chart Upgrades	Maintain_Standards	Infrastructure	01/01/2021	0	0	0	0	55	55
Regulator Stations	Station Pressure Stabilization	Maintain_Standards	Infrastructure	01/01/2021	0	0	0	0	220	220
Regulator Stations	KS-System Additional Feed, New Regulator Station Build	System_Enhancements	Infrastructure	01/01/2021	0	0	0	0	308	308
Regulator Stations	Regulator Station SCADA implemenation	System_Enhancements	Infrastructure	01/01/2021	0	0	0	0	220	220
Regulator Stations	Poughkeepsie Receival Low Pressure Rebuild	System_Enhancements	Infrastructure	01/01/2021	0	0	0	0	439	439
Regulator Stations	Highland Mills Heater	System_Enhancements	Infrastructure	01/01/2021	0	0	0	0	331	331
Regulator Stations	Prior Year Proects	Maintain_Standards	Infrastructure	01/01/2021	0	0	0	0	22	22
Regulator Stations	Subtotal Regulator Stations				1,212	590	1,502	1,571	1,596	6,471
New Business	Residential Conversion	System Enhancements	New Business	Multiple	8,319	8,531	8,447	8,656	8,853	42805
New Business	Commercial Conversion	System Enhancements	New Business	Multiple	2,017	2,068	2,048	2,098	2,146	10377
New Business	New Franchise / Large C&I Proj.	System Enhancements	New Business	Multiple	1,920	1,969	1,950	1,998	2,044	9882
New Business	Traditional NB Res/Comm	Non Discretionary	New Business	Multiple	1,819	1,866	1,847	1,893	1,936	9362
New Business	Subtotal New Business				14,075	14,434	14,293	14,645	14,980	72,427
Distribution	Corrosion Control - Emergent Projects	Maintain_Standards	Infrastructure	Multiple	133	138	159	162	166	759
Distribution	Unidentified Road Rebuild - Replacing Leak Prone Pipe	Maintain_Standards	Infrastructure	Multiple	461	472	793	811	830	3367
Distribution	Unidentified Road Rebuilds - Plastic or Protected Steel	Maintain_Standards	Infrastructure	Multiple	51	52	53	54	55	266
Distribution	Cast Iron Undermines	Non Discretionary	Compliance	Multiple	205	210	211	189	194	1009
Distribution	Unidentified Leaking Pipe Replacement	Maintain_Standards	Infrastructure	Multiple	179	184	793	811	830	2797
Distribution	Service Replacement Limited Term Work Orders - Emergent Work	Non Discretionary	Compliance	Multiple	1,435	1,364	1,374	1,405	1,329	6907
Distribution	Service Replacement Limited Terms - Associated w Identified LPP Projects	Non Discretionary	Compliance	Multiple	3,264	5,363	4,966	5,162	5,287	24042
Distribution	Replacements - Isolated Steel Services	Non Discretionary	Compliance	Multiple	538	525	423	216	111	1812
Distribution	Local Orders - Blankets - for replacement of LPP	Maintain_Standards	Infrastructure	Multiple	419	420	396	405.39	388	2028
Distribution	Local Orders - Blankets - for replacement of Plastic or Protected Steel	Maintain_Standards	Infrastructure	Multiple	105	111	132	135	166	649
Distribution	Mount Carmel and Delafield Neighborhood	Maintain_Standards	Infrastructure	2017	124	-	-	-	-	124
Distribution	North Water Street PN Line Replacement - POK	Maintain_Standards	Infrastructure	2017	-	881	-	-	-	881
Distribution	Uptown Kingston	Maintain_Standards	Infrastructure	2018	-	-	682	-	-	682
Distribution	Wappingers - PN Line	Maintain_Standards	Infrastructure	2019	-	-	2,643	-	-	2643
Distribution	PN - Near South Road	Maintain_Standards	Infrastructure	2020	-	-	-	2,703	-	2703
Distribution	PN - Next mile south	Maintain_Standards	Infrastructure	2021	-	-	-	-	2,768	2768
Distribution	Cornwall 2 Faculty Row/Academy	Maintain_Standards	Load Growth	2017	139	-	-	-	-	139
Distribution	Bement Avenue Neighborhood	Maintain_Standards	Load Growth	2017	275	-	-	-	-	275
Distribution	Fullerton to Robinson	Maintain_Standards	Load Growth	2017	268	-	-	-	-	268
Distribution	Roosevelt Park - Run 60 PSIG Feeder	Maintain_Standards	Load Growth	2017	615	-	-	-	-	615
Distribution	Jefferson Heights	Maintain_Standards	Load Growth	2017	395	-	-	-	-	395
Distribution	Arterial crossing - Pershing Avenue	Maintain_Standards	Load Growth	2017	307	-	-	-	-	307
Distribution	SM Line Carmel	Maintain_Standards	Load Growth	2017	512	4,721	-	-	-	5233
Distribution	South Wall Street	Maintain_Standards	Load Growth	2018	-	236	-	-	-	236

Appendix H1 2017 – 2021 Capital Forecast Budget Package

	GAS ADDITIONS				W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Discretion Level	Investment Type	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Distribution	Mansion Violet Hamilton	Maintain_Standards	Load Growth	2018	-	824	-	-	-	824
Distribution	North Clanceyville	Maintain_Standards	Load Growth	2018	-	169	-	-	-	169
Distribution	Uptown Kingston	Maintain_Standards	Load Growth	2019	-	-	201	-	-	201
Distribution	Fullerton to West St Newburgh	Maintain_Standards	Load Growth	2019	-	-	174	-	-	174
Distribution	Kings Street	Maintain_Standards	Load Growth	2019	-	-	296	-	-	296
Distribution	TV Line - Station Outlet	Maintain_Standards	Load Growth	2019	-	-	1,586	-	-	1586
Distribution	Cedar Avenue Neighborhood	Maintain_Standards	Load Growth	2020	-	-	-	496	-	496
Distribution	Mailer and Main - Cornwall	Maintain_Standards	Load Growth	2020	-	-	-	296	-	296
Distribution	Main Mill Bridge	Maintain_Standards	Load Growth	2020	-	-	-	235	-	235
Distribution	Fairview and Quarry	Maintain_Standards	Load Growth	2020	-	-	-	41	-	41
Distribution	Randolph	Maintain_Standards	Load Growth	2020	-	-	-	173	-	173
Distribution	Place Holder	Maintain_Standards	Load Growth	2021	-	-	-	-	1,246	1246
Distribution	Deleware Avenue Neighborhood Project	Non Discretionary	Compliance	2017	2,541	-	-	-	-	2541
Distribution	Mount Carmel and Delafield Neighborhood	Non Discretionary	Compliance	2017	2,833	-	-	-	-	2833
Distribution	BN Line Replacement	Non Discretionary	Compliance	2017	4,805	-	-	-	-	4805
Distribution	Cornwall 2 Faculty Row/Academy	Non Discretionary	Compliance	2017	867	-	-	-	-	867
Distribution	Bement Avenue Neighborhood	Non Discretionary	Compliance	2017	2,515	-	-	-	-	2515
Distribution	Fullerton to Robinson	Non Discretionary	Compliance	2017	3,137	-	-	-	-	3137
Distribution	Jefferson Heights	Non Discretionary	Compliance	2017	1,845	-	-	-	-	1845
Distribution	Roosevelt Park	Non Discretionary	Compliance	2018	-	4,935	-	-	-	4935
Distribution	South Wall Street	Non Discretionary	Compliance	2018	-	2,958	-	-	-	2958
Distribution	Mansion Violet Hamilton	Non Discretionary	Compliance	2018	-	3,128	-	-	-	3128
Distribution	Kingston and Wilbur Backyards	Non Discretionary	Compliance	2018	-	3,342	-	-	-	3342
Distribution	Cornwall 3 - Hasbrouck and Union Area	Non Discretionary	Compliance	2018	-	2,617	-	-	-	2617
Distribution	North Clanceyville	Non Discretionary	Compliance	2018	-	2,144	-	-	-	2144
Distribution	East Newburgh Broadway to Third	Non Discretionary	Compliance	2018	-	2,014	-	-	-	2014
Distribution	Albany Foxhall Manor Madison	Non Discretionary	Compliance	2019	-	-	2,420	-	-	2420
Distribution	West Saugerties	Non Discretionary	Compliance	2019	-	-	4,421	-	-	4421
Distribution	Uptown Kingston	Non Discretionary	Compliance	2019	-	-	1,542	-	-	1542
Distribution	Kings Street	Non Discretionary	Compliance	2019	-	-	4,226	-	-	4226
Distribution	SW Poughkeepsie Hooker/Hamilton	Non Discretionary	Compliance	2019	-	-	3,154	-	-	3154
Distribution	Fullerton to West St - Newburgh	Non Discretionary	Compliance	2019	-	-	3,459	-	-	3459
Distribution	Cornwall 4 - Main and Hudson	Non Discretionary	Compliance	2019	-	-	2,384	-	-	2384
Distribution	Clifton East Chester Neighborhood	Non Discretionary	Compliance	2020	-	-	-	3,054	-	3054
Distribution	Fairview/Quarry Street Area	Non Discretionary	Compliance	2020	-	-	-	3,154	-	3154
Distribution	East Saugerties	Non Discretionary	Compliance	2020	-	-	-	3,362	-	3362
Distribution	Randolph Ferris Beechwood Neighborhood	Non Discretionary	Compliance	2020	-	-	-	3,446	-	3446
Distribution	Main Mill Bridge	Non Discretionary	Compliance	2020	-	-	-	3,268	-	3268
Distribution	Cedar Avenue Neighborhood	Non Discretionary	Compliance	2020	-	-	-	2,185	-	2185
Distribution	Cornwall - Mailer Ave/Mill Street	Non Discretionary	Compliance	2020	-	-	-	2,353	-	2353
Distribution	West Newburgh Area	Non Discretionary	Compliance	2020	-	-	-	4,672	-	4672
Distribution	Place Holder - 2021 Neighborhood Projects	Non Discretionary	Compliance	2021	-	-	-	-	26,110	26110
Distribution	Subtotal Distribution Improvements				27,971	36,806	36,489	38,788	39,480	179,534
Meters	X081A - Gas Meters	Non Discretionary	New Business		1780	1817	1855	1894	1934	9281
Meters	X084A - Special Meter Installation	Non Discretionary	New Business		490	500	510	521	532	2553
Meters	Subtotall Gas Meters				2,269	2,317	2,366	2,415	2,466	11,834
	Total Gas				47,205	56,752	60,858	59,103	60,121	284,040

	COMMON ADDITIONS			W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Discretion Level	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Land & Buildings	Daily Operations - Electric	System Enhancements	on going	26	52	54	55	57	243
Land & Buildings	Daily Operations - Flooring	Maintain Standards	on going	26	52	54	55	57	243
Land & Buildings	Daily Operations - HVAC	Maintain Standards	on going	26	52	54	55	57	243
Land & Buildings	Daily Operations - Unidentified	System Enhancements	on going	256	521	536	553	567	2434
Land & Buildings	Repave Parking Lot (Multi Year) (Kingston)	System Enhancements	on going	154	260	268	277	284	1243
Land & Buildings	Repave Parking Lots (Multi Year)	Maintain Standards	on going	154	260	268	277	284	1243
Land & Buildings	Building 800 Window Replacement - 1st Floor	Maintain Standards	2017	390	0	0	0	0	390
Land & Buildings	Building 801 - VVT Automation	Enhancements	2017	82	0	0	0	0	82
Land & Buildings	Building 810 Control Center Replace Heat Pumps w/ RTU's	Enhancements	2017	82	0	0	0	0	82
Land & Buildings	Building 802 - VVT Automation	Enhancements	2017	82	0	0	0	0	82
Land & Buildings	Building 807 - Replace Roof - Auditorium	Maintain Standards	2017	103	0	0	0	0	103
Land & Buildings	Building 804 - Renovate OMS Office Area	Maintain Standards	2017	51	0	0	0	0	51
Land & Buildings	Install Pole Racks	Enhancements	2017	103	0	0	0	0	103
Land & Buildings	Enlarge Loading Dock / Install Leveler (Ellenville)	Enhancements	2017	51	0	0	0	0	51
Land & Buildings	Pole Barn along South side of property (40x80x15)(Ellenvill	Enhancements	2017	152	0	0	0	0	152
Land & Buildings	Install New sand/salt sheds (Fishkill)	Enhancements	2017	78	0	0	0	0	78
Land & Buildings	Replace Back Staircases (Fishkill)	Maintain Standards	2017	51	0	0	0	0	51
Land & Buildings	Relocate/Install new pole pile (Fishkill)	Enhancements	2017	41	0	0	0	0	41
Land & Buildings	Replace Pole Piles (Newburgh)	Maintain Standards	2017	41	0	0	0	0	41
Land & Buildings	Install Pole Barn - NE Side of Building	Enhancements	2017	152	0	0	0	0	152
Land & Buildings	Build Out Office Space Kingston)	Maintain Standards	2017	308	0	0	0	0	308
Land & Buildings	Enlarge Transformer Dock & Replace Roof (Ellenville)	Enhancements	2018	0	32	0	0	0	32
Land & Buildings	Replace Roof - 1/3 Back Building	Maintain Standards	2018	0	521	0	0	0	521
Land & Buildings	Build Pole Barn for Transformers (Newburgh)	Enhancements	2018	0	125	0	0	0	125
Land & Buildings	Window Replacements - Front and North Side	Enhancements	2018	0	135	0	0	0	135
Land & Buildings	Improve Drainage around Newburgh Building	Enhancements	2018	0	156	0	0	0	156
Land & Buildings	Building 802 - Replace Roof	Maintain Standards	2018	0	83	0	0	0	83
Land & Buildings	Replace Street Light Poles	Maintain Standards	2018	0	60	0	0	0	60
Land & Buildings	South Road Complex - Install New Curbing	Enhancements	2018	0	60	0	0	0	60
Land & Buildings	Building 806 Resurface and Restripe Garage Floors	Maintain Standards	2018	0	94	0	0	0	94
Land & Buildings	Building 808 - Replace Windows	Enhancements	2018	0	104	0	0	0	104
Land & Buildings	Building 807 - Replace Windows	Enhancements	2018	0	156	0	0	0	156
Land & Buildings	Build Additional Office/Cubical Space	Enhancements	2018	0	260	0	0	0	260
Land & Buildings	Building 807 Relocate Transformers and Replace Steps	Maintain Standards	2019	0	0	322	0	0	322
Land & Buildings	Repave Back Parking Lot near Line Garage (Newburgh)	Maintain Standards	2019	0	0	86	0	0	86
Land & Buildings	Renovate Cottage for Additional Meeting Space	Enhancements	2019	0	0	161	0	0	161
Land & Buildings	Paving front of Lodge and roadway into site	Maintain Standards	2019	0	0	161	0	0	161
Land & Buildings	Replace Ice Machine	Maintain Standards	2019	0	0	5	0	0	5
Land & Buildings	Building 802 - Install Awning @ Drafting Entrance	Enhancements	2019	0	0	11	0	0	11
Land & Buildings	Building 807 - Customer Service Entrance Awning	Enhancements	2019	0	0	11	0	0	11
Land & Buildings	Building 810 - Install Awning @ Back Entrance	Enhancements	2019	0	0	11	0	0	11

	COMMON ADDITIONS			W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Discretion Level	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Land & Buildings	Building 808 Fluid Containment Mechanics Garage	Enhancements	2019	0	0	27	0	0	27
Land & Buildings	Building 801 Replace 50 Ton RTU	Enhancements	2019	0	0	139	0	0	139
Land & Buildings	Building 803 - Call Center Break Room Renovation	Enhancements	2019	0	0	54	0	0	54
Land & Buildings	Building 810 - Replace Roof	Maintain Standards	2019	0	0	268	0	0	268
Land & Buildings	Replace Roof - 1/3 Back Building	Maintain Standards	2019	0	0	429	0	0	429
Land & Buildings	Remove Steam / Water Pipes - Main Building (Asbestos)	Enhancements	2019	0	0	86	0	0	86
Land & Buildings	Install Roof over wire storage area (Fishkill)	Enhancements	2019	0	0	129	0	0	129
Land & Buildings	Transformer Shop Upgrade	Enhancements	2019	0	0	161	0	0	161
Land & Buildings	Replace Storm Drains	Maintain Standards	2019	0	0	54	0	0	54
Land & Buildings	Pedestrian Entrance Doors - Main Building & Garage	Maintain Standards	2019	0	0	38	0	0	38
Land & Buildings	Swing Arm for Transformer Platform (Greenville)	Enhancements	2019	0	0	43	0	0	43
Land & Buildings	Pave Parking Lot	Maintain Standards	2020	0	0	0	166	0	166
Land & Buildings	Install Generator at Storeroom	Enhancements	2020	0	0	0	55	0	55
Land & Buildings	Lighting Upgrade - Storeroom	Enhancements	2020	0	0	0	44	0	44
Land & Buildings	Replace Exhaust Fan in lineman's garage	Maintain Standards	2020	0	0	0	28	0	28
Land & Buildings	Replace Pavillion & Bath House Roof	Maintain Standards	2020	0	0	0	77	0	77
Land & Buildings	Controls System HVAC	Enhancements	2020	0	0	0	111	0	111
Land & Buildings	Lighting Upgrade - Storeroom	Enhancements	2020	0	0	0	44	0	44
Land & Buildings	Replace/Upgrade 803 RTU's	Maintain Standards	2020	0	0	0	221	0	221
Land & Buildings	Replace Training Room HVAC Unit hook up to new controls	Maintain Standards	2020	0	0	0	66	0	66
Land & Buildings	Pave Pole & Equipment area	Maintain Standards	2020	0	0	0	89	0	89
Land & Buildings	Replace Carpeting - Call Centers	Maintain Standards	2020	0	0	0	83	0	83
Land & Buildings	Install fire protection under raised floor - Bldg 810	Enhancements	2020	0	0	0	102	0	102
Land & Buildings	Bldg 807 - Dispatch Center Renovation	Enhancements	2020	0	0	0	83	0	83
Land & Buildings	Upgrade Lighting - Mechanics Garage	Enhancements	2020	0	0	0	11	0	11
Land & Buildings	Install New signs	Maintain Standards	2020	0	0	0	11	0	11
Land & Buildings	Replace Roof - 1/3 Back Building	Maintain Standards	2020	0	0	0	443	0	443
Land & Buildings	Install fire protection @ EC Lineman's, Transformer, Storer	Enhancements	2020	0	0	0	199	0	199
Land & Buildings	Controls System HVAC	Enhancements	2021	0	0	0	0	340	340
Land & Buildings	Resurface Gas Garage Floors - Linemen's Garage	Maintain Standards	2021	0	0	0	0	57	57
Land & Buildings	Resurface Gas Garage Floors - Gas Garage	Maintain Standards	2021	0	0	0	0	57	57
Land & Buildings	Building 803 - Replace Asbestos Tile	Enhancements	2021	0	0	0	0	57	57
Land & Buildings	Building 800 - Create Women's Rest Room 1st Floor	Enhancements	2021	0	0	0	0	68	68
Land & Buildings	Building 805 Resurface and Restripe Garage Floors	Maintain Standards	2021	0	0	0	0	68	68
Land & Buildings	Building 808 - Roof Replacment	Enhancements	2021	0	0	0	0	284	284
Land & Buildings	Bldg 807 - Credit Union Roof Replacement	Maintain Standards	2021	0	0	0	0	284	284
Land & Buildings	Replace Carpeting - Main Bldg and Training Room (Fishkill)	Maintain Standards	2021	0	0	0	0	93	93
Land & Buildings	Replace Sidewalks	Maintain Standards	2021	0	0	0	0	62	62
Land & Buildings	Replace Roof Front Bldg	Maintain Standards	2021	0	0	0	0	159	159
Land & Buildings	Replace Sloped Roof - Front Annex Bldg	Maintain Standards	2021	0	0	0	0	397	397

	COMMON ADDITIONS			W/ AFUDC, Inflated & OH Adjustments					
CAT.	**Description**	**Discretion Level**	**Preliminary In-Service Date**	**2017**	**2018**	**2019**	**2020**	**2021**	**5-Year Total**
Land & Buildings	Building Expansion (Stanfordville)	Enhancements	2017	1539	0	0	0	0	1539
Land & Buildings	Kingston Build Out - 1st Floor	Enhancements	2020	0	0	0	1660	0	1660
Land & Buildings	Kingston Build Out - 2nd Floor	Enhancements	2019	0	0	1609	0	0	1609
Land & Buildings	System Operations Build Out	Enhancements	2018	0	625	0	0	0	625
Land & Buildings	Linemen and Gas Training Centers	Enhancements	2020	0	0	0	4426	0	4426
Land & Buildings	Parking Garage & Office Bldg	Enhancements	2021	0	0	0	0	11348	11348
Land & Buildings				3,947	3,611	5,037	9,191	14,579	36,365
Office Equipment	South Road - Daily Operations - Larger Projects	Maintain Standards	on going	66	68	69	71	72	346
Office Equipment	South Road - Misc. Furniture	Maintain Standards	on going	41	42	43	43	44	213
Office Equipment	South Road - Office Chair Replacement Program	Maintain Standards	on going	36	36	37	38	39	186
Office Equipment	New Office Furniture	Maintain Standards	2019	0	0	21	0	0	21
Office Equipment	Additional Cubicles - Lake Katrine	Maintain Standards	2020	0	0	0	43	67	110
Office Equipment	Upgrade Office Furniture - Fishkill	Maintain Standards	2017	61	0	0	0	0	61
Office Equipment	New Office Furniture (Stanfordville)	Maintain Standards	2018	0	62	0	0	0	62
Office Equipment	Bldg 807 - Dispatch Office	Maintain Standards	2020	0	0	0	22	0	22
Office Equipment	Bldg 810 - System Operations New Furniture	Maintain Standards	2018	0	104	0	0	0	104
Office Equipment	Rifton - Cottage Meeting Room	Maintain Standards	2019	0	0	43	0	0	43
Office Equipment	New Line & Gas Training Facility	Maintain Standards	2020	0	0	0	109	0	109
Office Equipment				204	312	213	326	222	1,276
EMS	EMS Jump Second Upgrade	System Enhancements	08/01/2016	663	0	0	0	0	663
EMS	DMS - New Distribution Management System and D-Scada	System Enhancements	03/30/2017	604	0	0	0	0	604
EMS	DMS - New Distribution Management System Phase II	System Enhancements	09/30/2017	674	0	0	0	0	674
EMS	DMS - DSO work area Bldg 810 S1	System Enhancements	12/31/2017	357	1562	0	0	0	1919
EMS	EMS PCC Mapboard Replacement (Video Wall)	System Enhancements	09/01/2018	0	2604	0	0	0	2604
EMS	EMS DTS Video Wall/Blackboard Software - Operator Trair	System Enhancements	09/01/2018	0	331	0	0	0	331
EMS	Network Infrastructure Upgrade	System Enhancements	12/31/2019	0	0	532	0	0	532
EMS	EMS eDNA Historian Upgrade	System Enhancements	08/01/2019	0	0	96	0	0	96
EMS	EMS Software Upgrade (non-JUMP)	System Enhancements	08/01/2021	0	0	0	109	4434	4542
4231	DMS - Software Upgrade	System Enhancements	06/01/2020	0	0	0	868	0	868
EMS	Miscellaneous Hardware and Software Failures	System Enhancements	Ongoing	51	52	53	54	55	266
EMS				2,349	4,549	680	1,031	4,489	13,099
Hardware	Hardware Minors	System Enhancements	Annual	130	245	153	163	166	857
Hardware	PC and Laptop Replacements	System Enhancements	Annual	368	655	588	543	554	2708
Hardware	Mobile (Pen) Computing Replacements	System Enhancements	Annual	173	209	235	271	277	1165
Hardware	Monitors, Network Printers-Adds/Repl.	System Enhancements	Annual	108	165	118	136	139	665
Hardware	Server Replacements and Storage Upgrades	System Enhancements	Annual	812	1263	882	923	942	4821
Hardware	Network Infrastructure Upgrades/Replacements	System Enhancements	Annual	271	438	353	380	388	1829
Hardware	Cyber Security	System Enhancements	Annual	65	120	82	109	111	486
Hardware	Copiers (new budget line item requested by Tim B)	System Enhancements	Annual	54	82	59	60	61	316
Hardware	IT Strategic Initiatives Hardware	System Enhancements	12/31/2019	0	0	638	543	554	1735

	COMMON ADDITIONS			W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Discretion Level	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Software	Business Intelligence (Cognos)	System Enhancements	many/year	848	1278	1315	1336	1380	6158
Software	Enterprise Content Management - Phase V	System Enhancements	12/31/2016	973	0	0	0	0	973
Software	Enterprise Content Management - future Phases	System Enhancements	Annual	0	1358	1398	445	460	3661
Software	Bill Redesign - OT Streamserve	System Enhancements	01/00/1900	0	533	658	167	172	1530
Software	EmpCenter Upgrades & Enhancements	System Enhancements	12/31/2015	0	80	164	167	172	584
Software	CIS / REV Modernization	System Enhancements	Annual	0	1758	2960	2951	2874	10543
Software	Claims System Replacement	System Enhancements	01/00/1900	0	107	0	0	57	164
Software	CDM - Financial Reporting	System Enhancements	01/00/1900	26	0	0	56	0	82
Software	Cyber Security	System Enhancements	Annual	340	426	438	445	460	2110
Software	Unified Communications, VoIP, IVR Upgrades & Enhancem	System Enhancements	Annual	169	426	987	668	690	2940
Software	Mainframe Bundled Releases	System Enhancements	01/00/1900	140	320	329	334	345	1467
Software	Mobility Upgrade - (Tim H)*	System Enhancements		1132	0	438	0	0	1570
Software	Emergency Management Software - Upgrades & Enhancem	System Enhancements	01/00/1900	0	320	329	334	345	1327
Software	Emergent Software Packages/Upgrades	System Enhancements	Annual	0	639	1096	1336	1610	4681
Software	Business Agility with an Enterprise SOA Framework	System Enhancements	Annual Releases	254	959	1261	1336	1380	5189
Software	Increase the Quality & Speed of Delivery of Application Tes	System Enhancements	Annual Releases	159	533	548	557	575	2371
Software	Digital Initiatives for Customer Engagement (DICE)(Include	System Enhancements	Annual Releases	127	1385	2412	2450	2530	8903
Software	Digital Analytics (REV CenHub)	System Enhancements	12/31/2017	212	0	0	0	0	212
Software	PPM - Project Portfolio Management Solution	System Enhancements	12/31/2016	0	217	219	223	230	889
Software	Wiki/CentralHudson.com Redesign - WCM	System Enhancements	12/31/2016	0	447	603	612	287	1950
Software	Chevin - Fleetwave Upgrades & Enhancements	System Enhancements	12/31/2015	0	107	219	111	115	552
Software	EAM - Enterprise Asset Mgmt	System Enhancements	12/31/2019	0	213	438	111	0	763
Software	HRIS - TotalHR Replacement	System Enhancements	12/31/2019	0	533	767	557	287	2144
Software	Electric GIS- Estimating Design (Frank B)	System Enhancements	06/01/2017	51	0	0	0	0	51
Software	Electric GIS- Underground manhole (Frank B)	System Enhancements	12/01/2019	0	365	389	0	0	755
Software	Electric GIS - Upgrades & Enhancements (Frank B)	System Enhancements	12/01/2021	0	0	0	0	575	575
Software	AP Automation System Upgrade - (Joe C)	System Enhancements	12/01/2015	0	266	0	0	287	554
Software	PowerPlan - Upgrades & Enhancements (Joe C)	System Enhancements	12/01/2018	0	0	0	668	0	668
Software	PowerPlan - Construction Budgeting upgrades (Chris R)	System Enhancements	06/01/2016	529	0	0	0	0	529
Software	Taurigma Automated Fault Location and Event Retriever (E	System Enhancements	Annual	68	73	78	0	0	219
Software	GL Essentials Upgrades & Enhancements	System Enhancements	Annual	0	0	274	0	0	274
Software	Clarity Replacement/Upgrade (Stan K)	System Enhancements	12/31/2019	0	692	0	0	0	692
Software	ARCOS Upgrades & Enhancements	System Enhancements	06/01/2016	0	160	0	0	172	332
Software	OMS Replacement (Tim H)	System Enhancements	06/01/2019	0	1164	1864	0	0	3028
Software	CYME (Adams)	System Enhancements	12/01/2018	0	107	0	0	0	107
Software	Loadflow (PSS/e - MUST)	System Enhancements	06/01/2019	69	0	0	0	0	69

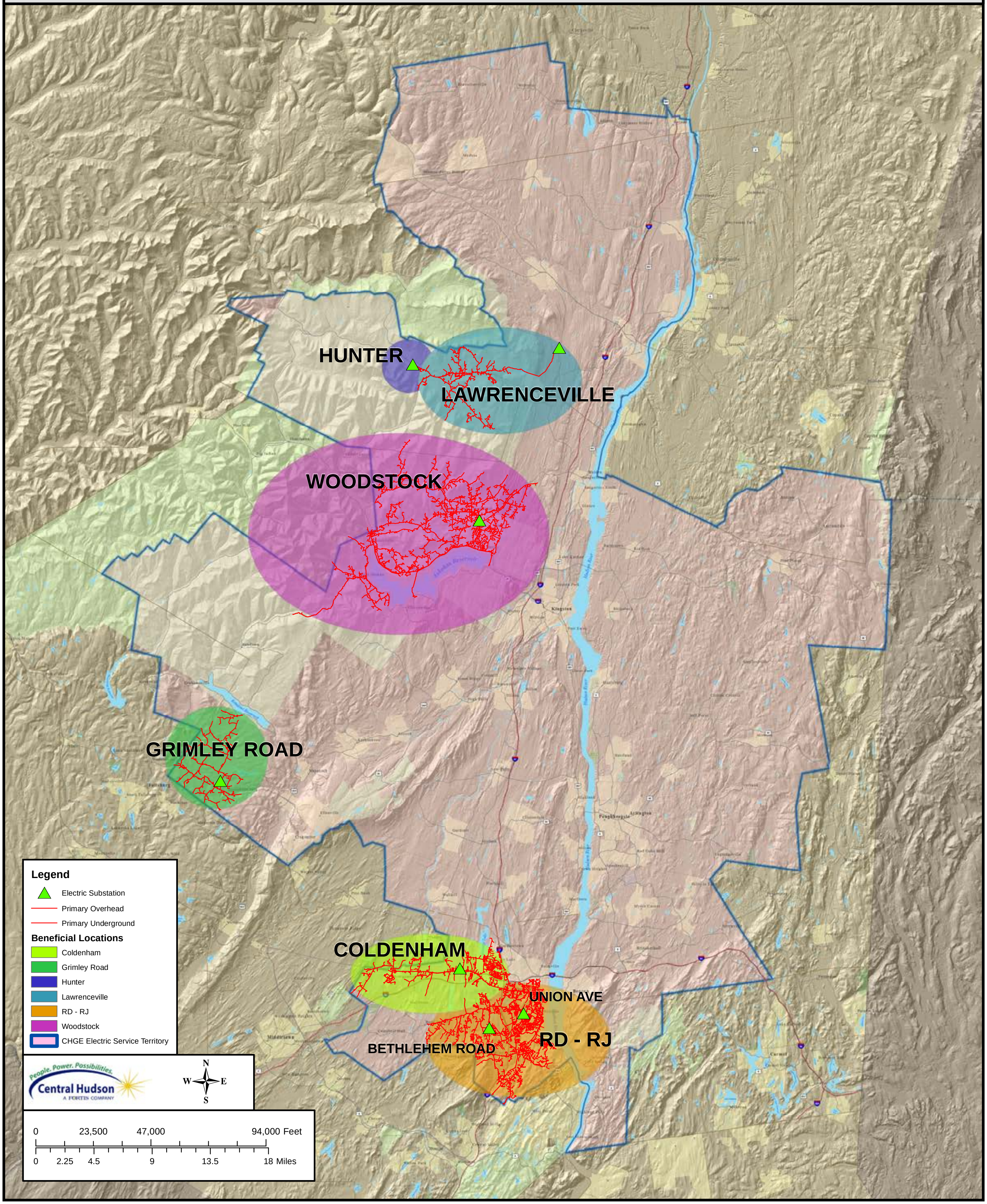
	COMMON ADDITIONS			W/ AFUDC, Inflated & OH Adjustments					
CAT.	Description	Discretion Level	Preliminary In-Service Date	2017	2018	2019	2020	2021	5-Year Total
Software & Hardware				7,077	17,641	22,293	17,993	18,197	83,201
Security	Security Guard Booths District Offices Phase 2	System Enhancements	2017	153	0	0	0	0	153
Security	Security Guard Booth Corporate Offices	System Enhancements	2017	204	0	0	0	0	204
Security	Fishkill Plains Sub Cameras/Intrusion detection	System Enhancements	2017	102	0	0	0	0	102
Security	Manchester Sub Cameras/Intrusion Detection	System Enhancements	2017	133	0	0	0	0	133
Security	Easy Lobby Visitor ID Program - District Offices	System Enhancements	2017	41	0	0	0	0	41
Security	Todd Hill Sub Cameras/Intrusion Detection	System Enhancements	2018	0	135	0	0	0	135
Security	Knapps Corners Sub Cameras/Intrusion Detection	System Enhancements	2018	0	135	0	0	0	135
Security	License Plate Cameras District Offices	System Enhancements	2018	0	208	0	0	0	208
Security	Poughkeepsie Gas Cameras/Intrusion detection	System Enhancements	2018	0	104	0	0	0	104
Security	Spackenkill Sub Cameras/Intrusion Detection	System Enhancements	2018	0	135	0	0	0	135
Security	Poughkeepsie River Crossing Pump House/Intrusion detect	System Enhancements	2019	0	0	149	0	0	149
Security	Hurley Ave Sub Thermal Security Cameras	System Enhancements	2019	0	0	186	0	0	186
Security	Hudson Crossing Cameras/Intrusion Detection	System Enhancements	2019	0	0	159	0	0	159
Security	Myers Corners Sub Cameras/Intrusion Detection	System Enhancements	2019	0	0	138	0	0	138
Security	Napanoch Sub Cameras/Intrusion Detection	System Enhancements	2020	0	0	0	109	0	109
Security	Substation Gunshot Detection System	System Enhancements	2020	0	0	0	109	0	109
Security	Rifton - Cameras/Intrusion Detection	System Enhancements	2020	0	0	0	141	0	141
Security	North Chelsea Sub Cameras/Intrusion Detection	System Enhancements	2020	0	0	0	141	0	141
Security	Mahopac Gas Sub Cameras/Intrusion detection	System Enhancements	2020	0	0	0	87	0	87
Security	Pleasant Valley Sub Additional Cameras/Intrusion detection	System Enhancements	2020	0	0	0	65	0	65
Security	Pleasant Valley Gas Sub Cameras/Intrusion detection	System Enhancements	2021	0	0	0	0	94	94
Security	Rock Tavern Sub Thermal Security Cameras	System Enhancements	2021	0	0	0	0	194	194
Security	Roseton Sub Thermal Security Cameras	System Enhancements	2021	0	0	0	0	89	89
Security	Smithfield Sub Cameras/Intrusion detection	System Enhancements	2021	0	0	0	0	111	111
Security	Highland Sub Cameras/Intrusion Detection	System Enhancements	2021	0	0	0	0	111	111
Security				632	719	633	651	599	3,233
Tools	Small Tools	Maintain Standards	0	1071	1630	1595	1357	1280	6933
Tools	Tools								
Communications	Network Strategy Pilot Project - Phase 2	System Enhancements	Ongoing	4444	4742	3935	2556	1108	16786
Communications	Radio Minor	System Enhancements	Ongoing	204	1250	425	326	222	2426
Communications	Communication			4,648	5,992	4,360	2,882	1,330	19,212
Transportation	Transportaion	Maintain Standards	0	7956	9216	10220	10626	11088	49107
	Total			27,883	43,670	45,031	44,058	51,783	212,426

2011-2015 Historical Capital Expenditures

	2011	2012	2013	2014	2015	AVG 2011-2015
ELECTRIC						
Production	3,037	4,714	751	167	730	1,107
Transmission	9,127	10,072	11,511	13,344	19,284	11,014
Substation	11,050	16,942	13,022	15,335	17,199	14,087
New Business	4,564	5,360	3,899	3,472	4,960	4,324
Dist. Improvements	19,293	21,959	19,879	20,536	28,737	20,417
Transformers	4,740	4,718	3,381	2,883	4,443	3,931
Meters	1,998	2,618	1,934	2,193	2,140	2,186
Storm Damage	2,782	1,995	125	110	19	1,253
TOTAL ELECTRIC	56,591	64,135	54,502	58,040	77,512	58,317
GAS						
Production	(2)	(3)				(3)
Transmission	1311	1363	2383	2432	1919	1872
Regulator Stations	649	1765	694	1422	1002	1133
New Business	4918	7258	10800	10148	15109	8281
Dist. Improvements	7877	13284	14254	12515	16574	11983
Meters	1932	2648	1770	2362	2358	2178
TOTAL GAS	16,685	26,315	29,901	28,879	36,962	25,445
COMMON						
PS&I	-					-
Land & Buildings	3,062	4,537	2,332	4,007	3,940	3,485
Office Equipment	-					-
General	178	137	329	219	270	216
EDP	2,137	4,972	1,868	2,936	-	2,978
Software	2,431	2,997	6,609	5,309	10,115	4,337
Tools	606	843	665	920	1,044	759
Communication	463	584	78	1,734	1,842	715
Transportation	4,526	5,264	5,444	7,762	6,983	5,749
Overheads	(925)	(685)	183	1,183	(865)	(61)
TOTAL COMMON	12,478	18,649	17,508	24,070	23,329	18,176
TOTAL CORP	85,754	109,099	101,911	110,989	137,803	101,938

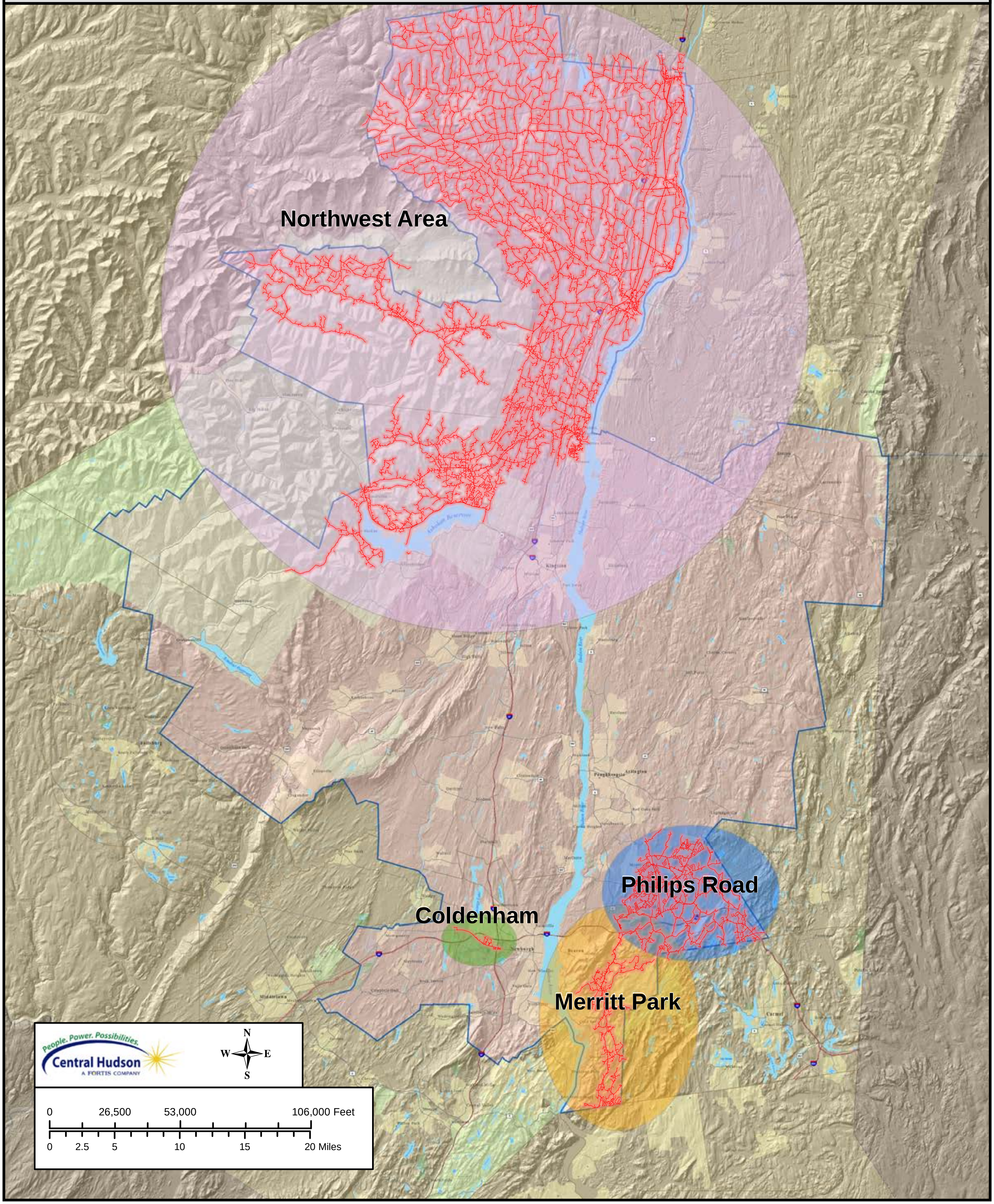
Appendix I Circuit Maps to the Beneficial Locations

Beneficial Locations System Map



Appendix J Circuit Maps to Non-Wire Alternative Projects

Non-Wire Alternatives Areas



Appendix K BCA Handbook

Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook

Version 1

June 30, 2016

People. Power. Possibilities.
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TABLE OF CONTENTS

ACRONYMS AND ABBREVIATIONS

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here at the front of the Handbook for ease of reference.

AC	Alternating Current
AGCC	Avoided Generation Capacity Costs
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost framework structure presented initially in the "Staff White Paper on Benefit-Cost Analysis" and finalized in the *BCA Order*.
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
C&I	Commercial and Industrial
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP Guidance Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
ICAP	Installed Capacity
JU	Joint Utilities (Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation)
kV	Kilovolt
LBMP	Locational Based Marginal Prices
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt
MWh	Megawatt Hour
NPV	Net Present Value
NO_x	Nitrogen Oxides
NWA	Non-Wires Alternatives
NYC	New York City
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance

PV	Photovoltaic
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model (National Renewable Energy Laboratory)
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SENY	Southeast New York (Ancillary Services Pricing Region)
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	Utility Cost Test

1. INTRODUCTION

The State of New York Public Service Commission (NYPSC) directed the Joint Utilities (JU)[1] to develop and file Benefit-Cost Analysis (BCA) Handbooks by June 30, 2016 as a requirement of the Order Establishing the Benefit-Cost Analysis Framework (*BCA Order)*.[2] The BCA Framework included in Appendix C of the *BCA Order* is incorporated into the BCA Handbooks. These handbooks are to be filed contemporaneously with each utility's initial Distributed System Implementation Plan (DSIP) filing and with each subsequent DSIP, scheduled to be filed every other year.[3]

The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The *BCA Order* requires that benefit-cost analysis be applied to the following four categories of utility expenditure:[4]

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection[5]
3. Procurement of DER through tariffs[6]
4. Energy efficiency programs

The BCA Handbook provides methods and assumptions that may be used to inform BCA for each of these four types of expenditure.

The *BCA Order* also includes a list of principles for the BCA Framework that are reflected in the BCA Handbook.[7] BCA should:

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

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[1] For the purpose of this document, Joint Utilities includes Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation.

[2] *BCA Order*: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

[3] DSIP Guidance Order, pg. 64: "shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018."

[4] *BCA Order*, pg. 1-2.

[5] Also known as non-wires alternatives (NWA).

[6] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).

[7] *BCA Order*, pg. 2.

1.1 Standardization of the BCA Approach

The BCA Order states: "The utilities, however, are directed to cooperate in the preparation of their Handbooks, and set forth common methodologies, including use of the SCT, for uniform application across the State to the extent feasible."[8]
In order to ensure the most accurate and consistent BCA methodology, Central Hudson developed this BCA Handbook in collaboration with the JU. Navigant Consulting, Inc. (Navigant) facilitated the development of a standard BCA template at the request of the JU. By design, the key assumptions, scope, and approach for a BCA included herein are largely consistent amongst all utilities' BCA handbooks. Where applicable, Central Hudson has customized the handbook to account for utility specific assumptions and information.

1.2 Application of the BCA Handbook

The BCA Handbook provides a common methodology to be applied in BCA across investment projects and portfolios. Version 1 of the BCA Handbook is meant to inform investments in DSP capabilities or the procurement of DERs through tariffs, and to be specifically applicable to procurement of DERs through competitive selections (i.e. non-wire alternatives) and/or energy efficiency programs. Common input assumptions and sources that are applicable statewide (e.g., information publicly provided by the New York Independent System Operator (NYISO) or by Department of Public Service (DPS) Staff directly in the *BCA Order*) and utility-specific inputs (e.g., marginal cost of service and losses) that may be commonly applicable to a variety of project-specific BCAs are provided within. Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

Table 1-1 lists the statewide data and sources to be used for BCA and referenced in this Handbook.

[8] BCA Order, Page 31

Table 1-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[9]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model[10]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[11]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[12]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[13]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 2[14]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[15]

[9] The 2016 Load & Capacity Data report is available in the Planning Data and Reference Docs folder at: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

[10] The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: http://www.dps.ny.gov. The filename is BCA Att A Jan 2016.xlsm.

[11] The finalized annual and hourly from 2016 CARIS Phase 2 will be available in the CARIS Study Outputs folder within the Economic Planning Studies folder at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. In the interim, work with DPS Staff on appropriate values to use for the ETIP filing.

[12] Historical ancillary service costs are available at: http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp. The values to apply are described in Section 4.1.5.

[13] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[14] The hourly allowance price assumptions for the 2016 CARIS Phase 2 study will be available in the CARIS Input Assumptions folder within Economic Planning Studies at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

[15] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table 1-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table 1-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	Order Approving Rate Plan issued and effective June 17, 2015 in Cases 14-E-0318 and 14-G-0319
Losses	2007 Central Hudson Gas & Electric Corporation Analysis of System Losses
Marginal Avoided Transmission & Distribution Costs	Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods, 2016
Reliability Statistics	DPS: Electric Service Reliability Reports[16]

The New York general and utility-specific assumptions that are included in this first version of the BCA Handbook (as listed in Table 1-1 and Table 1-2) are typically values by zone or utility system averages. In subsequent versions, application of the BCA Handbook may be enhanced by including more granular data, for example with respect to location (e.g., zone, substation, or circuit) or time (e.g., seasonal, monthly, or hourly).

The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.

1.3 BCA Handbook Version

Version 1 of the BCA Handbook provides techniques for quantifying the benefits and costs identified in the *BCA Order*. The BCA Handbook will be updated every two years and filed with the DSIP.[17] Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.4 Structure of the Handbook

The four remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

> **Section 2. General Methodological Considerations** describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.

[16] The 2014 Annual Electric Service Reliability Report is available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/D82A200687D96D3985257687006F39CA?OpenDocument

[17] DSIP Guidance Order, pg. 64: "shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018."

Section 3. Relevant Cost-Effectiveness Tests defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure (RIM). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.

Section 4. Benefits and Costs Methodology provides detailed definitions, calculation methods, and general considerations for each benefit and cost.

Section 5. Characterization of DER profiles discusses which benefits and costs are likely to apply to different types of DER, and provides examples for a sample selection of DERs.

Appendix A. Utility-Specific Assumptions includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

2. GENERAL METHODOLOGICAL CONSIDERATIONS

This section describes key issues and challenges that that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in Section 4.

2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Doubling-counting can be avoided by 1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and 2) clear definition and differentiation between the benefits and costs included in the analysis.

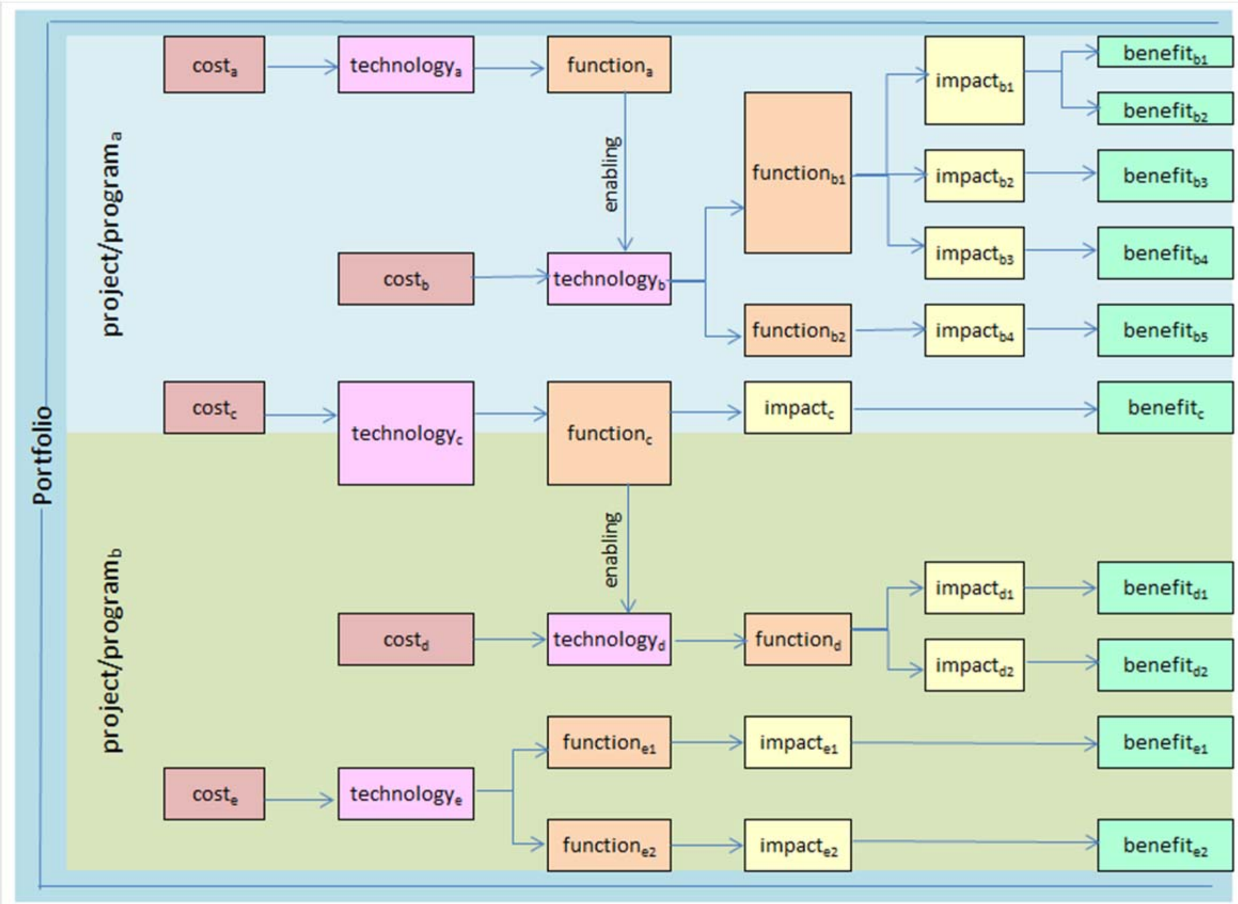
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

2.1.1 Accounting of Benefits and Costs Across Multiple Value Streams

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology also provides one or more functions that result in quantified impacts, which are valued as monetized benefits.

Figure 2-1 is an illustrative example of value streams that may be associated with a portfolio of projects or programs.

Figure 2-1. Illustrative Example of Value Streams that May be Associated with a Portfolio of Projects or Programs



Source: National Grid

Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies (e.g. technology$_b$ in Figure 2-1). Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function (e.g. technology$_c$ in Figure 2-1). It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Benefits and costs should also be allocated properly across different projects within a portfolio. This may present challenges especially in the case of enabling technologies. For example, the investment in technology$_c$ in Figure 2-1 is included as part of project/program$_a$. Some direct benefits from this technology are realized for project/program$_a$, however technology$_c$ also enables technology$_d$ that is included as part of project/program$_b$. In this example, the costs of technology$_c$ and the directly resulting benefit should be accounted for in project/program$_a$, and the cost for technology$_d$ and the resulting incremental benefits should be accounted for in project/program$_b$.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Over time, investments made as part of previous projects or portfolios may also enable or enhance new projects. The *BCA Order* states that utility BCA shall consider incremental T&D costs "to the extent that the characteristics of a project cause additional costs to be incurred."[18]

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility's distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. If there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder. As another example, the incremental improvement on reliability indices may diminish as more automated switching projects are in place.

2.1.2 Benefit Definitions and Differentiation

A key consideration identified in performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

As discussed in Section 3, the *BCA Order* identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section 4. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided LBMP, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided LBMP benefits may be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Sections 2.1.2.1 and 2.1.2.2 below define the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided LBMP, and differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits. Sections 2.1.1.1 and 2.1.1.2 also provide differentiation between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

---

[18] *BCA Order*, Appendix C pg. 18.

Table 2-1 provides a list of potentially overlapping AGCC, and Avoided LBMP benefits.

Table 2-1. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	• Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses
Avoided LBMP	• Net Avoided CO_2 • Net Avoided SO_2 and NO_x • Avoided Transmission Losses • Avoided Transmission Capacity • Avoided Distribution Losses

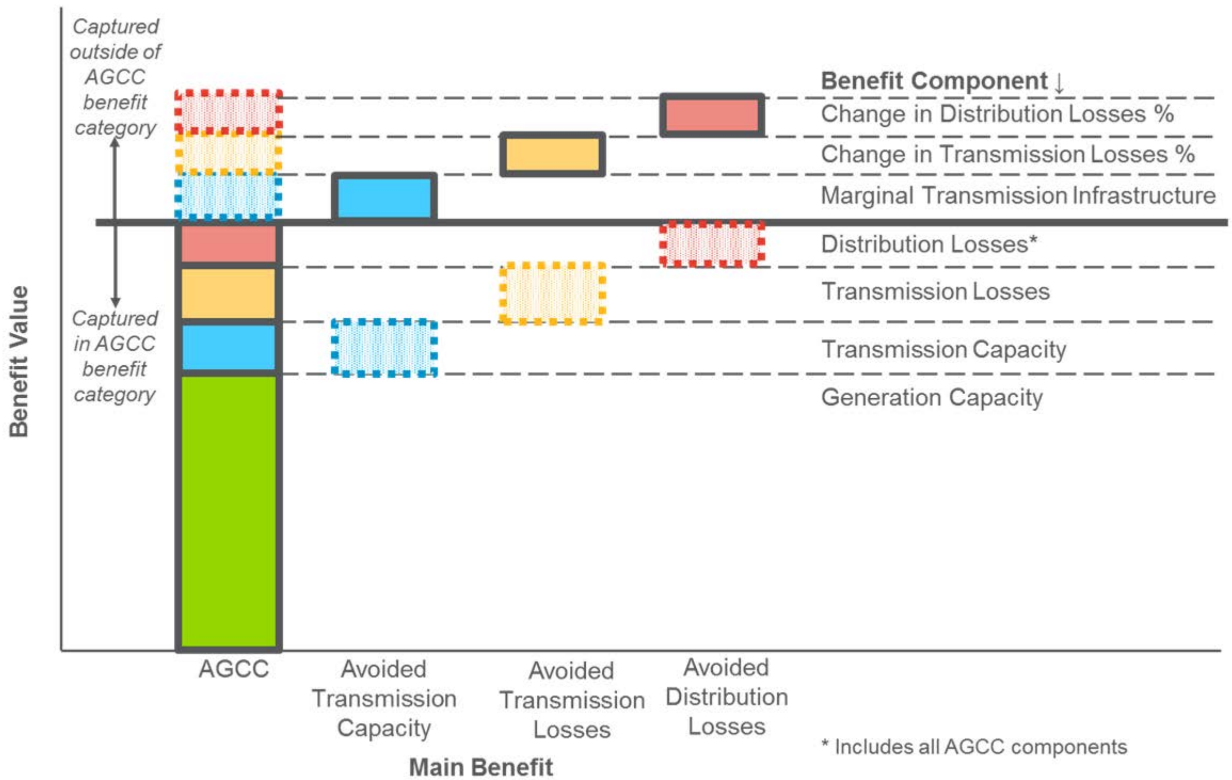
2.1.2.1 Benefits Overlapping with Avoided Generation Capacity Costs

AGCC assumptions used by the NYISO to calculate the AGCC values as captured in the AGCC benefit category; which are subsequently used by the DPS Staff in the ICAP Spreadsheet Model include benefits from sources other than Generation Capacity. In the figure below, components identified below the line depict all benefit values as captured in the AGCC benefit category; which include additional benefits from Transmission Capacity, and Transmission and Distribution Loss assumptions.

These components below the line must be identified discretely and then their effects removed from the NYISO AGCC assumption in order to provide a base from which to build in the actual impacts that locational and/or project specific values supply. In the figure below, components identified above the line depict locational and/or project specific benefits; which will be built into the values considered within the BCA assessment.

Figure 2-2 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure 2-2. Benefits Potentially Overlapping with Avoided Generation Capacity Costs (Illustrative)



Source: Navigant

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission tosses.[19] Additionally, distribution losses can affect the calculation of AGCC, depending on the project location on the system.[20] The AGCC calculation accounts for these distribution losses.

If a project changes the electrical topology and therefore changes the transmission loss percent itself, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

[19] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[20] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

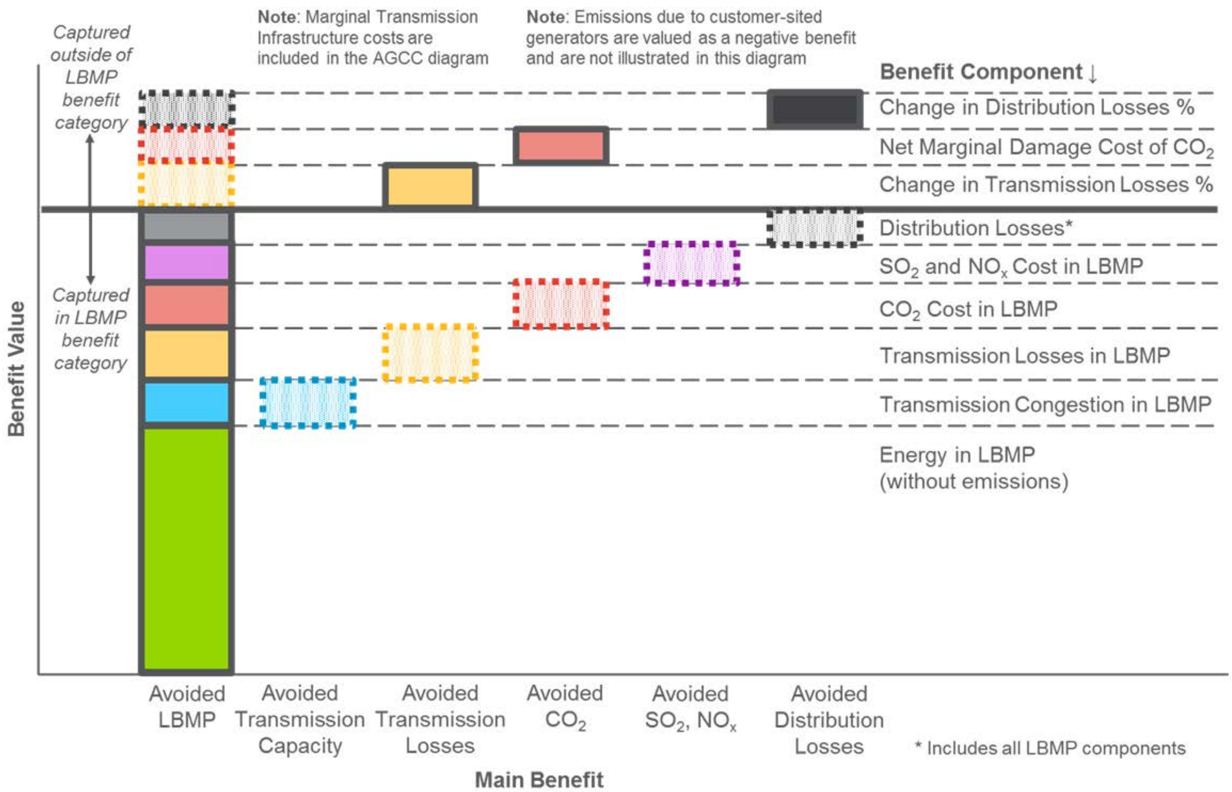
2.1.2.2 Benefits Overlapping with Avoided LBMP

Avoided LBMP assumptions used by the NYISO to calculate the LBMP values as captured in the LBMP benefit category, which are subsequently used by the DPS Staff in the ICAP Spreadsheet Model include benefits from sources other than Energy in LBMP. In the figure below, components identified below the line depict all benefit values as captured in the LBMP benefit category; which include additional benefits from Transmission Congestion, Transmission and Distribution Losses, and CO_2, SO_2 and NO_x Costs.

These components below the line must be identified discretely and then their effects removed from the NYISO LBMP assumption in order to provide a base from which to build in the actual impacts that locational and/or project specific values supply. In the figure below, components identified above the line depict locational and/or project specific benefits; which will be built into the values considered within the BCA assessment

Figure 2-3 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

Figure 2-3. Benefits Potentially Overlapping with Avoided LBMP Benefit (Illustrative)



Source: Navigant

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided LBMP benefit include costs for factors beyond simple energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided LBMP benefit:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the LBMP
- Transmission-level loss costs which are embedded in the LBMP
- Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the LBMP

Additionally, distribution losses can affect LBMP purchases, depending on the project location on the system, and should gross up the calculated LBMP benefits.[21] To the extent a project changes the electrical topology and changes the distribution loss percent itself, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, the variable losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[22] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from “loss percent”. The loss factor is 1 / (1 - Loss Percent).

[21] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the LBMP purchases due to higher losses.

[22] In the BCA equations outlined in Section 4 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

For consistency, the equations in Section 4 follow the same notation to represent various locations on the system:

- “r” subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[23]
- “i” subscript represents the interface of the distribution and transmission systems.
- “b” subscript represents the bulk system which is the level at which the values for AGCC and LBMP are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{\mathrm{b\to r}}$ would represent the loss percent between the bulk system (“b”) and the retail delivery or connection point (“r”). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. Because benefits of grid modernization projects accrue over many years, baselines must be valid across the same time horizon. This introduces a few points that merit consideration:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO’s CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.

[23] Transmission in this context refers to the distribution utility’s sub-transmission and internal transmission.

- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may take place independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment, expected system performance, or both. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions underlying the existing baseline.

2.4 Normalizing Impacts

In addition to establishing an appropriate baseline, normalizing impact data presents similar challenges. This is particularly true for distribution-level projects, where system performance is significantly affected by external conditions beyond that which occurs on the distribution system. For instance, quantifying the impact of technology investment on reliability indices would require the baseline data to be representative of expected feeder reliability performance. This is a challenging task, as historical data would require weather adjustments and contemporaneous data would be drawn from different, but similar, feeders.

A distribution feeder may go through changes that could influence feeder performance independent of the technologies implemented. For instance, planned outages due to routine maintenance activities or outages due to damages from a major storm could impact reliability indices and changes in the mix of customer load type (e.g., residential vs. commercial and industrial), which may impact feeder peak load.

2.5 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[24]

2.6 Granularity of Data for Analysis

The most accurate assumptions to use for assessing a BCA would leverage suitable location or temporal information. When the more granular data is not available, an appropriate annual average or system average maybe used, if applicable in reflecting the expected savings from use of DER.

More granular locational or temporal assumptions are always preferred to more accurately capture the savings from use of a resource. However, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where their use is required.

[24] *BCA Order*, pg. 2

2.7 Performing Sensitivity Analysis

The *BCA Order* indicates the BCA Handbook shall include "description of the sensitivity analysis that will be applied to key assumptions."[25] As Section 4 presents, there is a discussion of each of the benefits and costs, and a sensitivity analysis can be performed by changing selected parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided LBMP or AGCC. A sensitivity of LBMP, $/MWh, could be assessed by adjusting the LBMP by +/-10%.

In addition to adjusting the values of an individual parameter as a sensitivity, the applicability of certain benefits and costs would be considered as a sensitivity analysis of the cost-effectiveness tests. For example, inclusion of the Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.[26]

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[25] *BCA Order*, Appendix C, pg. 31.

[26] *BCA Order*, pg. 25 ("The evaluation would then be conducted showing separately the impacts both with and without the wholesale market price effect.")

3. RELEVANT COST-EFFECTIVENESS TESTS

The *BCA Order* states that the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 3-1.

Table 3-1. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The *BCA Order* positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and ratepayers. Some projects may not provide benefits to the utility and ratepayers, even if it is beneficial to society as a whole. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that the impact is of a "magnitude that is unacceptable".[27]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 2 General Methodological Considerations.

[27] *BCA Order*, pg. 13.

Table 3-2 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test.

Table 3-2. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
Benefit				
4.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
4.1.2	Avoided LBMP‡	✓	✓	✓
4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
4.1.5	Avoided Ancillary Services*	✓	✓	✓
4.1.6	Wholesale Market Price Impacts**		✓	✓
4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
4.2.2	Avoided O&M	✓	✓	✓
4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
4.3.1	Net Avoided Restoration Costs	✓	✓	✓
4.3.2	Net Avoided Outage Costs	✓		
4.4.1	Net Avoided CO_2‡	✓		
4.4.2	Net Avoided SO_2 and NO_x‡	✓		
4.4.3	Avoided Water Impacts	✓		
4.4.4	Avoided Land Impacts	✓		
4.4.5	Net Non-Energy Benefits***	✓	✓	✓
Cost				
4.5.1	Program Administration Costs	✓	✓	✓
4.5.2	Added Ancillary Service Costs*		✓	✓
4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
4.5.4	Participant DER Cost	✓		
4.5.5	Lost Utility Revenue			✓
4.5.6	Shareholder Incentives		✓	✓
4.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 2 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 2.1.2.1 for discussion of potential overlaps in accounting for these benefits.
** The amount of DER is not driver of the size of NYISO's Ancillary Services markets since a change in load will not result in a reduction in the NYISO requirements for Regulation and Reserves as the requirements for these services are set periodically by NYISO to maintain frequency and to cover the loss of the largest supply element(s) on the bulk power system. Therefore, there is no impact within the SCT as the overall Ancillary Services requirement remains unchanged. DER has potential to provide new distribution-level ancilliary service. However, it is uncertain whether such service can be cost-effectively provided.*
*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefits in each year of the analysis period (i.e., how much will it change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 4.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

A majority of the benefits included in the *BCA Order* can be evaluated under the SCT because their impact can be applied to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants in the *BCA Order*:

> "Wholesale markets already adjust to changes in demand and supply resources, and any resource cost savings that result are reflected in the SCT. Any price suppression over and above those market adjustments is essentially a transfer payment -- simply a shift of monetary gains and losses from one group of economic constituents to another. No efficiency gain results if, for example, generators are paid more or less while consumers experience equal and offsetting impacts. Therefore, the price suppression benefit is not properly included in the SCT beyond the savings already reflected there."[28]

[28] *BCA Order*, pg. 24

3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4. BENEFITS AND COSTS METHODOLOGY

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and general considerations.

There are four types of benefits which are further explained in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

Additionally, there are four types of costs that are also considered in the BCA Framework and explained in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

In this version of the Handbook, for energy, operational, and reliability-related benefits and costs,[29] it is assumed that impacts generate benefits/costs in the same year as the impact. In other words, there is no time delay between impacts and benefits/costs. However, for capacity, infrastructure, and market price-related benefits and costs,[30] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2016, the AGCC benefit would not be realized until 2017.

[29] Energy, operational, and reliability-related benefits and costs include: Avoided , the energy component of Avoided Transmission Losses, Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation), the energy portion of

Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, **Error! Reference source not found.**, **Error! Reference source not found.**, the energy component of Distribution Losses, Net Avoided CO_2, Net Avoided SO_2 and NO_x, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, Shareholder Incentives, and Net Non-Energy Costs.

[30] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, Wholesale Market Price Impact, , Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

4.1 Bulk System Benefits

4.1.1 Avoided Generation Capacity Costs

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[31] It is assumed that the benefit is realized in the year following the peak load reduction impact.

4.1.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2015 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

Equation 4-1. Avoided Generation Capacity Costs

$$\text{Benefit}_{\text{Y+1}} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{\text{Z,Y,r}}}{1\text{-Loss\%}_{\text{Z,Y,b}\rightarrow\text{r}}} * \text{SystemCoincidenceFactor}_{\text{Z,Y}} * \text{DeratingFactor}_{\text{Z,Y}} * \text{AGCC}_{\text{Z,Y,b}}$$

The indices of the parameters in Equation 4-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta\text{PeakLoad}_{\text{Z,Y,r}}}$ **(∆MW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\boldsymbol{\text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\boldsymbol{\text{SystemCoincidenceFactor}_{\text{Z,Y}}}$ **(dimensionless)** captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\boldsymbol{\text{DeratingFactor}_{\text{Z,Y}}}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit

[31] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$\mathrm{AGCC}_{\mathrm{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

4.1.1.2 General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast.[32] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[33] for more details on ICAP.

AGCC benefits are calculated using a static forecast of AGCC prices provided by Staff. Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section 4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (i.e. $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

[32] 2015 CARIS Phase 1 Study Appendix. http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2015_CARIS_Final_Appendices_FINAL.pdf

[33] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

4.1.2 Avoided LBMPs

Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP). The three components of the LBMP (i.e., energy, congestion, and losses) are all included in this benefit. See Section 2.1.2.1 for details on how the methodology avoids double counting between this benefit and others.

4.1.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-2 presents the benefit equation for Avoided LBMP:

Equation 4-2. Avoided LBMP

$$\text{Benefit}_{\text{Y}} = \sum_{\text{Z}} \sum_{\text{P}} \frac{\Delta\text{Energy}_{\text{Z,P,Y,r}}}{1 - \text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}} * \text{LBMP}_{\text{Z,P,Y,b}}$$

The indices of the parameters in Equation 4-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\text{Energy}_{\text{Z,P,Y,r}}$ **(∆MWh)** is the difference in energy purchased at the retail delivery or connection point ("r") before and after project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $Loss\%_{Z,b\rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\text{LBMP}_{\text{Z,P,Y,b}}$ **($/MWh)** is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

4.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section 4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that are valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the LBMP and the AGCC prices. Because static forecasts of LBMPs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

4.1.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation 4-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{C}} \frac{\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}}{\mathrm{Loss\%}_{\mathrm{Y,b\to r}}} * \mathrm{TransCoincidentFactor}_{\mathrm{C,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalTransCost}_{\mathrm{C,Y,b}}$$

The indices[34] of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system[35]
- Y = Year

[34] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[35] If system-wide marginal costs are used, this is not an applicable subscript.

- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\mathbf{PeakLoad}_{\mathbf{Y,r}}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%}_{\mathbf{Y,b\rightarrow r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2.

$\mathrm{TransCoincidentFactor}_{\mathrm{C,Y}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

$\mathbf{DeratingFactor}_{\mathbf{Y}}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\mathrm{MarginalTransCost}_{\mathrm{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3.

4.1.3.2 General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study.

Some transmission capacity costs are already embedded in both LBMP and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in LBMP and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in significant over- or under-valuation of the benefits or costs and may result in no savings in utility costs for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table A-3 include both capital and O&M, and cannot be split between the two benefits. Therefore care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section 4.2.2.

4.1.4 Avoided Transmission Losses

Avoided Transmission Losses is the benefit that is realized when a project changes the topology of the transmission system and results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided LBMP and Avoided Generation Capacity benefits as described above in Sections 4.1.2 and 4.1.1. In actuality, both the LBMP and AGCC would adjust to a change in system losses in future years; however, the static forecast used in this methodology does not capture these effects.

4.1.4.1 Benefit Equation, Variables, and Subscripts

Equation 4-4 presents the benefit equation for Avoided Transmission Losses:

Equation 4-4. Avoided Transmission Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i} = \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{post}}$$

The indices[36] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[37])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\mathrm{SystemEnergy}_{Z,Y+1,b}$ **(MWh)** is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b"), which includes transmission and distribution losses. Note that total system energy is used for this input, not the project-specific energy, because this benefit is only included in the BCA when the system topology is changed resulting in a change in the transmission loss percent, which affects all load in the relevant area.

$\mathrm{LBMP}_{Z,Y+1,b}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$\mathrm{SystemDemand}_{Z,Y,b}$ **(MW)** is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in transmission losses percent, which affects all load in the relevant zone.

$\mathrm{AGCC}_{Z,Y,b}$ **($/MW-yr)** represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level"[38] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$ **(Δ%)** is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

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[36] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[37] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

[38] "Transmission level" represents the bulk system level ("b").

$\mathbf{Loss\%_{Z,Y,b \rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,b \rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

4.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to selected DERs that are willing and qualify to provide ancillary services to NYISO. NYISO could purchase ancillary services from these DERs in lieu of conventional generators at a lower cost without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO. This value will be zero for nearly all cases and by exception would a value be included as part of the UCT and RIM.

DER causes a reduction in load but will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are periodically set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as the voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to communicate with and effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services unless and until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

4.1.5.1 Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of this benefit is project specific.

Frequency Regulation

Equation 4-5 presents the benefit equation for frequency regulation:

Equation 4-5. Frequency Regulation

$$\mathrm{Benefit}_{\mathrm{Y}} = \mathrm{Capacity}_{\mathrm{Y}} * \mathrm{n} * (\mathrm{CapPrice}_{\mathrm{Y}} + \mathrm{MovePrice}_{\mathrm{Y}} * \mathrm{RMM}_{\mathrm{Y}})$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$\mathrm{Capacity}_{\mathrm{Y}}$ (MW) is the amount of annual average frequency regulation capacity when provided to NYISO by the project. The amount is difficult to forecast.

n (hr) is the number of hours in a year that the resource is expected to provide the service.

$\mathrm{CapPrice}_{\mathrm{Y}}$ ($/MW·hr) is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$\mathrm{MovePrice}_{\mathrm{Y}}$ ($/ΔMW): is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

$\mathrm{RMM}_{\mathrm{Y}}$ (ΔMW/MW·hr): is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 4-6 presents the benefit equation for spinning reserves:

Equation 4-6. Spinning Reserves

$$\mathrm{Benefit}_{\mathrm{Y}} = \mathrm{Capacity}_{\mathrm{Y}} * \mathrm{n} * \mathrm{CapPrice}_{\mathrm{Y}}$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$\mathrm{Capacity}_{\mathrm{Y}}$ (MW) is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project. The amount is difficult to forecast.

n (hr): is the number of hours in a year that the resource is expected to provide the service.

$\mathrm{CapPrice}_{\mathrm{Y}}$ ($/MW·hr) is the average hourly spinning reserve capacity price. Default value uses the two-year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

NYISO in late 2015 changed the number of regions for Ancillary Services from two to three and two-year historical data is not available for all three regions. Thus, assume that EAST and SENY are equal to the historical data for EAST. The corresponding NYISO zones for EAST are F – K, and the corresponding zones for WEST are A – E.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period. To avoid the complication of the change in regions, the two-year historical average is based on November 1, 2013 through October 31, 2015.

The NYISO Ancillary Services Manual suggests that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.

4.1.6 Wholesale Market Price Impact

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., LBMP) and capacity (i.e., AGCC) due to a measure, project, or portfolio. LBMP impacts will be provided by Staff and are determined using the first year of the most recent CARIS database to calculate the static impact on wholesale LBMP of a 1% change in the level of load that must be met.[39] LBMP impact will be calculated for each NYISO zone. AGCC price impacts are characterized using Staff's ICAP Spreadsheet Model.

4.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

Equation 4-7. Wholesale Market Price Impact

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} (1 \text{ - } \mathrm{Hedging\%} * (\Delta\mathrm{LBMPImpact}_{Z,Y+1,b} * \frac{\Delta\mathrm{Energy}_{Z,Y+1,r}}{1 - \mathrm{Loss\%}_{Z,b\rightarrow r}} + \Delta\mathrm{AGCC}_{Z,Y,b} * \mathrm{ProjectedAvailableCapacity}_{Z,Y,b})$$

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K[40])

[39] *BCA Order*, Appendix C, pg. 8.

[40] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

- Y = Year
- b = Bulk System

$\mathbf{Hedging\%}$ **(%)** is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms in each year. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. The JU have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

$\mathbf{\Delta LBMPImpact_{Z,Y+1,b}}$ **(Δ$/MWh)** is the change in average annual LBMP at the bulk system ("b") before and after the project(s); requires wholesale market modeling to determine impact. This will be provided by DPS Staff.

$\mathbf{\Delta Energy_{Z,Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{Z,b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table A-2.

$\mathbf{WholesaleEnergy_{Z,Y,b}}$ **(MWh)** is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This must represent the energy at the LBMP.

$\mathbf{\Delta AGCC_{Z,Y,b}}$ **(Δ$/MW-yr)** is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[41] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\mathbf{ProjectedAvailableCapacity_{Z,Y,b}}$ **(MW)** is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

4.1.6.1 General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. LBMP market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS 2 database to calculate the static impact on LBMP of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT, but would be included in RIM and UCT as a sensitivity.

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[41] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

It is assumed that the capacity portion of Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand, quickly reducing the benefit.[42]. It is also assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact, and the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact.

4.2 Distribution System Benefits

4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

4.2.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation 4-8. Avoided Distribution Capacity Infrastructure

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{V}} \sum_{\mathrm{C}} \frac{\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b \to r}}} * \mathrm{DistCoincidentFactor}_{\mathrm{C,V,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalDistCost}_{\mathrm{C,V,Y,b}}$$

The indices of the parameters in Equation 4-8 include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[43]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}$ (ΔMW) is the nameplate demand reduction of the project at the retail delivery or connection point (“r”). This input is project specific. A positive value represents a reduction in peak load.

[42] The one year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015

[43] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

$\mathbf{Loss\%_{Y,b \rightarrow r}}$ **(%)** is the variable loss percent between the bulk system (“b”) and the retail delivery point (“r”). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2. This parameter to used to adjust the $\Delta \mathrm{PeakLoad}_{Y,r}$ parameter to the bulk system level.

$\mathbf{DistCoincidentFactor_{C,V,Y}}$ **(dimensionless)** captures the contribution to the distribution element’s peak relative to the project’s nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system. This input is project specific.

$\mathbf{DeratingFactor_{Y}}$ **(dimensionless)** is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system. This input is project specific.

$\mathbf{MarginalDistCost_{C,V,Y,b}}$ **($/MW-yr)** is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system (“b”). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3.

4.2.1.2 General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used when and wherever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure need may result in significant over- or under-valuation of the benefits or costs, and may result in no savings in utility costs for customers. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DERs could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. These values are provided in Table A-3.

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the constraint is relieved and benefits should not be realized from that point forward.

The marginal cost of distribution capacity values provided in Table A-3 include both capital and O&M, and cannot be split between the two benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section 4.2.2.

4.2.2 Avoided O&M

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. This benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. At this time, for most DER projects this benefit will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

4.2.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-9 presents the benefit equation for Avoided O&M Costs:

Equation 4-9. Avoided O&M

$$\mathrm{Benefit_Y} = \sum_{\mathrm{AT}} \Delta\mathrm{Expenses_{AT,Y}}$$

The indices of the parameters in Equation 4-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\Delta\mathrm{Expenses_{AT,Y}}$ (Δ$): Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

4.2.2.2 General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be zero for most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely. Labor and crew rates can be sourced using the utility's activity-based costing system or work management system, if that information is available.

4.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project changes distribution system losses, resulting in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%).

4.2.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-10 presents the benefit equation for Avoided Distribution Losses:

Equation 4-10. Avoided Distribution Losses

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{Z}} \mathrm{SystemEnergy}_{\mathrm{Z,Y+1,b}} * \mathrm{LBMP}_{\mathrm{Z,Y+1,b}} * \Delta\mathrm{Loss\%}_{\mathrm{Z,Y+1,i\to r}} + \mathrm{SystemDemand}_{\mathrm{Z,Y,b}} * \mathrm{AGCC}_{\mathrm{Z,Y,b}} * \Delta\mathrm{Loss\%}_{\mathrm{Z,Y,i\to r}}$$

Where,

$$\Delta\mathrm{Loss\%}_{\mathrm{Z,Y,i\to r}} = \mathrm{Loss\%}_{\mathrm{Z,Y,i\to r,baseline}} - \mathrm{Loss\%}_{\mathrm{Z,Y,i\to r,post}}$$

The indices[44] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[45])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathrm{SystemEnergy}_{\mathrm{Z,Y,b}}$ **(MWh)** is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, not the project-specific energy, because this benefit is only quantified when the distribution loss percent value is changed, which affects all load in the relevant part of the distribution system.

$\mathrm{LBMP}_{\mathrm{Z,Y,b}}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system l.evel (“b”). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO’s hourly LBMP forecast by zone rather than developing an

[44] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[45] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\mathrm{Loss\%_{Z,b \rightarrow r}}$ parameter. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent, which affects all load in the relevant part of the distribution system.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system level ("b") based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\mathbf{\Delta Loss\%_{Z,Y,i \rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,i \rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,i \rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

4.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses in the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses.

Because losses data is usually only available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the time delay of benefits relative to the impacts.

4.3 Reliability/Resiliency Benefits

4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, since utilities are required to fix the cause of an outage regardless of whether the DER allows the customer to operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of specific programs or specific projects are identified below. Use of methodology depends on the type of investment/technology under analysis. Equation 4-11 will generally apply to non-DER investments that allow the utility to save time and other expenses dispatching restoration crews. Equation 4-12 will generally apply to DER investments that are able to provide functionally equivalent reliability as an alternative to the traditional utility investment.

4.3.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-11 presents the benefit equation for Net Avoided Restoration Costs associated with non-DER invesments:

Equation 4-11. Net Avoided Restoration Costs

$$\text{Benefit}_{\text{Y}} = -\Delta\text{CrewTime}_{\text{Y}} * \text{CrewCost}_{\text{Y}} + \Delta\text{Expenses}_{\text{Y}}$$

Where,

$$\Delta\text{CrewTime}_{\text{Y}} = \#\text{Interruptions}_{\text{base,Y}} * (\text{CAIDI}_{\text{base,Y}} - \text{CAIDI}_{\text{post,Y}} * (1 - \%\text{ChangeSAIFI}_{\text{Y}}))$$

$$\%\text{ChangeSAIFI}_{\text{Y}} = \frac{\text{SAIFI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}}}{\text{SAIFI}_{\text{base,Y}}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for non-DER projects/programs that are applicable across a total system basis. More targeted & granular data should be utilized for localized and geographic specific projects that exhibit more localized impacts. Other reliability metrics will need to be developed to more suitably quantify reliability or resiliency benefits and costs associated with localized projects or programs. Once developed, the localized restoration cost metric will be applied and included in this handbook.

There is no subscript to represent the type of outage in Equation 4-11 because it assumes an average restoration crew cost that does not change based on the type of outage. The ability to reduce outages would be dependent on the outage type.

$\Delta\mathbf{CrewTime_Y}$ **(∆hours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. This data is project and/or program specific. A positive value represents a reduction in crew time.

$\mathbf{CrewCost_Y}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration as provided in Table A-4.

$\Delta\mathbf{Expenses_Y}$ **(∆$)** are the average expenses (e.g. equipment replacement) associated with outage restoration.

$\#\mathbf{Interruptions_{base,Y}}$ **(int/yr)** are the baseline (i.e., pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI excluding major storms is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. However, in localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. . Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\%\mathbf{ChangeSAIFI_Y}$ **(∆%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average and excludes major storms. It is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

Equation 4-12. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = \mathrm{MarginalCost_{R,Y}}$$

The indices of the parameters in Equation 4-12 are applicable to DER installations and include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\text{MarginalDistCost}_{R,Y}$ **($/yr):** Marginal cost of the reliability investment. This value is very project and location specific and a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent reliability as compared to the traditional distribution reliability investment that would have otherwise been installed/built; If the DER does not defer or avoid a traditional reliability investment, this benefit does not apply. When an individual or portfolio of DER is able to defer a distribution reliability investment, the value of the avoided restoration cost is already reflected in the Avoided Distribution Capacity Infrastructure benefit calculation. Care must be taken to avoid double counting.

4.3.1.2 General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline, not based on outside factors such as weather. The changes to these parameters should consider the appropriate context of the project, for example, impact to one feeder or impact to a portion of the distribution system. The baseline values should match the portion of the system impacted. In addition, one should consider the types of outage event and how the project may or may not address each type of outage event to inform the magnitude of impact.

In addition to being project-specific, the calculation of avoided restoration costs is dependent on projection of the impact of specific investments affecting the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. However, as measurement capabilities and DER experience evolve, utilities may be able to develop comparative evaluations of the reliability benefits of DER and traditional utility investments. Application of this benefit would be considered only for investments with validated reliability results.

4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

4.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-13 presents the benefit equation for Net Avoided Outage Costs:

Equation 4-13. Net Avoided Outage Costs

$$\text{Benefit}_Y = \sum_C \text{ValueOfService}_{C,Y,r} * \text{AverageDemand}_{C,Y,r} * \Delta\text{SAIDI}_Y$$

Where,

$$\Delta\text{SAIDI}_Y = \text{SAIFI}_{\text{base},Y} * \text{CAIDI}_{\text{base},Y} - \text{SAIFI}_{\text{post},Y} * \text{CAIDI}_{\text{post},Y}$$

The indices of the parameters in Equation 4-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\textbf{ValueOfService}_{C,Y,r}$ **($/kWh)** is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\textbf{AvgDemand}_{C,Y,r}$ **(kW)** is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\boldsymbol{\Delta}\textbf{SAIDI}_Y$ **(∆hr/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[46] Baseline system average reliability metrics can be found in Table A-4. A positive value represents a reduction in SAIDI.

$\textbf{SAIFI}_{\text{post},Y}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\textbf{CAIDI}_{\text{post},Y}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\textbf{SAIFI}_{\text{base},Y}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-

[46] SAIDI = SAIFI * CAIDI

wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

4.3.2.2 General Considerations

The value of the avoided outage cost benefit is to be customer-specific, customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming that the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

At this time, the Standard Interconnection Requirements do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

4.4 External Benefits

4.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[47] or the increase of CO_2 from onsite generation. The CARIS Phase 2 forecast of LBMP contains a cost of carbon based on the Regional Greenhouse Gas Initiative (RGGI). Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the LBMP. This adder is based on the United States Environmental Protection Agency damage cost estimates for a 3% real discount rate. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs is the full marginal damage cost less the cost of carbon embedded in the LBMP.

4.4.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-14 presents the benefit equation for Net Avoided CO_2:

[47] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

Equation 4-14. Net Avoided CO_2

$$\mathrm{Benefit_Y = CO2Cost\Delta LBMP_Y - CO2Cost\Delta OnsiteEmissions_Y}$$

Where,

$$\mathrm{CO2Cost\Delta LBMP_Y} = \left(\frac{\Delta \mathrm{Energy_{Y,r}}}{1 - \mathrm{Loss\%_{Y,b\rightarrow r}}} + \Delta \mathrm{Energy_{TransLosses,Y}} + \Delta \mathrm{Energy_{DistLosses,Y}}\right) * \mathrm{NetMarginalDamageCost_Y}$$

$$\Delta \mathrm{Energy_{TransLosses,Y} = SystemEnergy_{Y,b}} * \Delta \mathrm{Loss\%_{Y,b\rightarrow i}}$$

$$\Delta \mathrm{Energy_{DistLosses,Y} = SystemEnergy_{Y,b}} * \Delta \mathrm{Loss\%_{Y,i\rightarrow r}}$$

$$\Delta \mathrm{Loss\%_{Z,Y,b\rightarrow i} = Loss\%_{Z,Y,b\rightarrow i,baseline} - Loss\%_{Z,Y,b\rightarrow i,post}}$$

$$\Delta \mathrm{Loss\%_{Z,Y,i\rightarrow r} = Loss\%_{Z,Y,i\rightarrow r,baseline} - Loss\%_{Z,Y,i\rightarrow r,post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions_Y} = \Delta \mathrm{OnsiteEnergy_Y} * \mathrm{CO2Intensity_Y} * \mathrm{SocialCostCO2_Y}$$

The indices of the parameters in Equation 4-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\mathbf{CO2Cost\Delta LBMP_Y}$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided LBMP benefit. The incremental value of CO_2 is captured in this benefit, and is valued at the net marginal cost of CO_2, as described below.

$\mathbf{CO2Cost\Delta OnsiteEmissions_Y}$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\mathbf{\Delta Energy_{Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table A-2.

$\mathbf{\Delta Energy_{TransLosses,Y}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\Delta \mathbf{Energy}_{\mathbf{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section 4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathbf{NetMarginalDamageCost}_{\mathbf{Y}}$ **($/MWh)** is the “adder” Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of LBMP from CARIS Phase 2. The LBMP forecast from CARIS Phase 2 includes the cost of carbon based on the RGGI, but does include the SCC from the U.S. EPA.

$\Delta \mathbf{Loss\%}_{\mathbf{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%}_{\mathbf{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface between the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%}_{\mathbf{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface between the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). Thus, this reflects the transmission loss percent post-project, which is found in Table A-2.

$\Delta \mathbf{Loss\%}_{\mathbf{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems (“i”) and the retail delivery point (“r”) resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%}_{\mathbf{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%}_{\mathbf{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”). Thus, this reflects the distribution loss percent post-project, which is found in Table A-2.

$\Delta \mathbf{OnsiteEnergy}_{\mathbf{Y}}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathrm{CO2Intensity}_{\mathrm{Y}}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation. Note that there is a difference between metric tons and short tons[48].

$\mathbf{SocialCostCO2}_{\mathbf{Y}}$ **($ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in carbon dioxide emissions. Annual values are provided by EPA, and are also located in Table A of Attachment B of the BCA Order. Per the BCA Order, the values

[48] 1 metric ton = 1.10231 short tons

associated with a 3% real discount rate shall be used. Note that Table A provides values in 2011 dollars; these values must be converted to nominal values prior to using the equation above.

4.4.1.2 General Considerations

The equation above represents two sources of emissions based on: (1) a change in LBMP purchases, which is valued at the $/MWh adder (i.e., $NetMarginalDamageCost_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power [CHP]), which is valued at the social cost of carbon from EPA.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided LBMP benefit. The LBMP impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in LBMP due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The methodology outlined in this section to value Avoided CO_2 may change. The *BCA Order* indicates "utilities shall rely on the costs to comply with New York's Clean Energy Standard once those costs are known."[49]

4.4.2 Net Avoided SO_2 and NO_x

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

4.4.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation 4-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit_Y} = \sum_{\mathrm{p}} \mathrm{OnsiteEmissionsFlag_Y} * \mathrm{OnsiteEnergy_{Y,r}} * \mathrm{PollutantIntensity_{p,Y}} * \mathrm{SocialCostPollutant_{p,Y}}$$

The indices of the parameters in Equation 4-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag_Y}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW is implemented as a result of the project.

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[49] *BCA Order*, Appendix C, 16.

$\mathbf{OnsiteEnergy_{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

$\mathbf{PollutantIntensity_{p,Y}}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$\mathbf{SocialCostPollutant_{p,Y}}$ **($/ton)** is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2

4.4.2.2 General Considerations

LBMPs already include the cost of pollutants (i.e., SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: “Annual NO_x” and “Ozone NO_x.” Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

4.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

4.5 Costs Analysis

4.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

4.5.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-16 presents the cost equation for Program Administration Costs:

Equation 4-16. Program Administration Costs

$$\text{Cost}_{\text{Y}} = \sum_{\text{M}} \Delta\text{ProgramAdminCost}_{\text{M,Y}}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

$\Delta\text{ProgramAdminCost}_{\text{M,Y}}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

4.5.1.2 General Considerations

Program Administration Costs are program- and project-specific, therefore without a better understanding of the details it is not possible to estimate in advance the Project Administration Cost. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

4.5.2 Added Ancillary Service Costs

Added Ancillary Service Costs occur when DER causes additional ancillary service cost on the system. These costs shall be considered and monetized in a similar manner to the method described in the 4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

4.5.3 Incremental Transmission & Distribution and DSP Costs

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional T&D infrastructure costs caused shall be considered and monetized in a similar manner to the method described in Section 4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. These factors make estimating a value of incremental T&D costs in advance without project-specific information difficult.

Depending on the nature of a specific DER project the incremental costs could be borne by the interconnecting facility or shared among all ratepayers. For instance, a utility may need to make further investment in their T&D infrastructure, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

4.5.4 Participant DER Cost

Participant DER Cost includes the equipment and participation costs assumed by DER providers which need to be considered when evaluating the societal costs of a project or program. These costs are the full cost of the DER net of program rebates, and incentives that are included as part of Program Administration Costs. Together Participant DER Cost and Program Administration Costs equal the total cost of the DER project.

The Participant DER Costs includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment, balance of system and labor for the installation. Operating costs include ongoing maintenance expenses.

This section provides four examples of DER technologies with illustrative cost information based on assumptions that will ultimately vary given the facts and circumstances specific to each DER application:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – reciprocating engine (100 kW)
- Demand Response (DR) – controllable thermostat
- Energy Efficiency (EE) – commercial lighting

All cost numbers presented herein should be considered illustrative estimates only. These represent the full costs of the DER and do not account for or net out any rebates or incentives. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from, each of which have different combinations of cost and efficiency.

- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the state
- **Available rebates and incentives:** include federal, state, and/or utility funding

The Commission noted in the February 2015 Track 1 Order that the approach employed to obtain DER will evolve over time,

"The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach."[50]

Thus, the acquisition of most DER in the near term will be through competitive solicitations rather than the establishment of tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation.[51] Company competitive solicitations for DER will require the disclosure of costs by the bidders, including but not limited to capital, installation, marketing, administrative, fixed and variable O&M, lost opportunity and/or behavioral incentive costs. The Company will use the submitted costs in the project/program/portfolio BCA evaluation. Additionally, the Company will employ this information to develop and update technology specific benchmark costs as they evolve over time. .

For illustrative purposes, examples for a small subset of DER technologies are provided below.

4.5.4.1 Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table 4-1 for the intermittent solar PV example are derived based on information provided in the E3's NEM Study for New York ("E3 Report").[52] In this study, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in NY from 2003 to 2015. This is just one example of evaluating the potential cost of solar PV technology. For a project-specific cost analysis, actual estimated project costs would be used.

[50] At 33

[51] BCA Order, Appendix C pg. 18.

[52] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

Table 4-1. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[53]	4,430
Fixed Operating Cost ($/kW)	15

Note: These costs would change as DER project-specific data is considered.

1. **Capital and Installation Cost:** Based on E3's estimate for NYSERDA of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4 kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.
2. **Fixed Operating Cost:** E3's estimate for NYSERDA of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

4.5.4.2 CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. For this illustration, cost parameter values were obtained from the EPA's Catalog of CHP Technologies[54] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can affect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural-gas fired CHP system. All of these elements would need to be reviewed and incorporated to develop the Company's service territory technology specific benchmarks.

Table 4-2. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [55]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[56]

[53] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

[54] EPA CHP Report available at: https://www.epa.gov/chp/catalog-chp-technologies

[55] EPA CHP Report. pg. 2-15.

[56] EPA CHP Report. pg. 2-17.

4.5.4.3 DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell. The DR technology benchmarks will evolve as the company gains experience with development and implementation of a DR program portfolio.

Table 4-3. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$140

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature.
2. **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

4.5.4.4 EE Example

The energy efficient lighting used in this example is indoor installation of a linear fluorescent lighting fixture in a commercial office setting. Lighting cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed. The Company would need to incorporate its service territory specific information when developing its DR technology benchmarks.

Table 4-4. EE Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/Unit)	$80

Note: This illustration would change as projects and locations are considered.

1. **Installed Capital Cost:** Based on Navigant Consulting's review of manufacturer information and energy efficiency evaluation reports. The Company would need to incorporate its service territory specific information when developing its EE technology benchmarks.

4.5.5 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue "losses" due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other ratepayers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

4.5.6 Shareholder Incentives

Shareholder Incentives include the annual costs to ratepayers of utility shareholder incentives that are tied to the projects or programs being evaluated.

Shareholder incentives should be project or program specific and should be evaluated as such.

4.5.7 Net Non-Energy Costs

A suggested methodology for determining this benefit is not included in this version of the Handbook. In cases where non-energy impacts are attributable to the specific project or program, they may be assessed qualitatively. Net Non-Energy Costs may be applicable to any of the cost-effectiveness tests defined in the *BCA Order* depending on the specific project and non-energy impact.

5. CHARACTERIZATION OF DER PROFILES

This section discusses the characterization of DERs using several examples, and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are: *intermittent*, *baseload*, *dispatchable* and *load reduction*. There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table 5-1 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook.

Table 5-1. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies that have been selected as examples are shown in Table 5-2. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table 5-2.

Table 5-2. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER is capable of enabling a different set of benefits and incurs a different set of costs, as illustrated in Table 5-3.

Table 5-3. General applicability for each DER to contribute to each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
Benefits					
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided LBMP	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	●	●	●	●
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
Costs					
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Shareholder Incentives	●	●	●	●
23	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section 4, each quantifiable benefit typically has two types of parameters. The defined benefits established to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), however key parameters assess the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). In other words, the amount of the underlying value that is captured by the DER resource is driven by the key parameters. Table 5-4 identifies the parameters which are necessary to characterize DER benefits. As described in Section 4, several benefits potentially applicable to DER require further investigation to estimate and quantify the impacts, and project-specific information before they can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table 5-4. Key parameter for quantifying how DER may contribute to each benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	**SystemCoincidenceFactor**
2	Avoided LBMP	**ΔEnergy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**ΔEnergy (annual)** **ΔAGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[57]
12	Net Avoided CO_2	**CO_2Intensity** (limited to CHP)
13	Net Avoided SO_2 and NO_x	**PollutantIntensity** (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

Table 5-5 further describes the key parameters identified in Table 5-4.

[57] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table 5-5. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[58] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[59]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
ΔEnergy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ΔEnergy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the ΔEnergy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[60]

[58] This parameter is also used to calculate the Wholesale Market Price Impact benefit.

[59] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided LBMP and AGCC. This transmission coincidence factor is applicable for the Avoided Transmission Capacity Infrastructure and Related O&M benefit, which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs and Avoided LBMPs benefits.

[60] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit.

5.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

5.1.1 Bulk System

According to the NYISO, the bulk system peaks generally occur during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM. Table 5-6 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes.

Table 5-6. NYCA Peak Dates and Times

Year	Date of Peak	Time of Peak
2011	7/22/2011	Hour Ending 5 PM
2012	7/17/2012	Hour Ending 3 PM
2013	7/19/2013	Hour Ending 6 PM
2014	9/2/2014	Hour Ending 5 PM
2015	7/29/2015	Hour Ending 5 PM

5.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. In general, the benefits of a reduced transmission peak would be captured through the Avoided LBMP and AGCC benefits.

5.1.3 Distribution

The distribution peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood. The distribution system peak may differ or coincide with the NYCA system peak and the transmission peak. System-wide averages have been historically acceptable to use for some investment portfolios such as Energy Efficiency where the programs are broad based, and system-wide averages are provided in the Technical Resource Manual (TRM), which assumes a historical coincidence for the NYCA peak. Going forward, for investments that are more targeted in nature, a more localized coincidence factor is likely to be appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be low or zero if no constrained element is relieved (e.g., no distribution investment is otherwise required in capacity in that location, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

5.2 Estimating Coincidence Factors

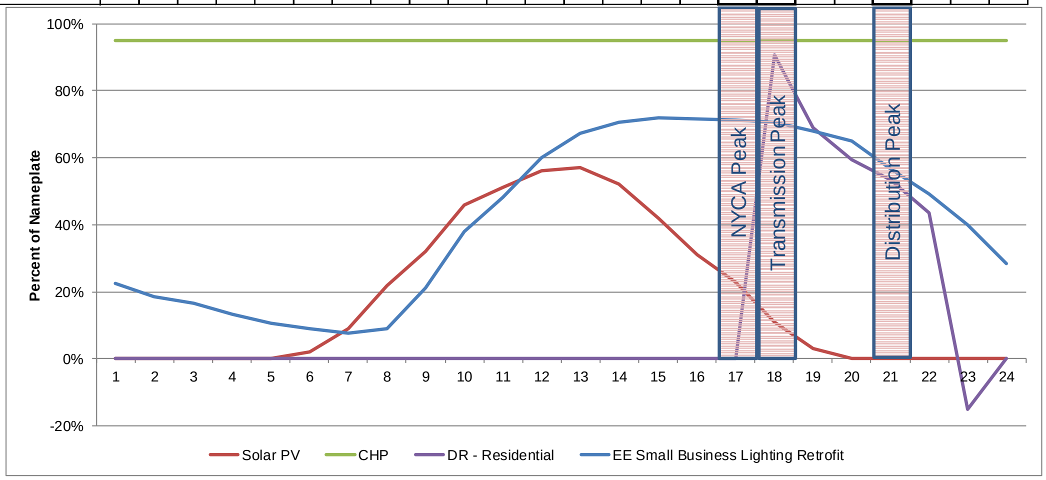
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable in some situations.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a ‘typical day’, or using a subset of hours that are appropriate that specific DER.

Figure 5-1 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource.

Figure 5-1. Illustrative Example of Coincidence Factors

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

The individual DER example technologies that have been selected are discussed below.[61]

The values for the DER examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in E3's NEM Study for New York ("E3 Report")[62] based on a simulation of a large number of solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

[61] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DERs, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DERs and distribution system information is less generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWAs it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DERs, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, economic energy delivery. The BCA handbook incorporates derating factors in various benefit calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it was not included.

[62] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

5.3 Solar PV Example

Solar PV is selected to depict an **intermittent** DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions, were obtained from the E3 Report.

The following examples include illustrative coincidence factors for several technologies. Actual locational estimates of coincidence with specific DER technologies are included in Appendix N of the DSIP.

5.3.1 Example System Description

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

5.3.2 Benefit Parameters

The benefit parameters in Table 5-7 for the intermittent solar PV example are based on information provided in the E3 Report.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted-averages based on electricity delivered by utility are provided in Table 5-7. These values are illustrative estimates that may be refined as more data becomes available. To calculate project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (LBMP) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Table 5-7. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
∆Energy (time-differentiated)	Hourly

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC, that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[63] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section 4.1.1).
2. **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
3. **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[64] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
4. **∆Energy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly LBMPs.

5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

5.4.1 Example System Description

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance. The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[65]

5.4.2 Benefit Parameters

Benefit parameters for the baseload CHP example are a combination of assumptions on system use and system characteristics.

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[63] NYISO ICAP Manual 4, June 2016 – Summer Unforced Capacity Percentage – Solar (Fixed Tilt Arrays) – pg. 4-23

[64] E3 Report, "Based on E3's NEM Ratepayer Impacts Evaluation in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed." PDF pg. 49.

[65] https://www.epa.gov/chp/catalog-chp-technologies

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, with the exception of downtime for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[66]

The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[67] "CHP Technology," "Fuel," "Unit Capacity" and "Operation" were the four inputs required. Based on the example, a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors.

Table 5-8. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
ΔEnergy (time-differentiated)	Annual average

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.1).
5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.2). There are no SO_2 emissions from burning natural gas.

[66] EPA CHP Report. pg. 2-20.

[67] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.

6. **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

5.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it is reduces demand on request from the system operator or utility.[68] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g., <100 hrs). The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

The coincidence factors shown below do not account for load or device availability. Load availability is defined as the percentage of total potential capacity that can be shed from the load connected to the DR system at the time the DR event is called. Device availability is defined as the ability the DR system to accurately receive the DR signal and control the load. These factors, multiplied by the total potential capacity of the DR asset, would produce the average demand reduction for the asset. Average demand reduction multiplied by the coincidence factor is then defined as the average peak coincidence demand. These values are not presented here but are project- and technology-specific and will differ substantially among DR technologies and loads. As such, project-specific analyses would need to consider the load and system availability, as well as response rate (as described above) to accurately determine the appropriate coincidence factors.

This DR example is designed to reduce system peak (consistent with most existing DR programs), thus the system coincidence factor is 1.0 such that the DR resource is called to reduce the system peak load.[69] Given the small number of calls annually, the coincidence factor with the system peak is assumed to be 1, while the coincidence factors for the transmission and distribution peaks is assumed to be 0.5 which is consistent with the assumption that this particular DR example is not targeted to be coincident with those peaks.[70]

As an alternative approach, to calculate the coincidence factors for a specific DR resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system with the peak demand of the other systems. Comparing the coincidence of the top 50

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[68] Some DR programs may be “dispatched” or scheduled by third-party aggregators.

[69] Note, the controllable load may not be operating at the time of peak.

[70] Con Edison Callable Load Study, Page 78, Submitted May 2008.
http://www.coned.com/documents/Con%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

hours of total system load and top 50 hours of each feeder's load would produce the distribution coincidence factor for a DR project that targets system peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the DR program. Coincidence factors for DR projects should use the most recently available data.

The value of reduced energy use attributable to the DR asset can be calculated using the average LBMP of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2 hour events, 4 hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

5.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above.

Table 5-9. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	0.5
DistCoincidenceFactor	0.5
∆Energy (time-differentiated)	Average of highest 100 hours

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is assumed to be 1.0, based on the assumption that the DR system is called upon at the time of system peak.
2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[71] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.
3. **DistCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[72] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above. If instead the DR asset were used to defer distribution capacity, the coincidence factor could be as high as 1 (though the system

[71] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://www.coned.com/documents/Con%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

[72] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://www.coned.com/documents/Con%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

coincident factor could then be as low as zero, since if the peak periods were to occur at the same time, the project could only be dispatched for one program).

4. **∆Energy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings can be estimated based on the *average* demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time-differentiated LBMP.

5.6 Energy Efficiency Example

Energy efficient lighting depicts a **load-reducing** DER where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology. The parameter assumptions, and methodology used to develop those assumptions, developed using the NY TRM.[73]

5.6.1 Example System Description

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting with an estimated utilization of 3,013 hours/year.[74] The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of an indoor, office-setting lighting system assumes that the coincidence factor is calculated during operational hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks.

5.6.2 Benefit Parameters

The benefit parameters described here were developed using guidance from the NY TRM.

Table 5-10. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	1.0
∆Energy (time-differentiated)	~7 am to ~7 pm weekdays

[73] New York State Technical Resource Manual (TRM)l: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 4, Issued on April 29, 2016 – Lighting operating hour data is sourced from the 2008 California DEER Update study.

[74] Ibid.

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 1.0 under the assumption that the system peak occurs while standard office lighting systems are operating.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 1.0 under the assumption that the transmission system peak occurs while standard office lighting system are operating.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 1.0 under the assumption that the distribution system peak occurs while standard office lighting systems are operating.
4. **∆Energy (time-differentiated):** This value is calculated using the lighting hours per year (3,013) as provided for General Office types[75] in the NY TRM, divided by the total hours in a year (8,760). This time period is subject to building operation, which is roughly between 7 am and 7 pm, 5 days a week, 52 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

[75] New York State Technical Resource Manual (TRM)l: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 4, Issued on April 29, 2016 - pg. 221

APPENDIX A. UTILITY-SPECIFIC ASSUMPTIONS

This section includes utility-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 4.

The discount rate is set by the utility cost of capital, which is included in Table A-1.

Table A-1. Utility Weighted Average Cost of Capital

For Use in SCT	For Use in UCT, RIM
6.62%	9.43%
Source: Order Approving Rate Plan issued and effective June 17, 2015 in Cases 14-E-0318 and 14-G-0319	

System loss values may be affected by certain projects which alter the topography of the transmission and/or distribution systems. Central Hudson does not currently have disaggregated fixed and variable loss information available. Where loss values are applicable to calculations within the handbook, system average values should be used. System annual average loss data is shown in Table A-2.

Table A-2. Utility Loss Data

System	Average Loss Percent
Transmission	2.03%
Primary Distribution	2.54%
Secondary Distribution	2.16%
Total System	6.73%
Source: 2007 Central Hudson Gas & Electric Corporation Analysis of System Losses, produced by Management Applications Consulting, Inc. for Central Hudson	

Utility-specific system average marginal costs of service are found in Table A-3.

[76] Regulatory Weighted Cost of Capital does not include the impact of taxes and is utilized for the SCT test

Table A-3. 10-Year Average Utility System Marginal Avoided T&D Costs

Forecast Year	Distribution Substation	Transmission	Total
2016	$0.00	$0.00	$0.00
2017	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00
2020	$0.03	$12.38	$12.41
2021	$0.12	$26.65	$26.77
2022	$0.19	$31.52	$31.71
2023	$0.25	$36.28	$36.53
2024	$0.32	$37.42	$37.74
2025	$0.30	$38.82	$39.11
10-Year	**$0.09**	**$14.33**	**$14.42**

Source: Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods, 2016, produced by Nexant for Central Hudson

Note: System-wide values account for the percentage of load which occurs in areas with forecasted growth related investments. All values are in nominal dollars.

Average restoration costs are found in Table A-4.

Table A-4. Average Hourly Restoration Costs

Average Hourly Restoration Costs
Restoration Costs will be determined for each specific project as applicable
Source: Project Specific

Table A-5. Operation & Maintenance Costs

Average Hourly Restoration Costs
O&M Costs will be determined for each specific project as applicable
Source: Project Specific

Appendix L System Peak Demand Forecast

Methodology

A regression model was developed to relate historical daily peak demand to daily load factor, several weather variables, and an economic driver. Based on the results of an analysis of the timing of the annual system peak over the most recent ten years and forty years which indicated that ninety percent of annual peaks occur in the months of July or August and all annual peaks occur on weekdays, the model was constructed from actual daily weekday peak load for the months of July and August for 2010 through 2015. Weather variables included mean daily dry bulb temperature, maximum daily dry bulb temperature, and prior day mean daily dry bulb temperature, with temperatures obtained from the Dutchess County Airport. Total employment was utilized as the economic driver.

Normal Demand Projections

The system peak normal demand projections for 2016 through 2021 and the normalization of actual peak demand over the estimation period of 2010 through 2015 are based on an estimated normal peak day defined as the upper 95% mean over 30 years, with the normal mean daily dry bulb temperature approximating 82.6 degrees Fahrenheit, the normal maximum daily dry bulb temperature approximating 95.7 degrees Fahrenheit, and the normal prior day mean daily dry bulb temperature approximating 80.8 degrees Fahrenheit. The daily load factor was estimated from a regression equation, with load factor defined as a function of maximum daily dry bulb temperature and prior day mean daily dry bulb temperature.

Design Demand Projections

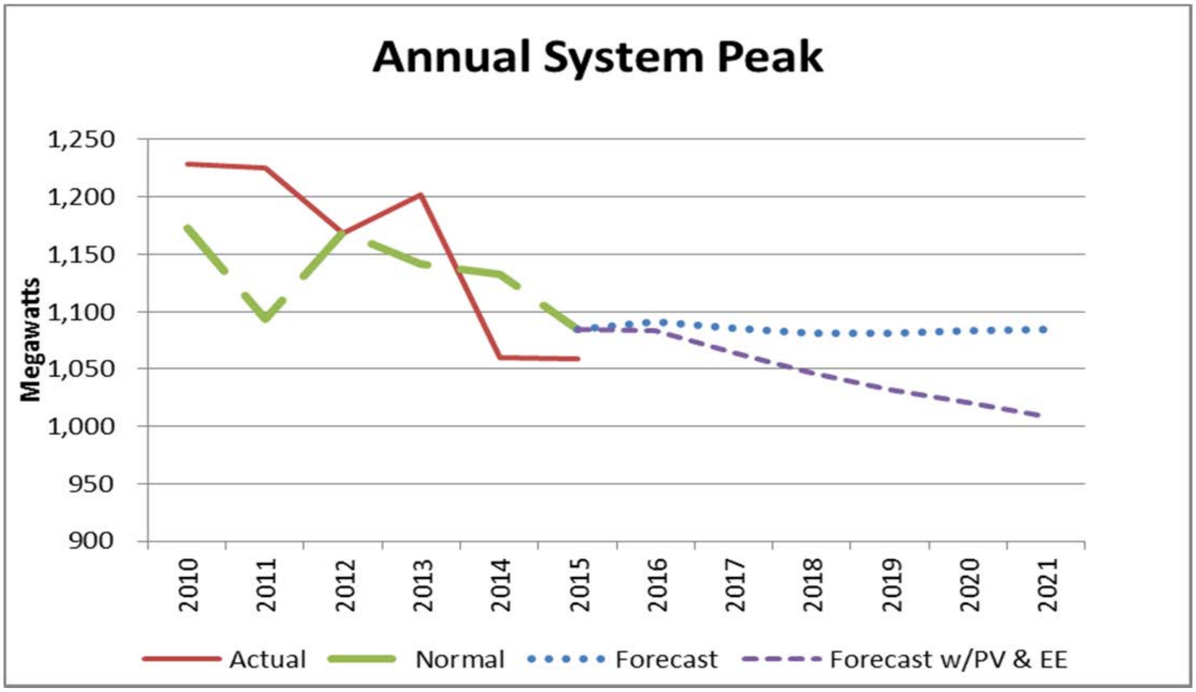
The system peak design demand projections are based on the normalization methodology utilized for the Company's submission of weather normalized 2015 peak to the NYISO Load Forecasting Task Force which utilizes a composite temperature variable defined as the square root of the product of the dry bulb peak hour temperature and the average hourly wet bulb temperature on the day of the peak. The methodology 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, with the design temperature determined as the maximum composite temperature variable experienced since 1980.

Adjustments

Once the base projections are developed, adjustments for energy efficiency ("EE") and distributed energy resources, specifically net-metered customer sited photovoltaic units ("PV"), are applied to yield net projections. Since the impacts of all EE and PV are embedded in the historical demand data, the demand projections must be reduced by an estimate of the incremental impacts of future EE and PV. The reductions attributable to EE were developed by utilizing data available from the NYISO's 2016 Gold Book, specifically applying the historic trend of the ratio of Central Hudson's peak to the total of peaks for Zones E and G to the NYISO's incremental EE reductions anticipated for Zones E and G. Since the actual impact of PV varies considerably by hour of the day, the reductions attributable to PV were developed by estimating the peak hour MW impact for the month of July for hour ending 1700, the most likely hour of occurrence for the system peak. The forecast of PV MW installed prepared for the most recent sales forecast was utilized, but de-rated by fifty percent to reflect additional regulatory activity occurring in Case 14-M-0101 since the development of the forecast that might dampen PV installations from the level anticipated in the initial forecast.

Results

System Peak Demand				
			With Estimated EE and PV Reductions	
Year	Actual MW	Normal MW	Projected Normal MW	Projected Design MW
2010	1,229	1,173		
2011	1,225	1,094		
2012	1,168	1,170		
2013	1,202	1,142		
2014	1,060	1,133		
2015	1,059	1,085		
2016			1,083	1,254
2017			1,064	1,235
2018			1,046	1,217
2019			1,032	1,203
2020			1,021	1,192
2021			1,009	1,180



Forecast Variability

As with any forecast, the forecasts of system peak demand presented here depend on other forecasts of key variables and adjustments. Fluctuations in these variables can dramatically impact the forecasts. The annual system peak demand is very sensitive to weather conditions and can vary significantly as the result of abnormal weather conditions.

Additionally, fundamental changes in electricity use stimulated by regulatory policy may also have a significant impact on the forecasts. For example, as the Company gains experience with its newly implemented dynamic load management programs and the demand response programs to be implemented under its non-wires alternative project additional adjustments to the forecasts may be required. Changes in electricity use stimulated by evolving technology, and aided by regulatory policy, such as the emergence and penetration of electric vehicles may also impact the forecasts and will also need to be monitored in order to maintain and increase forecast accuracy.

June 2016

Appendix M System Energy Sales Forecast

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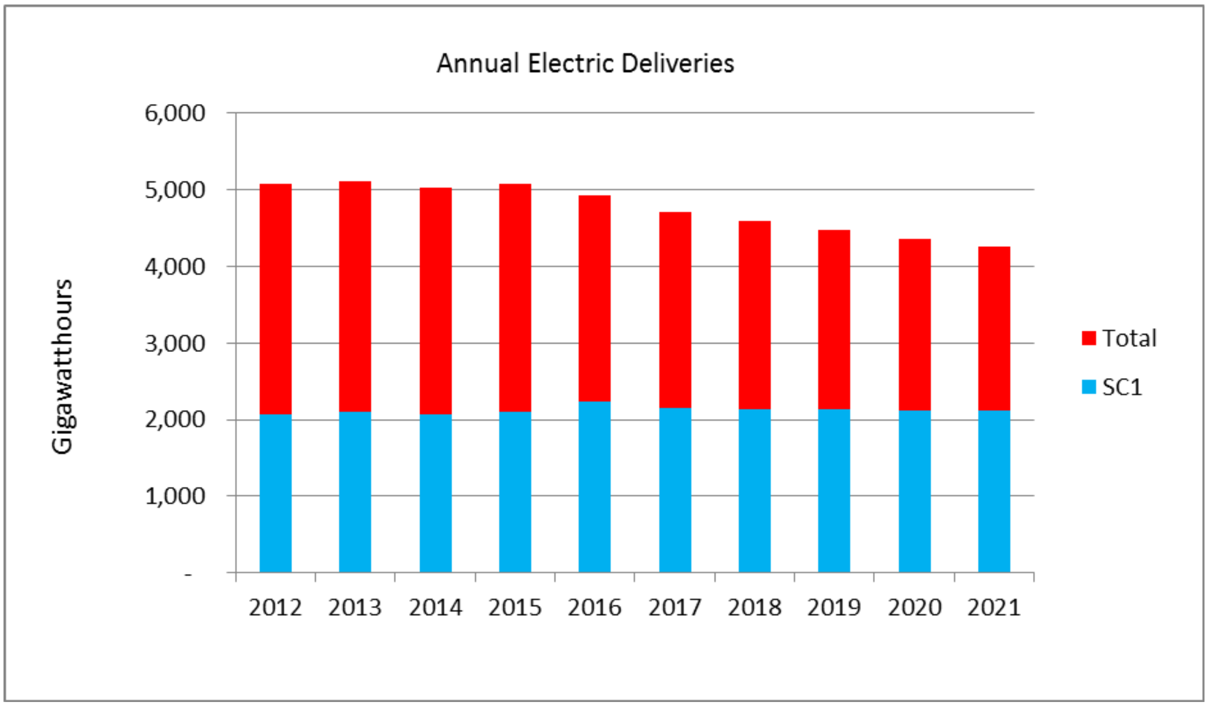
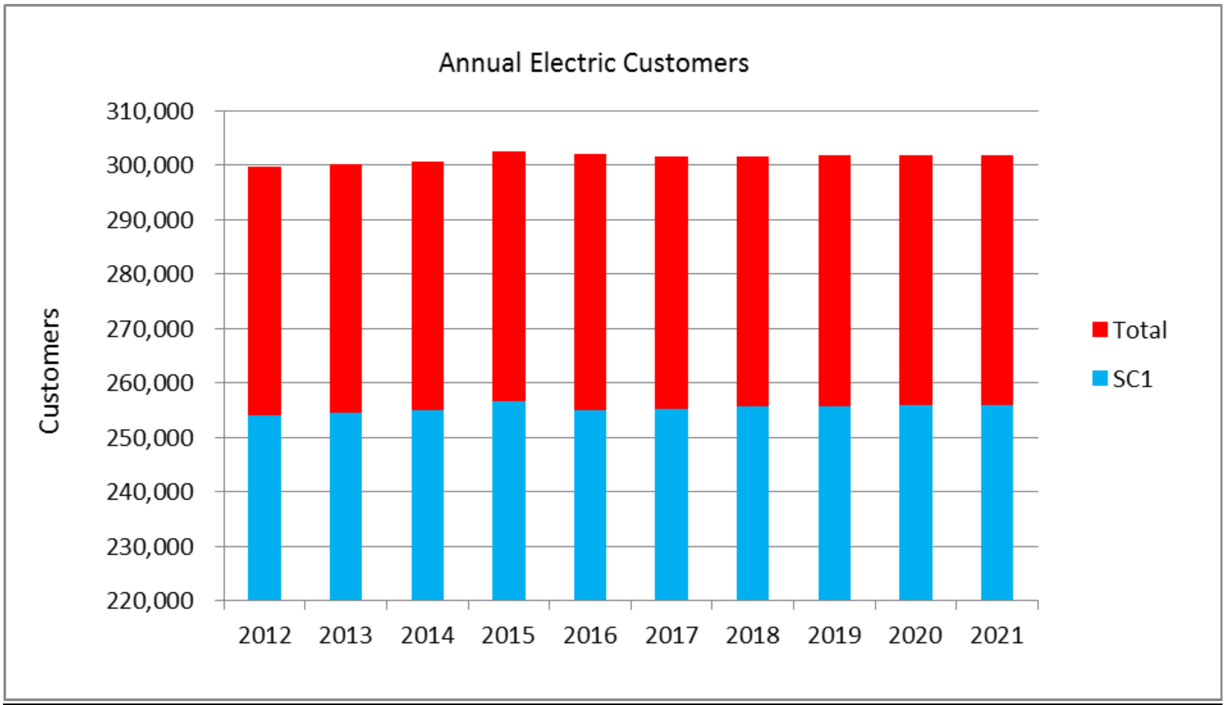
Summary

While the Company continues to experience a slight growth in the number of electric customers, overall use per customer has decreased since 2005. Use per customer is forecasted to continue to decline, with usage reductions due to the EEPS in Case 07-M-0548 and lost electric sales due to PV net-metering contributing to this decline. As a result, electric sales are forecasted to decrease.



Sources:
2012-2015: Actual deliveries
2016: 2016-2020 Sales Forecast
2017-2021: Current Sales Forecast



Sources:
2012-2015: Actual customers
2016: 2016-2020 Sales Forecast
2017-2021: Current Sales Forecast

Data

The sales forecast process primarily utilizes historic monthly billed customer, 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 ("OPA"), lighting and interdepartmental.

Forecast Variables

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

Demographic and Economic Variables

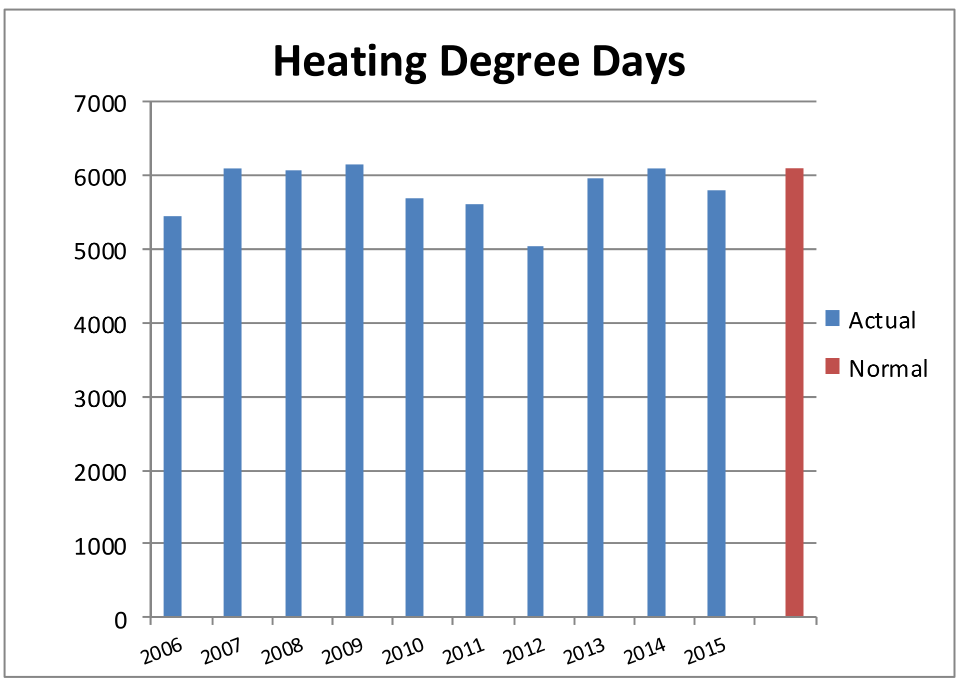
Demographic and economic variables, both historic and forecast for the region served by the Company are based on the August 2015 forecast provided by Moody's Analytics to the NYISO for statewide forecasting. Composite forecast drivers for the Central Hudson region were constructed from four data regions included in the forecast: Albany, Catskills (Ulster and Greene counties), Dutchess County and Newburgh. The composite economic forecast drivers were calculated as a weighted sum of the regional forecasts, where the weights reflect actual average residential and non-residential sales in the region for calendar years 2013 through 2015.

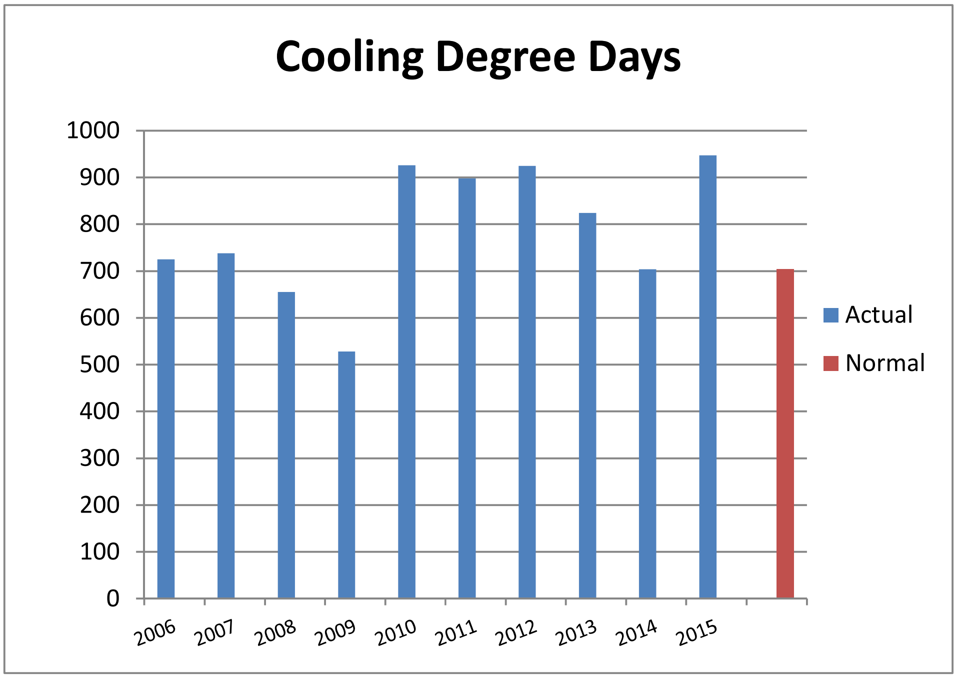
The variables constructed in this manner are intended to provide an economic forecast that is more reflective of the economic conditions in the Company's territory than either using any one individual regional forecast or the New York State forecast. A few selected economic and demographic variables that were utilized in the forecast are summarized below.

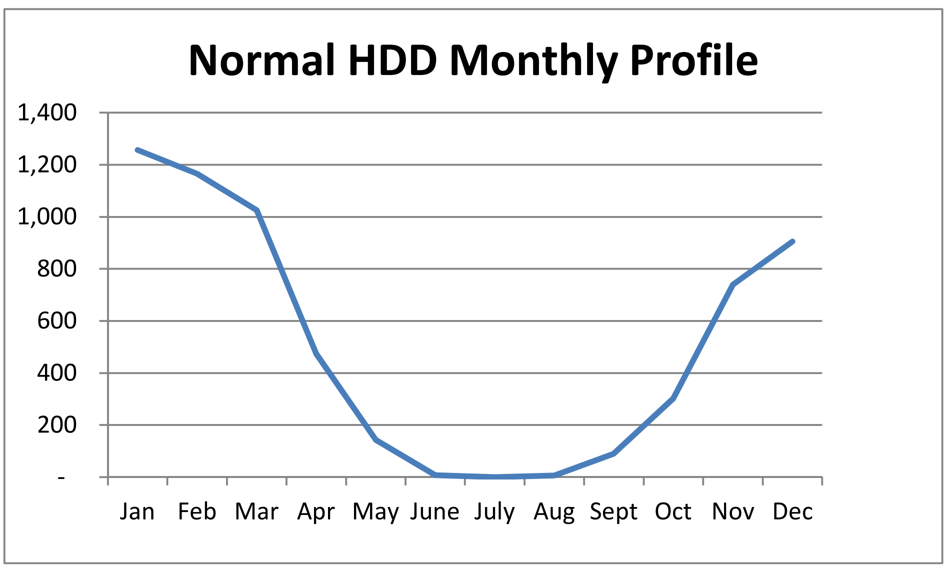
- **Populations-** Since 2010 the region's population growth has slowed dramatically and more recently has exhibited an outright decline as every county in the mid-Hudson region, excluding Orange County, has experienced a decrease in population level. This decline in population is primarily due to significant domestic out-migration, with migration out of the region outnumbering migration between counties within the region by a margin of approximately 3 to 1. Much of the out-migration continues to be driven by aging baby boomers retiring to warmer locations and displaced workers, including hi-tech professionals, who are unable to be absorbed into the local job market.
- **Household Income –**The region's proximity to the New York metro area continues to have a significant impact on its economy as areas of the Hudson Valley act as bedroom communities to the New York City workers. The area continues to provide a cost of living advantage for commuters as well as an affordable alternative for businesses looking for the proximity but at a lower cost. Growth in household income is expected to continue a positive growth of 2.8 percent for the remainder of 2016 and beyond.
- **Unemployment –** While the region's unemployment rate continues to decline, and continues to be among the lowest in the state, more recently this decline has been primarily attributable to job growth rather than a combination of job growth coupled with a shrinking labor force participation rate as had been experienced since 2009. Private sector employment has continued to fuel job market gains, with growth in the natural resources, mining and construction and the educational and health services sectors accounting for about 71% of recent overall job growth in the region.

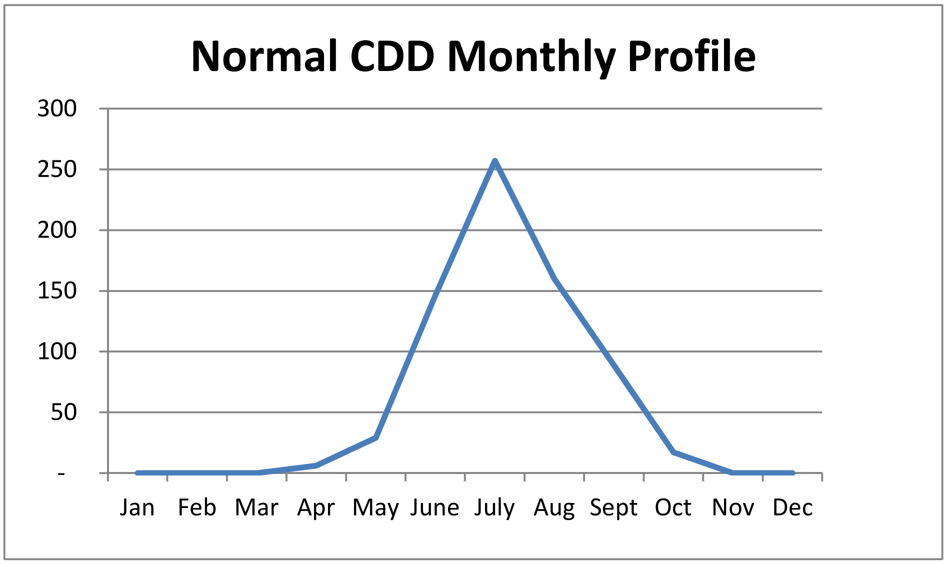
Weather

Weather is incorporated into the sales models through the use of heating degree days ("HDD") and cooling degree days ("CDD"). Electric HDD are defined as the amount by which 65 degrees Fahrenheit exceeds the average of the high and low dry bulb temperatures for a given day as measured midnight to midnight at the Dutchess County Airport. CDD are defined as the amount by which the average of the high and low dry bulb temperatures for a given day, as measured midnight to midnight, exceed 65 degrees Fahrenheit. Monthly actual degree days are transformed into billed degree-days to more closely correspond to the sales billing periods. The sales forecasts are based on normal weather conditions, where the normal weather is determined by a ten-year average of actual monthly HDD or CDD, as applicable and pursuant to the Commission's Order in Case 08-E-0887, for the calendar year ending 2015, which is the latest calendar year for which this information was available at the time of the Company prepared its sales forecast.




Cooling Degree Days
1000
900
800
700
600
500
400
300
200
100
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
Actual
Normal


Normal HDD Monthly Profile
1,400
1,200
1,000
800
600
400
200
-
Jan
Feb
Mar
Apr
May
June
July
Aug
Sept
Oct
Nov
Dec



Price

The historic price series for each class was 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, projected annual delivery rate increases of approximately $15 million effective July 1, 2018, as well as Merchant Function Charges, the New York State Assessment , System Benefits Charges , including costs associated with clean energy activities conducted by the New York State Energy Research and Development Authority ("NYSERDA") and energy efficiency programs implemented by the Company, the Purchased Power Adjustment , Miscellaneous Charges and the Market Price Charge ("MPC"). The MPC, or supply price, was forecasted using monthly regression equations to estimate MPC prices as a function of the on-peak price forecast for NYISO Zone G as of February 19, 2016 as obtained from SNL Financial. The price variable is indexed against the Consumer Price Index and expressed as a twelve-month moving average on a one-month lag.

End-Use Saturation and Efficiency Trends

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.

Forecast Methodology and Assumptions

For sales forecasting purposes, the previously identified customer sectors were further delineated into thirteen individual forecasting classes, distinguishing between either heat and non-heat (for residential classes) or demand and non-demand (for non-residential classes). The models and methods incorporate a number of assumptions regarding economic activity, prices and consumption patterns.

Quantitative methods were utilized whenever possible in the forecasting process, as discussed below, with reliance on judgment as applicable as judgment is an integral part in the development of any forecast. Forecasts of customers and sales were developed utilizing various econometric or time series models, or trend projections. The models developed to produce the forecasts were estimated using actual monthly billed customer and sales data with estimation periods varying somewhat for the different classes in order to recognize systemic changes or structural changes to the billing process and data quality issues that can sometimes limit data availability.

Analytical Techniques

The sales forecast for the large industrial class was 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 considered 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 were 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 were based on an analysis of several years of actual sales data.

Customers

Customer forecasts were developed for each electric customer class. Econometric models were constructed to forecast customer levels for the electric residential classes. Two types of variables were employed in the specification of these models: economic and binary (or dummy), with the number of households utilized as the economic variable. Utilization of binary or “dummy” variables is reflected in many of the customer and sales models presented here, consistent with standard modeling practices. In many instances, this type of variable was added as a switch to turn various parameters on and off, such as differences in odd/even month billing to reflect bimonthly billing for certain accounts, or to accommodate a specific data point to reduce model error, while maintaining a longer estimation period. The remaining customer forecasts were developed through either time series analyses, trend projections, or in the case large industrial (those customers who require service at transmission voltage or who have provided all the necessary equipment to take service directly from a substation) through discussion with specific customers.

Sales

For a number of classes, sales volume forecasts were 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 were 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. For instance, total residential consumption can be influenced by such factors as customer count (e.g., total number of residential customers), weather, and the economy. In this example, weather will most likely not influence the number of customers, but could greatly influence use per customer. As a result, separating total consumption into components provides the opportunity to incorporate more structure into the forecast of each component.

Econometric models were generally constructed to forecast sales for all electric classes, excluding: large industrial, the three lighting classes, and interdepartmental. Further, the forecasts developed for the electric residential and commercial classes utilize Statistically Adjusted End-Use ("SAE") 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 that also reflect weather, price and economic drivers. For the residential classes these SAE models incorporate end-use intensity (kWh per household) indices that capture changes in appliance ownership, efficiency improvements, changes in housing size and improvements in housing shell thermal integrity.

Models Specified

Customer and sales forecasts were developed utilizing various econometric or time series models, or trend projections, as summarized below.

List of Electric Customer and Sales Forecast Methods		
Class	Customers	Sales
Res. Heat	econometric	econometric (per customer)
Res. Non-Heat	econometric	econometric (per customer)
Com. Demand	time series	econometric (per customer)

Com. Non-Dmd.	time series	econometric (per customer)
OPA Demand	time series	econometric (per customer)
OPA Non-Dmd.	time series	econometric (per customer)
Ind. Demand	historic constant	econometric (per customer)
Ind. Non-Dmd.	historic constant	econometric (per customer)
Large Industrial	Individual	individual
Area Light	historic trend	fixture specific growth
Street Light	historic constant	fixture specific growth
Traffic Signal	historic trend	historic trend
Interdepartmental	historic constant	historic constant

Forecast Adjustments

For sales forecasting purposes, both energy efficiency (“EE”) and customer-sited net-metered photovoltaic installation (“PV “) were addressed external to the sales modeling process. This prevented the sales regression models from assuming that the historical EE and PV growth patterns will continue in the future, allowing the growth patterns to be altered. This was 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. EE and PV forecasts were then developed, as discussed below, with the resulting applied as post forecast adjustments to arrive at the final sales forecast.

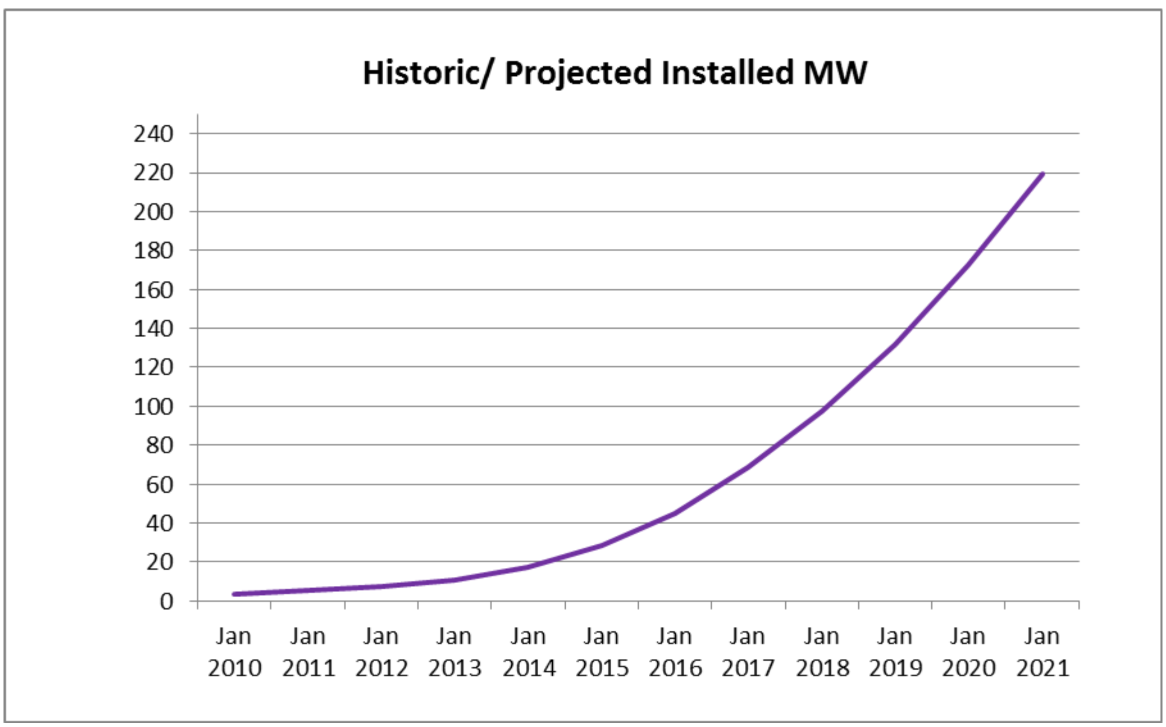
<u>Energy Efficiency</u>

Realized EE MWh savings reflect information filed by Central Hudson and NYSERDA with the Public Service Commission in Case 07-M-0548. 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 Energy Efficiency Transition Implementation Plan program savings targets as ordered in Case 15-M-0252 and a portion of Clean Energy Fund minimum 10 year energy efficiency 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.

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.

Net-Metered PV

In developing sales reductions attributable to increased penetration of net-metered PV systems, the Company employed the same methodology utilized in the sales forecasts approved by the Commission in Case 14-E-0318. Historic PV output was based on an estimate of the production of the actual kilowatt ("kW") capacity of installed PV systems. The forecast of sales reductions attributable to PV penetration was based on a forecast of net-metered PV installations developed by applying a polynomial regression to the monthly cumulative kW installed for the period January 2012 through December 2015, reflecting the most recent response to legislative, regulatory and Company initiatives. The resulting monthly kW was converted to energy output based on historic realized savings and allocated across applicable customer classes. Historic and forecast installed MW can be seen in the chart below.



Appendix N DER Forecasting Methodology Details

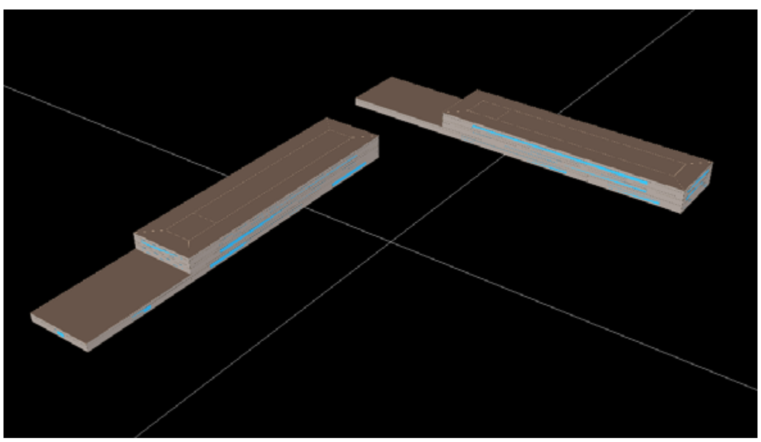
N.1 Energy Efficiency Forecasting and Dispersion Methodology

N.1.a End Use Load Shape Development

eQUEST Modeling

Plug loads, HVAC, lighting, and whole building end-use 8760 load shapes were derived from eQUEST modeling. The modeling task used 36 available DEER building prototypes that characterized 22 different facility types.[2] A 'facility type' is defined as a building modeled in eQUEST that represents a particular segment of Central Hudson's building stock (e.g. office, manufacturing, retail, etc.). Figure N-1 shows a rendering of the model used for the Community College facility type. However, in practice, the HVAC systems used within some building segments can vary considerably. Therefore, some of the facility types were modeled multiple times using different HVAC system types common to each facility type. Each combination of facility type and HVAC system yielded a new eQUEST building prototype. The three HVAC systems employed in the modeling were heat pump, direct expansion cooling with gas heat, and central heating and cooling plant. Consequently, each facility type had between one and three eQUEST building prototypes.

Figure N-1: Graphical Depiction of Community College Facility Type Model



Additionally, each eQUEST building prototype was simulated using two weather files for Dutchess County – one from 2010 and one from 2013.[3] During each simulation, the prototype building's HVAC equipment was sized for design day loads in accordance with the observed weather.

With a high volume of simulations to perform, Nexant developed a batch processor to quickly run the simulations. This process used the DOE2.2 simulation engine due to its significantly faster processing speed over EnergyPlus. The DEER models automatically create hourly reports, summarizing energy

[2] http://www.doe2.com/equest/

[3] Annual weather data was sourced from NOAA, and irradiance values from TMY3 file.

consumption by end use, which go into the simulation output (".sim") files. Once all the .sim files were produced, a VBA macro was developed to extract the desired 8760 load shapes from each .sim file.

N.1.b AC Load Shape Development

Load research sample data (8760 hourly loads) was used in conjunction with regression analysis to derive estimated 8760 load shapes for residential air conditioning use. This approach was used because it was deemed to produce a more realistic load shape for this particular end use than the Equest modeling approach used for other end uses. The primary inputs were the 2013 load research sample, 2013 billing data, and weather data for Poughkeepsie (2013 and 2010). The regression based approach applied three main steps:

- Identify customers with high weather sensitivity: Classify all customers in the load research sample into weather sensitivity tertiles based on the correlation being temperature and usage. The high sensitivity tertile is used as a proxy for the customer with air conditioning usage.
- Identify the temperature at which weather neutral usage occurs: Heating end uses cause usage to be higher below this temperature while cooling usage increases usage above this temperature. Usage at this low point is a proxy for weather insensitive or weather neutral usage.
- Estimate hourly AC usage: Use a regression to establish a predictive relationship between weather temperature and usage. Use this regression to predict total loads and weather neutral loads. Estimated AC usage loads are simply total loads minus weather neutral loads. This was done for both 2013 weather and 2010 weather as proxies for 1 in 2 and 1 in 10 weather, respectively.

N.1.c Lighting Load Shapes

Lighting load shapes were drawn from a light metering study conducted in Pennsylvania.[4] The purpose of the study was to estimate lighting load profiles to be used as inputs in calculations of peak demand and energy savings from lighting in Pennsylvania. The study was conducted by installing loggers in a sample of buildings in the residential and commercial sectors. The loggers measured hours of use of lights in various rooms on an hourly basis. Although the loggers were not installed for an entire year, lighting loads are not weather dependent, and can therefore be annualized using a simple sinusoidal model that accounts for the length of the day.

The resulting 8760 lighting load shapes, although specific to Pennsylvania, can be applied to Central Hudson territory. Central Hudson territory is relatively close to Pennsylvania; the latitude of each area is similar enough that days have similar length in both areas, so lighting hours of use will be similar.

N.1.d Forecast Inputs

Nexant first determined forecast annual savings for each energy efficiency program in Central Hudson's territory. The source of the forecast differed according to whether the program was administrated by Central Hudson, or NYSERDA, which offers programs throughout New York State. While forecast savings

[4] http://www.puc.state.pa.us/Electric/pdf/Act129/SWE_PY6-Final_Annual_Report.pdf

described in this section are incremental, they were summed before combining with other inputs in order to ensure that the forecast was cumulative, with the base year of 2015 set to 0.

Central Hudson's forecast annual savings were derived from their Energy Efficiency Transition Implementation Plan (E-TIP) filing. The incremental annual savings for 2016 through 2018 for Central Hudson's portfolio of energy efficiency programs was constant at 34,240 MWh each year. Nexant assumed the target remained constant for 2019 onwards. Table N-1 shows the breakdown of Central Hudson's E-TIP target by program, which Central Hudson provided. The majority of the savings are from residential programs, specifically from lighting and behavioral modification programs.

Table N-1: Forecast of Incremental Annual Savings (MWh) for Central Hudson's Energy Efficiency Portfolio

Program Name	Sector	Forecast Net Acquired Annual Savings (MWh)	Percent of Total Target (%)
Electric HVAC	Residential	1,046	3.1%
Retail POS Lighting	Residential	8,547	25.0%
Appliance Recycling	Residential	633	1.8%
Exchange Online Portal	Residential	1,400	4.1%
Behavioral Modification	Residential	8,381	24.5%
Demand Response (EE Lights)	Residential	577	1.7%
Electric Prescriptive	Commercial	2,086	6.1%
Electric Custom	Commercial	225	0.7%
SBDI	Commercial	6,545	19.1%
New SBDI Program	Commercial	1,800	5.3%
Online Lighting Portal	Commercial	3,000	8.8%
Total	**-**	**34,240**	**100.0%**

NYSERDA's forecast annual savings were derived from the Clean Energy Fund (CEF) investment plans.[5] The CEF investment plans include forecasts of savings derived from energy efficiency programs for New York State. Statewide savings were scaled to Central Hudson's territory using the ratio of savings in Central Hudson's territory to statewide savings that were filed in the PSC scorecards in 2014, which was the most recent year available.[6] Savings in Central Hudson's territory in 2014 accounted for 3.3% of net acquired annual MWh savings in New York State attributed to NYSERDA's energy efficiency portfiolio. Table 2 shows the breakdown of NYSERDA's CEF targets by program. Nexant reviewed program descriptions and determined that the programs were generally targeted at the commercial sector. Unlike

[5] http://www.nyserda.ny.gov/About/Clean-Energy-Fund

[6] http://documents.dps.ny.gov/public/EEPS/EEPSPortfolio.aspx?TabType=AR&PA=12&ProgramType=Electric,Gas&ProgramStatus=Open,Closed&Sectors=2,3,1&MReportingPeriod=Jan/2015&QReportingPeriod=Q1/2016

savings forecasts for Central Hudson's energy efficiency portfolio, savings are not constant over time, but vary with each program's fluctuation in savings, as well as the introduction and cessation of different programs. Note that Table N-2 shows statewide reductions, and that the portion in Central Hudson's territory is only 3.3% of the figures displayed.

Table N-2: Forecast of Incremental Annual Savings (MWh) for NYSERDA's Statewide Energy Efficiency Portfolio

Program Name	Sector	Net Acquired MWh								
		2016	2017	2018	2019	2020	2021	2022	2023	2024
Real Estate Tenant	Commercial	5,600	13,100	18,600	22,400	26,100	18,600	11,200	5,600	3,700
Real Time Energy Management	Commercial	20,500	36,200	51,100	53,900	61,900	45,700	22,500	10,300	8,930
REV Campus Challenge	Commercial	0	15,400	15,400	11,600	11,600	77,200	77,200	77,200	77,200
Clean Energy Communities	Commercial	74,700	29,400	26,100	0	0	0	0	0	0
Continuous Energy Improvement	Commercial	49,500	15,000	12,000	0	0	0	0	0	0
Total	**-**	**150,300**	**109,100**	**123,200**	**87,900**	**99,600**	**141,500**	**110,900**	**93,100**	**89,830**

A key input to the analysis is the distribution of EE savings by substation, end use and sector. Central Hudson provided a database of historical retrofits for certain programs in its energy efficiency portfolio. This included retrofits installed under the Electric HVAC, and Appliance Recycling residential programs, as well as the SBDI, New SBDI, and Online Lighting Portal commercial programs. Using the database of retrofits, Nexant mapped customer account numbers to circuit, which was in turn matched to substation. The database included the end use, which was used to allocate savings across different end uses and apply the correct load shapes. Finally, savings were allocated to sector according to which sector the program targeted, and SIC code was used to allocate commercial customers to the correct division.[7] A database of savings was not available for every program. For the 6 Central Hudson programs without a database of installations, Nexant made simplifying assumptions in order to distribute savings across substation, end use, and sector. The allocation of savings across substations was assumed to be equal to the distribution of annual consumption in 2013 for the residential or commercial sector, depending on that which the program targeted. The distribution of end uses could often be inferred from the program name, for example the Retail POS Lighting program clearly pertains to lighting. If the end use was not clear from the program description, Nexant used whole building load, so as to be agnostic as to the end use that was targeted. The sector that savings were applied to was also determined by the program, as each program targeted either residential or commercial sectors. To distribute savings for NYSERDA programs, which also did not have a database of historical retrofits, Nexant used a similar methodology.

The load shapes are the final input to the forecast. They contain load for various end uses and sectors for each of 8,760 hours in a year, for both 1-in-2 and 1-in-10 weather years. Nexant normalized each load shape using total consumption (kWh) to render the load shapes unitless so they may be easily combined with forecast annual savings for a particular end use and sector. Although the eQUEST load shapes, which were generated analytically, included various end uses, including lighting and AC, Nexant used empirically derived lighting and AC load shapes

[7] eQUEST and lighting end use load shapes were stratified by division, so Nexant was able to use the EE database to take a weighted average of load shapes according to the distribution of divisions that a particular program targeted.

N.1.e Combining Forecast Inputs

The inputs are combined to yield forecast kW of savings for each substation for every hour of forecast years 2016-2024, from which the 5-year forecast is pulled. Because the appropriate distribution of savings by end use and sector are applied to each program prior to aggregation, the aggregated savings reflect the portfolio distribution of end uses and sectors. Table N-3 shows the steps performed to combine forecast inputs. Each row represents a step, and describes the input, the step itself, dimensions, and units of the analysis dataset.

Table N-3: Combination of Inputs

Step	Input Added	Description	Dimensions	Units
1	Annual Savings Forecasts by Program	Initial input.	Program, Forecast Year	kWh
2	Savings Distribution by Substation, End Use, Sector	Program savings are distributed according to the program's substation distribution, end uses, and target sector	Program, Forecast Year, Substation	kWh
3	Load Shapes	Load shapes (%) are combined with annual kWh for each program, forecast year and substation to yield hourly kW values.	Program, Forecast Year, Substation, Weather Year, Hour	kW
4	-	Disaggregated program level savings are collapsed to get portfolio level savings for each forecast year, substation, weather year, and hour.	Forecast Year, Substation, Weather Year, Hour	kW

N.1.f Photovoltaic Forecast Detailed Methodology

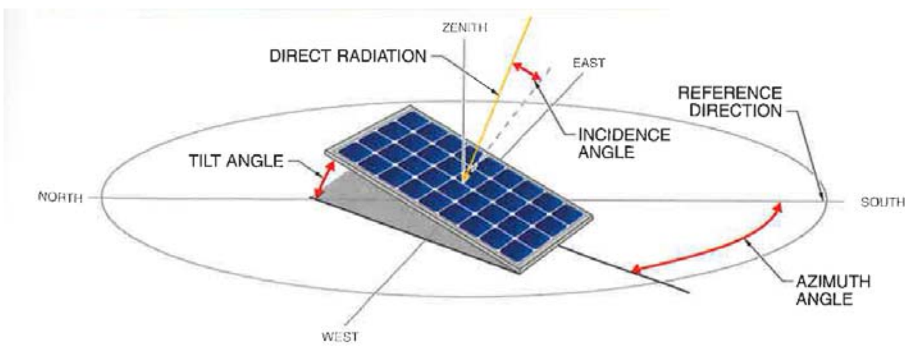
PV Load Shape Development

Load shapes for solar photovoltaic (PV) systems were generated using NREL's System Advisor Model (SAM). SAM is a free performance and financial modeling software designed to facilitate decision making for people involved in the renewable energy industry. One of the technologies SAM models is solar PV.

The SAM calculator inputs used for this analysis were generally kept at the default values since these were seen as reasonable estimations for average system specifications. PV SAM default values used included those for module performance, inverter performance, and system losses.

Two key inputs to determining a solar PV array's electrical output are the panels' tilt and orientation. Tilt refers to the vertical angle between horizontal (ground) and the panel's surface, while azimuth is the horizontal angle between a reference direction and the direction the panel's surface faces. In Figure N-26N-2, the azimuth reference direction is south. This analysis sought to model a scenario where the system's energy production was optimized, so batch simulations were performed where the tilt angle was varied between 0 and 50 degrees in 5 degree increments and the azimuth angle was varied between 90 degrees (east) and 270 degrees (west) in 10 degree increments (PV SAM's azimuth reference is north). The system's energy production was found to be optimized at a tilt angle of 35 degrees and an azimuth of 180 degrees (south).

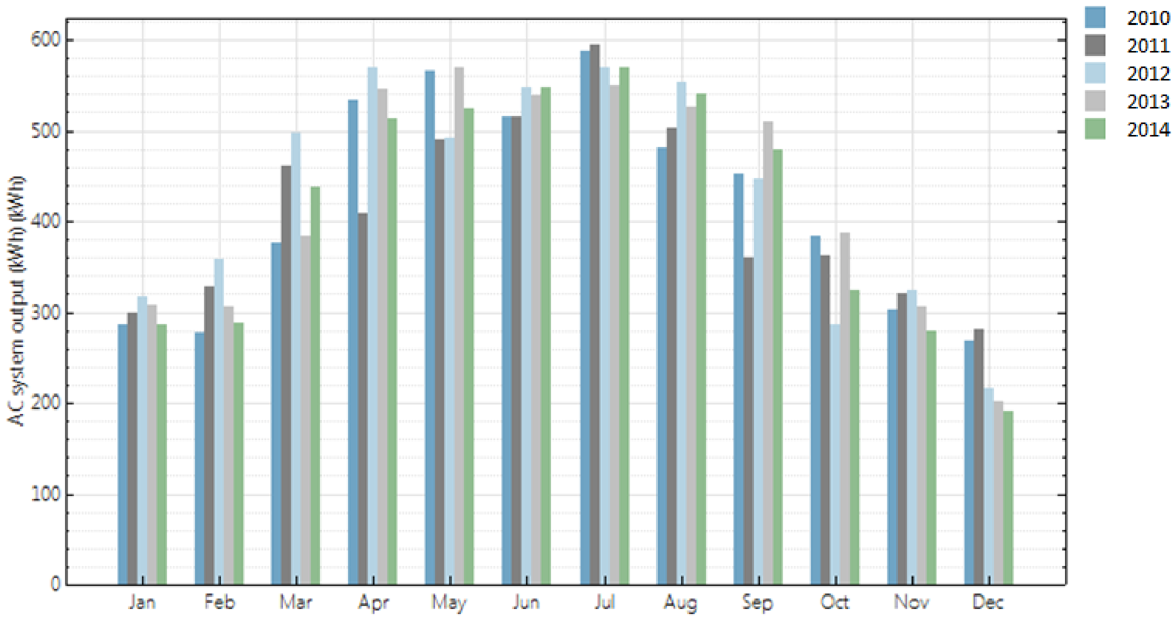
Figure N-26: Panel Orientation[8]



Once the system was defined, yearly weather data from years 2010-2014 for Poughkeepsie, NY were retrieved from NREL's National Solar Radiation Database and used to generate 5 different simulations. Each of those simulations yielded estimated system AC kW production for each hour of the year. For reference, the monthly system output from those 5 simulations is shown in Figure N-327. While this solar PV system's actual output can vary year to year on weather conditions, the total yearly production varies by less than 5% between any two years.

[8] Dunlop, James P. (2010) *Photovoltaic Systems Second Edtition*, Orland Park, IL, American Technical Publishers, Inc.

Figure N-327: Monthly System Outputs for 4 kW System in Poughkeepsie, NY by Year

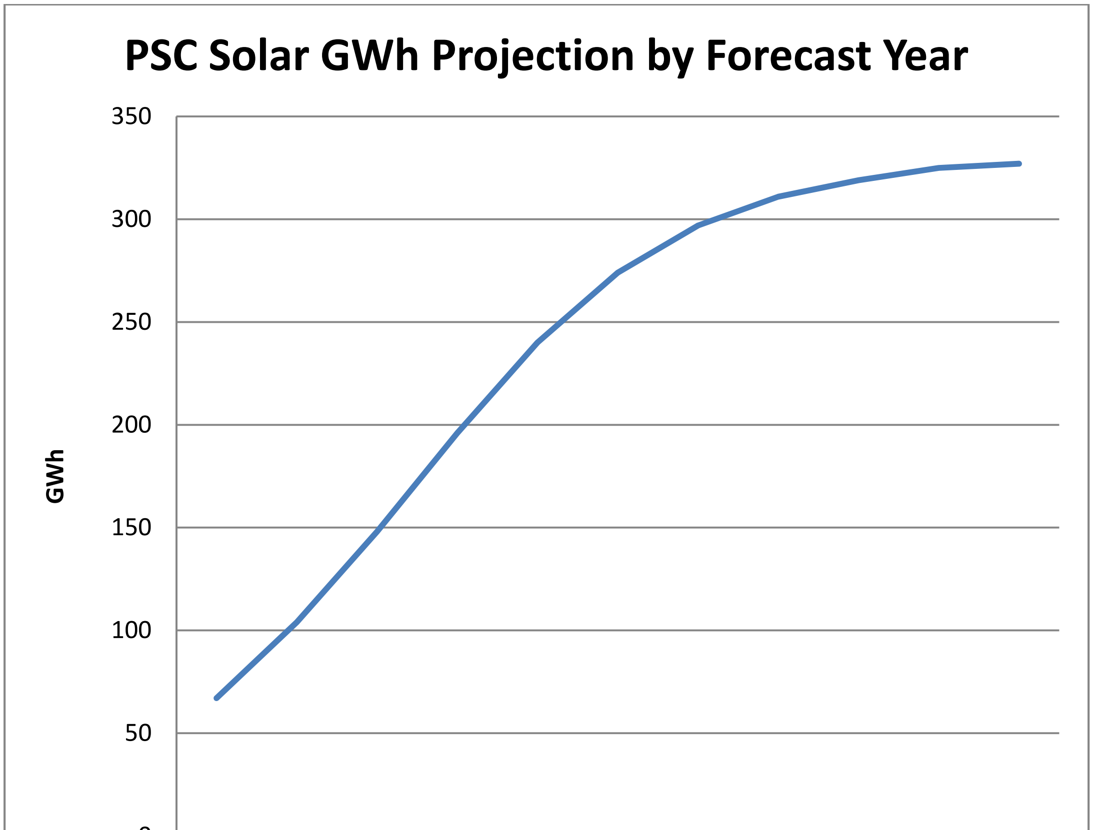


N.1.g Forecast Inputs

Nexant first determined the current installed solar capacity at each substation using a database of historical PV interconnections. The database, provided by Central Hudson, lists each interconnection in the territory and its associated nameplate capacity in kW and its circuit. By mapping circuits to substations and aggregating solar capacity to the substation level, we identified the solar capacity at each substation.

A key input to the analysis is solar forecasts from the 2015 NYISO Load and Capacity Data "Gold Book," which forecasts existing and proposed generation and other capacity resources. The forecast of behind-the-meter generation attributed to retail solar PV installations in NYISO zone G was available for years 2015 through 2025. Figure 3 shows the forecast of annual retail solar PV generation in GWh per year for zone G. Forecast generation increases at a steady rate from 2015 to 2020 at which point the rate of increase starts to decline. Note that prior to incorporating solar forecasts with other inputs, year 2015 annual output is subtracted from all forecast years to render 2015 the base year at which output is 0. This step is taken in order to yield a cumulative forecast that takes into account only new solar capacity installed after 2015.

Figure N-4: Forecast of Annual Retail Solar PV Generation for Zone G



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GWh	67	104	148	196	240	274	297	311	319	325	327

The load shapes developed using the PV SAM tool are the final input to the PV forecast. The load shapes, which contain PV system output for each of 8,760 hours in a year, were for 1-in-2, and 1-in-10 weather year, and each was for a 4 kW system. Nexant normalized the load shapes using total system output for each year (kWh), to render the load shapes unitless so they may be easily combined with forecast annual output. System output in each year (kWh) was also divided by the nameplate capacity of the system to calculate efficiency factors for each year (kWh / kW). This is equivalent to dividing the system output in each hour in kWh by 4 to scale output by the nameplate capacity of the system.

N.1.h Combining Forecast Inputs

The inputs are combined to yield forecast kW of PV generation for each substation for every hour of forecast years 2015-2025, from which the 5-year forecast is pulled. The inputs are combined in sequence, and the addition of each input adds another dimension to the forecast. Table 1 shows the steps performed to combine forecast inputs. Each row represents a step, and describes the input, description of the step itself, dimensions, and units of the analysis dataset.

Table N-4: Combination of Inputs

Step	Input Added	Description	Dimensions	Units
1	Installed PV kW by Substation	Initial input.	Substation	kW
2	Weather Year Efficiency Factors (kWh/kW)	Substation solar capacity is scaled to account for total output in each weather year.	Substation, Weather Year	kWh
3	"Gold Book" Targets	"Gold Book" targets for forecast years are combined with weather year output for each substation to yield future annual generation in kWh at each substation for each forecast year.	Substation, Weather Year, Forecast Year	kWh
4	Load Shapes	8760 production load shapes (percent of annual production in each hour) are combined with annual kWh for each substation, weather year, and forecast year to yield hourly kW values.	Substation, Weather Year, Forecast Year, Hour	kW

N.2 Electric Vehicle Forecasting Methodology

N.2.a Electric Vehicle Load Shape Development

Plug-in electric vehicle (EV) load shapes were available through a study performed for PG&E to analyze and identify existing end-use loads that are sizeable enough and flexible enough to help address operational and planning needs. A part of the study was to analyze how operational needs were expected to change with the projected penetration of renewable generation and electric vehicle loads by 2017, and hence EV load shapes were developed as part of the study.

EV load shapes were developed using difference-in-differences regression analysis with whole building interval data from 2013. When PG&E had information about when an EV was adopted by a household, an external control group that had nearly identical consumption patterns prior to adoption of the end use was identified. Because of the data structure, a change in load was observed in customers who adopted the new end-use, but no similar change was observed in the control group. Any pre-existing differences between the two groups (prior to adoption of the end-use) were treated as errors and were subtracted out to improve precision of the estimates. This approach yielded an estimate of electric vehicle load shapes for 2013.

N.2.b Forecast Inputs

A key input to the analysis is historical EV registrations in Central Hudson territory. Nexant used NYSERDA's EvaluateNY Tool, which provides access to comprehensive data from New York State's EV market, to source historical new registrations of EVs from 2011 to 2014.[9] Table N-5 shows new registrations in Central Hudson territory from 2011 through 2014. Overall, EV registrations are few in number. Nexant assumed the stock of EV registrations was 0 in 2010; the market for EVs was in its infancy and there were very few registered in 2011, suggesting this is a tenable assumption.

Table N-5: New Registrations

Year	BEV Registrations	PHEV Registrations	EV Registrations	All Registrations
2011	5	12	17	36,037
2012	24	114	138	40,819
2013	47	173	220	42,661
2014	42	144	186	39,999

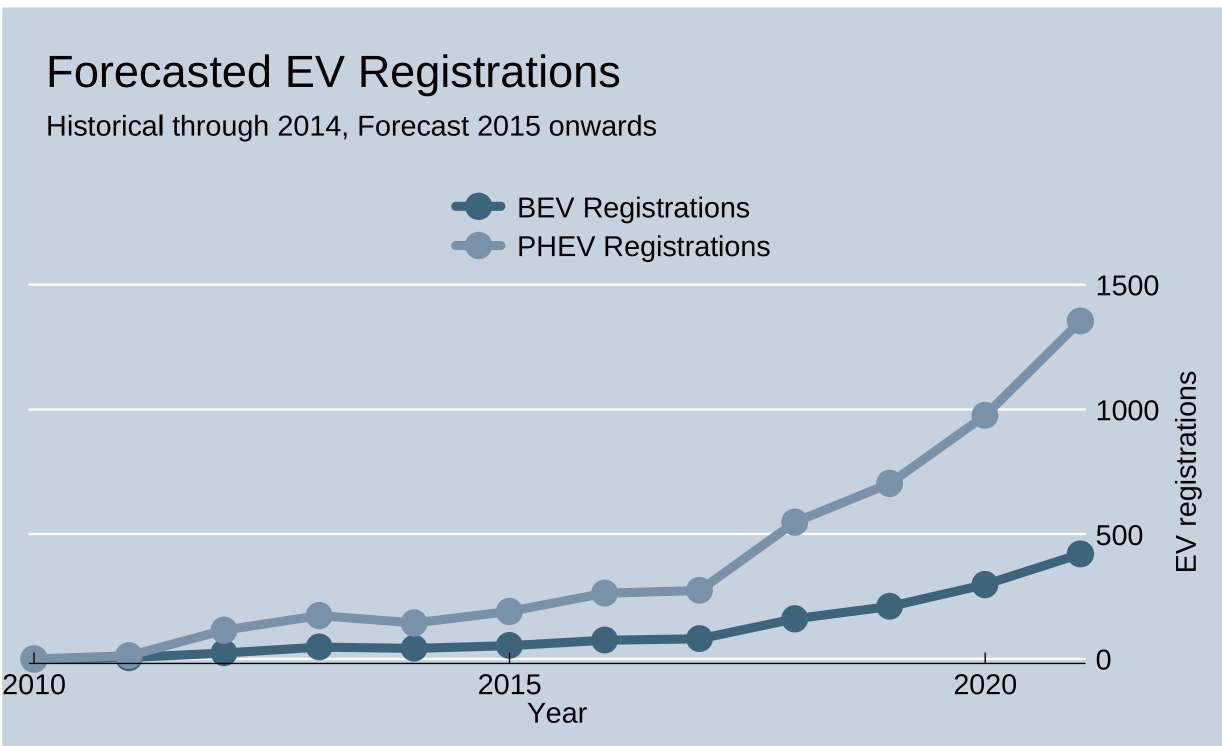
The load EV load shapes, which contain EV load for each of 8,760 hours in 2013, must be normalized for 2010. Electric vehicle charging patterns are not particularly weather sensitive, but do show variation with day of week and season. To develop EV load shapes for 2010, Nexant averaged the EV load shape for each month, day of week, and hour, and applied that to 2010 to account for the different dates that days

[9] http://www.nyserda.ny.gov/-/media/Files/Publications/Research/Transportation/EValuateNY-User-Guide.pdf

of the week and holidays fall on. This yielded EV load shapes for all 8,760 hours in 2010, in addition to 2013.

Nexant used Tesla Model 3 pre-orders figures to account for growth in the EV market. Tesla's global sales in 2014 were 35,000 and it has received 400,000 pre-orders for its Model 3, scheduled to be delivered in 2017 and 2018. We assumed Tesla will ultimately fulfill half, or 200,000, of those pre-orders, either because customers back out, or because it cannot meet its production targets. Furthermore, we assumed that a third of the 200,000 cars will be delivered in 2017 and the other two thirds will be delivered in 2018. Relative to 2014 levels, this amounts to a 90% increase in sales in 2017, and a 280% increase in sales in 2018. Those growth factors are applied to BEV and PHEV registrations in 2014 to yield registrations in 2017 and 2018. Nexant then fits a curve from 2011 through 2018 and uses the fit to predict registrations for future years.[10] Figure N-5 shows the output of this procedure, which includes EV registrations for 2010 through 2021. Before combining with the load shapes, new registrations are set to 0 in 2015 and summed from 2016 onwards to generate cumulative registrations for forecast years.

Figure N-5: Forecast EV Registrations in Central Hudson Territory



N.2.c Combining Forecast Inputs

The inputs are combined to yield forecast kW of EV load for each substation for every hour of forecast years 2015-2021, from which the 5 year forecast is pulled. The inputs are combined in sequence, and the addition of each input adds another dimension to the forecast. Table N-6 shows the steps performed to

[10] Curve is fit using a generalized linear model (GLM) with a logistic link function where EV registrations are Poisson distributed.

combine forecast inputs. Each row represents a step, and describes the input, the step itself, dimensions, and units of the analysis dataset.

Table N-6: Combination of Inputs

Step	Input Added	Description	Dimensions	Units
1	Cumulative EV registrations from 2015 through 2021	Initial input.	Forecast Year	# Vehicles
2	Substation Distribution	Vehicles distributed by substation according to annual residential consumption.	Forecast Year, Substation	# Vehicles
3	Load Shapes	Load shapes (kW) are combined with vehicle counts at each substation for each forecast year to yield aggregate EV load in kW	Forecast Year, Substation, Weather Year, Hour	kW

N.3 DER Conversion Factors

Table L-1: 2016 Forecast Peak Contribution by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	0.14	0.07	0.00	0.51	0.00	0.06	0.00	0.07	0.00	0.13	0.06	1.04
Hurley-Milan	July	Weekday	16	0.27	0.07	0.00	0.49	0.00	0.27	0.00	0.06	0.00	0.69	0.09	1.95
Mid-Dutchess	July	Weekday	15	0.23	0.08	0.00	0.53	0.00	0.28	0.00	0.06	0.00	0.54	0.14	1.86
Northwest 115-69 Area	July	Weekday	17	0.21	0.17	0.00	1.14	0.00	0.20	0.00	0.17	0.00	0.77	0.13	2.80
Northwest 69kV Area	July	Weekday	18	0.19	0.13	0.00	1.01	0.00	0.13	0.00	0.13	0.00	0.43	0.10	2.12
Pleasant Valley 69	May	Weekday	18	0.14	0.10	0.00	0.42	0.00	0.09	0.00	0.08	0.00	0.36	0.08	1.26
RD-RJ Lines	July	Weekday	16	0.12	0.08	0.00	0.50	0.00	0.29	0.00	0.08	0.00	0.83	0.10	1.99
Southern Dutchess	July	Weekday	15	0.15	0.08	0.00	0.55	0.00	0.16	0.00	0.08	0.00	0.43	0.16	1.63
WM Line	December	Weekday	18	0.00	0.02	0.00	0.02	0.00	0.05	0.00	0.01	0.00	0.00	0.05	0.15
Westerlo Loop	January	Weekday	18	0.00	0.09	0.00	0.07	0.00	0.09	0.00	0.11	0.00	0.00	0.07	0.43
CH System	July	Weekday	17	2.14	1.06	0.01	7.13	0.00	2.10	0.02	1.03	0.00	6.20	1.06	20.75

Table 2: 2017 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	0.28	0.15	0.00	1.01	0.00	0.12	0.00	0.08	0.00	0.28	0.06	1.99
Hurley-Milan	July	Weekday	16	0.54	0.14	0.00	0.98	0.00	0.53	0.00	0.07	0.00	1.51	0.09	3.88
Mid-Dutchess	July	Weekday	15	0.46	0.16	0.00	1.06	0.00	0.56	0.00	0.07	0.00	1.19	0.14	3.63
Northwest 115-69 Area	July	Weekday	17	0.43	0.34	0.00	2.27	0.00	0.39	0.01	0.20	0.00	1.69	0.13	5.46
Northwest 69kV Area	July	Weekday	18	0.38	0.26	0.00	2.02	0.00	0.26	0.00	0.15	0.00	0.93	0.10	4.11
Pleasant Valley 69	May	Weekday	18	0.27	0.20	0.00	0.84	0.00	0.18	0.00	0.09	0.00	0.78	0.08	2.44
RD-RJ Lines	July	Weekday	16	0.24	0.16	0.00	1.00	0.00	0.59	0.00	0.09	0.00	1.81	0.10	3.98
Southern Dutchess	July	Weekday	15	0.31	0.16	0.00	1.10	0.00	0.33	0.00	0.09	0.00	0.94	0.16	3.10
WM Line	December	Weekday	18	0.00	0.05	0.00	0.04	0.00	0.11	0.00	0.01	0.00	0.00	0.05	0.25
Westerlo Loop	January	Weekday	18	0.00	0.18	0.00	0.14	0.00	0.18	0.00	0.13	0.00	0.00	0.07	0.70
CH System	July	Weekday	17	4.29	2.13	0.01	14.25	0.00	4.19	0.04	1.16	0.00	13.57	1.06	40.71

Table 3: 2018 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	0.42	0.22	0.00	1.52	0.00	0.19	0.00	0.10	0.00	0.45	0.06	2.97
Hurley-Milan	July	Weekday	16	0.81	0.21	0.00	1.47	0.00	0.80	0.01	0.10	0.00	2.41	0.09	5.90
Mid-Dutchess	July	Weekday	15	0.68	0.23	0.00	1.60	0.00	0.84	0.00	0.09	0.00	1.89	0.14	5.48
Northwest 115-69 Area	July	Weekday	17	0.64	0.51	0.00	3.41	0.00	0.59	0.01	0.26	0.00	2.69	0.13	8.24
Northwest 69kV Area	July	Weekday	18	0.56	0.40	0.00	3.04	0.00	0.39	0.00	0.20	0.00	1.49	0.10	6.18
Pleasant Valley 69	May	Weekday	18	0.41	0.30	0.00	1.26	0.00	0.27	0.00	0.12	0.00	1.24	0.08	3.68
RD-RJ Lines	July	Weekday	16	0.36	0.23	0.00	1.50	0.00	0.88	0.01	0.12	0.00	2.89	0.10	6.08
Southern Dutchess	July	Weekday	15	0.46	0.24	0.00	1.65	0.00	0.49	0.00	0.13	0.00	1.50	0.16	4.64
WM Line	December	Weekday	18	0.00	0.07	0.00	0.05	0.00	0.16	0.00	0.01	0.00	0.00	0.05	0.34
Westerlo Loop	January	Weekday	18	0.01	0.28	0.00	0.21	0.00	0.27	0.00	0.17	0.00	0.00	0.07	1.00
CH System	July	Weekday	17	6.43	3.19	0.02	21.38	0.00	6.29	0.06	1.56	0.00	21.62	1.06	61.61

Table 4: 2019 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	0.56	0.30	0.00	2.03	0.00	0.25	0.00	0.11	0.00	0.60	0.06	3.91
Hurley-Milan	July	Weekday	16	1.09	0.29	0.00	1.96	0.00	1.06	0.01	0.11	0.00	3.23	0.09	7.83
Mid-Dutchess	July	Weekday	15	0.91	0.31	0.00	2.13	0.00	1.12	0.00	0.10	0.00	2.54	0.14	7.25
Northwest 115-69 Area	July	Weekday	17	0.85	0.68	0.00	4.54	0.00	0.78	0.02	0.29	0.00	3.61	0.13	10.91
Northwest 69kV Area	July	Weekday	18	0.75	0.53	0.00	4.05	0.00	0.53	0.01	0.22	0.00	2.00	0.10	8.18
Pleasant Valley 69	May	Weekday	18	0.55	0.41	0.00	1.68	0.00	0.35	0.00	0.14	0.00	1.67	0.08	4.87
RD-RJ Lines	July	Weekday	16	0.48	0.31	0.00	1.99	0.00	1.18	0.01	0.13	0.00	3.88	0.10	8.07
Southern Dutchess	July	Weekday	15	0.62	0.32	0.00	2.20	0.00	0.66	0.00	0.14	0.00	2.01	0.16	6.11
WM Line	December	Weekday	18	0.00	0.09	0.00	0.07	0.00	0.22	0.00	0.01	0.00	0.00	0.05	0.44
Westerlo Loop	January	Weekday	18	0.01	0.37	0.00	0.28	0.00	0.36	0.00	0.19	0.00	0.00	0.07	1.27
CH System	July	Weekday	17	8.58	4.25	0.03	28.50	0.00	8.39	0.08	1.72	0.00	28.99	1.06	81.60

Table 5: 2020 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	0.69	0.37	0.00	2.53	0.00	0.31	0.00	0.14	0.00	0.72	0.06	4.84
Hurley-Milan	July	Weekday	16	1.36	0.36	0.00	2.45	0.00	1.33	0.01	0.13	0.00	3.87	0.09	9.59
Mid-Dutchess	July	Weekday	15	1.14	0.39	0.00	2.66	0.00	1.40	0.01	0.13	0.00	3.03	0.14	8.89
Northwest 115-69 Area	July	Weekday	17	1.07	0.85	0.00	5.68	0.00	0.98	0.02	0.36	0.00	4.32	0.13	13.40
Northwest 69kV Area	July	Weekday	18	0.94	0.66	0.00	5.06	0.00	0.66	0.01	0.27	0.00	2.39	0.10	10.08
Pleasant Valley 69	May	Weekday	18	0.68	0.51	0.00	2.10	0.00	0.44	0.00	0.17	0.00	1.99	0.08	5.97
RD-RJ Lines	July	Weekday	16	0.60	0.39	0.00	2.49	0.00	1.47	0.01	0.16	0.00	4.64	0.10	9.85
Southern Dutchess	July	Weekday	15	0.77	0.40	0.00	2.75	0.00	0.82	0.00	0.17	0.00	2.41	0.16	7.49
WM Line	December	Weekday	18	0.00	0.11	0.00	0.09	0.00	0.27	0.00	0.01	0.00	0.00	0.05	0.54
Westerlo Loop	January	Weekday	18	0.01	0.46	0.00	0.34	0.00	0.45	0.00	0.23	0.00	0.00	0.07	1.56
CH System	July	Weekday	17	10.72	5.31	0.04	35.63	0.00	10.49	0.10	2.11	0.00	34.68	1.06	100.14

Table 6: 2021 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	0.83	0.45	0.00	3.04	0.00	0.37	0.00	0.18	0.00	0.80	0.06	5.74
Hurley-Milan	July	Weekday	16	1.63	0.43	0.00	2.93	0.00	1.59	0.01	0.16	0.00	4.29	0.09	11.15
Mid-Dutchess	July	Weekday	15	1.37	0.47	0.00	3.19	0.00	1.68	0.01	0.16	0.00	3.37	0.14	10.38
Northwest 115-69 Area	July	Weekday	17	1.28	1.02	0.01	6.82	0.00	1.17	0.03	0.45	0.00	4.80	0.13	15.69
Northwest 69kV Area	July	Weekday	18	1.13	0.79	0.00	6.07	0.00	0.79	0.01	0.33	0.00	2.65	0.10	11.88
Pleasant Valley 69	May	Weekday	18	0.82	0.61	0.00	2.52	0.00	0.53	0.00	0.21	0.00	2.21	0.08	6.99
RD-RJ Lines	July	Weekday	16	0.72	0.47	0.00	2.99	0.00	1.76	0.01	0.20	0.00	5.15	0.10	11.40
Southern Dutchess	July	Weekday	15	0.93	0.48	0.00	3.30	0.00	0.98	0.01	0.21	0.00	2.67	0.16	8.75
WM Line	December	Weekday	18	0.00	0.14	0.00	0.11	0.00	0.32	0.00	0.02	0.00	0.00	0.05	0.63
Westerlo Loop	January	Weekday	18	0.01	0.55	0.00	0.41	0.00	0.53	0.00	0.29	0.00	0.00	0.07	1.87
CH System	July	Weekday	17	12.87	6.38	0.04	42.75	0.00	12.58	0.12	2.63	0.00	38.54	1.06	116.97

Table 7: 2016 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	0.07	0.09	0.00	0.26	0.00	0.13	0.00	0.11	0.00	0.73	0.06	1.46
Hurley-Milan	July	Weekday	14	0.20	0.08	0.00	0.39	0.00	0.28	0.00	0.09	0.00	0.80	0.09	1.95
Mid-Dutchess	July	Weekday	17	0.19	0.07	0.00	0.47	0.00	0.22	0.00	0.07	0.00	0.36	0.13	1.51
Northwest 115-69 Area	July	Weekday	13	0.12	0.19	0.00	0.70	0.00	0.25	0.00	0.25	0.00	0.87	0.14	2.52
Northwest 69kV Area	July	Weekday	15	0.11	0.14	0.00	0.66	0.00	0.20	0.00	0.21	0.00	0.84	0.11	2.27
Pleasant Valley 69	July	Weekday	17	0.18	0.09	0.00	0.55	0.00	0.11	0.00	0.11	0.00	0.58	0.08	1.69
RD-RJ Lines	July	Weekday	17	0.10	0.07	0.00	0.47	0.00	0.25	0.00	0.08	0.00	0.64	0.08	1.70
Southern Dutchess	July	Weekday	17	0.13	0.08	0.00	0.48	0.00	0.13	0.00	0.09	0.00	0.29	0.16	1.36
WM Line	July	Weekday	17	0.01	0.02	0.00	0.12	0.00	0.06	0.00	0.02	0.00	0.09	0.05	0.37
Westerlo Loop	December	Weekday	18	0.00	0.09	0.00	0.06	0.00	0.09	0.00	0.08	0.00	0.00	0.07	0.40
CH System	July	Weekday	17	1.80	0.99	0.01	6.38	0.00	2.14	0.02	1.22	0.00	6.02	1.03	19.59

Table 8: 2017 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	0.14	0.19	0.00	0.53	0.00	0.25	0.00	0.12	0.00	1.60	0.06	2.90
Hurley-Milan	July	Weekday	14	0.40	0.16	0.00	0.78	0.00	0.57	0.00	0.11	0.00	1.76	0.09	3.87
Mid-Dutchess	July	Weekday	17	0.37	0.15	0.00	0.94	0.00	0.44	0.00	0.08	0.00	0.79	0.13	2.90
Northwest 115-69 Area	July	Weekday	13	0.24	0.39	0.00	1.39	0.00	0.49	0.01	0.28	0.00	1.91	0.14	4.86
Northwest 69kV Area	July	Weekday	15	0.23	0.27	0.00	1.31	0.00	0.41	0.00	0.24	0.00	1.83	0.11	4.40
Pleasant Valley 69	July	Weekday	17	0.36	0.17	0.00	1.10	0.00	0.22	0.00	0.12	0.00	1.26	0.08	3.32
RD-RJ Lines	July	Weekday	17	0.21	0.15	0.00	0.94	0.00	0.51	0.00	0.09	0.00	1.40	0.08	3.38
Southern Dutchess	July	Weekday	17	0.25	0.15	0.00	0.97	0.00	0.26	0.00	0.11	0.00	0.63	0.16	2.53
WM Line	July	Weekday	17	0.02	0.04	0.00	0.23	0.00	0.13	0.00	0.02	0.00	0.21	0.05	0.69
Westerlo Loop	December	Weekday	18	0.00	0.19	0.00	0.13	0.00	0.18	0.00	0.09	0.00	0.00	0.07	0.66
CH System	July	Weekday	17	3.60	1.99	0.01	12.75	0.00	4.27	0.04	1.38	0.00	13.17	1.03	38.24

Table 9: 2018 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	0.20	0.28	0.00	0.79	0.00	0.38	0.00	0.17	0.00	2.55	0.06	4.44
Hurley-Milan	July	Weekday	14	0.61	0.24	0.00	1.17	0.00	0.85	0.01	0.14	0.00	2.80	0.09	5.91
Mid-Dutchess	July	Weekday	17	0.56	0.22	0.00	1.41	0.00	0.66	0.00	0.11	0.00	1.26	0.13	4.35
Northwest 115-69 Area	July	Weekday	13	0.36	0.58	0.00	2.09	0.00	0.74	0.01	0.38	0.00	3.05	0.14	7.36
Northwest 69kV Area	July	Weekday	15	0.34	0.41	0.00	1.97	0.00	0.61	0.00	0.32	0.00	2.92	0.11	6.68
Pleasant Valley 69	July	Weekday	17	0.55	0.26	0.00	1.65	0.00	0.33	0.00	0.16	0.00	2.01	0.08	5.04
RD-RJ Lines	July	Weekday	17	0.31	0.22	0.00	1.41	0.00	0.76	0.01	0.12	0.00	2.23	0.08	5.14
Southern Dutchess	July	Weekday	17	0.38	0.23	0.00	1.45	0.00	0.39	0.00	0.14	0.00	1.00	0.16	3.76
WM Line	July	Weekday	17	0.03	0.06	0.00	0.35	0.00	0.19	0.00	0.02	0.00	0.33	0.05	1.04
Westerlo Loop	December	Weekday	18	0.01	0.28	0.00	0.19	0.00	0.27	0.00	0.12	0.00	0.00	0.07	0.94
CH System	July	Weekday	17	5.41	2.98	0.02	19.13	0.00	6.41	0.05	1.85	0.00	20.98	1.03	57.85

Table 10: 2019 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	0.27	0.37	0.00	1.06	0.00	0.50	0.00	0.18	0.00	3.43	0.06	5.88
Hurley-Milan	July	Weekday	14	0.81	0.32	0.00	1.56	0.00	1.13	0.01	0.16	0.00	3.76	0.09	7.84
Mid-Dutchess	July	Weekday	17	0.75	0.29	0.00	1.88	0.00	0.89	0.00	0.12	0.00	1.69	0.13	5.74
Northwest 115-69 Area	July	Weekday	13	0.48	0.78	0.00	2.79	0.00	0.99	0.02	0.42	0.00	4.09	0.14	9.70
Northwest 69kV Area	July	Weekday	15	0.46	0.54	0.00	2.63	0.00	0.81	0.01	0.35	0.00	3.91	0.11	8.82
Pleasant Valley 69	July	Weekday	17	0.73	0.34	0.00	2.20	0.00	0.44	0.00	0.18	0.00	2.70	0.08	6.67
RD-RJ Lines	July	Weekday	17	0.42	0.29	0.00	1.87	0.00	1.01	0.01	0.13	0.00	2.99	0.08	6.81
Southern Dutchess	July	Weekday	17	0.51	0.30	0.00	1.94	0.00	0.52	0.00	0.16	0.00	1.34	0.16	4.93
WM Line	July	Weekday	17	0.04	0.08	0.00	0.47	0.00	0.26	0.00	0.03	0.00	0.44	0.05	1.36
Westerlo Loop	December	Weekday	18	0.01	0.38	0.00	0.26	0.00	0.36	0.00	0.14	0.00	0.00	0.07	1.21
CH System	July	Weekday	17	7.21	3.97	0.03	25.50	0.00	8.54	0.07	2.04	0.00	28.13	1.03	76.53

Table 11: 2020 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	0.34	0.47	0.00	1.32	0.00	0.63	0.00	0.22	0.00	4.10	0.06	7.15
Hurley-Milan	July	Weekday	14	1.01	0.41	0.00	1.95	0.00	1.41	0.01	0.19	0.00	4.50	0.09	9.57
Mid-Dutchess	July	Weekday	17	0.93	0.37	0.00	2.35	0.00	1.11	0.01	0.14	0.00	2.02	0.13	7.05
Northwest 115-69 Area	July	Weekday	13	0.60	0.97	0.00	3.49	0.00	1.23	0.02	0.51	0.00	4.89	0.14	11.86
Northwest 69kV Area	July	Weekday	15	0.57	0.68	0.00	3.29	0.00	1.02	0.01	0.43	0.00	4.68	0.11	10.78
Pleasant Valley 69	July	Weekday	17	0.91	0.43	0.00	2.75	0.00	0.55	0.00	0.22	0.00	3.22	0.08	8.17
RD-RJ Lines	July	Weekday	17	0.52	0.37	0.00	2.34	0.00	1.26	0.01	0.16	0.00	3.58	0.08	8.33
Southern Dutchess	July	Weekday	17	0.63	0.38	0.00	2.42	0.00	0.65	0.00	0.19	0.00	1.60	0.16	6.05
WM Line	July	Weekday	17	0.05	0.10	0.00	0.58	0.00	0.32	0.00	0.03	0.00	0.53	0.05	1.67
Westerlo Loop	December	Weekday	18	0.01	0.47	0.00	0.32	0.00	0.45	0.00	0.17	0.00	0.00	0.07	1.49
CH System	July	Weekday	17	9.01	4.97	0.04	31.88	0.00	10.68	0.09	2.50	0.00	33.66	1.03	93.85

Table 12: 2021 Forecast Peak Contribution (MW) by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	0.41	0.56	0.00	1.59	0.00	0.75	0.00	0.28	0.00	4.55	0.06	8.21
Hurley-Milan	July	Weekday	14	1.21	0.49	0.00	2.34	0.00	1.70	0.01	0.24	0.00	4.99	0.09	11.08
Mid-Dutchess	July	Weekday	17	1.12	0.44	0.00	2.81	0.00	1.33	0.01	0.18	0.00	2.24	0.13	8.26
Northwest 115-69 Area	July	Weekday	13	0.72	1.17	0.01	4.18	0.00	1.48	0.02	0.64	0.00	5.43	0.14	13.79
Northwest 69kV Area	July	Weekday	15	0.68	0.82	0.00	3.94	0.00	1.22	0.01	0.54	0.00	5.20	0.11	12.52
Pleasant Valley 69	July	Weekday	17	1.09	0.51	0.00	3.30	0.00	0.66	0.00	0.28	0.00	3.58	0.08	9.51
RD-RJ Lines	July	Weekday	17	0.63	0.44	0.00	2.81	0.00	1.52	0.01	0.20	0.00	3.98	0.08	9.67
Southern Dutchess	July	Weekday	17	0.76	0.45	0.00	2.91	0.00	0.78	0.01	0.24	0.00	1.78	0.16	7.09
WM Line	July	Weekday	17	0.06	0.12	0.00	0.70	0.00	0.39	0.00	0.04	0.00	0.59	0.05	1.95
Westerlo Loop	December	Weekday	18	0.01	0.57	0.00	0.39	0.00	0.54	0.00	0.21	0.00	0.00	0.07	1.78
CH System	July	Weekday	17	10.81	5.96	0.04	38.25	0.00	12.81	0.11	3.12	0.00	37.40	1.03	109.54

Table 13: 2016 Forecast Peak Contribution (MW) by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.01	0.03	0.00	0.16	0.00	0.06	0.00	0.01	0.00	0.32	0.04	0.63
Boulevard	July	Weekday	14	0.01	0.02	0.00	0.09	0.00	0.03	0.00	0.02	0.00	0.11	0.03	0.31
Clinton Ave	February	Weekday	12	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.03
Coldenham	July	Weekday	15	0.01	0.02	0.00	0.15	0.00	0.29	0.00	0.02	0.00	0.43	0.04	0.97
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	December	Weekday	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Eastkingston	July	Weekday	17	0.17	0.02	0.00	0.10	0.00	0.06	0.00	0.01	0.00	0.07	0.01	0.45
Eastpark	July	Weekday	18	0.06	0.02	0.00	0.11	0.00	0.02	0.00	0.01	0.00	0.02	0.01	0.24
East Walden	July	Weekday	16	0.04	0.02	0.00	0.13	0.00	0.02	0.00	0.02	0.00	0.20	0.02	0.44
Fishkill Plains	July	Weekday	17	0.09	0.05	0.00	0.36	0.00	0.04	0.00	0.03	0.00	0.30	0.04	0.90
Forgebrook	July	Weekday	17	0.10	0.02	0.00	0.15	0.00	0.05	0.00	0.03	0.00	0.11	0.03	0.49
Galeville	July	Weekday	11	0.01	0.02	0.00	0.06	0.00	0.01	0.00	0.01	0.00	0.26	0.01	0.38
Grimley Rd	July	Weekday	19	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02
Hibernia	July	Weekday	16	0.01	0.02	0.00	0.11	0.00	0.03	0.00	0.02	0.00	0.36	0.01	0.56
High Falls	July	Weekday	16	0.09	0.03	0.00	0.18	0.00	0.04	0.00	0.02	0.00	0.18	0.02	0.55
Highland	July	Weekday	16	0.10	0.02	0.00	0.16	0.00	0.06	0.00	0.02	0.00	0.34	0.02	0.73
Honk Falls	July	Weekday	13	0.01	0.01	0.00	0.03	0.00	0.01	0.00	0.01	0.00	0.02	0.01	0.08
Hunter	December	Weekday	21	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.04
Hurley Ave	July	Weekday	17	0.02	0.02	0.00	0.13	0.00	0.05	0.00	0.02	0.00	0.11	0.02	0.37
Inwood Ave	July	Weekday	16	0.00	0.02	0.00	0.13	0.00	0.05	0.00	0.03	0.00	0.04	0.03	0.28
Knapps Corners	July	Weekday	17	0.00	0.02	0.00	0.03	0.00	0.03	0.00	0.01	0.00	0.14	0.02	0.24
Lawrenceville	December	Weekday	21	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.02	0.05
Lincoln Park	July	Weekday	9	0.00	0.03	0.00	0.04	0.00	0.03	0.00	0.02	0.00	0.14	0.04	0.30
Marlboro	July	Weekday	17	0.03	0.02	0.00	0.16	0.00	0.04	0.00	0.02	0.00	0.18	0.02	0.47

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.01	0.01	0.00	0.09	0.00	0.05	0.00	0.01	0.00	0.06	0.02	0.25
Merritt Park	July	Weekday	16	0.01	0.02	0.00	0.15	0.00	0.06	0.00	0.02	0.00	0.05	0.03	0.35
Milan	July	Weekday	10	0.01	0.01	0.00	0.02	0.00	0.01	0.00	0.01	0.00	0.05	0.01	0.12
Millerton	January	Weekday	18	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.04
Modena	July	Weekday	17	0.02	0.02	0.00	0.12	0.00	0.01	0.00	0.01	0.00	0.15	0.01	0.35
Myers Corners	July	Weekday	18	0.00	0.02	0.00	0.15	0.00	0.03	0.00	0.01	0.00	0.05	0.03	0.29
New Baltimore	July	Weekday	18	0.01	0.01	0.00	0.09	0.00	0.01	0.00	0.01	0.00	0.05	0.01	0.19
North Catskill	July	Weekday	16	0.04	0.03	0.00	0.21	0.00	0.04	0.00	0.04	0.00	0.13	0.03	0.51
North Chelsea	July	Weekday	17	0.15	0.02	0.00	0.13	0.00	0.03	0.00	0.03	0.00	0.05	0.02	0.43
Ohioville	July	Weekday	15	0.10	0.02	0.00	0.14	0.00	0.07	0.00	0.03	0.00	0.25	0.03	0.63
Pulvers Corners	January	Weekday	18	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.04
Reynolds Hill	July	Weekday	14	0.12	0.02	0.00	0.11	0.00	0.16	0.00	0.03	0.00	0.09	0.03	0.55
Rhinebeck	July	Weekday	18	0.07	0.03	0.00	0.20	0.00	0.08	0.00	0.03	0.00	0.16	0.03	0.61
Sand Dock	July	Weekday	13	0.00	0.00	0.00	0.02	0.00	0.02	0.00	0.00	0.00	0.02	0.03	0.10
Saugerties	July	Weekday	17	0.05	0.03	0.00	0.17	0.00	0.03	0.00	0.02	0.00	0.16	0.02	0.49
Shenandoah	July	Weekday	15	0.02	0.02	0.00	0.13	0.00	0.01	0.00	0.01	0.00	0.08	0.08	0.34
Smithfield	December	Weekday	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	July	Weekday	18	0.21	0.03	0.00	0.21	0.00	0.06	0.00	0.02	0.00	0.06	0.04	0.64
Staatsburg	July	Weekday	18	0.02	0.01	0.00	0.09	0.00	0.01	0.00	0.01	0.00	0.04	0.01	0.20
Stanfordville	December	Weekday	18	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.04
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	0.06	0.02	0.00	0.11	0.00	0.03	0.00	0.02	0.00	0.06	0.02	0.33
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	0.05	0.03	0.00	0.22	0.00	0.04	0.00	0.02	0.00	0.18	0.02	0.57
Union Ave	September	Weekday	16	0.09	0.06	0.00	0.26	0.00	0.23	0.00	0.05	0.00	0.42	0.06	1.17

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.03
Westbalmville	July	Weekday	16	0.00	0.03	0.00	0.18	0.00	0.04	0.00	0.02	0.00	0.17	0.04	0.48
Westerlo	July	Weekday	15	0.01	0.01	0.00	0.08	0.00	0.02	0.00	0.01	0.00	0.11	0.01	0.25
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	0.07	0.03	0.00	0.22	0.00	0.02	0.00	0.03	0.00	0.09	0.02	0.48
Total System	July	Weekday	17	2.14	1.06	0.01	7.13	0.00	2.10	0.02	1.03	0.00	6.20	1.06	20.75

Table 14: 2017 Forecast Peak Contribution (MW) by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.02	0.05	0.00	0.33	0.00	0.11	0.00	0.02	0.00	0.69	0.04	1.26
Boulevard	July	Weekday	14	0.02	0.04	0.00	0.18	0.00	0.07	0.00	0.02	0.00	0.25	0.03	0.61
Clinton Ave	February	Weekday	12	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.01	0.00	0.05
Coldenham	July	Weekday	15	0.02	0.05	0.00	0.31	0.00	0.58	0.00	0.02	0.00	0.94	0.04	1.97
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	December	Weekday	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Eastkingston	July	Weekday	17	0.34	0.03	0.00	0.21	0.00	0.12	0.00	0.01	0.00	0.16	0.01	0.88
Eastpark	July	Weekday	18	0.11	0.03	0.00	0.21	0.00	0.03	0.00	0.01	0.00	0.05	0.01	0.47
East Walden	July	Weekday	16	0.07	0.04	0.00	0.26	0.00	0.03	0.00	0.02	0.00	0.44	0.02	0.88
Fishkill Plains	July	Weekday	17	0.17	0.11	0.00	0.72	0.00	0.07	0.00	0.03	0.00	0.65	0.04	1.79
Forgebrook	July	Weekday	17	0.19	0.04	0.00	0.29	0.00	0.11	0.00	0.03	0.00	0.25	0.03	0.95
Galeville	July	Weekday	11	0.03	0.03	0.00	0.12	0.00	0.02	0.00	0.01	0.00	0.57	0.01	0.79
Grimley Rd	July	Weekday	19	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04
Hibernia	July	Weekday	16	0.03	0.03	0.00	0.22	0.00	0.06	0.00	0.02	0.00	0.79	0.01	1.16
High Falls	July	Weekday	16	0.17	0.05	0.00	0.35	0.00	0.07	0.00	0.03	0.00	0.39	0.02	1.09
Highland	July	Weekday	16	0.20	0.05	0.00	0.32	0.00	0.11	0.00	0.03	0.00	0.75	0.02	1.48
Honk Falls	July	Weekday	13	0.02	0.01	0.00	0.05	0.00	0.01	0.00	0.01	0.00	0.04	0.01	0.14
Hunter	December	Weekday	21	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.05
Hurley Ave	July	Weekday	17	0.04	0.04	0.00	0.26	0.00	0.10	0.00	0.03	0.00	0.24	0.02	0.73
Inwood Ave	July	Weekday	16	0.00	0.04	0.00	0.26	0.00	0.10	0.00	0.03	0.00	0.08	0.03	0.53
Knapps Corners	July	Weekday	17	0.00	0.03	0.00	0.06	0.00	0.06	0.00	0.01	0.00	0.30	0.02	0.48
Lawrenceville	December	Weekday	21	0.00	0.02	0.00	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.02	0.07
Lincoln Park	July	Weekday	9	0.01	0.06	0.00	0.09	0.00	0.05	0.00	0.02	0.00	0.30	0.04	0.57
Marlboro	July	Weekday	17	0.05	0.05	0.00	0.32	0.00	0.07	0.00	0.02	0.00	0.40	0.02	0.94

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.02	0.03	0.00	0.19	0.00	0.10	0.00	0.01	0.00	0.12	0.02	0.49
Merritt Park	July	Weekday	16	0.03	0.05	0.00	0.30	0.00	0.12	0.00	0.02	0.00	0.11	0.03	0.66
Milan	July	Weekday	10	0.02	0.02	0.00	0.05	0.00	0.03	0.00	0.01	0.00	0.10	0.01	0.24
Millerton	January	Weekday	18	0.00	0.01	0.00	0.01	0.00	0.02	0.00	0.01	0.00	0.00	0.00	0.06
Modena	July	Weekday	17	0.04	0.04	0.00	0.24	0.00	0.02	0.00	0.02	0.00	0.33	0.01	0.70
Myers Corners	July	Weekday	18	0.00	0.04	0.00	0.31	0.00	0.05	0.00	0.02	0.00	0.10	0.03	0.55
New Baltimore	July	Weekday	18	0.01	0.03	0.00	0.19	0.00	0.02	0.00	0.01	0.00	0.11	0.01	0.38
North Catskill	July	Weekday	16	0.08	0.06	0.00	0.41	0.00	0.07	0.01	0.04	0.00	0.29	0.03	0.98
North Chelsea	July	Weekday	17	0.30	0.04	0.00	0.26	0.00	0.05	0.00	0.03	0.00	0.12	0.02	0.82
Ohioville	July	Weekday	15	0.20	0.04	0.00	0.27	0.00	0.13	0.00	0.03	0.00	0.55	0.03	1.25
Pulvers Corners	January	Weekday	18	0.00	0.02	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.07
Reynolds Hill	July	Weekday	14	0.23	0.04	0.00	0.21	0.00	0.32	0.00	0.04	0.00	0.19	0.03	1.06
Rhinebeck	July	Weekday	18	0.14	0.06	0.00	0.41	0.00	0.16	0.00	0.03	0.00	0.35	0.03	1.18
Sand Dock	July	Weekday	13	0.00	0.01	0.00	0.05	0.00	0.04	0.00	0.00	0.00	0.04	0.03	0.17
Saugerties	July	Weekday	17	0.11	0.05	0.00	0.35	0.00	0.06	0.00	0.03	0.00	0.34	0.02	0.97
Shenandoah	July	Weekday	15	0.03	0.04	0.00	0.25	0.00	0.02	0.00	0.01	0.00	0.17	0.08	0.61
Smithfield	December	Weekday	8	0.00	0.00	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	0.43	0.06	0.00	0.43	0.00	0.13	0.00	0.02	0.00	0.13	0.04	1.23
Staatsburg	July	Weekday	18	0.05	0.03	0.00	0.18	0.00	0.01	0.00	0.01	0.00	0.08	0.01	0.38
Stanfordville	December	Weekday	18	0.00	0.02	0.00	0.02	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.06
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	0.13	0.04	0.00	0.23	0.00	0.06	0.00	0.03	0.00	0.14	0.02	0.63
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	0.10	0.06	0.00	0.43	0.00	0.08	0.00	0.02	0.00	0.40	0.02	1.13
Union Ave	September	Weekday	16	0.17	0.12	0.00	0.52	0.00	0.47	0.00	0.05	0.00	0.92	0.06	2.32

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.00	0.02	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.05
Westbalmville	July	Weekday	16	0.00	0.06	0.00	0.37	0.00	0.08	0.00	0.02	0.00	0.38	0.04	0.94
Westerlo	July	Weekday	15	0.02	0.02	0.00	0.16	0.00	0.03	0.00	0.01	0.00	0.24	0.01	0.49
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	0.14	0.06	0.00	0.44	0.00	0.05	0.00	0.03	0.00	0.19	0.02	0.93
Total System	July	Weekday	17	4.29	2.13	0.01	14.25	0.00	4.19	0.04	1.16	0.00	13.57	1.06	40.71

Table 15: 2018 Forecast Peak Contribution (MW) by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.02	0.08	0.00	0.49	0.00	0.17	0.00	0.02	0.00	1.10	0.04	1.93
Boulevard	July	Weekday	14	0.03	0.06	0.00	0.26	0.00	0.10	0.00	0.03	0.00	0.39	0.03	0.91
Clinton Ave	February	Weekday	12	0.00	0.01	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.01	0.00	0.08
Coldenham	July	Weekday	15	0.03	0.07	0.00	0.46	0.00	0.88	0.00	0.03	0.00	1.49	0.04	3.01
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	December	Weekday	8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Eastkingston	July	Weekday	17	0.51	0.05	0.00	0.31	0.00	0.18	0.00	0.02	0.00	0.25	0.01	1.33
Eastpark	July	Weekday	18	0.17	0.05	0.00	0.32	0.00	0.05	0.00	0.02	0.00	0.09	0.01	0.70
East Walden	July	Weekday	16	0.11	0.06	0.00	0.39	0.00	0.05	0.00	0.02	0.00	0.70	0.02	1.36
Fishkill Plains	July	Weekday	17	0.26	0.16	0.00	1.08	0.00	0.11	0.00	0.04	0.00	1.03	0.04	2.72
Forgebrook	July	Weekday	17	0.29	0.07	0.00	0.44	0.00	0.16	0.00	0.04	0.00	0.40	0.03	1.42
Galeville	July	Weekday	11	0.04	0.05	0.00	0.18	0.00	0.03	0.00	0.01	0.00	0.90	0.01	1.22
Grimley Rd	July	Weekday	19	0.00	0.01	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.05
Hibernia	July	Weekday	16	0.04	0.05	0.00	0.32	0.00	0.08	0.00	0.03	0.00	1.26	0.01	1.80
High Falls	July	Weekday	16	0.26	0.08	0.00	0.53	0.00	0.11	0.00	0.04	0.00	0.63	0.02	1.66
Highland	July	Weekday	16	0.31	0.07	0.00	0.48	0.00	0.17	0.00	0.03	0.00	1.19	0.02	2.27
Honk Falls	July	Weekday	13	0.03	0.02	0.00	0.08	0.00	0.02	0.00	0.01	0.00	0.06	0.01	0.21
Hunter	December	Weekday	21	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.07
Hurley Ave	July	Weekday	17	0.06	0.06	0.00	0.39	0.00	0.15	0.00	0.03	0.00	0.38	0.02	1.10
Inwood Ave	July	Weekday	16	0.00	0.06	0.00	0.38	0.00	0.15	0.00	0.04	0.00	0.12	0.03	0.78
Knapps Corners	July	Weekday	17	0.00	0.05	0.00	0.10	0.00	0.09	0.00	0.01	0.00	0.47	0.02	0.74
Lawrenceville	December	Weekday	21	0.00	0.03	0.00	0.02	0.00	0.00	0.00	0.02	0.00	0.00	0.02	0.09
Lincoln Park	July	Weekday	9	0.01	0.08	0.00	0.13	0.00	0.08	0.00	0.02	0.00	0.48	0.04	0.85
Marlboro	July	Weekday	17	0.08	0.07	0.00	0.48	0.00	0.11	0.00	0.03	0.00	0.63	0.02	1.43

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.03	0.04	0.00	0.28	0.00	0.15	0.00	0.01	0.00	0.20	0.02	0.73
Merritt Park	July	Weekday	16	0.04	0.07	0.00	0.45	0.00	0.18	0.00	0.03	0.00	0.17	0.03	0.98
Milan	July	Weekday	10	0.04	0.03	0.00	0.07	0.00	0.04	0.00	0.01	0.00	0.16	0.01	0.36
Millerton	January	Weekday	18	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.00	0.00	0.09
Modena	July	Weekday	17	0.07	0.06	0.00	0.35	0.00	0.03	0.00	0.02	0.00	0.52	0.01	1.07
Myers Corners	July	Weekday	18	0.00	0.06	0.00	0.46	0.00	0.08	0.00	0.02	0.00	0.16	0.03	0.82
New Baltimore	July	Weekday	18	0.02	0.04	0.00	0.28	0.00	0.04	0.00	0.02	0.00	0.17	0.01	0.57
North Catskill	July	Weekday	16	0.12	0.09	0.00	0.62	0.00	0.11	0.01	0.05	0.00	0.45	0.03	1.48
North Chelsea	July	Weekday	17	0.45	0.06	0.00	0.38	0.00	0.08	0.00	0.04	0.00	0.19	0.02	1.22
Ohioville	July	Weekday	15	0.30	0.06	0.00	0.41	0.00	0.20	0.00	0.04	0.00	0.87	0.03	1.91
Pulvers Corners	January	Weekday	18	0.00	0.03	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.00	0.01	0.09
Reynolds Hill	July	Weekday	14	0.35	0.06	0.00	0.32	0.00	0.48	0.00	0.05	0.00	0.30	0.03	1.59
Rhinebeck	July	Weekday	18	0.22	0.09	0.00	0.61	0.00	0.23	0.01	0.05	0.00	0.56	0.03	1.79
Sand Dock	July	Weekday	13	0.00	0.01	0.00	0.07	0.00	0.06	0.00	0.00	0.00	0.07	0.03	0.25
Saugerties	July	Weekday	17	0.16	0.08	0.00	0.52	0.00	0.09	0.00	0.04	0.00	0.55	0.02	1.47
Shenandoah	July	Weekday	15	0.05	0.06	0.00	0.38	0.00	0.03	0.00	0.02	0.00	0.27	0.08	0.89
Smithfield	December	Weekday	8	0.00	0.00	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	0.64	0.09	0.00	0.64	0.00	0.19	0.00	0.03	0.00	0.21	0.04	1.84
Staatsburg	July	Weekday	18	0.07	0.04	0.00	0.28	0.00	0.02	0.00	0.01	0.00	0.13	0.01	0.57
Stanfordville	December	Weekday	18	0.00	0.03	0.00	0.02	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.09
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	0.19	0.06	0.00	0.34	0.00	0.08	0.00	0.04	0.00	0.22	0.02	0.94
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	0.15	0.10	0.00	0.65	0.00	0.12	0.00	0.03	0.00	0.64	0.02	1.71
Union Ave	September	Weekday	16	0.26	0.18	0.00	0.79	0.00	0.70	0.01	0.07	0.00	1.47	0.06	3.53

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.00	0.03	0.00	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.07
Westbalmville	July	Weekday	16	0.00	0.09	0.00	0.55	0.00	0.12	0.00	0.03	0.00	0.61	0.04	1.43
Westerlo	July	Weekday	15	0.02	0.04	0.00	0.24	0.00	0.05	0.00	0.02	0.00	0.38	0.01	0.75
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	0.21	0.09	0.00	0.66	0.00	0.07	0.00	0.04	0.00	0.30	0.02	1.40
Total System	July	Weekday	17	6.43	3.19	0.02	21.38	0.00	6.29	0.06	1.56	0.00	21.62	1.06	61.61

Table 16: 2019 Forecast Peak Contribution (MW) by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.03	0.11	0.00	0.65	0.00	0.23	0.00	0.02	0.00	1.48	0.04	2.56
Boulevard	July	Weekday	14	0.04	0.08	0.00	0.35	0.00	0.13	0.01	0.03	0.00	0.53	0.03	1.21
Clinton Ave	February	Weekday	12	0.00	0.01	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.01	0.00	0.10
Coldenham	July	Weekday	15	0.04	0.10	0.00	0.62	0.00	1.17	0.00	0.04	0.00	2.00	0.04	4.01
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	0.01
Eastkingston	July	Weekday	17	0.68	0.06	0.00	0.42	0.00	0.23	0.00	0.02	0.00	0.34	0.01	1.77
Eastpark	July	Weekday	18	0.22	0.07	0.00	0.42	0.00	0.06	0.00	0.02	0.00	0.11	0.01	0.93
East Walden	July	Weekday	16	0.14	0.08	0.00	0.52	0.00	0.07	0.00	0.03	0.00	0.94	0.02	1.80
Fishkill Plains	July	Weekday	17	0.34	0.21	0.00	1.44	0.00	0.14	0.00	0.05	0.00	1.38	0.04	3.61
Forgebrook	July	Weekday	17	0.39	0.09	0.00	0.58	0.00	0.21	0.00	0.04	0.00	0.53	0.03	1.88
Galeville	July	Weekday	11	0.06	0.06	0.00	0.24	0.00	0.04	0.00	0.01	0.00	1.21	0.01	1.63
Grimley Rd	July	Weekday	19	0.00	0.01	0.00	0.04	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.07
Hibernia	July	Weekday	16	0.05	0.06	0.00	0.43	0.00	0.11	0.00	0.03	0.00	1.69	0.01	2.40
High Falls	July	Weekday	16	0.34	0.10	0.00	0.71	0.00	0.14	0.00	0.04	0.00	0.84	0.02	2.20
Highland	July	Weekday	16	0.41	0.09	0.00	0.64	0.00	0.22	0.00	0.04	0.00	1.59	0.02	3.02
Honk Falls	July	Weekday	13	0.04	0.02	0.00	0.10	0.00	0.02	0.00	0.01	0.00	0.08	0.01	0.28
Hunter	December	Weekday	21	0.00	0.02	0.00	0.02	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.09
Hurley Ave	July	Weekday	17	0.08	0.08	0.00	0.52	0.00	0.20	0.00	0.04	0.00	0.50	0.02	1.45
Inwood Ave	July	Weekday	16	0.00	0.08	0.00	0.51	0.00	0.20	0.00	0.04	0.00	0.17	0.03	1.03
Knapps Corners	July	Weekday	17	0.00	0.07	0.00	0.13	0.00	0.12	0.00	0.01	0.00	0.63	0.02	0.98
Lawrenceville	December	Weekday	21	0.00	0.04	0.00	0.03	0.00	0.00	0.00	0.02	0.00	0.00	0.02	0.11
Lincoln Park	July	Weekday	9	0.01	0.11	0.00	0.18	0.00	0.11	0.00	0.03	0.00	0.64	0.04	1.12
Marlboro	July	Weekday	17	0.10	0.10	0.00	0.65	0.00	0.15	0.01	0.03	0.00	0.85	0.02	1.90

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.04	0.06	0.00	0.37	0.00	0.20	0.00	0.02	0.00	0.27	0.02	0.97
Merritt Park	July	Weekday	16	0.06	0.09	0.00	0.60	0.00	0.24	0.00	0.03	0.00	0.23	0.03	1.29
Milan	July	Weekday	10	0.05	0.04	0.00	0.10	0.00	0.05	0.00	0.01	0.00	0.22	0.01	0.47
Millerton	January	Weekday	18	0.00	0.03	0.00	0.02	0.00	0.03	0.00	0.02	0.00	0.00	0.00	0.11
Modena	July	Weekday	17	0.09	0.08	0.00	0.47	0.00	0.04	0.01	0.02	0.00	0.70	0.01	1.43
Myers Corners	July	Weekday	18	0.00	0.08	0.00	0.62	0.00	0.11	0.00	0.02	0.00	0.22	0.03	1.08
New Baltimore	July	Weekday	18	0.03	0.05	0.00	0.37	0.00	0.05	0.00	0.02	0.00	0.23	0.01	0.76
North Catskill	July	Weekday	16	0.16	0.12	0.00	0.82	0.00	0.14	0.01	0.06	0.00	0.61	0.03	1.96
North Chelsea	July	Weekday	17	0.60	0.08	0.00	0.51	0.00	0.10	0.00	0.04	0.00	0.25	0.02	1.62
Ohioville	July	Weekday	15	0.40	0.08	0.00	0.55	0.00	0.27	0.00	0.04	0.00	1.17	0.03	2.54
Pulvers Corners	January	Weekday	18	0.00	0.04	0.00	0.03	0.00	0.03	0.00	0.02	0.00	0.00	0.01	0.12
Reynolds Hill	July	Weekday	14	0.47	0.08	0.00	0.42	0.00	0.64	0.00	0.05	0.00	0.41	0.03	2.10
Rhinebeck	July	Weekday	18	0.29	0.12	0.00	0.81	0.00	0.31	0.01	0.05	0.00	0.74	0.03	2.37
Sand Dock	July	Weekday	13	0.00	0.02	0.00	0.10	0.00	0.07	0.00	0.00	0.00	0.10	0.03	0.32
Saugerties	July	Weekday	17	0.22	0.10	0.00	0.70	0.00	0.12	0.00	0.04	0.00	0.73	0.02	1.94
Shenandoah	July	Weekday	15	0.07	0.07	0.00	0.51	0.00	0.04	0.00	0.02	0.00	0.36	0.08	1.16
Smithfield	December	Weekday	8	0.00	0.00	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	0.86	0.13	0.00	0.86	0.00	0.25	0.00	0.03	0.00	0.28	0.04	2.44
Staatsburg	July	Weekday	18	0.10	0.05	0.00	0.37	0.00	0.03	0.00	0.01	0.00	0.18	0.01	0.76
Stanfordville	December	Weekday	18	0.00	0.04	0.00	0.03	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.12
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	0.25	0.07	0.00	0.45	0.00	0.11	0.00	0.04	0.00	0.30	0.02	1.24
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	0.20	0.13	0.00	0.87	0.00	0.16	0.00	0.03	0.00	0.86	0.02	2.28
Union Ave	September	Weekday	16	0.35	0.24	0.00	1.05	0.00	0.94	0.01	0.08	0.00	1.97	0.06	4.68

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.00	0.03	0.00	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.09
Westbalmville	July	Weekday	16	0.00	0.11	0.00	0.73	0.00	0.16	0.00	0.03	0.00	0.82	0.04	1.89
Westerlo	July	Weekday	15	0.03	0.05	0.00	0.31	0.00	0.07	0.00	0.02	0.00	0.51	0.01	1.00
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	0.28	0.11	0.00	0.88	0.00	0.09	0.01	0.05	0.00	0.41	0.02	1.85
Total System	July	Weekday	17	8.58	4.25	0.03	28.50	0.00	8.39	0.08	1.72	0.00	28.99	1.06	81.60

Table 17: 2020 Forecast Peak Contribution (MW) by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.04	0.13	0.00	0.81	0.00	0.29	0.00	0.03	0.00	1.77	0.04	3.12
Boulevard	July	Weekday	14	0.06	0.11	0.00	0.44	0.00	0.16	0.01	0.04	0.00	0.63	0.03	1.47
Clinton Ave	February	Weekday	12	0.00	0.01	0.00	0.01	0.00	0.09	0.00	0.01	0.00	0.01	0.00	0.13
Coldenham	July	Weekday	15	0.05	0.12	0.00	0.77	0.00	1.46	0.01	0.04	0.00	2.40	0.04	4.89
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
Eastkingston	July	Weekday	17	0.85	0.08	0.00	0.52	0.00	0.29	0.00	0.02	0.00	0.41	0.01	2.19
Eastpark	July	Weekday	18	0.28	0.08	0.00	0.53	0.00	0.08	0.00	0.03	0.00	0.14	0.01	1.15
East Walden	July	Weekday	16	0.18	0.10	0.00	0.66	0.00	0.09	0.00	0.03	0.00	1.13	0.02	2.20
Fishkill Plains	July	Weekday	17	0.43	0.27	0.00	1.80	0.00	0.18	0.00	0.06	0.00	1.65	0.04	4.43
Forgebrook	July	Weekday	17	0.49	0.11	0.00	0.73	0.00	0.26	0.00	0.05	0.00	0.64	0.03	2.31
Galeville	July	Weekday	11	0.07	0.08	0.00	0.30	0.00	0.05	0.00	0.02	0.00	1.45	0.01	1.98
Grimley Rd	July	Weekday	19	0.00	0.01	0.00	0.05	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.08
Hibernia	July	Weekday	16	0.07	0.08	0.00	0.54	0.00	0.14	0.00	0.04	0.00	2.02	0.01	2.90
High Falls	July	Weekday	16	0.43	0.13	0.00	0.89	0.00	0.18	0.00	0.05	0.00	1.01	0.02	2.70
Highland	July	Weekday	16	0.51	0.12	0.00	0.80	0.00	0.28	0.00	0.05	0.00	1.91	0.02	3.69
Honk Falls	July	Weekday	13	0.05	0.03	0.00	0.13	0.00	0.03	0.00	0.01	0.00	0.09	0.01	0.35
Hunter	December	Weekday	21	0.00	0.03	0.00	0.03	0.00	0.03	0.00	0.01	0.00	0.00	0.01	0.11
Hurley Ave	July	Weekday	17	0.10	0.11	0.00	0.65	0.00	0.25	0.00	0.05	0.00	0.60	0.02	1.78
Inwood Ave	July	Weekday	16	0.00	0.10	0.00	0.64	0.00	0.24	0.00	0.05	0.00	0.20	0.03	1.27
Knapps Corners	July	Weekday	17	0.00	0.08	0.00	0.16	0.00	0.14	0.00	0.01	0.00	0.76	0.02	1.18
Lawrenceville	December	Weekday	21	0.00	0.05	0.00	0.04	0.00	0.00	0.00	0.02	0.00	0.00	0.02	0.13
Lincoln Park	July	Weekday	9	0.02	0.14	0.00	0.22	0.00	0.13	0.00	0.03	0.00	0.76	0.04	1.36
Marlboro	July	Weekday	17	0.13	0.12	0.00	0.81	0.00	0.19	0.01	0.04	0.00	1.02	0.02	2.32

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.05	0.07	0.00	0.46	0.00	0.24	0.00	0.02	0.00	0.32	0.02	1.19
Merritt Park	July	Weekday	16	0.07	0.12	0.00	0.75	0.00	0.30	0.00	0.04	0.00	0.28	0.03	1.59
Milan	July	Weekday	10	0.06	0.05	0.00	0.12	0.00	0.06	0.00	0.01	0.00	0.26	0.01	0.58
Millerton	January	Weekday	18	0.00	0.03	0.00	0.03	0.00	0.04	0.00	0.03	0.00	0.00	0.00	0.13
Modena	July	Weekday	17	0.11	0.10	0.00	0.59	0.00	0.05	0.01	0.03	0.00	0.84	0.01	1.74
Myers Corners	July	Weekday	18	0.00	0.10	0.00	0.77	0.00	0.13	0.00	0.03	0.00	0.26	0.03	1.33
New Baltimore	July	Weekday	18	0.04	0.07	0.00	0.46	0.00	0.06	0.00	0.02	0.00	0.27	0.01	0.93
North Catskill	July	Weekday	16	0.20	0.15	0.00	1.03	0.00	0.18	0.01	0.07	0.00	0.73	0.03	2.41
North Chelsea	July	Weekday	17	0.75	0.10	0.00	0.64	0.00	0.13	0.00	0.05	0.00	0.30	0.02	2.00
Ohioville	July	Weekday	15	0.51	0.10	0.00	0.68	0.00	0.33	0.00	0.05	0.00	1.40	0.03	3.10
Pulvers Corners	January	Weekday	18	0.00	0.05	0.00	0.03	0.00	0.04	0.00	0.02	0.00	0.00	0.01	0.15
Reynolds Hill	July	Weekday	14	0.59	0.10	0.00	0.53	0.00	0.79	0.00	0.06	0.00	0.49	0.03	2.60
Rhinebeck	July	Weekday	18	0.36	0.15	0.00	1.01	0.00	0.39	0.01	0.06	0.00	0.89	0.03	2.91
Sand Dock	July	Weekday	13	0.01	0.02	0.00	0.12	0.00	0.09	0.00	0.00	0.00	0.11	0.03	0.39
Saugerties	July	Weekday	17	0.27	0.13	0.00	0.87	0.00	0.15	0.00	0.05	0.00	0.88	0.02	2.38
Shenandoah	July	Weekday	15	0.09	0.09	0.00	0.63	0.00	0.06	0.00	0.02	0.00	0.44	0.08	1.41
Smithfield	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	0.01
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	July	Weekday	18	1.07	0.16	0.00	1.07	0.00	0.32	0.00	0.04	0.00	0.33	0.04	3.02
Staatsburg	July	Weekday	18	0.12	0.07	0.00	0.46	0.00	0.04	0.00	0.02	0.00	0.22	0.01	0.93
Stanfordville	December	Weekday	18	0.01	0.05	0.00	0.04	0.00	0.03	0.00	0.01	0.00	0.00	0.01	0.14
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	0.32	0.09	0.00	0.57	0.00	0.14	0.00	0.05	0.00	0.36	0.02	1.53
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	0.25	0.16	0.00	1.08	0.00	0.20	0.01	0.04	0.00	1.03	0.02	2.79
Union Ave	September	Weekday	16	0.43	0.30	0.00	1.31	0.00	1.17	0.01	0.09	0.00	2.35	0.06	5.73

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	February	Weekday	20	0.00	0.04	0.00	0.04	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.10
Westbalmville	July	Weekday	16	0.01	0.14	0.00	0.91	0.00	0.19	0.00	0.04	0.00	0.98	0.04	2.31
Westerlo	July	Weekday	15	0.04	0.06	0.00	0.39	0.00	0.09	0.00	0.02	0.00	0.61	0.01	1.22
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	0.35	0.14	0.00	1.10	0.00	0.12	0.01	0.06	0.00	0.49	0.02	2.28
Total System	July	Weekday	17	10.72	5.31	0.04	35.63	0.00	10.49	0.10	2.11	0.00	34.68	1.06	100.14

Table 18: 2021 Forecast Peak Contribution (MW) by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
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	0.98	0.00	0.34	0.00	0.03	0.00	1.97	0.04	3.57
Boulevard	July	Weekday	14	0.07	0.13	0.00	0.53	0.00	0.20	0.01	0.05	0.00	0.70	0.03	1.71
Clinton Ave	February	Weekday	12	0.00	0.01	0.00	0.01	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	0.92	0.00	1.75	0.01	0.05	0.00	2.66	0.04	5.65
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
Eastkingston	July	Weekday	17	1.02	0.09	0.00	0.63	0.00	0.35	0.00	0.03	0.00	0.45	0.01	2.59
Eastpark	July	Weekday	18	0.34	0.10	0.00	0.63	0.00	0.09	0.00	0.03	0.00	0.15	0.01	1.36
East Walden	July	Weekday	16	0.22	0.12	0.00	0.79	0.00	0.10	0.00	0.04	0.00	1.25	0.02	2.54
Fishkill Plains	July	Weekday	17	0.51	0.32	0.00	2.16	0.00	0.21	0.00	0.07	0.00	1.84	0.04	5.16
Forgebrook	July	Weekday	17	0.58	0.13	0.00	0.87	0.00	0.32	0.01	0.07	0.00	0.71	0.03	2.72
Galeville	July	Weekday	11	0.09	0.10	0.00	0.35	0.00	0.06	0.00	0.02	0.00	1.61	0.01	2.24
Grimley Rd	July	Weekday	19	0.00	0.01	0.00	0.07	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.10
Hibernia	July	Weekday	16	0.08	0.09	0.00	0.65	0.00	0.17	0.00	0.05	0.00	2.25	0.01	3.30
High Falls	July	Weekday	16	0.51	0.16	0.00	1.06	0.00	0.22	0.00	0.06	0.00	1.12	0.02	3.14
Highland	July	Weekday	16	0.61	0.14	0.00	0.96	0.00	0.33	0.00	0.06	0.00	2.12	0.02	4.25
Honk Falls	July	Weekday	13	0.06	0.03	0.00	0.15	0.00	0.04	0.00	0.02	0.00	0.10	0.01	0.41
Hunter	December	Weekday	21	0.00	0.04	0.00	0.03	0.00	0.03	0.00	0.02	0.00	0.00	0.01	0.13
Hurley Ave	July	Weekday	17	0.13	0.13	0.00	0.78	0.00	0.30	0.00	0.06	0.00	0.67	0.02	2.08
Inwood Ave	July	Weekday	16	0.01	0.12	0.00	0.77	0.00	0.29	0.00	0.06	0.00	0.22	0.03	1.50
Knapps Corners	July	Weekday	17	0.00	0.10	0.00	0.19	0.00	0.17	0.00	0.02	0.00	0.84	0.02	1.35
Lawrenceville	December	Weekday	21	0.00	0.06	0.00	0.05	0.00	0.01	0.00	0.03	0.00	0.00	0.02	0.16
Lincoln Park	July	Weekday	9	0.02	0.17	0.00	0.27	0.00	0.16	0.00	0.04	0.00	0.85	0.04	1.55
Marlboro	July	Weekday	17	0.15	0.14	0.00	0.97	0.00	0.22	0.01	0.05	0.00	1.13	0.02	2.69

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.06	0.09	0.00	0.56	0.00	0.29	0.00	0.02	0.00	0.35	0.02	1.40
Merritt Park	July	Weekday	16	0.08	0.14	0.00	0.90	0.00	0.36	0.00	0.05	0.00	0.31	0.03	1.88
Milan	July	Weekday	10	0.07	0.07	0.00	0.15	0.00	0.08	0.00	0.02	0.00	0.29	0.01	0.67
Millerton	January	Weekday	18	0.00	0.04	0.00	0.03	0.00	0.05	0.00	0.03	0.00	0.00	0.00	0.16
Modena	July	Weekday	17	0.13	0.12	0.00	0.71	0.00	0.07	0.01	0.04	0.00	0.94	0.01	2.01
Myers Corners	July	Weekday	18	0.00	0.12	0.00	0.92	0.00	0.16	0.00	0.04	0.00	0.29	0.03	1.56
New Baltimore	July	Weekday	18	0.04	0.08	0.00	0.56	0.00	0.07	0.00	0.03	0.00	0.30	0.01	1.09
North Catskill	July	Weekday	16	0.24	0.18	0.00	1.23	0.00	0.22	0.02	0.09	0.00	0.81	0.03	2.82
North Chelsea	July	Weekday	17	0.90	0.12	0.00	0.77	0.00	0.16	0.00	0.07	0.00	0.34	0.02	2.37
Ohioville	July	Weekday	15	0.61	0.12	0.00	0.82	0.00	0.40	0.00	0.07	0.00	1.55	0.03	3.59
Pulvers Corners	January	Weekday	18	0.00	0.05	0.00	0.04	0.00	0.04	0.00	0.03	0.00	0.00	0.01	0.18
Reynolds Hill	July	Weekday	14	0.70	0.12	0.00	0.64	0.00	0.95	0.00	0.08	0.00	0.54	0.03	3.07
Rhinebeck	July	Weekday	18	0.43	0.18	0.00	1.22	0.00	0.47	0.01	0.08	0.00	0.99	0.03	3.41
Sand Dock	July	Weekday	13	0.01	0.03	0.00	0.15	0.00	0.11	0.00	0.00	0.00	0.13	0.03	0.45
Saugerties	July	Weekday	17	0.33	0.16	0.00	1.05	0.00	0.18	0.00	0.06	0.00	0.98	0.02	2.78
Shenandoah	July	Weekday	15	0.10	0.11	0.00	0.76	0.00	0.07	0.00	0.03	0.00	0.48	0.08	1.63
Smithfield	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
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	1.29	0.00	0.38	0.00	0.04	0.00	0.37	0.04	3.59
Staatsburg	July	Weekday	18	0.15	0.08	0.00	0.55	0.00	0.04	0.00	0.02	0.00	0.24	0.01	1.10
Stanfordville	December	Weekday	18	0.01	0.07	0.00	0.05	0.00	0.03	0.00	0.01	0.00	0.00	0.01	0.17
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	0.68	0.00	0.17	0.00	0.06	0.00	0.39	0.02	1.81
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	1.30	0.00	0.24	0.01	0.05	0.00	1.15	0.02	3.25
Union Ave	September	Weekday	16	0.52	0.36	0.00	1.57	0.00	1.41	0.01	0.12	0.00	2.61	0.06	6.66

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
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	0.04	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.12
Westbalmville	July	Weekday	16	0.01	0.17	0.00	1.10	0.00	0.23	0.00	0.05	0.00	1.09	0.04	2.68
Westerlo	July	Weekday	15	0.05	0.07	0.00	0.47	0.00	0.10	0.00	0.03	0.00	0.68	0.01	1.41
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	1.32	0.00	0.14	0.01	0.07	0.00	0.54	0.02	2.70
Total System	July	Weekday	17	12.87	6.38	0.04	42.75	0.00	12.58	0.12	2.63	0.00	38.54	1.06	116.97

Table 19: 2016 Forecast Peak Contribution (MW) by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.01	0.02	0.00	0.16	0.00	0.06	0.00	0.01	0.00	0.31	0.05	0.62
Boulevard	July	Weekday	15	0.01	0.02	0.00	0.11	0.00	0.03	0.00	0.03	0.00	0.10	0.02	0.33
Clinton Ave	January	Weekday	20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Coldenham	July	Weekday	16	0.01	0.02	0.00	0.15	0.00	0.28	0.00	0.03	0.00	0.36	0.03	0.89
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.03
Eastkingston	July	Weekday	15	0.14	0.01	0.00	0.09	0.00	0.08	0.00	0.01	0.00	0.10	0.01	0.45
Eastpark	July	Weekday	18	0.06	0.02	0.00	0.12	0.00	0.01	0.00	0.02	0.00	0.02	0.01	0.26
East Walden	July	Weekday	18	0.03	0.02	0.00	0.13	0.00	0.01	0.00	0.02	0.00	0.10	0.02	0.33
Fishkill Plains	July	Weekday	17	0.07	0.05	0.00	0.32	0.00	0.04	0.00	0.03	0.00	0.29	0.04	0.84
Forgebrook	July	Weekday	14	0.07	0.02	0.00	0.12	0.00	0.07	0.00	0.04	0.00	0.17	0.03	0.52
Galeville	December	Weekday	18	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.05
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	0.01	0.01	0.00	0.10	0.00	0.02	0.00	0.02	0.00	0.18	0.01	0.35
High Falls	July	Weekday	18	0.07	0.02	0.00	0.16	0.00	0.03	0.00	0.03	0.00	0.09	0.02	0.42
Highland	July	Weekday	18	0.09	0.02	0.00	0.15	0.00	0.04	0.00	0.03	0.00	0.16	0.02	0.50
Honk Falls	July	Weekday	12	0.01	0.01	0.00	0.02	0.00	0.01	0.00	0.01	0.00	0.02	0.01	0.07
Hunter	December	Weekday	8	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.03
Hurley Ave	July	Weekday	17	0.02	0.02	0.00	0.12	0.00	0.05	0.00	0.02	0.00	0.10	0.02	0.37
Inwood Ave	July	Weekday	16	0.00	0.02	0.00	0.12	0.00	0.05	0.00	0.03	0.00	0.03	0.03	0.29
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	0.01	0.03	0.00	0.13	0.00	0.09	0.00	0.03	0.00	0.31	0.05	0.65
Marlboro	July	Weekday	17	0.02	0.02	0.00	0.14	0.00	0.04	0.00	0.02	0.00	0.18	0.02	0.44

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.01	0.01	0.00	0.10	0.00	0.05	0.00	0.01	0.00	0.06	0.02	0.26
Merritt Park	July	Weekday	16	0.01	0.02	0.00	0.15	0.00	0.06	0.00	0.02	0.00	0.05	0.03	0.35
Milan	July	Weekday	16	0.03	0.01	0.00	0.06	0.00	0.01	0.00	0.01	0.00	0.06	0.00	0.19
Millerton	January	Weekday	18	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.03
Modena	July	Weekday	17	0.02	0.02	0.00	0.12	0.00	0.01	0.00	0.02	0.00	0.15	0.01	0.34
Myers Corners	July	Weekday	17	0.00	0.02	0.00	0.12	0.00	0.04	0.00	0.02	0.00	0.07	0.03	0.30
New Baltimore	July	Weekday	14	0.00	0.02	0.00	0.07	0.00	0.02	0.00	0.02	0.00	0.12	0.01	0.25
North Catskill	July	Weekday	14	0.03	0.03	0.00	0.16	0.00	0.04	0.00	0.05	0.00	0.15	0.03	0.50
North Chelsea	July	Weekday	18	0.15	0.02	0.00	0.13	0.00	0.02	0.00	0.03	0.00	0.03	0.02	0.40
Ohioville	July	Weekday	16	0.09	0.02	0.00	0.12	0.00	0.06	0.00	0.03	0.00	0.21	0.03	0.57
Pulvers Corners	July	Weekday	17	0.01	0.01	0.00	0.04	0.00	0.01	0.00	0.01	0.00	0.04	0.01	0.13
Reynolds Hill	July	Weekday	16	0.11	0.02	0.00	0.10	0.00	0.15	0.00	0.04	0.00	0.07	0.04	0.52
Rhinebeck	June	Weekday	13	0.02	0.04	0.00	0.08	0.00	0.12	0.00	0.04	0.00	0.34	0.03	0.67
Sand Dock	August	Weekday	16	0.00	0.00	0.00	0.01	0.00	0.02	0.00	0.00	0.00	0.01	0.03	0.08
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	0.02	0.02	0.00	0.12	0.00	0.01	0.00	0.01	0.00	0.03	0.08	0.28
Smithfield	December	Weekday	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.03
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	0.02	0.01	0.00	0.09	0.00	0.01	0.00	0.01	0.00	0.04	0.01	0.19
Stanfordville	July	Weekday	19	0.02	0.01	0.00	0.06	0.00	0.01	0.00	0.01	0.00	0.01	0.01	0.12
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	0.06	0.02	0.00	0.12	0.00	0.03	0.00	0.03	0.00	0.08	0.02	0.35
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	0.04	0.03	0.00	0.21	0.00	0.03	0.00	0.02	0.00	0.11	0.03	0.48
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03
Westbalmville	July	Weekday	16	0.00	0.03	0.00	0.18	0.00	0.04	0.00	0.02	0.00	0.17	0.04	0.48
Westerlo	April	Weekday	20	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.05
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	0.00	0.03	0.00	0.02	0.00	0.03	0.00	0.03	0.00	0.08	0.02	0.22
Total System	July	Weekday	17	1.80	0.99	0.01	6.38	0.00	2.14	0.02	1.22	0.00	6.02	1.03	19.59

Table 20: 2017 Forecast Peak Contribution (MW) by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.01	0.05	0.00	0.32	0.00	0.12	0.00	0.02	0.00	0.68	0.05	1.25
Boulevard	July	Weekday	15	0.03	0.04	0.00	0.22	0.00	0.06	0.00	0.03	0.00	0.22	0.02	0.63
Clinton Ave	January	Weekday	20	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.02
Coldenham	July	Weekday	16	0.02	0.05	0.00	0.30	0.00	0.56	0.00	0.03	0.00	0.80	0.03	1.79
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.05
Eastkingston	July	Weekday	15	0.29	0.03	0.00	0.18	0.00	0.15	0.00	0.02	0.00	0.22	0.01	0.90
Eastpark	July	Weekday	18	0.12	0.03	0.00	0.23	0.00	0.03	0.00	0.02	0.00	0.05	0.01	0.50
East Walden	July	Weekday	18	0.07	0.04	0.00	0.26	0.00	0.03	0.00	0.02	0.00	0.22	0.02	0.65
Fishkill Plains	July	Weekday	17	0.14	0.10	0.00	0.64	0.00	0.07	0.00	0.04	0.00	0.63	0.04	1.67
Forgebrook	July	Weekday	14	0.15	0.05	0.00	0.24	0.00	0.14	0.00	0.04	0.00	0.37	0.03	1.02
Galeville	December	Weekday	18	0.00	0.03	0.00	0.02	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.08
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	0.02	0.03	0.00	0.20	0.00	0.04	0.00	0.02	0.00	0.38	0.01	0.71
High Falls	July	Weekday	18	0.14	0.05	0.00	0.32	0.00	0.05	0.00	0.03	0.00	0.19	0.02	0.80
Highland	July	Weekday	18	0.17	0.04	0.00	0.29	0.00	0.08	0.00	0.03	0.00	0.36	0.02	0.99
Honk Falls	July	Weekday	12	0.02	0.01	0.00	0.04	0.00	0.01	0.00	0.01	0.00	0.03	0.01	0.13
Hunter	December	Weekday	8	0.00	0.01	0.00	0.01	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.05
Hurley Ave	July	Weekday	17	0.04	0.04	0.00	0.25	0.00	0.10	0.00	0.03	0.00	0.23	0.02	0.71
Inwood Ave	July	Weekday	16	0.00	0.04	0.00	0.25	0.00	0.10	0.00	0.03	0.00	0.08	0.03	0.53
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	0.02	0.05	0.00	0.26	0.00	0.18	0.00	0.04	0.00	0.69	0.05	1.29
Marlboro	July	Weekday	17	0.04	0.05	0.00	0.29	0.00	0.07	0.00	0.02	0.00	0.39	0.02	0.88

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.02	0.03	0.00	0.21	0.00	0.10	0.00	0.01	0.00	0.12	0.02	0.51
Merritt Park	July	Weekday	16	0.03	0.05	0.00	0.29	0.00	0.12	0.00	0.03	0.00	0.11	0.03	0.65
Milan	July	Weekday	16	0.06	0.02	0.00	0.12	0.00	0.03	0.00	0.02	0.00	0.12	0.00	0.37
Millerton	January	Weekday	18	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.01	0.05
Modena	July	Weekday	17	0.04	0.04	0.00	0.23	0.00	0.02	0.00	0.02	0.00	0.32	0.01	0.69
Myers Corners	July	Weekday	17	0.00	0.04	0.00	0.25	0.00	0.07	0.00	0.02	0.00	0.16	0.03	0.57
New Baltimore	July	Weekday	14	0.01	0.03	0.00	0.14	0.00	0.04	0.00	0.02	0.00	0.26	0.01	0.51
North Catskill	July	Weekday	14	0.06	0.07	0.00	0.33	0.00	0.08	0.01	0.06	0.00	0.33	0.03	0.96
North Chelsea	July	Weekday	18	0.29	0.04	0.00	0.27	0.00	0.04	0.00	0.03	0.00	0.07	0.02	0.76
Ohioville	July	Weekday	16	0.18	0.04	0.00	0.25	0.00	0.13	0.00	0.04	0.00	0.46	0.03	1.12
Pulvers Corners	July	Weekday	17	0.02	0.02	0.00	0.08	0.00	0.02	0.00	0.01	0.00	0.09	0.01	0.24
Reynolds Hill	July	Weekday	16	0.22	0.03	0.00	0.21	0.00	0.30	0.00	0.05	0.00	0.15	0.04	0.99
Rhinebeck	June	Weekday	13	0.05	0.07	0.00	0.16	0.00	0.24	0.00	0.05	0.00	0.74	0.03	1.34
Sand Dock	August	Weekday	16	0.00	0.01	0.00	0.02	0.00	0.04	0.00	0.00	0.00	0.02	0.03	0.12
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	0.03	0.03	0.00	0.24	0.00	0.01	0.00	0.01	0.00	0.07	0.08	0.48
Smithfield	December	Weekday	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.06
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	0.05	0.03	0.00	0.18	0.00	0.01	0.00	0.01	0.00	0.08	0.01	0.37
Stanfordville	July	Weekday	19	0.04	0.02	0.00	0.12	0.00	0.02	0.00	0.01	0.00	0.02	0.01	0.23
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	0.12	0.04	0.00	0.23	0.00	0.07	0.00	0.03	0.00	0.17	0.02	0.68
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	0.09	0.06	0.00	0.41	0.00	0.07	0.00	0.02	0.00	0.25	0.03	0.94
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04
Westbalmville	July	Weekday	16	0.00	0.05	0.00	0.36	0.00	0.08	0.00	0.02	0.00	0.38	0.04	0.93
Westerlo	April	Weekday	20	0.00	0.03	0.00	0.03	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.09
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	0.00	0.06	0.00	0.04	0.00	0.06	0.00	0.04	0.00	0.18	0.02	0.41
Total System	July	Weekday	17	3.60	1.99	0.01	12.75	0.00	4.27	0.04	1.38	0.00	13.17	1.03	38.24

Table 21: 2018 Forecast Peak Contribution (MW) by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.02	0.07	0.00	0.48	0.00	0.17	0.00	0.02	0.00	1.09	0.05	1.91
Boulevard	July	Weekday	15	0.04	0.05	0.00	0.33	0.00	0.09	0.00	0.05	0.00	0.35	0.02	0.95
Clinton Ave	January	Weekday	20	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.03
Coldenham	July	Weekday	16	0.03	0.07	0.00	0.45	0.00	0.84	0.00	0.04	0.00	1.27	0.03	2.74
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.08
Eastkingston	July	Weekday	15	0.43	0.04	0.00	0.28	0.00	0.23	0.00	0.02	0.00	0.35	0.01	1.36
Eastpark	July	Weekday	18	0.18	0.05	0.00	0.35	0.00	0.04	0.00	0.02	0.00	0.08	0.01	0.75
East Walden	July	Weekday	18	0.10	0.06	0.00	0.40	0.00	0.04	0.00	0.02	0.00	0.35	0.02	0.98
Fishkill Plains	July	Weekday	17	0.21	0.15	0.00	0.97	0.00	0.11	0.00	0.05	0.00	1.00	0.04	2.53
Forgebrook	July	Weekday	14	0.22	0.07	0.00	0.35	0.00	0.21	0.00	0.06	0.00	0.59	0.03	1.54
Galeville	December	Weekday	18	0.00	0.04	0.00	0.03	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.11
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	0.03	0.04	0.00	0.30	0.00	0.06	0.00	0.03	0.00	0.61	0.01	1.09
High Falls	July	Weekday	18	0.22	0.07	0.00	0.48	0.00	0.08	0.00	0.04	0.00	0.30	0.02	1.21
Highland	July	Weekday	18	0.26	0.06	0.00	0.44	0.00	0.12	0.00	0.04	0.00	0.57	0.02	1.51
Honk Falls	July	Weekday	12	0.02	0.02	0.00	0.07	0.00	0.02	0.00	0.01	0.00	0.05	0.01	0.20
Hunter	December	Weekday	8	0.00	0.01	0.00	0.01	0.00	0.03	0.00	0.01	0.00	0.00	0.01	0.07
Hurley Ave	July	Weekday	17	0.06	0.06	0.00	0.37	0.00	0.16	0.00	0.04	0.00	0.36	0.02	1.07
Inwood Ave	July	Weekday	16	0.00	0.06	0.00	0.37	0.00	0.15	0.00	0.05	0.00	0.12	0.03	0.78
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	0.03	0.08	0.00	0.40	0.00	0.26	0.00	0.05	0.00	1.09	0.05	1.96
Marlboro	July	Weekday	17	0.06	0.07	0.00	0.43	0.00	0.11	0.00	0.03	0.00	0.61	0.02	1.35

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.03	0.04	0.00	0.31	0.00	0.15	0.00	0.02	0.00	0.20	0.02	0.77
Merritt Park	July	Weekday	16	0.04	0.07	0.00	0.44	0.00	0.18	0.00	0.04	0.00	0.17	0.03	0.97
Milan	July	Weekday	16	0.09	0.03	0.00	0.18	0.00	0.04	0.00	0.02	0.00	0.19	0.00	0.56
Millerton	January	Weekday	18	0.00	0.02	0.00	0.02	0.00	0.01	0.00	0.02	0.00	0.00	0.01	0.07
Modena	July	Weekday	17	0.06	0.05	0.00	0.35	0.00	0.03	0.00	0.02	0.00	0.52	0.01	1.05
Myers Corners	July	Weekday	17	0.00	0.06	0.00	0.37	0.00	0.11	0.00	0.03	0.00	0.25	0.03	0.85
New Baltimore	July	Weekday	14	0.01	0.05	0.00	0.20	0.00	0.05	0.00	0.02	0.00	0.42	0.01	0.78
North Catskill	July	Weekday	14	0.09	0.10	0.00	0.49	0.00	0.12	0.01	0.08	0.00	0.53	0.03	1.45
North Chelsea	July	Weekday	18	0.44	0.06	0.00	0.40	0.00	0.06	0.00	0.04	0.00	0.12	0.02	1.14
Ohioville	July	Weekday	16	0.26	0.06	0.00	0.37	0.00	0.19	0.00	0.05	0.00	0.74	0.03	1.71
Pulvers Corners	July	Weekday	17	0.02	0.02	0.00	0.12	0.00	0.03	0.00	0.02	0.00	0.15	0.01	0.37
Reynolds Hill	July	Weekday	16	0.32	0.05	0.00	0.31	0.00	0.45	0.00	0.06	0.00	0.24	0.04	1.47
Rhinebeck	June	Weekday	13	0.07	0.11	0.00	0.23	0.00	0.36	0.00	0.06	0.00	1.18	0.03	2.05
Sand Dock	August	Weekday	16	0.00	0.01	0.00	0.04	0.00	0.05	0.00	0.00	0.00	0.04	0.03	0.17
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	0.05	0.05	0.00	0.36	0.00	0.02	0.00	0.02	0.00	0.12	0.08	0.69
Smithfield	December	Weekday	10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.09
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	0.07	0.04	0.00	0.27	0.00	0.02	0.00	0.02	0.00	0.13	0.01	0.56
Stanfordville	July	Weekday	19	0.06	0.03	0.00	0.17	0.00	0.02	0.00	0.01	0.00	0.04	0.01	0.34
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	0.18	0.05	0.00	0.35	0.00	0.10	0.00	0.05	0.00	0.28	0.02	1.02
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	0.13	0.09	0.00	0.62	0.00	0.10	0.00	0.03	0.00	0.40	0.03	1.41
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.00	0.02	0.00	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.06
Westbalmville	July	Weekday	16	0.00	0.08	0.00	0.53	0.00	0.12	0.00	0.03	0.00	0.60	0.04	1.41
Westerlo	April	Weekday	20	0.00	0.04	0.00	0.04	0.00	0.02	0.00	0.01	0.00	0.00	0.01	0.13
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	0.01	0.09	0.00	0.06	0.00	0.09	0.01	0.05	0.00	0.29	0.02	0.61
Total System	July	Weekday	17	5.41	2.98	0.02	19.13	0.00	6.41	0.05	1.85	0.00	20.98	1.03	57.85

Table 22: 2019 Forecast Peak Contribution (MW) by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.03	0.10	0.00	0.64	0.00	0.23	0.00	0.02	0.00	1.46	0.05	2.53
Boulevard	July	Weekday	15	0.06	0.07	0.00	0.44	0.00	0.12	0.01	0.05	0.00	0.47	0.02	1.25
Clinton Ave	January	Weekday	20	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.03
Coldenham	July	Weekday	16	0.04	0.10	0.00	0.60	0.00	1.12	0.00	0.04	0.00	1.70	0.03	3.64
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	0.00	0.01	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.10
Eastkingston	July	Weekday	15	0.57	0.06	0.00	0.37	0.00	0.30	0.00	0.02	0.00	0.47	0.01	1.81
Eastpark	July	Weekday	18	0.24	0.07	0.00	0.47	0.00	0.06	0.00	0.03	0.00	0.11	0.01	0.99
East Walden	July	Weekday	18	0.13	0.07	0.00	0.53	0.00	0.05	0.00	0.03	0.00	0.46	0.02	1.30
Fishkill Plains	July	Weekday	17	0.29	0.20	0.00	1.29	0.00	0.14	0.00	0.06	0.00	1.34	0.04	3.36
Forgebrook	July	Weekday	14	0.30	0.10	0.00	0.47	0.00	0.28	0.00	0.06	0.00	0.79	0.03	2.03
Galeville	December	Weekday	18	0.00	0.06	0.00	0.04	0.00	0.03	0.00	0.01	0.00	0.00	0.01	0.15
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	0.05	0.06	0.00	0.40	0.00	0.08	0.00	0.04	0.00	0.82	0.01	1.45
High Falls	July	Weekday	18	0.29	0.09	0.00	0.64	0.00	0.10	0.00	0.05	0.00	0.40	0.02	1.60
Highland	July	Weekday	18	0.34	0.09	0.00	0.58	0.00	0.16	0.00	0.05	0.00	0.76	0.02	2.00
Honk Falls	July	Weekday	12	0.03	0.02	0.00	0.09	0.00	0.02	0.00	0.02	0.00	0.07	0.01	0.26
Hunter	December	Weekday	8	0.00	0.01	0.00	0.01	0.00	0.04	0.00	0.01	0.00	0.00	0.01	0.09
Hurley Ave	July	Weekday	17	0.08	0.08	0.00	0.50	0.00	0.21	0.00	0.04	0.00	0.49	0.02	1.42
Inwood Ave	July	Weekday	16	0.00	0.08	0.00	0.50	0.00	0.20	0.00	0.05	0.00	0.16	0.03	1.02
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	0.04	0.11	0.00	0.53	0.00	0.35	0.00	0.06	0.00	1.47	0.05	2.60
Marlboro	July	Weekday	17	0.09	0.09	0.00	0.58	0.00	0.15	0.00	0.04	0.00	0.82	0.02	1.78

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.05	0.06	0.00	0.42	0.00	0.19	0.00	0.02	0.00	0.26	0.02	1.01
Merritt Park	July	Weekday	16	0.05	0.09	0.00	0.58	0.00	0.24	0.00	0.04	0.00	0.23	0.03	1.27
Milan	July	Weekday	16	0.13	0.04	0.00	0.24	0.00	0.05	0.00	0.02	0.00	0.26	0.00	0.74
Millerton	January	Weekday	18	0.00	0.03	0.00	0.02	0.00	0.01	0.00	0.02	0.00	0.00	0.01	0.09
Modena	July	Weekday	17	0.08	0.07	0.00	0.46	0.00	0.04	0.00	0.03	0.00	0.69	0.01	1.40
Myers Corners	July	Weekday	17	0.00	0.08	0.00	0.50	0.00	0.15	0.00	0.03	0.00	0.33	0.03	1.12
New Baltimore	July	Weekday	14	0.02	0.07	0.00	0.27	0.00	0.07	0.00	0.03	0.00	0.56	0.01	1.03
North Catskill	July	Weekday	14	0.12	0.14	0.00	0.66	0.00	0.16	0.01	0.09	0.00	0.71	0.03	1.91
North Chelsea	July	Weekday	18	0.58	0.08	0.00	0.54	0.00	0.08	0.00	0.05	0.00	0.16	0.02	1.50
Ohioville	July	Weekday	16	0.35	0.08	0.00	0.50	0.00	0.26	0.00	0.06	0.00	0.99	0.03	2.26
Pulvers Corners	July	Weekday	17	0.03	0.03	0.00	0.17	0.00	0.03	0.00	0.02	0.00	0.19	0.01	0.48
Reynolds Hill	July	Weekday	16	0.43	0.07	0.00	0.41	0.00	0.60	0.00	0.07	0.00	0.32	0.04	1.94
Rhinebeck	June	Weekday	13	0.10	0.14	0.00	0.31	0.00	0.48	0.00	0.07	0.00	1.58	0.03	2.72
Sand Dock	August	Weekday	16	0.00	0.02	0.00	0.05	0.00	0.07	0.00	0.00	0.00	0.05	0.03	0.22
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	0.06	0.07	0.00	0.48	0.00	0.03	0.00	0.02	0.00	0.15	0.08	0.89
Smithfield	December	Weekday	10	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.12
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	0.09	0.05	0.00	0.36	0.00	0.03	0.00	0.02	0.00	0.18	0.01	0.74
Stanfordville	July	Weekday	19	0.08	0.04	0.00	0.23	0.00	0.03	0.00	0.02	0.00	0.05	0.01	0.45
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	0.24	0.07	0.00	0.46	0.00	0.13	0.00	0.05	0.00	0.37	0.02	1.34
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	0.18	0.12	0.00	0.83	0.00	0.14	0.00	0.04	0.00	0.53	0.03	1.86
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.00	0.03	0.00	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.07
Westbalmville	July	Weekday	16	0.00	0.11	0.00	0.71	0.00	0.16	0.00	0.04	0.00	0.80	0.04	1.86
Westerlo	April	Weekday	20	0.00	0.06	0.00	0.05	0.00	0.03	0.00	0.01	0.00	0.00	0.01	0.16
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	0.01	0.12	0.00	0.08	0.00	0.12	0.01	0.06	0.00	0.38	0.02	0.79
Total System	July	Weekday	17	7.21	3.97	0.03	25.50	0.00	8.54	0.07	2.04	0.00	28.13	1.03	76.53

Table 23: 2020 Forecast Peak Contribution (MW) by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.04	0.12	0.00	0.80	0.00	0.29	0.00	0.03	0.00	1.74	0.05	3.07
Boulevard	July	Weekday	15	0.07	0.09	0.00	0.55	0.00	0.16	0.01	0.06	0.00	0.57	0.02	1.53
Clinton Ave	January	Weekday	20	0.00	0.01	0.00	0.01	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.04
Coldenham	July	Weekday	16	0.05	0.12	0.00	0.76	0.00	1.39	0.01	0.05	0.00	2.04	0.03	4.45
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	0.00	0.01	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.13
Eastkingston	July	Weekday	15	0.71	0.07	0.00	0.46	0.00	0.38	0.00	0.03	0.00	0.57	0.01	2.24
Eastpark	July	Weekday	18	0.30	0.08	0.00	0.59	0.00	0.07	0.00	0.03	0.00	0.14	0.01	1.23
East Walden	July	Weekday	18	0.17	0.09	0.00	0.66	0.00	0.07	0.00	0.03	0.00	0.56	0.02	1.59
Fishkill Plains	July	Weekday	17	0.36	0.25	0.00	1.61	0.00	0.18	0.00	0.07	0.00	1.60	0.04	4.12
Forgebrook	July	Weekday	14	0.37	0.12	0.00	0.59	0.00	0.35	0.00	0.08	0.00	0.94	0.03	2.49
Galeville	December	Weekday	18	0.00	0.07	0.00	0.05	0.00	0.03	0.00	0.02	0.00	0.00	0.01	0.18
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	0.06	0.07	0.00	0.50	0.00	0.10	0.00	0.04	0.00	0.98	0.01	1.76
High Falls	July	Weekday	18	0.36	0.12	0.00	0.80	0.00	0.13	0.00	0.06	0.00	0.48	0.02	1.97
Highland	July	Weekday	18	0.43	0.11	0.00	0.73	0.00	0.20	0.00	0.06	0.00	0.91	0.02	2.45
Honk Falls	July	Weekday	12	0.04	0.03	0.00	0.11	0.00	0.03	0.00	0.02	0.00	0.09	0.01	0.32
Hunter	December	Weekday	8	0.00	0.02	0.00	0.01	0.00	0.05	0.00	0.01	0.00	0.00	0.01	0.11
Hurley Ave	July	Weekday	17	0.10	0.10	0.00	0.62	0.00	0.26	0.00	0.05	0.00	0.58	0.02	1.74
Inwood Ave	July	Weekday	16	0.00	0.10	0.00	0.62	0.00	0.25	0.00	0.06	0.00	0.20	0.03	1.26
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	0.05	0.14	0.00	0.66	0.00	0.44	0.00	0.07	0.00	1.75	0.05	3.16
Marlboro	July	Weekday	17	0.11	0.11	0.00	0.72	0.00	0.18	0.00	0.04	0.00	0.99	0.02	2.18

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.06	0.07	0.00	0.52	0.00	0.24	0.00	0.02	0.00	0.31	0.02	1.25
Merritt Park	July	Weekday	16	0.07	0.11	0.00	0.73	0.00	0.30	0.00	0.05	0.00	0.27	0.03	1.57
Milan	July	Weekday	16	0.16	0.05	0.00	0.30	0.00	0.07	0.00	0.03	0.00	0.31	0.00	0.91
Millerton	January	Weekday	18	0.00	0.04	0.00	0.03	0.00	0.02	0.01	0.02	0.00	0.00	0.01	0.11
Modena	July	Weekday	17	0.10	0.09	0.00	0.58	0.00	0.05	0.00	0.03	0.00	0.83	0.01	1.70
Myers Corners	July	Weekday	17	0.00	0.10	0.00	0.62	0.00	0.18	0.00	0.04	0.00	0.40	0.03	1.38
New Baltimore	July	Weekday	14	0.02	0.08	0.00	0.34	0.00	0.09	0.00	0.03	0.00	0.67	0.01	1.25
North Catskill	July	Weekday	14	0.15	0.17	0.00	0.82	0.00	0.20	0.01	0.11	0.00	0.85	0.03	2.34
North Chelsea	July	Weekday	18	0.73	0.09	0.00	0.67	0.00	0.11	0.00	0.06	0.00	0.19	0.02	1.87
Ohioville	July	Weekday	16	0.44	0.10	0.00	0.62	0.00	0.32	0.00	0.07	0.00	1.18	0.03	2.77
Pulvers Corners	July	Weekday	17	0.04	0.04	0.00	0.21	0.00	0.04	0.00	0.02	0.00	0.23	0.01	0.59
Reynolds Hill	July	Weekday	16	0.54	0.08	0.00	0.52	0.00	0.75	0.00	0.08	0.00	0.39	0.04	2.39
Rhinebeck	June	Weekday	13	0.12	0.18	0.00	0.39	0.00	0.60	0.01	0.08	0.00	1.89	0.03	3.30
Sand Dock	August	Weekday	16	0.00	0.02	0.00	0.06	0.00	0.09	0.00	0.00	0.00	0.06	0.03	0.27
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	0.08	0.08	0.00	0.60	0.00	0.03	0.00	0.02	0.00	0.19	0.08	1.08
Smithfield	December	Weekday	10	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.14
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	0.11	0.06	0.00	0.45	0.00	0.04	0.00	0.02	0.00	0.22	0.01	0.91
Stanfordville	July	Weekday	19	0.10	0.05	0.00	0.29	0.00	0.04	0.00	0.02	0.00	0.06	0.01	0.55
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	0.31	0.09	0.00	0.58	0.00	0.16	0.00	0.06	0.00	0.45	0.02	1.65
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	0.22	0.15	0.00	1.04	0.00	0.17	0.01	0.04	0.00	0.64	0.03	2.29
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.00	0.04	0.00	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.09
Westbalmville	July	Weekday	16	0.00	0.14	0.00	0.89	0.00	0.19	0.00	0.04	0.00	0.96	0.04	2.28
Westerlo	April	Weekday	20	0.00	0.07	0.00	0.07	0.00	0.04	0.00	0.01	0.00	0.00	0.01	0.20
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	0.01	0.15	0.00	0.10	0.00	0.15	0.01	0.07	0.00	0.46	0.02	0.97
Total System	July	Weekday	17	9.01	4.97	0.04	31.88	0.00	10.68	0.09	2.50	0.00	33.66	1.03	93.85

Table 24: 2021 Forecast Peak Contribution (MW) by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	0.04	0.15	0.00	0.96	0.00	0.35	0.00	0.04	0.00	1.94	0.05	3.52
Boulevard	July	Weekday	15	0.08	0.11	0.00	0.66	0.00	0.19	0.01	0.08	0.00	0.63	0.02	1.78
Clinton Ave	January	Weekday	20	0.00	0.01	0.00	0.01	0.00	0.02	0.00	0.01	0.00	0.00	0.00	0.05
Coldenham	July	Weekday	16	0.06	0.14	0.00	0.91	0.00	1.67	0.01	0.06	0.00	2.27	0.03	5.15
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	0.00	0.01	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.15
Eastkingston	July	Weekday	15	0.86	0.09	0.00	0.55	0.00	0.45	0.00	0.04	0.00	0.63	0.01	2.63
Eastpark	July	Weekday	18	0.36	0.10	0.00	0.70	0.00	0.09	0.00	0.04	0.00	0.15	0.01	1.46
East Walden	July	Weekday	18	0.20	0.11	0.00	0.79	0.00	0.08	0.00	0.04	0.00	0.62	0.02	1.86
Fishkill Plains	July	Weekday	17	0.43	0.30	0.00	1.93	0.00	0.22	0.00	0.08	0.00	1.78	0.04	4.79
Forgebrook	July	Weekday	14	0.45	0.14	0.00	0.71	0.00	0.42	0.00	0.09	0.00	1.05	0.03	2.90
Galeville	December	Weekday	18	0.00	0.08	0.00	0.06	0.00	0.04	0.00	0.02	0.00	0.00	0.01	0.22
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	0.07	0.08	0.00	0.60	0.00	0.12	0.00	0.05	0.00	1.09	0.01	2.03
High Falls	July	Weekday	18	0.43	0.14	0.00	0.96	0.00	0.15	0.00	0.07	0.00	0.53	0.02	2.32
Highland	July	Weekday	18	0.52	0.13	0.00	0.88	0.00	0.24	0.00	0.07	0.00	1.01	0.02	2.86
Honk Falls	July	Weekday	12	0.05	0.03	0.00	0.13	0.00	0.04	0.00	0.02	0.00	0.10	0.01	0.38
Hunter	December	Weekday	8	0.00	0.02	0.00	0.02	0.00	0.06	0.00	0.01	0.00	0.00	0.01	0.13
Hurley Ave	July	Weekday	17	0.12	0.12	0.00	0.75	0.00	0.31	0.00	0.06	0.00	0.65	0.02	2.03
Inwood Ave	July	Weekday	16	0.01	0.12	0.00	0.75	0.00	0.30	0.00	0.08	0.00	0.22	0.03	1.49
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	0.06	0.16	0.00	0.79	0.00	0.53	0.00	0.08	0.00	1.95	0.05	3.63
Marlboro	July	Weekday	17	0.13	0.14	0.00	0.87	0.00	0.22	0.00	0.06	0.00	1.10	0.02	2.53

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	0.07	0.09	0.00	0.62	0.00	0.29	0.00	0.03	0.00	0.35	0.02	1.47
Merritt Park	July	Weekday	16	0.08	0.14	0.00	0.87	0.00	0.36	0.00	0.06	0.00	0.30	0.03	1.85
Milan	July	Weekday	16	0.19	0.06	0.00	0.36	0.00	0.08	0.00	0.03	0.00	0.34	0.00	1.07
Millerton	January	Weekday	18	0.00	0.04	0.00	0.03	0.00	0.02	0.01	0.03	0.00	0.00	0.01	0.14
Modena	July	Weekday	17	0.12	0.11	0.00	0.69	0.00	0.07	0.00	0.04	0.00	0.92	0.01	1.97
Myers Corners	July	Weekday	17	0.00	0.12	0.00	0.75	0.00	0.22	0.00	0.05	0.00	0.44	0.03	1.61
New Baltimore	July	Weekday	14	0.03	0.10	0.00	0.41	0.00	0.11	0.00	0.04	0.00	0.75	0.01	1.44
North Catskill	July	Weekday	14	0.18	0.20	0.00	0.98	0.00	0.24	0.02	0.14	0.00	0.94	0.03	2.74
North Chelsea	July	Weekday	18	0.87	0.11	0.00	0.80	0.00	0.13	0.00	0.07	0.00	0.21	0.02	2.22
Ohioville	July	Weekday	16	0.53	0.12	0.00	0.75	0.00	0.38	0.00	0.09	0.00	1.32	0.03	3.21
Pulvers Corners	July	Weekday	17	0.05	0.05	0.00	0.25	0.00	0.05	0.00	0.03	0.00	0.26	0.01	0.69
Reynolds Hill	July	Weekday	16	0.65	0.10	0.00	0.62	0.00	0.90	0.00	0.10	0.00	0.43	0.04	2.83
Rhinebeck	June	Weekday	13	0.14	0.21	0.00	0.47	0.00	0.72	0.01	0.10	0.00	2.10	0.03	3.79
Sand Dock	August	Weekday	16	0.00	0.02	0.00	0.07	0.00	0.11	0.00	0.00	0.00	0.07	0.03	0.31
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	0.09	0.10	0.00	0.72	0.00	0.04	0.00	0.03	0.00	0.21	0.08	1.27
Smithfield	December	Weekday	10	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.13	0.00	0.16
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	0.14	0.08	0.00	0.54	0.00	0.04	0.00	0.03	0.00	0.24	0.01	1.07
Stanfordville	July	Weekday	19	0.11	0.06	0.00	0.35	0.00	0.05	0.00	0.02	0.00	0.06	0.01	0.66
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	0.37	0.11	0.00	0.69	0.00	0.20	0.00	0.08	0.00	0.49	0.02	1.95
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	0.27	0.18	0.00	1.24	0.00	0.20	0.01	0.05	0.00	0.71	0.03	2.69
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.00	0.04	0.00	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.10
Westbalmville	July	Weekday	16	0.01	0.16	0.00	1.07	0.00	0.23	0.00	0.06	0.00	1.07	0.04	2.64
Westerlo	April	Weekday	20	0.00	0.09	0.00	0.08	0.00	0.05	0.00	0.01	0.00	0.00	0.01	0.24
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	0.01	0.18	0.00	0.11	0.00	0.18	0.01	0.09	0.00	0.51	0.02	1.12
Total System	July	Weekday	17	10.81	5.96	0.04	38.25	0.00	12.81	0.11	3.12	0.00	37.40	1.03	109.54

N.4 DER Conversion Factors

Table 1: Single Peak Hour Conversion Factors by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	10.90	1.01	0.67	6.39	2.85	1.02	2.54	1.18	2.14	0.07	1.00	NA
Hurley-Milan	July	Weekday	16	12.60	1.04	0.67	6.62	3.59	2.00	2.59	1.24	2.14	0.35	1.00	NA
Mid-Dutchess	July	Weekday	15	12.35	1.02	0.67	6.48	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	0.67	6.38	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	0.67	6.88	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	0.67	4.36	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	0.67	6.07	3.32	1.92	2.52	1.42	2.14	0.35	1.00	NA
Southern Dutchess	July	Weekday	15	12.32	1.02	0.67	6.48	3.55	2.09	2.59	1.30	2.14	0.41	1.00	NA
WM Line	December	Weekday	18	0.50	1.16	0.67	0.84	1.47	1.43	3.49	0.62	2.14	0.00	1.00	NA
Westerlo Loop	January	Weekday	18	0.43	1.12	0.67	0.78	1.22	1.37	0.00	1.68	2.14	0.00	1.00	NA
CH 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	NA

Table 2: Single Peak Hour Conversion Factors by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	5.34	1.26	0.67	3.34	2.67	2.04	2.11	1.88	1.87	0.40	1.00	NA
Hurley-Milan	July	Weekday	14	9.37	1.18	0.67	5.28	2.95	2.13	2.44	1.82	1.87	0.41	1.00	NA
Mid-Dutchess	July	Weekday	17	10.09	0.95	0.67	5.71	3.07	1.69	2.58	1.48	1.87	0.27	1.00	NA
Northwest 115-69 Area	July	Weekday	13	6.39	1.17	0.67	3.92	2.97	2.05	2.41	1.79	1.87	0.32	1.00	NA
Northwest 69kV Area	July	Weekday	15	7.38	0.99	0.67	4.47	2.90	2.02	2.23	1.89	1.87	0.35	1.00	NA
Pleasant Valley 69	July	Weekday	17	10.03	0.95	0.67	5.71	3.07	1.66	2.58	1.48	1.87	0.27	1.00	NA
RD-RJ Lines	July	Weekday	17	10.03	0.95	0.67	5.71	3.07	1.65	2.58	1.48	1.87	0.27	1.00	NA
Southern Dutchess	July	Weekday	17	10.07	0.95	0.67	5.71	3.07	1.65	2.58	1.48	1.87	0.27	1.00	NA
WM Line	July	Weekday	17	9.47	0.99	0.67	5.59	2.58	1.71	2.37	1.50	1.87	0.27	1.00	NA
Westerlo Loop	December	Weekday	18	0.46	1.16	0.67	0.73	1.37	1.37	0.00	1.22	1.87	0.00	1.00	NA
CH System	July	Weekday	17	9.95	0.95	0.67	5.71	3.07	1.65	2.41	1.48	1.87	0.27	1.00	NA

Table 3: Single Peak Hour Conversion Factors by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	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	NA
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	NA
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	NA
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	NA
Coxsackie	NA	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	NA
Eastkingston	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	NA
Eastpark	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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
Lincoln Park	July	Weekday	9	2.78	1.18	0.67	1.80	1.69	0.67	0.00	0.89	2.14	0.18	1.00	NA
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	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
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	NA
South Cairo	NA	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	NA
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	NA
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	NA
Sturgeon Pool	NA	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	NA
Tioronda	NA	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	NA
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	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	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	NA
Westbalmville	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	NA
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	NA
Wiccopee	NA	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	NA
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	NA

Table 4: Single Peak Conversion Factors by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	9.80	0.95	0.67	5.71	3.07	1.62	2.58	1.48	1.87	0.27	1.00	NA
Boulevard	July	Weekday	15	9.76	0.99	0.67	5.73	3.09	2.07	2.58	1.79	1.87	0.39	1.00	NA
Clinton Ave	January	Weekday	20	0.00	1.55	0.00	1.20	1.29	0.42	0.00	1.28	1.87	0.00	1.00	NA
Coldenham	July	Weekday	16	10.06	0.98	0.67	5.79	2.69	1.99	2.41	1.66	1.87	0.34	1.00	NA
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	10.14	0.95	0.67	5.71	3.07	1.40	0.00	1.48	1.87	0.27	1.00	NA
Eastkingston	July	Weekday	15	10.26	0.95	0.67	5.62	2.55	2.15	2.32	1.74	1.87	0.39	1.00	NA
Eastpark	July	Weekday	18	10.89	0.93	0.67	6.11	2.74	1.30	0.00	1.46	1.87	0.17	1.00	NA
East Walden	July	Weekday	18	10.43	0.93	0.67	6.11	2.74	1.39	0.00	1.46	1.87	0.17	1.00	NA
Fishkill Plains	July	Weekday	17	10.01	0.95	0.67	5.71	3.07	1.64	0.00	1.48	1.87	0.27	1.00	NA
Forgebrook	July	Weekday	14	9.42	1.12	0.67	5.19	2.53	2.14	2.29	1.72	1.87	0.41	1.00	NA
Galeville	December	Weekday	18	0.40	1.13	0.67	0.78	1.33	1.31	0.00	1.29	1.87	0.00	1.00	NA
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	10.71	0.93	0.67	6.11	2.74	1.33	0.00	1.46	1.87	0.17	1.00	NA
High Falls	July	Weekday	18	10.02	0.95	0.67	6.01	2.51	1.42	0.00	1.49	1.87	0.17	1.00	NA
Highland	July	Weekday	18	10.33	0.95	0.67	6.01	2.51	1.42	2.43	1.49	1.87	0.17	1.00	NA
Honk Falls	July	Weekday	12	7.47	1.20	0.67	4.42	2.88	1.73	0.00	1.90	1.87	0.39	1.00	NA
Hunter	December	Weekday	8	0.63	0.80	0.67	0.72	0.77	1.22	0.00	1.36	1.87	0.02	1.00	NA
Hurley Ave	July	Weekday	17	9.41	0.99	0.67	5.59	2.58	1.68	0.00	1.50	1.87	0.27	1.00	NA
Inwood Ave	July	Weekday	16	9.89	0.98	0.67	5.92	3.16	1.94	0.00	1.69	1.87	0.34	1.00	NA
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	9.01	1.18	0.67	5.28	2.95	2.18	0.00	1.82	1.87	0.41	1.00	NA
Marlboro	July	Weekday	17	9.95	0.95	0.67	5.71	3.07	1.72	1.29	1.48	1.87	0.27	1.00	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	10.25	0.93	0.67	6.11	2.74	1.39	2.50	1.46	1.87	0.17	1.00	NA
Merritt Park	July	Weekday	16	10.20	0.98	0.67	5.92	3.16	2.02	0.00	1.69	1.87	0.34	1.00	NA
Milan	July	Weekday	16	10.05	0.98	0.67	5.79	2.69	1.97	0.00	1.66	1.87	0.34	1.00	NA
Millerton	January	Weekday	18	0.37	1.17	0.67	0.85	1.45	0.65	3.91	1.30	1.87	0.00	1.00	NA
Modena	July	Weekday	17	9.85	0.95	0.67	5.71	3.07	1.73	1.29	1.48	1.87	0.27	1.00	NA
Myers Corners	July	Weekday	17	9.26	0.99	0.67	5.59	2.58	1.71	0.00	1.50	1.87	0.27	1.00	NA
New Baltimore	July	Weekday	14	7.62	1.18	0.67	4.55	3.19	1.94	0.00	1.84	1.87	0.43	1.00	NA
North Catskill	July	Weekday	14	9.04	1.18	0.67	5.28	2.95	2.07	2.63	1.82	1.87	0.41	1.00	NA
North Chelsea	July	Weekday	18	10.96	0.93	0.67	6.11	2.74	1.39	2.50	1.46	1.87	0.17	1.00	NA
Ohioville	July	Weekday	16	10.16	0.98	0.67	5.92	3.16	1.92	0.00	1.69	1.87	0.34	1.00	NA
Pulvers Corners	July	Weekday	17	8.31	1.02	0.00	4.87	3.14	1.65	0.00	1.57	1.87	0.28	1.00	NA
Reynolds Hill	July	Weekday	16	10.63	0.98	0.67	5.79	2.69	2.06	0.00	1.66	1.87	0.34	1.00	NA
Rhinebeck	June	Weekday	13	3.73	1.17	0.67	2.40	2.85	2.10	1.90	1.60	1.87	0.36	1.00	NA
Sand Dock	August	Weekday	16	4.24	0.98	0.67	2.77	1.94	2.05	0.00	1.50	1.87	0.24	1.00	NA
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	10.35	0.93	0.67	6.11	2.74	1.34	0.00	1.46	1.87	0.17	1.00	NA
Smithfield	December	Weekday	10	0.00	1.26	0.00	0.73	0.00	0.00	0.00	1.58	1.87	0.36	1.00	NA
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	10.85	0.93	0.67	6.11	2.74	1.37	0.00	1.46	1.87	0.17	1.00	NA
Stanfordville	July	Weekday	19	9.16	1.01	0.67	5.72	2.71	1.12	0.00	1.30	1.87	0.07	1.00	NA
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	10.45	0.98	0.67	5.92	3.16	1.95	0.00	1.69	1.87	0.34	1.00	NA
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	10.55	0.93	0.67	6.11	2.74	1.35	2.50	1.46	1.87	0.17	1.00	NA
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.61	1.31	0.00	0.99	1.46	0.58	0.00	1.50	1.87	0.00	1.00	NA
Westbalmville	July	Weekday	16	9.89	0.98	0.67	5.92	3.16	2.00	0.00	1.69	1.87	0.34	1.00	NA
Westerlo	April	Weekday	20	0.07	1.19	0.67	1.00	0.41	0.92	0.00	0.66	1.87	0.00	1.00	NA
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	0.35	1.01	0.67	0.60	1.33	1.69	3.21	1.37	1.87	0.17	1.00	NA
Total System	July	Weekday	17	9.95	0.95	0.67	5.71	3.07	1.65	2.41	1.48	1.87	0.27	1.00	NA

Table 5: Top 100 Hour Conversion Factors by Transmission Area and Central Hudson's System for 1-in-2 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	19	8.85	1.08	0.00	5.15	2.93	1.39	2.39	1.11	2.14	2.68	1.00	NA
Hurley-Milan	July	Weekday	16	9.86	1.06	0.00	5.32	3.08	1.72	2.44	1.16	2.14	3.66	1.00	NA
Mid-Dutchess	July	Weekday	15	9.85	1.04	0.00	5.31	3.08	1.76	2.45	1.16	2.14	2.41	1.00	NA
Northwest 115-69 Area	July	Weekday	17	6.74	1.13	0.01	4.10	2.51	1.48	2.54	1.35	2.14	3.15	1.00	NA
Northwest 69kV Area	July	Weekday	18	4.58	1.20	0.00	3.03	2.07	1.37	2.77	1.55	2.14	1.76	1.00	NA
Pleasant Valley 69	May	Weekday	18	7.57	1.09	0.00	4.26	2.77	1.67	2.28	1.16	2.14	3.08	1.00	NA
RD-RJ Lines	July	Weekday	16	9.74	1.05	0.00	5.29	3.09	1.69	2.44	1.16	2.14	4.34	1.00	NA
Southern Dutchess	July	Weekday	15	9.94	1.06	0.00	5.36	3.09	1.67	2.45	1.16	2.14	1.92	1.00	NA
WM Line	December	Weekday	18	2.87	1.28	0.00	2.18	1.75	1.20	2.92	0.84	2.14	0.14	1.00	NA
Westerlo Loop	January	Weekday	18	0.52	1.33	0.00	0.99	1.26	1.16	0.00	2.33	2.14	0.07	1.00	NA
CH System	July	Weekday	17	9.83	1.04	0.04	5.40	3.03	1.60	2.44	1.17	2.14	6.04	1.00	NA

Table 6: Top 100 Hour Conversion Factors by Transmission Area and Central Hudson's System for 1-in-10 Year Weather

Transmission Name	Transmission Peak Month	Transmission Peak Day Type	Transmission Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Ellenville	July	Weekday	12	7.46	1.07	0.00	4.54	2.75	1.74	2.32	1.58	1.87	3.26	1.00	NA
Hurley-Milan	July	Weekday	14	8.20	1.06	0.00	4.71	2.76	1.89	2.33	1.62	1.87	3.77	1.00	NA
Mid-Dutchess	July	Weekday	17	8.23	1.05	0.00	4.72	2.71	1.82	2.33	1.55	1.87	2.39	1.00	NA
Northwest 115-69 Area	July	Weekday	13	7.29	1.06	0.01	4.46	2.69	1.72	2.37	1.56	1.87	4.60	1.00	NA
Northwest 69kV Area	July	Weekday	15	6.54	1.08	0.00	4.08	2.48	1.64	2.55	1.52	1.87	3.45	1.00	NA
Pleasant Valley 69	July	Weekday	17	8.41	1.04	0.00	4.87	2.75	1.62	2.36	1.51	1.87	3.48	1.00	NA
RD-RJ Lines	July	Weekday	17	8.19	1.03	0.00	4.76	2.72	1.66	2.33	1.51	1.87	3.88	1.00	NA
Southern Dutchess	July	Weekday	17	8.47	1.04	0.00	4.89	2.69	1.63	2.36	1.50	1.87	1.67	1.00	NA
WM Line	July	Weekday	17	7.85	1.02	0.00	4.80	2.64	1.59	2.35	1.44	1.87	0.52	1.00	NA
Westerlo Loop	December	Weekday	18	1.24	1.30	0.00	1.31	1.41	1.13	0.00	1.28	1.87	0.37	1.00	NA
CH System	July	Weekday	17	8.45	1.03	0.04	4.92	2.76	1.68	2.28	1.53	1.87	5.87	1.00	NA

Table 7: Top 100 Hour Conversion Factors by Substation for 1-in-2 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	9.23	1.05	0.00	5.22	2.92	1.50	2.38	1.17	2.14	1.85	1.00	NA
Boulevard	July	Weekday	14	8.21	1.10	0.00	4.75	3.11	1.85	2.37	1.14	2.14	0.52	1.00	NA
Clinton Ave	February	Weekday	12	0.00	1.35	0.00	0.80	1.23	1.86	0.00	1.53	2.14	0.02	1.00	NA
Coldenham	July	Weekday	15	9.24	1.05	0.00	5.21	3.12	1.81	2.44	1.16	2.14	2.08	1.00	NA
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	December	Weekday	8	4.25	1.05	0.00	2.63	1.79	1.23	0.00	0.75	2.14	0.04	1.00	NA
Eastkingston	July	Weekday	17	9.68	1.05	0.00	5.16	3.01	1.66	2.42	1.16	2.14	0.45	1.00	NA
Eastpark	July	Weekday	18	9.69	1.03	0.00	5.17	2.90	1.40	0.00	1.10	2.14	0.21	1.00	NA
East Walden	July	Weekday	16	9.55	1.04	0.00	5.39	2.99	1.47	0.00	1.15	2.14	0.89	1.00	NA
Fishkill Plains	July	Weekday	17	10.06	1.05	0.00	5.47	2.97	1.43	0.00	1.13	2.14	1.69	1.00	NA
Forgebrook	July	Weekday	17	10.10	1.05	0.00	5.34	3.06	1.66	2.45	1.17	2.14	0.72	1.00	NA
Galeville	July	Weekday	11	7.72	1.08	0.00	4.48	2.80	1.61	0.00	1.02	2.14	1.20	1.00	NA
Grimley Rd	July	Weekday	19	8.90	1.06	0.00	5.31	0.00	0.00	0.00	1.09	2.14	0.02	1.00	NA
Hibernia	July	Weekday	16	9.91	1.07	0.00	5.33	3.05	1.60	0.00	1.16	2.14	2.01	1.00	NA
High Falls	July	Weekday	16	9.35	1.05	0.00	5.43	2.93	1.44	0.00	1.13	2.14	0.78	1.00	NA
Highland	July	Weekday	16	9.72	1.05	0.00	5.43	2.93	1.44	2.44	1.13	2.14	1.47	1.00	NA
Honk Falls	July	Weekday	13	9.08	1.08	0.00	5.18	3.01	1.40	0.00	1.16	2.14	0.07	1.00	NA
Hunter	December	Weekday	21	0.65	0.98	0.00	0.89	0.86	0.61	0.00	1.89	2.14	0.00	1.00	NA
Hurley Ave	July	Weekday	17	8.77	1.06	0.00	5.12	2.98	1.64	0.00	1.13	2.14	0.68	1.00	NA
Inwood Ave	July	Weekday	16	8.23	1.06	0.00	4.90	3.00	1.84	0.00	1.14	2.14	0.20	1.00	NA
Knapps Corners	July	Weekday	17	0.00	1.08	0.00	4.22	2.63	1.44	0.00	1.06	2.14	0.87	1.00	NA
Lawrenceville	December	Weekday	21	0.50	1.09	0.00	0.91	0.96	0.77	0.00	1.96	2.14	0.00	1.00	NA
Lincoln Park	July	Weekday	9	6.18	0.87	0.00	3.62	2.02	0.86	0.00	1.05	2.14	0.58	1.00	NA
Marlboro	July	Weekday	17	9.68	1.04	0.00	5.34	3.04	1.64	2.42	1.14	2.14	1.05	1.00	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	8.86	1.02	0.00	5.15	2.94	1.56	2.39	1.14	2.14	0.49	1.00	NA
Merritt Park	July	Weekday	16	9.24	1.05	0.00	5.25	3.06	1.71	0.00	1.16	2.14	0.26	1.00	NA
Milan	July	Weekday	10	8.54	1.03	0.00	4.88	2.74	1.27	0.00	1.08	2.14	0.22	1.00	NA
Millerton	January	Weekday	18	0.31	1.29	0.00	0.86	1.28	1.31	2.95	1.76	2.14	0.03	1.00	NA
Modena	July	Weekday	17	9.72	1.03	0.00	5.46	2.93	1.44	2.09	1.13	2.14	0.77	1.00	NA
Myers Corners	July	Weekday	18	9.00	1.02	0.00	5.36	3.01	1.64	0.00	1.14	2.14	0.42	1.00	NA
New Baltimore	July	Weekday	18	8.98	1.03	0.00	5.16	2.89	1.47	0.00	1.15	2.14	0.41	1.00	NA
North Catskill	July	Weekday	16	9.30	1.05	0.00	5.28	3.01	1.61	2.42	1.17	2.14	0.65	1.00	NA
North Chelsea	July	Weekday	17	10.22	1.03	0.00	5.40	2.92	1.45	2.43	1.14	2.14	0.28	1.00	NA
Ohioville	July	Weekday	15	8.86	1.07	0.00	5.08	3.10	1.75	0.00	1.14	2.14	1.13	1.00	NA
Pulvers Corners	January	Weekday	18	0.57	1.27	0.00	0.95	1.26	1.19	0.00	1.62	2.14	0.08	1.00	NA
Reynolds Hill	July	Weekday	14	9.41	1.09	0.00	4.95	3.12	1.94	0.00	1.17	2.14	0.43	1.00	NA
Rhinebeck	July	Weekday	18	9.64	1.07	0.00	5.42	2.99	1.47	2.46	1.14	2.14	1.53	1.00	NA
Sand Dock	July	Weekday	13	8.25	1.08	0.00	4.88	3.09	1.97	0.00	1.18	2.14	0.10	1.00	NA
Saugerties	July	Weekday	17	9.19	1.04	0.00	5.38	2.99	1.63	0.00	1.16	2.14	0.91	1.00	NA
Shenandoah	July	Weekday	15	9.21	1.09	0.00	5.22	3.14	1.76	0.00	1.15	2.14	0.36	1.00	NA
Smithfield	December	Weekday	8	0.41	1.11	0.00	0.90	0.00	0.00	0.00	0.72	2.14	0.05	1.00	NA
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	July	Weekday	18	9.82	1.00	0.00	5.33	2.84	1.39	0.00	1.13	2.14	0.42	1.00	NA
Staatsburg	July	Weekday	18	10.29	1.04	0.00	5.48	2.89	1.43	0.00	1.16	2.14	0.33	1.00	NA
Stanfordville	December	Weekday	18	0.75	1.33	0.00	1.15	1.34	0.94	0.00	1.84	2.14	0.00	1.00	NA
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	17	9.97	1.05	0.00	5.47	2.98	1.46	0.00	1.15	2.14	0.38	1.00	NA
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	17	9.79	1.05	0.00	5.41	2.95	1.39	2.44	1.12	2.14	1.05	1.00	NA
Union Ave	September	Weekday	16	9.13	1.08	0.00	4.95	3.11	1.77	2.40	1.09	2.14	2.38	1.00	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	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	0.99	1.19	0.87	0.00	2.73	2.14	0.02	1.00	NA
Westbalmville	July	Weekday	16	8.97	1.05	0.00	5.31	3.09	1.74	0.00	1.17	2.14	0.90	1.00	NA
Westerlo	July	Weekday	15	6.79	1.10	0.00	4.18	2.58	1.44	0.00	1.37	2.14	0.34	1.00	NA
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	July	Weekday	18	4.92	1.20	0.00	3.20	2.10	1.28	2.86	1.89	2.14	0.36	1.00	NA
Total System	July	Weekday	17	9.83	1.04	0.04	5.40	3.03	1.60	2.44	1.17	2.14	6.04	1.00	NA

Table 8: Top 100 Hour Conversion Factors by Substation for 1-in-10 Year Weather

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Barnegat	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bethlehem Rd	July	Weekday	17	7.67	1.03	0.00	4.62	2.59	1.53	2.26	1.48	1.87	1.67	1.00	NA
Boulevard	July	Weekday	15	7.70	1.07	0.00	4.64	2.75	1.87	2.32	1.65	1.87	0.51	1.00	NA
Clinton Ave	January	Weekday	20	0.00	1.42	0.00	1.97	1.59	1.07	0.00	1.37	1.87	0.02	1.00	NA
Coldenham	July	Weekday	16	7.69	1.05	0.00	4.58	2.65	1.83	2.29	1.57	1.87	1.97	1.00	NA
Coxsackie	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Dashville	July	Weekday	17	7.28	1.04	0.00	4.32	2.41	1.14	0.00	1.33	1.87	0.04	1.00	NA
Eastkingston	July	Weekday	15	8.18	1.06	0.00	4.62	2.70	1.87	2.30	1.61	1.87	0.49	1.00	NA
Eastpark	July	Weekday	18	8.65	1.02	0.00	4.94	2.72	1.46	0.00	1.41	1.87	0.21	1.00	NA
East Walden	July	Weekday	18	8.13	1.03	0.00	4.86	2.69	1.48	0.00	1.43	1.87	0.85	1.00	NA
Fishkill Plains	July	Weekday	17	8.50	1.03	0.00	4.95	2.73	1.47	0.00	1.41	1.87	1.59	1.00	NA
Forgebrook	July	Weekday	14	8.54	1.05	0.00	4.83	2.67	1.72	2.34	1.53	1.87	0.71	1.00	NA
Galeville	December	Weekday	18	0.34	1.28	0.00	0.72	1.22	1.56	0.00	1.18	1.87	0.33	1.00	NA
Grimley Rd	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hibernia	July	Weekday	18	6.56	1.12	0.00	3.94	2.38	1.57	0.00	1.49	1.87	1.39	1.00	NA
High Falls	July	Weekday	18	6.86	0.97	0.00	4.23	2.42	1.41	0.00	1.41	1.87	0.63	1.00	NA
Highland	July	Weekday	18	7.08	0.97	0.00	4.23	2.42	1.41	1.97	1.41	1.87	1.20	1.00	NA
Honk Falls	July	Weekday	12	7.50	1.07	0.00	4.53	2.74	1.50	0.00	1.60	1.87	0.07	1.00	NA
Hunter	December	Weekday	8	0.55	1.01	0.00	0.75	0.96	0.92	0.00	1.21	1.87	0.01	1.00	NA
Hurley Ave	July	Weekday	17	7.79	1.05	0.00	4.74	2.75	1.77	0.00	1.57	1.87	0.70	1.00	NA
Inwood Ave	July	Weekday	16	7.63	1.03	0.00	4.74	2.67	1.75	0.00	1.54	1.87	0.17	1.00	NA
Knapps Corners	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lawrenceville	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lincoln Park	July	Weekday	14	7.56	1.08	0.00	4.52	2.76	2.04	0.00	1.66	1.87	1.59	1.00	NA
Marlboro	July	Weekday	17	8.00	1.06	0.00	4.70	2.72	1.64	1.67	1.46	1.87	1.08	1.00	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Maybrook	July	Weekday	18	7.97	1.00	0.00	4.88	2.63	1.52	2.31	1.45	1.87	0.43	1.00	NA
Merritt Park	July	Weekday	16	8.11	1.03	0.00	4.86	2.65	1.67	0.00	1.48	1.87	0.22	1.00	NA
Milan	July	Weekday	16	7.90	1.03	0.00	4.76	2.68	1.41	0.00	1.42	1.87	0.23	1.00	NA
Millerton	January	Weekday	18	1.56	1.21	0.00	1.43	1.48	1.21	3.27	1.36	1.87	0.06	1.00	NA
Modena	July	Weekday	17	8.01	1.03	0.00	4.80	2.64	1.48	1.60	1.38	1.87	0.74	1.00	NA
Myers Corners	July	Weekday	17	7.79	1.05	0.00	4.83	2.79	1.61	0.00	1.51	1.87	0.45	1.00	NA
New Baltimore	July	Weekday	14	6.41	1.13	0.00	3.88	2.71	1.91	0.00	1.65	1.87	0.61	1.00	NA
North Catskill	July	Weekday	14	6.72	0.92	0.00	4.03	2.34	1.39	1.88	1.45	1.87	0.46	1.00	NA
North Chelsea	July	Weekday	18	7.69	1.00	0.00	4.48	2.45	1.19	2.26	1.26	1.87	0.19	1.00	NA
Ohioville	July	Weekday	16	7.56	1.06	0.00	4.57	2.67	1.79	0.00	1.55	1.87	1.11	1.00	NA
Pulvers Corners	July	Weekday	17	6.38	0.96	0.00	3.85	2.28	1.36	0.00	1.40	1.87	0.15	1.00	NA
Reynolds Hill	July	Weekday	16	7.66	1.10	0.00	4.30	2.73	2.07	0.00	1.70	1.87	0.44	1.00	NA
Rhinebeck	June	Weekday	13	7.57	1.06	0.00	4.52	2.74	1.69	2.29	1.53	1.87	1.55	1.00	NA
Sand Dock	August	Weekday	16	6.02	1.07	0.00	3.78	2.56	2.02	0.00	1.64	1.87	0.09	1.00	NA
Saugerties	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Shenandoah	July	Weekday	18	7.65	1.06	0.00	4.61	2.79	1.79	0.00	1.57	1.87	0.32	1.00	NA
Smithfield	December	Weekday	10	0.05	1.14	0.00	0.69	0.00	0.00	0.00	1.34	1.87	0.06	1.00	NA
South Cairo	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spackenkill	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Staatsburg	July	Weekday	18	8.34	1.00	0.00	4.82	2.60	1.46	0.00	1.38	1.87	0.27	1.00	NA
Stanfordville	July	Weekday	19	7.25	1.03	0.00	4.52	2.51	1.31	0.00	1.37	1.87	0.17	1.00	NA
Sturgeon Pool	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Tinkertown	July	Weekday	16	8.40	1.04	0.00	4.90	2.76	1.68	0.00	1.52	1.87	0.39	1.00	NA
Tioronda	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Todd Hill	July	Weekday	18	8.38	1.03	0.00	4.95	2.70	1.44	2.37	1.41	1.87	0.94	1.00	NA
Union Ave	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Substation Name	Substation Peak Month	Substation Peak Day Type	Substation Peak Hour	Residential				Commercial				All segments			Total
				HVAC	Lighting	Other	General	HVAC	Lighting	Other	General	EV	PV	Flat	
Van Wagner	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vinegar Hill	January	Weekday	19	0.62	1.30	0.00	0.97	1.19	0.73	0.00	1.28	1.87	0.01	1.00	NA
Westbalmville	July	Weekday	16	7.89	1.02	0.00	4.89	2.73	1.73	0.00	1.54	1.87	0.79	1.00	NA
Westerlo	April	Weekday	20	1.96	1.12	0.00	1.67	1.35	1.17	0.00	1.14	1.87	0.15	1.00	NA
Wiccopee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Woodstock	February	Weekday	9	3.12	1.22	0.00	2.30	1.81	1.16	3.02	1.34	1.87	0.30	1.00	NA
Total System	July	Weekday	17	8.45	1.03	0.04	4.92	2.76	1.68	2.28	1.53	1.87	5.87	1.00	NA