NYSEG RG&E

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June 30, 2016

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, New York 12223

Re: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision – Distributed System Implementation Plan

Dear Secretary Burgess,

Pursuant to the Commission's April 30, 2016 Order Adopting Distributed System Implementation Plan Guidance, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (the "Companies") hereby submit their Initial Distributed System Implementation Plan ("Initial DSIP"), including an Advanced Metering Infrastructure business case. As a member of the Iberdrola Group of Companies, the Companies are committed to the development of clean energy, investment in smart grids and other energy efficient technologies, and respect for the environment.

This Initial DSIP is our five-year (2017-2021) plan to build the Distributed System Platform ("DSP"). Our DSIP will transform our business to integrate clean energy resources, provide our customers with products and services that offer greater control over their energy usage and total energy bills, and provide market participants with information to make informed investment decisions. As the Distributed Systems Platform Provider ("DSPP"), we envision a technology-driven future with increased customer involvement in energy management, robust energy efficiency programs, and an intelligent DSP that integrates operations, planning and market functions. The Companies embrace this future and are confident in our ability to serve as the DSPP.

On this same day and under separate cover, pursuant the Commission's January 21, 2016 Order Establishing the Benefit Cost Analysis Framework, the Companies are submitting their Benefit Cost Analysis Handbook ("BCA Handbook").

The Companies welcome feedback from customers, third parties, the Commission, Staff, and other stakeholders in the coming months.

Respectfully submitted,

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AVANGRID

Distributed System Implementation Plan

June 30, 2016

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Acronyms

AC	Alternating Current
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
AMS	Asset Management System
BCA	Benefit-Cost Analysis
BRC	Business Reply Cards
CARIS	Congestion Assessment and Resource Integration Study
CCA	Community Choice Aggregation
CCS	Customer Care System
CEAC	Clean Energy Advisory Council
CEC	Community Energy Coordination
CIP	Five-Year Capital Investment Plan
CL&P	Connecticut Light and Power
CIS	Customer Information System
C&I	Commercial and Industrial
CMP	Central Maine Power Company
CPP	Critical Peak Pricing
CRM&B	Customer Relationship Management & Billing System
CSP	Cyber Security Plan
CSR	Call Center Representative
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DER	Distributed Energy Resource(s)
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DO	Distribution Operator
DOE	Department of Energy
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSP	Distributed System Platform
DSPP	Distributed System Platform Provider
EAP	Enterprise Analytics Platform
ECC	Energy Control Center
EDI	Electronic Data Interchange
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
EM	Energy Marketplace
EMS	Energy Management System
EM&V	Evaluation, Measurement & Verification
EPRI	Electric Power Research Institute
ESC	Energy Smart Community
ESCO	Energy Services Company

FAN	Field-Area Networks
FICS	Flexible Interconnect Capacity Solution
FLISR	Fault Location, Isolation and Service Restoration
FTP	File Transfer Protocol
GBC	Green Button Connect
GIS	Geographic Information System
GRTA	Ginna Retirement Transmission Alternative
HAN	Home Area Network
HER	Home Energy Reports
HES	Head-End System
ICAP	Installed Capacity
ICE	Interruption Cost Estimate
ISP	Integrated System Planning
IT	Information Technology
kW	kilowatt
LBMP	Location Based Marginal Prices
LMI	Low- and Moderate-Income
LHV	Lower Hudson Valley
LTC	Load-Tap Changers
MDMS	Meter Data Management System
MHP	Mandatory Hourly Pricing
MVA	Mega-Volt Ampere
MW	Megawatt(s)
NAN	Neighborhood Area Networks
NEM	Net Energy Metering
NIST	National Institute of Standards and Technology
NPV	Net Present Value
NWA	Non-Wires Alternative(s)
NYISO	New York Independent System Operator
NYSEG	New York State Electric & Gas Corporation
OG&E	Oklahoma Gas and Electric
O&M	Operating & Maintenance
OMS	Outage Management System
OT	Operational Technology
PII	Personal Identifiable Information
PMO	Program Management Office
POD	Point of Delivery
PV	Photovoltaic
RAM	Rate Adjustment Mechanism
RARP	Rochester Area Reliability Project
RIM	Ratepayer Impact Measure
RCT	Randomized Control Trial
REV	Reforming the Energy Vision
RFI	Request for Information

RFP	Request for Proposal
RG&E	Rochester Gas and Electric Corporation
RGGI	Regional Greenhouse Gas Initiative
RIM	Ratepayer Impact Measure
ROS	Rest of State
RTP	Real-Time Pricing
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SIR	Standardized Interconnection Requirements
SMB	Small and Medium Business
SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas Company
T&D	Transmission and Distribution
TOU	Time of Use
TVP	Time Varying Pricing
UCT	Utility Cost Test
VVO	Volt/var Optimization
WACC	Weighted Average Cost of Capital
WAN	Wide Area Network

Executive Summary

New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E") (collectively, the "Companies") present this Distributed System Implementation Plan ("DSIP") to transform our business to integrate clean energy resources, provide our customers with products and services that offer greater control over their energy usage and total energy bills, and provide market participants with information to make informed investment decisions.[1] As the Distributed Systems Platform Provider ("DSPP"), we envision a technology-driven future with increased customer involvement in energy management, robust energy efficiency programs, and an intelligent Distributed System Platform ("DSP") that integrates operations, planning and market functions. The Companies embrace this future and are confident in our ability to serve as the DSPP.

This plan recognizes that our business environment is rapidly evolving and that significant changes will be required to meet customer expectations and needs. Transformation of our business will be facilitated through new and revised business processes, associated capabilities and enabling technologies. We present detailed developmental "roadmaps" to our business, and to provide the core DSPP functions of Grid Operations, Integrated System Planning, and Market Enablement.

This Initial DSIP is our five-year (2017-2021) plan to build the DSP. It describes services we contemplate providing, required capability enhancements, and projected investments during this period.[2] We will organize the DSIP effort by executing a number of interdependent "projects" and "initiatives" in a thoughtful, phased plan. This phased approach will allow us to continue providing reliable electricity service as we steadily add new services and redesign the way we do business. We will test many of our new services, processes and technologies in our Energy Smart Community ("ESC") project before deploying them across all of the New York communities we serve.[3] We are particularly interested in learning what services customers will be most interested in and how to engage them in new opportunities. The Companies are also engaged in three other demonstration projects that will further prepare us to serve as the DSPP.[4]

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[1] The DSIP complies with the State of New York Public Service Commission's ("Commission") Order Adopting Distributed System Implementation Plan Guidance issued on April 20, 2016 in the Reforming the Energy Vision ("REV") proceeding, Case 14-M-0101.

[2] Although not specifically addressed in this Initial DSIP, the transition to the DSP role must be accompanied by changes to the regulatory model to ensure the long run financial viability of distribution utilities necessary to finance our DSIP and future investments.

[3] The Companies proposed the ESC "test-bed" concept in July 2015 as part of its rate case filing in Case No. 15-E-0283, *et. al*.

[4] See Chapter V for a detailed description of the ESC, demonstration projects, and our innovation "pipeline" process.

Our Vision

The Companies' vision is to be a leader in the energy sector, providing reliable service for our customers with a commitment to the wellbeing of our communities.[5] We seek to provide clean energy through innovation, technology, and sustainable sources and are committed to reducing our corporate carbon footprint.[6]

As a member of the Iberdrola Group of Companies ("Iberdrola"), commitment to the development of clean energy, investment in smart grids and other energy efficient technologies, and respect for the environment are the pillars of the Group's energy production model and distinguish Iberdrola in the energy sector as one of the leading companies worldwide. The innovation and technology expertise that exists throughout the Group has been leveraged in the development of the plans that are described in this DSIP. The Companies' DSIP plan to implement the "Smart Integrator" future Utility model directly aligns with our strategies and our commitments to carbon reduction through clean energy, energy efficiency, and technology innovation.

The Smart Integrator

- Serve as a platform for customers and third-party service providers, enabling the growth, integration, and optimization of DER.
- Enable new value-added products and services that benefit customers directly and the overall efficiency of New York's energy markets.
- Improve delivery service efficiency while improving the reliability and resiliency of the network.
- Enable the participation of customers and suppliers in evolving distribution markets.

The Companies will continue to own and operate the transmission and distribution ("T&D") network (including meters). We will continue to maintain our existing infrastructure and add new infrastructure while connecting, integrating and coordinating distributed energy resources ("DER"). Our relationships with DER providers and other third-party vendors will expand to include transactions in which the DSPP is a seller, buyer, and/or partner.

The DSPP will perform three core functions: "Grid Operations" (operating a complex power grid), "Integrated System Planning" (planning that leverages DER as a potential resource to solve traditional network challenges, and providing information to our customers and DER providers that supports their decision-making), and "Market Enablement" (engaging customers and third parties in market opportunities).

[5] The Companies are the New York-based utility subsidiaries of AVANGRID, the United States diversified energy company that is majority owned by Iberdrola Group.

[6] Iberdrola Group has a goal of being carbon-neutral by 2050.

Enhanced Capabilities Required to Execute Our Vision

Achieving our vision will require building several new capabilities within each of the three core DSP functions.

Grid Operations (*Chapter II*) is the DSP function that manages, maintains, and operates the electric power system in order to deliver system stability, power quality, and reliability. Grid Operations is also responsible for restoring power after a power outage in a manner that ensures the safety of employees and customers. The grid must become significantly more "intelligent" in order to continue to fulfill these obligations while accommodating a substantial increase in DER that is widely dispersed throughout the network. Real-time network and DER performance data is necessary to coordinate and control grid resources, ensure the stability of the network, and maintain the quality of power delivered to our residential and business customers. It is clear that extensive automation, enabled by real-time telecommunication of network performance data, will be required.

The Companies intend to build five Grid Operations capabilities:

(1) DER Monitoring and Observability: *Monitor and communicate DER and network performance data to support grid operations;*

(2) DER Coordination and Control: *Coordinate and control DER in high and low penetration areas in order to maintain network performance;*

(3) Real-Time Distribution System Optimization: *Establish optimization protocols and develop enabling decision-support tools and systems;*

(4) T&D Resource Coordination: *Establish distribution resource rules, roles and responsibilities to support market transactions; and*

(5) Integration of Grid and Market Operations: *Establish the interface definition between the DSP and the New York Independent System Operator ("NYISO") and enable the aggregation of DER to support coordination between NYISO operations and markets with related distribution functions.*

Integrated System Planning ("ISP") (*Chapter III*) is the DSP function that ensures the reliable, safe, and efficient design of our electric distribution network. The ISP function will integrate actual and forecasted DER locations and performance into complex models that will help us plan the network to accommodate load requirements and respond to recurrent system constraints. The models will consider both traditional utility infrastructure investments and DER as a resource that can supplement, offset or defer the need for a utility investment when the Companies' assessment indicates that a "non-wires alternative" ("NWA") may be feasible from a technical and economic perspective.[7]

[7] Hence, the function is being renamed from "Distribution System Planning" to "Integrated System Planning".

The ISP function will also provide insightful information valued by customers and third parties to support their planning and investment decisions. The Companies will intend to build six ISP capabilities:

(1) Integrated System Planning with DER: *redesign the distribution planning process (and supporting models) to reflect connected DER and the potential impacts of new DER, utility-owned storage as a grid asset (i.e. not on a customer premises), and consideration of micro grids;*[8]

(2) Beneficial Locations, Hosting Capacity, and Locational DER Value: (a) *identify high-priority locations where DER could provide distribution system relief, (b) calculate "hosting capacity" at the distribution substation and circuit level, and (c) estimate the locational value of DER to the distribution network;*

(3) Demand and Energy Forecasting with DER: *enhance demand and energy forecasting methodologies and tools to incorporate the impact of DER on the baseline demand and energy forecasts and produce forecasts at a more detailed level (e.g. at the substation or circuit level*[9]*);*

(4) Capital Planning with DER: *incorporate the impact of DER, including the potential for NWA, into the development of the annual capital forecast;*

(5) Procurement of Non-Wires Alternatives: *(a) identify, and evaluate NWA opportunities, and (b) procure and manage NWA-related DER solutions; and*

(6) Probabilistic Integrated System Planning: *define and implement probabilistic and scenario-based planning techniques that capture uncertainties related to DER penetration and performance.*

<u>Market Enablement</u> (*Chapter IV*) is the DSP function that will enable new products and services that will be brought to market. It is an end-to-end function that connects customers to market solutions by providing data and information that helps them identify opportunities and engage with market providers. The function includes generating awareness and engaging customers, providing customers and their potential suppliers with access to customer usage and other relevant information, providing DER suppliers with system information to help them make investment decisions, and billing customers and third-party vendors for services provided by the Utility/DSP. Market Enablement also facilitates DER connections by streamlining the interconnection process. The Companies intend to build seven Market Enablement capabilities:

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[8] A microgrid is a local energy grid with the ability to disconnect from the utility distribution system and operate autonomously.

[9] A distribution substation is connected to the transmission system and lowers the voltage level. The circuit transmits power from the distribution substation to a load area where it is then connected through service transformers to circuits that deliver power to customer premises.

(1) Customer Care Processes and Systems: *Integrating platform technologies with relationship management and billing tools to enhance the customer experience, while delivering timely and accurate invoices to end-users;*

(2) Customer Data and Portals: *Improve data access platforms and ability to provide data to customers and DER providers, with Energy Manager*[10] *as our initial platform, as well as integrating other data provision functions such as Green Button Connect ("GBC");*

(3) Sharing Customer Data with Customers and DER Providers: *Provide timely and accurate customer usage and other relevant data, consistent with the Companies' security and privacy requirements;*

(4) Outreach, Marketing, and Sales: *Communicate new products, services, and utility-sponsored programs to target audiences to engage customers and increase participation in these programs;*

(5) Sharing System Data and Information with DER Providers: *Provide DER providers with timely access to system data;*

(6) DSP Markets: *Participate in efforts to develop statewide transactive markets for products and services that could be efficiently provided through organized market mechanisms; and*

(7) Interconnection Processes: *Streamline interconnection processes to provide grid reliability and optimization and accommodate an increasing penetration of DER.*

This comprehensive list of capability enhancements reveals the detailed and complex nature of the analysis required to determine DSP operational requirements and the extraordinary degree to which the DSPP will rely in the future on vast quantities of data that is more granular with respect to location and time variation than has been previously required to operate the traditional utility. This set of capabilities will need to be addressed in an integrated manner that considers all three DSP functions. It is clear that grid automation, telecommunications, and information systems technologies will be required to collect and take advantage of this increased granularity in both system and customer data. As a consequence, certain capabilities that are dependent on foundational technology investments to compile and manage granular data (e.g. future distribution markets) will be built during the later years of the DSIP. Nonetheless, certain DSIP investments

[10] *Energy Manager* is an online portal that has been deployed at Central Maine Power, an affiliate of the Companies. *Energy Manager* presents energy usage information, encourages customers to set energy savings goals, and engages customers in meeting those goals by presenting personalized tips and actions they can take to reduce energy usage and costs. Hourly interval data for residential customers is available and updated each day, accessible through a secure login. Usage and cost data is presented in graphs by hour, day, and billing cycle for an entire year. In addition to seeing hourly data presented in graphs, customers are able to download their data either to a spreadsheet or in Green Button Connect format.

are being designed today with these future markets in mind, with flexibility built into the design process to accommodate a likely statewide approach to market design.[11]

Implementation Strategy

Consistent with our corporate strategy to deploy distribution automation and Advanced Metering Infrastructure ("AMI") in all jurisdictions, the DSIP accelerates distribution network investments that we have been making in anticipation of increased penetration of rooftop solar and other distributed generation ("DG") technologies.[12] Thus, the DSIP aligns with the Companies' existing efforts to prepare to serve as a platform provider.

We refer to the most important technology investments, which include AMI, as our "Foundational Platform Technology" supporting the three core DSP functions, as shown in Figure ES-1.

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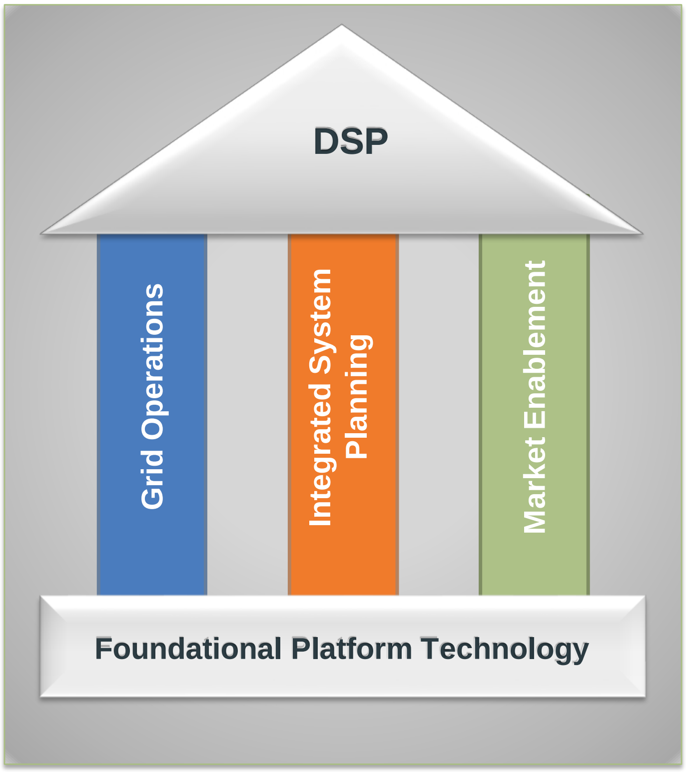
[11] For example, the Customer Relationship Management & Billing "(CRM&B") system will allow the Companies to introduce customized product and service options for individual customers based on profile information. These products and services may include real-time data services (e.g. monitoring generation from on-site resources, etc.), demand response opportunities, connected home services, and many other features.

[12] These include the Siemens Spectrum Advanced Distribution Management System ("ADMS") platform, Distribution Automation ("DA"), and network telecommunications systems. Several of these investments are identified in the Companies' current Five-Year Capital Investment Plan ("CIP").

FIGURE ES-1: DSP BUSINESS PILLARS AND CAPABILITIES[13]



DSP Capabilities

Grid Operations

- DER Monitoring and Observability
- DER Coordination and Control
- Real-Time Distribution System Optimization
- T&D Resource Coordination
- Integration of Grid and Market Operations

Integrated System Planning

- Integrated System Planning with DER
- Beneficial Locations, Hosting Capacity, and Locational DER Value
- Demand and Energy Forecasting with DER
- Capital Planning with DER
- Procurement of Non-Wires Alternatives
- Probabilistic Integrated System Planning

Market Enablement

- Customer Care Processes and Systems
- Customer Data and Portals
- Sharing Customer Data with Customers and DER Providers
- Outreach, Marketing, and Sales
- Sharing System Data and Information with DER Providers
- DSP Markets
- Interconnection Processes

The Companies consider each core function and their associated capabilities to be a DSP "pillar" that is an essential component of an integrated DSP solution. The DSP will not realize its potential without any one of the three pillars, and they are each supported by the Foundational Platform Technologies. The integrated set of foundational technology investments are designed as a group to optimize support of the three core DSP functions.

Approach to Developing the DSIP

We employed a five-step process to develop the Initial DSIP, as illustrated in Figure ES-2.

[13] Throughout this document the three core DSP functions are consistently represented in figures using this color coding scheme: blue for Grid Operations; orange for Integrated System Planning; and green for Market Enablement.

FIGURE ES-2: APPROACH TO DEVELOPING THE DSIP

1. Identify and define specific required DSP operational capabilities
2. Develop "roadmaps" that assign each capability enhancement to one of three phases: Near-term (2017-2018), longer-term Initial DSIP period (2019-2021), and (2022+)
3. Identify foundational technologies required to form the DSP technical platform (i.e., map functions to technologies)
4. Define specific technology projects using a "line-of-sight" methodology that connects each project to the specific capabilities it will enable (i.e., map technology requirements to specific projects)
5. Prepare an AMI business case that applies the Commission's Benefit Cost Analysis (BCA) methodology

Chapters II, III, and IV include detailed roadmaps for each of the three core DSP functions that present a strategic, sensible, and staged approach to implementation. These roadmaps consider:

- Certain capability improvements as baseline building blocks that must logically precede the implementation of "dependent" capability developments;
- Highly integrated DSP functional capabilities that must be developed as part of an integrated, comprehensive set;
- The need to maintain, if not improve, network reliability and customer services throughout the transition to the DSP;
- A desire to accommodate accelerated DER penetration and to deliver value to customers as early in the development process as possible;
- An objective to maintain alignment between the costs necessary to build capabilities and the value that customers will receive and acknowledge; and
- Learning from early experiences and from demonstration projects that will reduce deployment risks and contribute to a more efficient and cost-effective DSP capability build-out.

This Initial DSIP represents the most appropriate path forward, based on what the Companies know today. Several "near-term" implementation actions will occur during the first two years. The

Companies will continue to engage with stakeholders through the Supplemental DSIP stakeholder process, the ESC and demonstration projects, and other ongoing outreach efforts. Our subsequent DSIP filings will also reflect the experience gained performing as the DSP and lessons learned during demonstration projects,

The collection of five interrelated foundational technologies identified in Step 3 form our Foundational Platform Technology:

(1) Smart Metering (also referred to as AMI);

(2) Distribution Automation ("DA");

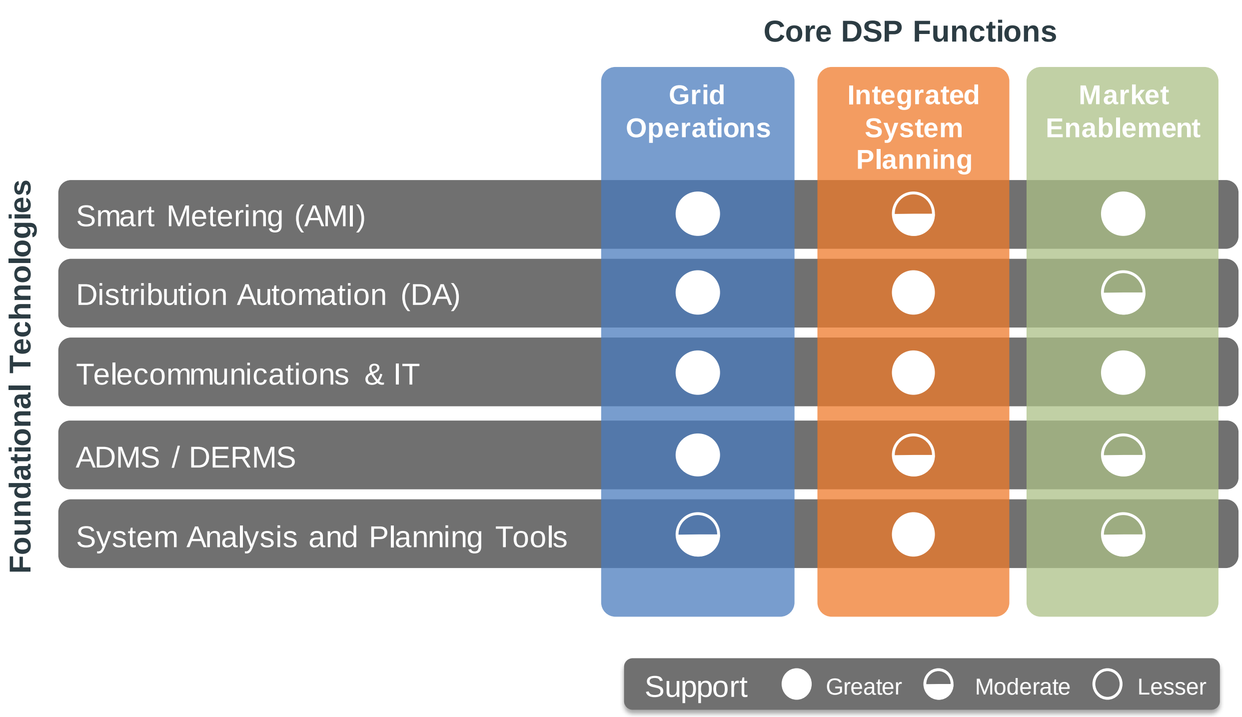
(3) Telecommunications and IT;

(4) ADMS including Distributed Energy Resources Management System ("DERMS"); and

(5) System Analysis and Planning Tools.

The contributions of these technologies to the three core DSP functions are presented in Figure ES-3.

FIGURE ES-3: FOUNDATIONAL PLATFORM TECHNOLOGIES AND CORE DSP FUNCTIONS



Having identified the five Foundational Platform Technologies, the Companies then defined five technology projects and AMI using a Line-of-Sight methodology that connects each project to capabilities enablement in each of the core DSP functions. Details for the five technology projects and AMI are contained in *Chapters VI and VII*):

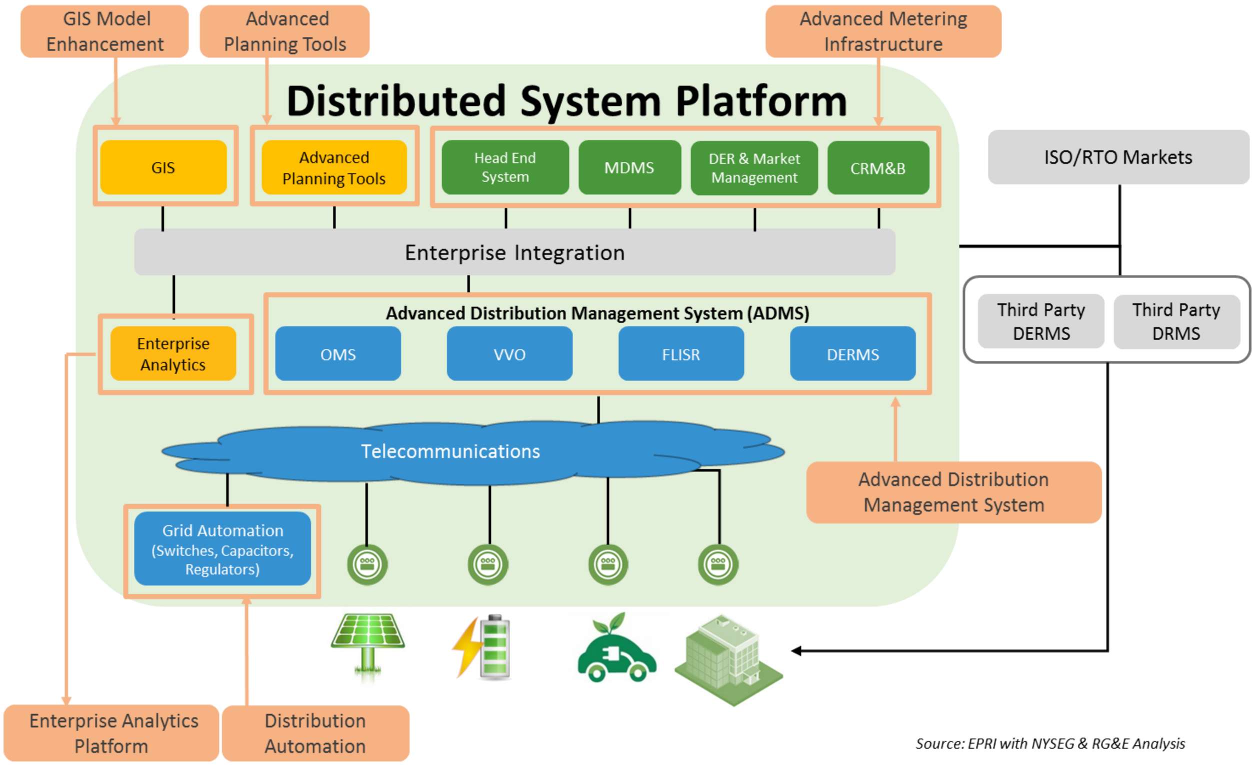
TABLE ES-1: DSIP TECHNOLOGY PROJECT PORTFOLIO

Technology Project	Description
AMI, AMI-OMS Integration, CRM&B	System-wide implementation of AMI to provide customer usage by time interval and system data, and upgraded billing / back-end systems
Grid Automation	Automate the line regulators, capacitors, sectionalizers, tie switches and single-phase reclosers to enable control over network facilities.
GIS Model Enhancement	Enhance the Geographic Information System (“GIS”) grid model to provide DER and impedance data for planning and operations to enable and enhance interconnections analysis, hosting capacity analysis, circuit optimization, Volt/var control, and other functions.
Advanced Planning Tools	Provide the capability to determine the DER hosting capacity in a manner consistent with the other New York Utilities, accurately forecast load, incorporate distributed generation and energy storage into Integrated System Planning., and implement a DER Developer Web Portal to communicate system data and accept interconnection requests.
Advanced Distribution Management System	Expand the Siemens Spectrum system to include distribution power flow, Volt/var optimization (“VVO”), demand response, DERMS, Fault Location, Isolation, and Service Restoration (“FLISR”). The ADMS will enable DER visibility and control and support DER transactions.
Enterprise Analytics Platform	Develop a comprehensive Enterprise Analytics Platform to fully leverage the vast quantities of granular system and customer data that supports our vision for data management, business intelligence, and advanced analytics.

The DSP and AMI investment projects are preliminary and will be updated as project plans are refined to reflect the results of stakeholder input, competitive bidding outcomes where appropriate, and other detailed planning activities. The updates will form the basis of specific requests for project approval and associated cost recovery. The Companies require timely and complete cost recovery of these investments in order to build the DSP on financially viable terms.

The technology projects plus AMI make it possible to integrate significant penetrations of DER into the planning and operation of the electric distribution grid while enhancing its reliability, resiliency and safety. These projects are shown in Figure ES-4.

FIGURE ES-4: DSP TECHNOLOGY PROJECTS AND AMI



Source: EPRI with NYSEG & RG&E Analysis

AMI is the most significant of the Companies' platform technology investments. The AMI business plan is presented in Chapter VII. The plan identifies the various investments that comprise AMI, describes how it will be deployed, and describes the value it will provide to our customers. AMI provides both operational and societal benefits and produces a positive net benefit. The largest benefits derive from operational benefits and Conservation Voltage Reduction ("CVR"). The remainder of the benefits are derived from integration of AMI with the Companies' Outage Management System ("OMS") and Opt-in Time Varying Pricing ("TVP") and outage alerts. A detailed benefit-cost analysis is presented as Appendix G.

Conclusion

The Companies are confident in our ability to respond to the challenges and opportunities of developing an intelligent electric grid and performing as the DSPP. This DSIP is consistent with the strategies of both the Companies and of our global parent corporation.

The Companies vision is to implement the Smart Integrator future utility model by building several new capability enhancements to support the DSP. Our DSIP identifies the capabilities and explains how we will leverage commercially available technologies to develop our technology platform. It represents a comprehensive, thoughtful approach that builds on opportunities to learn from our ESC and demonstration projects.

Moreover, our DSIP fulfills the objectives of our customers, other stakeholders, and the Commission while balancing the benefits with costs to implement. The Companies welcome feedback from customers, third parties, the Commission, Staff, and other stakeholders in the coming months.

I. Introduction

A. Initial DSIP

This Initial DSIP is our five-year (2017-2021) plan to build the DSP and assume the role of DSPP. It describes services we will provide, capabilities we will build, and investments we would need to make during this period. Assuming the role of DSPP aligns with our corporate vision and strategy, and as a consequence, the DSIP is aligns with technology investments that we have either already begun or have been in the planning stages.

The plan includes detailed "roadmaps" for each of the three core DSP functions: Grid Operations, Integrated System Planning, and Market Enablement. Capability building consists of investments in enabling technologies, establishment of new business processes, and employee training. The Initial DSIP also describes the Companies' "Foundational" Platform Technology investments to monitor and control the network and telecommunications to transmit granular customer and system data. The Companies will also invest in several information systems, capable of managing system and customer data in a secure and private manner with advanced analytical tools that support DSP decision-making and operations.

Although the Companies began planning to serve as the DSP well over a year ago, this Initial DSIP is the first formal filing in a multi-year process to develop the DSP. The Supplemental DSIP, to be filed by the Joint Utilities[14] on November 1, 2016, will be the next step. Stakeholders will again be directly involved, working with the Companies and participating in the stakeholder engagement process that will inform the Supplemental DSIP. The Supplemental DSIP is likely to require adjustments to our Initial DSIP, as noted within certain chapters (e.g. Chapter 3: Integrated System Planning), where the Supplemental DSIP seeks to develop common utility approaches to certain processes.

B. DSIP Contents and Organization

This Initial DSIP communicates the Companies plan to serve as the DSPP for our customers, the Commission, and other stakeholders.

The plan reduces complex topics to their essential elements by addressing a common set of questions:

- What are the Companies' aspirations with respect to each core DSP function?

[14] For purposes of the REV Proceeding, the "Joint Utilities" refers to Consolidated Edison Company of New York, Inc. ("Con Edison"), Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation.

- What are the Companies' current capabilities with respect to these aspirations? What gaps need to be addressed through capability enhancements?
- What DSP platform technology investments and other actions will the Companies implement to enhance capabilities and how much will they cost?
- How will each of the core DSP functions "mature" over the five-year Initial DSIP period? What are the operational requirements associated with each phase?
- How will the DSIP deliver value to the Companies' customers?

The first three chapters present the Companies' plan to develop the capabilities necessary to provide the three core DSP functions: Grid Operations, Integrated System Planning, and Market Enablement. Maturity model roadmaps are used to show the key initiatives required to develop the sets of capabilities within each core function. The first two roadmap years (2017-2018) are referred to as "near-term initiatives," years three to five (2019-2021) are longer-term "DSP 1.0" initiatives, and 2022 and beyond are termed "DSP 2.0" and out of scope of this initial DSIP.

II. **Grid Operations:** describes the capabilities required to integrate DER penetration growth and initiatives undertaken during the first two years to build these capabilities. These include changes to processes and protocols that allow visibility of network performance and actions necessary to respond to operational issues under varying load conditions.

III. **Integrated System Planning:** describes the advances made to transform the distribution system planning function to incorporate the impact of DER into many sub-processes and to provide system data, information and insights to DER providers. Many of these enhancements require a common approach and methodology among New York's utilities and will also be addressed in the Supplemental DSIP filing.

IV. **Market Enablement:** describes efforts to make customer and system data available to customers and third parties, and efforts to engage both customers and third-parties in new market opportunities.

V. **Energy Smart Community and REV Demonstration Projects:** describes the contributions of the ESC and the demonstration projects to REV policy and the Companies' ability to serve as the DSP, including the engagement of customers in new products and services.

The final three chapters describe the foundational technology investments that enable the DSP.

VI. **Technology Platform:** describes the Companies' "Line-of-Sight" methodology, which starts with the DSPP objectives, defines all of the necessary capabilities, determines the foundational technologies, and establishes a set of specific technology projects that together will enable the greatest capability improvements and associated functionalities.

VII. **Advanced Metering Infrastructure Business Plan:** provides the Companies' business plan with costs and benefits for system wide AMI implementation.

VIII. **Financial Impacts and Cost Recovery:** presents the Companies' proposed cost recovery mechanisms, consistent with the 2016 rate case order.[15]

This filing also includes seven appendices:

A. **Stakeholder Engagement:** a summary of the Companies' Initial DSIP stakeholder engagement process and feedback.

B. **Beneficial Locations:** tables that identify beneficial substations and circuits for NYSEG and RG&E.

C. **Additions to the Companies' Distribution Planning Manual**: a summary of the changes to the Companies' Distribution Planning Manual required to incorporate DER and NWA into the distribution planning process.

D. **Five-Year Historical Capital Spending**: five-year historical spending on infrastructure, telecommunications, information technology and shared services.[16]

E. **Five-Year Forecast Capital Budgets:** five-year forecast budgets for infrastructure, telecommunications, information technology and shared services.

F. **Benefit Cost Analysis ("BCA") Handbook**: reference to the concurrent filing of the Companies' BCA Handbook.

G. **AMI Benefit-Cost Analysis**: a detailed benefit-cost analysis supporting the Companies' AMI Plan.

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15 Order Approving Electric and Gas Rate Plans in Accordance with Joint Proposal, Case Nos. 15-E-0283, 15-G-0284, 15-E-0285 and 15-G-0286, dated June 15, 2016.

16 Five-year historic and forecast capital budgets are provided as required in Attachment 1 of the Commission's April 20, 2016 Order Adopting Distributed System Implementation Plan Guidance (Case 14-M-0101).

II. Grid Operations

A. Introduction and Overview

Grid Operations is the core DSP function that monitors and operates the electric power system in order to maintain system stability, power quality, resiliency, and reliability of service to every customer throughout the Companies' service areas. Grid Operations must deliver electricity within specified standards to assure continual stability of the electric T&D network. Grid Operations is also responsible for preventing equipment failures and restoring power after a system disturbance by coordinating switching activities in a manner that ensures the safety of employees and customers.

Fulfilling these obligations becomes significantly more challenging with high penetrations of variable DER, located throughout the service territory. DER may impact customer load profiles by changing demand during peak hours and throughout the year. The existing network was designed and built to accommodate one-way power flows from large central power stations to customer premises. The Grid Operations function, and its enabling technology, was organized to operate this much simpler network.

High DER penetration will substantially impact how the Companies must approach operating the distribution network as well as the tools that operators in the Energy Control Centers ("ECC") will need to control network conditions and maintain the quality of network service.[17] Grid Operations must monitor DER performance, relative to distributed loads in near real time[18], which involves acquiring DER performance data at a granular level at thousands of load and DER measurement points.

Operators not only require real-time visibility of grid performance, but the analytical tools to convert this system data into actionable intelligence that they can use to manage the grid. These actions include the ability to coordinate and control DER in response to dynamic power flow conditions, particularly where DER is relied upon to meet system demand. Operators require data for each DER resource and the ability to forecast the situational availability and performance characteristics in order to optimize system integration of wind, solar, demand response, storage and other DER. Because most DER are small relative to traditional central station generation resources, the operator must be able to aggregate DER for dispatch purposes to efficiently manage the grid. Enhanced grid operations capabilities will allow the Companies to coordinate,

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[17] The Companies have two ECCs, one for each Company.

[18] "Near real-time" in this circumstance refers to the time delay caused by the need to transmit data to the ECC.

manage, and optimize grid and DER resources together to respond to network conditions and help restore power after outages.[19]

Grid Operations will support the interconnection of optimal amounts of DER and accommodate new products and services offered by the Companies and third parties. Efficient operations are always imperative, including coordinating with the NYISO to promote efficiencies in wholesale markets.

Our proposed platform technology will provide the integrated functionality required to operate a significantly more complex grid. The Companies' AMI/smart meter investment will complement technology investments to help support Grid Operations.

B. Capability Enhancements

A combination of new business processes, information systems, analytics, adaptive protection, telecommunications, several other grid technologies, and operator training will provide the necessary capability improvements. The Companies have been investing, and will continue to invest in ADMS and related technologies (such as VVO and DERMS) to help manage the grid. The Companies will need to continue to build capabilities in five distinct areas in order to operate the grid in a high-DER penetration environment:

(1) **DER Monitoring and Observability:** *Monitor and communicate DER and network performance data to support grid operations;*

(2) **DER Coordination and Control:** *Coordinate and control DER in high and low penetration areas in order to maintain network performance;*

(3) **Real-Time Distribution System Optimization:** *Establish optimization protocols and develop enabling decision-support tools and systems;*

(4) **T&D Resource Coordination:** *Establish distribution resource rules, roles and responsibilities to support market transactions; and*

(5) **Integration of Grid and Market Operations:** *Establish the interface definition between the DSP and the NYISO and enable the aggregation of DER to support coordination between NYISO operations and markets with related distribution functions.*

Each of these capabilities will be addressed in detail in the remainder of this chapter. A brief description of each capability as well as the Companies' corresponding current status is presented in the following table.

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[19] Management of DER does not necessarily imply "curtailment". Rather, the Companies will provide voltage and var set points to DER to optimize the grid in a coordinated fashion. However, under abnormal (i.e. emergency) conditions, the Companies may need to curtail or partially curtail DER output at times, similar to protocols at the NYISO.

TABLE II-1: GRID OPERATIONS: CURRENT CAPABILITIES

Capability	DSP Requirements	Current Status
DER Monitoring and Observability	• Full visibility of DER including location, capability, and performance • Integration of DER with Supervisory Control and Data Acquisition ("SCADA") and real-time systems	• Monitoring and observability for 100% of DG installations above 1MW • No visibility of DER smaller than 1 megawatt ("MW") • Siemens Spectrum is in place as an *Energy Control System* but will need to be upgraded for full DSP functionality
DER Coordination and Control	• DER Smart Inverter Integration • Aggregation and management with DERMS	• The Companies do not currently control DER resources < 1 MW • There is no existing process for managing DER performance • NY standards for a smart inverter interface do not exist. Voltage control, real and reactive power control, voltage and frequency ride through[20] and bi-directional communication standards need to be addressed • NY standards for DER coordination and control have not been defined
Real-Time Distribution System Optimization	• Optimization with respect to multiple criteria (efficiency, reliability, fuel mix) • System reconfiguration • VVO	• Limited monitoring, control, and data acquisition at the Companies substations (see Table II-2) • Monitoring, control, and data acquisition of three-phase reclosers – low at NYSEG, high at RG&E (see Table II-3) • Additional phases of system automation will be required to fully enable the DSP platform • The Companies do not currently have VVO
T&D Resource Coordination	• End-to-end integrated planning • Aggregation of distributed systems for bulk system support (i.e. a "virtual power plant")	• DER not currently used by the ECC to optimize the grid and interface with NYISO • DER performance is not tracked. Construction of the DER data management database is underway • Information for currently connected DER needs to be validated

[20] Voltage and frequency ride-through permits DER to remain on line during low voltage and low frequency conditions and avoid cascading failure of the grid.

Capability	DSP Requirements	Current Status
Integration of Grid and Market Operations	• Aggregation of load and DER for bulk market products • Support of distributed/retail products and services	• Interface definitions between the DSP and the NYISO have not been defined • DER not currently used by the ECC to optimize the grid and distribution market operations are not currently defined

Capability enhancing foundational technologies will be initially deployed and tested in the ESC, providing an integrated pilot environment at acceptable risk and cost. The ESC should be thought of as the first phase of a fully integrated rollout of the technology platform and AMI.

As discussed below and in Chapter VI, several smart grid and technical platform investments will be implemented to improve the efficiency, reliability and operations of the grid:

- DA enables control over electrical power grid functions;
- ADMS supports the planning, management and monitoring of the grid based on a shared representation of the entire electric distribution network; and
- DERMS supports greater control of DER to support grid operations.

These technologies will support new grid capabilities including VVO, circuit optimization, fault location, isolation, and service restoration ("FLISR"). The Companies have already begun implementing some of these technology solutions.[21] These enhancements are necessary to improve reliability and prepare to operate a grid with increased DER penetrations.

As described in Chapter VII, AMI will support Grid Operations by providing:

- Granular data to improve operational visibility, as well as load and DER forecasts.
- A telecommunication network for smart meters, DA, and DER. The Companies will leverage the AMI telecommunications network to monitor and control distribution automation equipment, as well as to interface with DER smart inverters to support the DER management platform. It will be desirable to communicate with smart inverters through the smart meters using standard interfaces and communication protocols such that the smart meter acts as a gateway to the behind-the-meter DER.
- Integration with OMS for "last gasp" communications from a smart meter, pinging and other signals that can inform restoration activities. The Companies' affiliate, Central Maine

[21] Investments in Distribution Automation (Level I) and Telecommunications, have been included in the 2016 five-year CIP.

Power Company ("CMP") has linked legacy OMS to AMI and has begun to realize the benefits of this technology.

- End-of-line voltage sensors to enhance the performance of VVO. This closed-loop application will use end-of-line voltages to increase the accuracy and effectiveness of its algorithm.

Improving circuit data is a key gap that must be addressed to perform both Integrated System Planning and Grid Operations DSP functions. Accurate physical/electric circuit data is required for modeling circuit performance for DER interconnection, reliability assessments, and monitoring of operational performance. In addition, accurate SCADA/metered time-sequence data must be available for both modeling and for forecasting future customer usage and DER impacts.

Currently, we have many gaps in both physical/electric data and in SCADA/metered time-sequence data for our distribution circuits. Distribution circuit modeling currently requires the use of significant assumptions, including substituting default data for missing information.

Table II-2, Table II-3, and Table II-4 present a summary of the current status of level of automation for the Companies' substations, line reclosers, and distribution line automation devices. The data highlight the need for the acceleration of investments for system automation and telecommunications. The Companies recognize the need to improve our telecommunications and control capabilities as expeditiously as practical.

TABLE II-2: CURRENT SUBSTATION CAPABILITIES

Item	Company	Total Units	Non-Automated Units
Substations	NYSEG	471	220
	RG&E	170	48
Three-Phase Reclosers	NYSEG	595	483
	RG&E	255	73
Line Regulators (Full Replacement)	NYSEG	750	749
	RG&E	138	138
Line Regulators (Add Telecommunications)	NYSEG	450	450
	RG&E	120	120
Line Regulators (Upgrade Controller)	NYSEG	77	77
	RG&E	17	17
Capacitor Banks	NYSEG	240	210
	RG&E	289	289
Switches	NYSEG	2961	2908
	RG&E	1760	1760
Single-Phase Reclosers	NYSEG	20	20
	RG&E	50	50

TABLE II-3: CURRENT LINE RECLOSER CAPABILITIES

Company	1PH Automated	3PH Automated	Total 1PH Sites	Total 3PH Sites	1PH % Automated	3PH % Automated	Overall % Automated
NYSEG	6	111	71	564	9%	20%	18%
RG&E	1	177	1	221	100%	80%	80%

TABLE II-4: CURRENT DISTRIBUTION LINE AUTOMATION

Voltage Class (High Side Voltage)	Substations	Substations with Full Supervisory Control	Substations with Partial Supervisory Control	Substations without SCADA	Substations with SCADA
NYSEG					
69 kV	2	0	2	0	2
46 kV	84	3	30	51	33
34.5 kV	240	10	66	164	76
13.2 kV and Below	1	0	0	1	0
Total	**327**	**13**	**98**	**216**	**111**
RG&E					
345 kV	2	0	2	0	2
115 kV	33	8	21	4	29
35 kV	109	2	57	50	59
11 kV	16	0	11	5	11
4 kV	1	0	0	1	0
Total	**161**	**10**	**91**	**60**	**101**

1. DER Monitoring and Observability

Effective monitoring and observation of loads and DER, particularly in high DER penetration areas, will be an increasingly important Grid Operations capability. Integrating DER resources into grid management processes requires more comprehensive visibility into conditions throughout the distribution network. In order to achieve system-wide visibility and thereby enable greater penetrations of renewable DER, the Companies plan to build out the existing telecommunications network to enable visibility and control of DER throughout the distribution system. In addition, the AMI telecommunications infrastructure will be designed with the proper requirements to support monitoring and automation.

The Companies are improving remote monitoring and control on substations and circuits as a result of the existing Distribution Automation effort. Increasing SCADA penetration is needed to establish aggregated dispatch interface with DER through smart inverters and the Energy Management System ("EMS") and to dispatch output (e.g. kilowatts [kW], kvar, volts). SCADA telecommunications are also necessary to manage power flows.

TABLE II-5: DER MONITORING AND OBSERVABILITY

<table>
<tr><th>Near-term initiatives
(2017-2018)</th><th>DSP 1.0
(2019-2021)</th><th>DSP 2.0
(2022+)</th></tr>
<tr><td><u>Complete Base OMS</u>
Complete OMS with full distribution system SCADA plus geographic maps as the foundational system to build DER and market management functions.</td><td colspan="2"><u>Install Enhanced ADMS</u>
Complete geographic model for ADMS functionality, which will represent all customers, circuit sections, switches, and transformers to ECC operators on geographic circuit maps. The model will include line impedances for the distribution load flow model, and complete an accurate 3-phase model.</td></tr>
<tr><td><u>ESC AMI</u>
Install 12,000 Smart Meters and supporting communications for DA and grid optimization functions.</td><td colspan="2"><u>DER Resource Availability / Reserves</u>
Implement a process for tracking resource availability for outage scheduling and the following dispatching functions:
• DER Availability Reporting
• Characteristics Data Collection
• Applying Capacity Factor Assumptions & Reserves
• Measurement and Verification (“M&V”) of DER</td></tr>
<tr><td><u>ESC SCADA & ADMS</u>
Implement & enhance SCADA capabilities in the following areas:
• ADMS
• Distribution Automation</td><td colspan="2"><u>DER Metering & Verification</u>
Enhance SCADA capabilities for DER monitoring on all DER, and ensure voltage var & Control Mode are monitored.</td></tr>
</table>

Note: ESC activities are designated in a purple hue on all capability roadmaps.

Our Technology Platform (Chapter VI) proposes required incremental technology investments in SCADA and ADMS. Additional ADMS functionality will allow the Companies to monitor, automate, control, and optimize performance of the distribution grid. The ADMS technology project leverages and builds upon the existing Siemens Spectrum platform, including its complete distribution grid connectivity model. Specific ADMS-enabled functions include power flow optimization, Volt/var optimization, identification of all DER on operator maps by type with associated characteristics, detailed distribution system schematic maps, identification of resources within an operator-specified sub-circuit area, day-ahead and month-ahead planning tools, aggregated dispatching tools, and smart inverter management. The ADMS capabilities will make circuit map representations available to ECC operators that include all customers, circuit sections, switches, and transformers.

Grid Operations will also require distribution analysis capabilities for rapid analysis and configuration optimization to allow for real-time adjustments to optimize operation of the network and maintain optimal power flow. This process must include measures to ensure accuracy of data maintained for network analysis. The ADMS coding will include line impedances for the distribution load flow model and completion of a validated three-phase distribution model.

The Grid Operations function is contributing to the development of a standard EMS platform to be implemented in each ECC. This effort is expected to be complete in 2017, and includes development of foundational ADMS. It requires the development of outage scheduling, switching, and grid optimization processes in order to incorporate DER into the standard platform.

The Companies' Distribution Operator ("DO") role addresses outage requests, switching, and system restoration. This role will need to monitor and control DER, an increasingly complex responsibility with increasing DER penetration. As part of our DSIP development plans, the Companies are revising the competency exam and training requirements for its DO position to align with expanded demands that will be placed on operators.

2. DER Coordination and Control

The Companies require the capability to coordinate and control DER in order to respond to grid conditions when necessary to maintain reliability of the network. This requires adjustments to existing DER interface specifications, development of a DER database to track DER attributes, establishment of a more sophisticated DER dispatch function capable of dispatching aggregations of individual DER, and an update to our current emergency voltage reduction solution. This will be accomplished by making revisions to several existing systems, including integrated EMS, Distribution SCADA, OMS, GIS, Customer Care System ("CCS"), and Asset Management System ("AMS").

Maintaining this reliability will also require distribution substation automation, distribution line automation, and development of a DER master database. These capabilities will require new data and analytics capabilities including establishment of an aggregated dispatch interface with DER (smart inverters, EMS, etc.) to dispatch output (kW, kvar, volts, etc.) and to integrate these resources into a coordinated VVO application. The operator interface will need to be flexible enough to select resources based on type and location (circuit, bus, substation, stage of regulation, zone of protection, etc.), and to establishment an algorithm to optimize the use of varied DER (Photovoltaic solar ("PV"), wind, battery, demand response ("DR"), etc.) for dispatching on an hourly basis. A closed-loop VVO function will also be possible using select smart meters as end-of-line voltage sensors.

The coordination and control capability development efforts are presented in the following roadmap.

TABLE II-6: DER COORDINATION AND CONTROL

Near-term initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)

SCADA for DER

Develop statewide DER interface monitoring and control specifications, protocols, and operational forecasting methodologies.

Voltage Control / Flicker

Enable DER dispatch for voltage and var purposes.

Micro Grid Management / Islanding

Establish performance, power quality, interface, and control standards for Microgrids containing more than one customer and protect islands and equipment from damage.

Smart Inverters to Optimize Voltage & vars

Perform a proof-of-concept interface for integrating Smart Inverters into an envisioned ancillary services market.

Managing / Dispatching Aggregated Resources

Build a standard DER interface and aggregated dispatch tool, supported by a DER database, protocols that govern DER operations, and operation forecast techniques.

AMI (Integrate AMI with ECC)

Integrate HES with OMS throughout distribution system.

AMI (Integrate AMI with ECC for ESC Project)

Integrate HES with ADMS for 12,000 AMI ESC meters.

Resource Forecast

DER forecast for planned operations and unplanned events supported by:

- DER Master Database, DER displayed on EMS and GIS, DER included in load and resource forecasting, including season, month, week, and 1-day DER hourly forecast by area for outage planning, switching, and unplanned events.

Closed Loop Voltage Control & Power Flow Management

Implement closed loop voltage control and integrate in EMS, automate line regulator and capacitor controllers, and Incorporate AMI voltage sensors with alarms into EMS.

ADMS for the ESC

- Implement advanced distribution management system, including power flow model, for the ESC.
- Implement automation in the ESC for VVO, circuit optimization, and FLISR.

Real Time Load Transfers

- Use real-time load transfer capability to maximize grid efficiency and reliability.
- Automate all gang-operated tie and sectionalizing switches to maximize centralized switching & tying capability.
- Add distribution analysis (on-line load flow) capability for rapid analysis and configuration optimization

Manage Grid Assets

Use automation to optimize grid operation and to detect equipment alarms to allow:

- Real-time optimization of the grid utilizing all available resources
- Detection of controller alarms, open capacitor bank fuses, etc.
- Detection of DER availability or issues which grid operations may be dependent

Communications Infrastructure

- Extract greater efficiency and capability from capital projects.
- Vertical infrastructure (poles/towers) for wireless communications.
- Transmission fiber optic cables (add / re-build / re-conductor)
- Distribution fiber optic cables

Upgrade Protection for DER with Installed Controllers

Upgrade protection schemes to consider DER with installed device controllers that are capable of providing protection with SCADA.

As with DER Monitoring and Observability, DER Coordination and Control depends on the extension of SCADA and the implementation of the Siemens ADMS in high-DER penetration areas. The Companies must establish guidelines and identify dispatch limitations for each type of DER that can be communicated to DER owners and providers. It will be desirable to aggregate small DER and dispatch them for VVO, reserves, or to respond to other emergencies using smart meter capability with a standard interface for smart inverters. The ability to dispatch DER require schedules that specify their availability to be dispatched incorporating planned outages and their availability to be dispatched in response to unplanned outages. The ability to coordinate and control DER is directly related to the DA plan, as they work together to manage renewable/intermittent resources and to enable greater DER penetrations.

Dispatching procedures and protocols must change to reflect DER resources, which will comprise a growing share of the region's generation mix. The Companies have identified a number of capability improvement areas to reflect needed changes, including establishing a standard interface for aggregate resources, DER coordination processes, dispatch optimization algorithms, and voltage protocols.

- Standard Interface: A standard interface must include a DER database and a process to dispatch resources based on flexible selection criteria to allow for optimal DER selection based on specifications that are designed to provide adequate network support. Establishing a standard interface for dispatch of smaller DER utilizing smart meters is envisioned. The standard ADMS interface will control meter connect/disconnect for small DER and must be programmed for aggregated dispatch.
- DER Coordination Processes: A coordination process for DER to report availability will be required to ensure that when network analysis is performed, Grid Operations is aware of all available DER, and is able to make decisions regarding optimal power flow/contingencies.
- Dispatch Optimization Algorithms: Grid Operations will need to develop algorithms to optimize aggregated dispatch instructions based on a variety of resource limitations and hourly kW dispatch criteria. These algorithms would automatically dispatch numerous DER to maintain optimal power flow/network conditions.
- Voltage Protocols: Additional voltage protocols will be required to reflect the varied nature of grid resources, comprised of traditional utility-scale generation and various DER resources. For example, energy storage could be used to support load and maintain optimal voltage when needed.

3. Real-Time Distribution System Optimization

Real-time distribution system optimization refers to the goal of optimizing network facilities and DER on an integrated basis to respond to network conditions and to help restore power after outages. This process requires a complete analysis for optimization of the distribution system to effectively coordinate and control DER in high penetration areas. The system optimization algorithms should support optimization with respect to multiple criteria including reliability, costs (efficiency), and fuel mix. This requires the establishment of optimization protocols and the development of decision-support tools and associated systems.

The Real-Time Distribution System Optimization capability development efforts are presented in the following roadmap.

TABLE II-7: REAL-TIME DISTRIBUTION SYSTEM OPTIMIZATION

<table>
<tr><th>Near-term initiatives
(2017-2018)</th><th>DSP 1.0
(2019-2021)</th><th>DSP 2.0
(2022+)</th></tr>
<tr><td colspan="3">Alternative Settings for Reverse Power Flow & Circuit Configurations
Manage the grid under conditions of reverse power flow due to DER energy output. Includes alternative device settings, circuit switching, and on-line power flow analysis.</td></tr>
<tr><td colspan="3">Spectrum / ADMS
Implement ADMS power flow analysis solution, which includes on-line power flow analysis, switching/contingency analysis, circuit optimization, and distribution outage scheduling analysis.</td></tr>
<tr><td colspan="3">Level 1 Automation – Substation & 3-Phase Reclosers
Continue to automate substations and 3-Phase reclosers to increase visibility and control.</td></tr>
<tr><td colspan="3">Level 2 Automation – Regulator, Capacitor, and Switch
• Automate regulators and capacitors on circuits targeted for VVO
• Automate switches for circuit optimization and FLISR</td></tr>
<tr><td rowspan="2">ESC VVO / Closed Loop Voltage Control
Implement automation (Level 2), sensors, and DER controls for closed-loop VVO:
• Perform VVO pilot
• Automate regulators and capacitors on circuits targeted for VVO</td><td colspan="2">Level 3 Automation – 1 Phase Reclosers
Automate 1-Phase reclosers for further visibility, control, and sectionalizing capability</td></tr>
<tr><td colspan="2">System Wide VVO / Closed Loop Voltage Control
Implement automation, sensors, and DER controls for closed-loop VVO:
• Automate regulators and capacitors on circuits targeted for VVO
• Implement AMI interface to utilize smart meters as end-of-line voltage sensors.
• Incorporate DER in VVO scheme.</td></tr>
</table>

The Companies must develop tools and technologies to monitor and control real-time distribution power flow. Increasing SCADA availability through the distribution automation plan will help address this issue, as will the installation of alternative settings on regulating, protection equipment for reverse power flow and alternate circuit configurations, and ADMS implementation. For these efforts, the Companies will complete analyses that are required for optimization of the distribution system. The following section discusses specific near-term initiatives needed to develop real-time distribution system optimization capabilities.

4. T&D Resource Coordination

The T&D resource coordination capability establishes an interface definition between the DSP and the NYISO. This interface definition includes data requirements and mechanisms for aggregation of DER as well as the tools that are necessary to manage the collection of information from the distribution system and to share that data with the NYISO to support coordinated operations between transmission and distribution systems. The Companies are developing a master DER database that will be a compilation of all of the attributes of DER that are relevant for purposes of planning, managing and operating the grid, including attributes that are necessary for dispatching DER as part of the ADMS. This master DER database will establish the ability to track the availability of each DER for forecasting, for use in outage scheduling, and dispatching/interfacing with the NYISO. The coordination process must also accommodate the ability to dispatch DER in aggregate by operator-identified dispatch grouping criteria (e.g. located on the same circuit(s), bus(ses), transformer(s), station(s)). The system must be able to translate holistic hourly dispatch directives (e.g. “xx” MW at “zz” Station) into sub-instructions for each type of resource deployed (e.g. wind, solar, battery, DR, etc.) within the limits of the available resources and taking into account the recharge characteristics of each DER. New processes must be developed to support performance evaluation, measurement, and verification (“EM&V”) of DER.

The T&D Resource Coordination capability development efforts are presented in the following roadmap.

TABLE II-8: T&D RESOURCE COORDINATION

Near-term initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
	DSP & NYISO Network Management • Interface between the DSP and the NYISO for effective distribution network management • Develop Interface definition between the DSP and the NYISO, including data requirements and mechanisms for aggregation of DER.	
	DER Resource Tracking & Master Database • Capability to track resource availability for forecasting, outage scheduling, and dispatching / interfacing with the NYISO. • Develop a master DER database showing all resources, services, and capabilities incorporated into the ADMS for operating and dispatching within the market.	

DER are not currently used by the ECC to optimize the grid and interface with the NYISO. It is therefore necessary to define the interface for purposes of coordination between the DSP and the

NYISO, including data requirements and methods for aggregation of DER. T&D Coordination will also require collaboration to define information requirements and telecommunication protocols necessary to support coordination. Many of these issues will be addressed in the Supplemental DSIP. There are no near-term initiatives that contribute to T&D Resource Coordination, although we anticipate that statewide standards will be developed in the Supplemental DSIP.

5. Integration of Grid and Market Operations

Establishment of market mechanisms for distribution services is still in the conceptual stages. In the near term, New York's distribution utilities will be transacting with DER providers through NWA contracts. It is appropriate to begin to establish the foundation for more complex transactive arrangements in the future. The T&D Resource Coordination capability development activities will also support the Integration of Grid and Market Operations.

The Integration of Grid and Market Operations capability development efforts are presented in the following roadmap.

TABLE II-9: INTEGRATION OF GRID AND MARKET OPERATIONS

Near-term initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
DER Data Management A master DER database including geo-fields is required for day-ahead planning.		
Resource Availability / Reserves • DER availability reporting • DER characteristics collection (ramp rate, storage capacity, recovery rate and period, etc.) • DER capacity factor assumptions • DER reserves SOP	**Resource Availability / Reserves** (continued)	
Performance Testing & Specification for Voltage & var Requirements • Requirement for smart inverters • Specification of voltage and var capabilities for DER • Performance of voltage and var capability testing	**Performance Testing & Specification for Voltage & var Requirements** (continued)	

DER are currently not used by the ECC to optimize the grid. Moreover, distribution market operations are not currently defined. It is expected that progress in these areas will be made through the Supplemental DSIP process as stakeholders address DER EM&V as well as potential performance incentive and penalty mechanisms.

There is currently no distribution DER market operations role in the ECC. There are transmission market operation functions performed in coordination with the NYISO (e.g. resource availability scheduling, and day-ahead planning). Given the experience in operating within the NYISO marketplace, competencies exist for market operations, but new skills associated with the distribution market will need to be developed. Once the distribution market is defined, roles and responsibilities could be established to manage market operations.

C. Grid Operations Standards

The execution of each of these five Grid Operations' capabilities is supported by several sets of standards and monitoring and evaluation procedures needed to guarantee network reliability and stability as DER penetration grows, including DER monitoring and control standards, development of network reliability standards, and performance standards. These include:

- DER Monitoring and Control Standards: DER standards for monitor and control specifications are being developed through the Supplemental DSIP process. This includes developing standard control levels, SCADA monitoring, and control points (e.g. Remote Terminal Unit ("RTU") specifications or smart inverter interface specifications) for DER.
- Network Reliability Standards: Development of protocols that govern DER operations for network reliability and stability, including development of standard requirements that govern grid operator ability to control DER (e.g. voltage and var dispatch). These standards are important for distribution network management based on changes in load flow and the intermittent/dynamic nature of renewable DER.
- Performance Standards: There are a number of performance standards that must be developed to allow the Companies to monitor and control its growing breadth of resources. For example, the Companies must institute a DER performance auditing process (i.e. EM&V); including metrics, to ensure that DER performance validates specifications for network analysis.

In addition to these performance standards, the Companies must integrate smart meters and the OMS for outage and restoration sensing, incorporating smart meter data into OMS (e.g. for on/off events for outage prediction/restoration times). The Companies must also incorporate AMI voltage sensors into the EMS with alarms to provide enhanced accuracy and supplement the ADMS/network optimization. Voltage monitoring and VVO utilizing smart meters to monitor voltage and dispatch DER accordingly utilizing AMI are also needed.

D. Cyber Security and Communication of Network Data

The Companies' Corporate Security Program controls and protects information related to customers, employees, and the Companies' transmission and distribution infrastructure. The codified rules in Table II-10 address industry standards and best practices as documented by the National Institute of Standards and Technology, the SANS Institute, ISO 27000, and other industry standards. The Companies' information security professionals, specifically those responsible for implementing our Corporate Security Program, participate in industry working groups related to cyber security and the protection of customer and system data. Policies, procedures, and related documentation are reviewed and updated on a regular basis to ensure adherence and meet the intent of State and Federal regulations. A collection of existing cyber security rules that apply to the Companies appears in Table II-10 below.

TABLE II-10: CYBER SECURITY RULES

Rule	Description
Acceptable Use	Defines the acceptable use of electronic resources, electronic messaging, internet and email
Asset Management	Identifies a set of controls to be used to manage cyber assets based on their levels of sensitivity, value and criticality
Information/Data Classification	Identifies a set of controls to be used to classify information/data assets based on their levels of sensitivity, value and criticality
Access Management	Identifies a set of controls for the protection of corporate assets and processing facilities from unauthorized users and use
Third-Party Risk Management and the REV Review Process	Evaluates and determines risks of third parties based on the type of service provided or purchased and/ or data they are accessing, storing, processing and our transmitting to ensure that proper cyber security controls and data protections are in place
Exception Processing	Where resources (i.e. cost, time, system, process) to remediate processes, procedures, systems, applications, etc. that are not compliant with applicable policies, rules, standards or procedures significantly exceeds the risks of non-compliance, an exception may be granted by following this process
Teleworking/Telecommuting	Ensures that current employees are made aware and understand their roles and responsibilities for protecting the cyber infrastructure and associated assets when teleworking or telecommuting

Rule	Description
Human Resources Security	Establishes the awareness and understanding for potential and current employees and non-employees (contractors, vendors, contingent workers and temporary workers) of their roles and responsibilities for protecting the cyber-infrastructure and associated assets
Operations and Network Telecommunications	Identifies a set of technical measures and controls used to detect, prevent, respond and mitigate risks to the cyber infrastructure
System Acquisition, Development, and Maintenance	Identifies a set of controls to ensure that cyber security is an integral part of infrastructure information systems across the entire systems lifecycle
Incident Response and Management	Identifies a set of controls used to protect cyber infrastructure assets, as well as reputation, by developing and implementing an incident response infrastructure for quickly discovering an attack and then effectively containing the damage, eradicating the attackers' presence and restoring the integrity of the cyber infrastructure lifecycle
Background Checks	Identifies the criteria and procedures for background checks on contractors and contractor representatives who are expected to have regular access to company facilities, assets, and confidential data or computer systems

III. Integrated System Planning

A. Introduction and Overview

We are transforming our traditional distribution system planning function to a new “integrated system planning” function that will explicitly incorporate increasing penetrations of DER. The primary objectives of distribution system planning remain largely unchanged: to design the distribution network to provide reliable, quality and safe service, and to improve the resiliency of the network. However, the approach to planning, specific activities, and supporting data and tools will change dramatically.

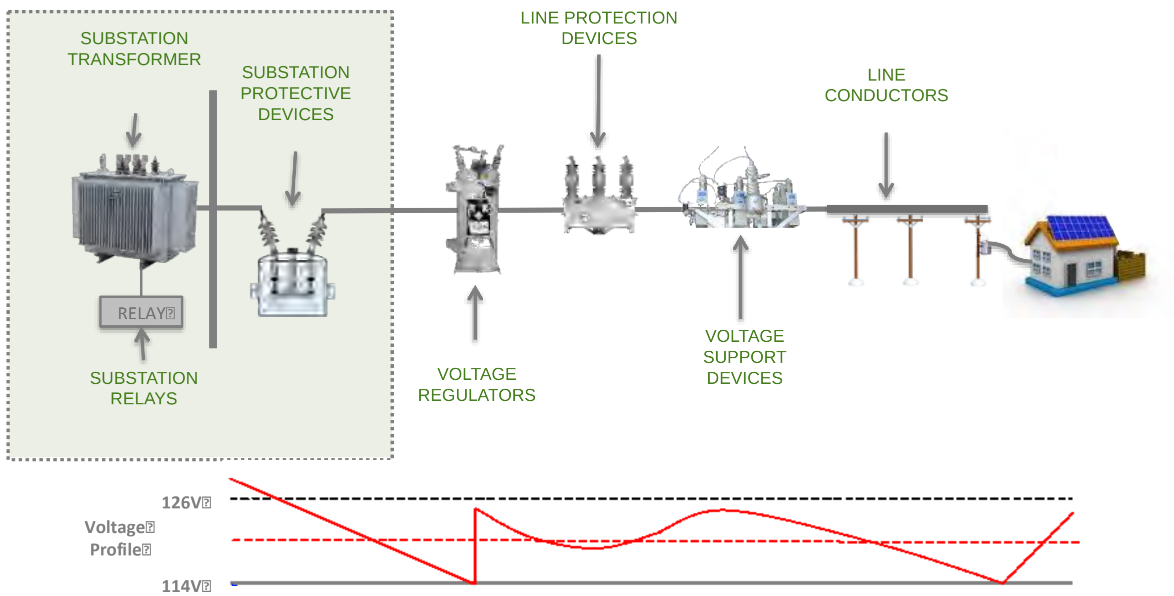
1. Traditional Distribution Planning Process

The current distribution planning approach reflects a distribution system that was designed to flow power primarily in one direction from the high-voltage transmission grid to end-use customers. Investment decisions to add or replace network facilities have been based on forecasted growth in customer loads and the need to replace equipment that was nearing the end of its useful life.

Distribution planning analyses have focused on whether the network had sufficient substation and circuit capacity, maintained proper voltage and power quality, and could respond with sufficient flexibility to respond to operational issues and support an efficient response to power outages. Complex distribution planning models assess the current and projected operating states of the electric distribution system with respect to recommended criteria and guidelines that have been established by the industry over decades and Company-specific planning standards that reflect the unique characteristics of the service area and our distribution network. Generally, our service areas are characterized by small cities surrounded by suburban housing and vast areas of low-density population living in rural communities. Accordingly, the existing planning and design criteria reflect a distribution system that is dominated by radial distribution with short three-phase circuits and long single-phase circuits designed to serve distributed loads.

A typical distribution system design is presented in Figure III-1.

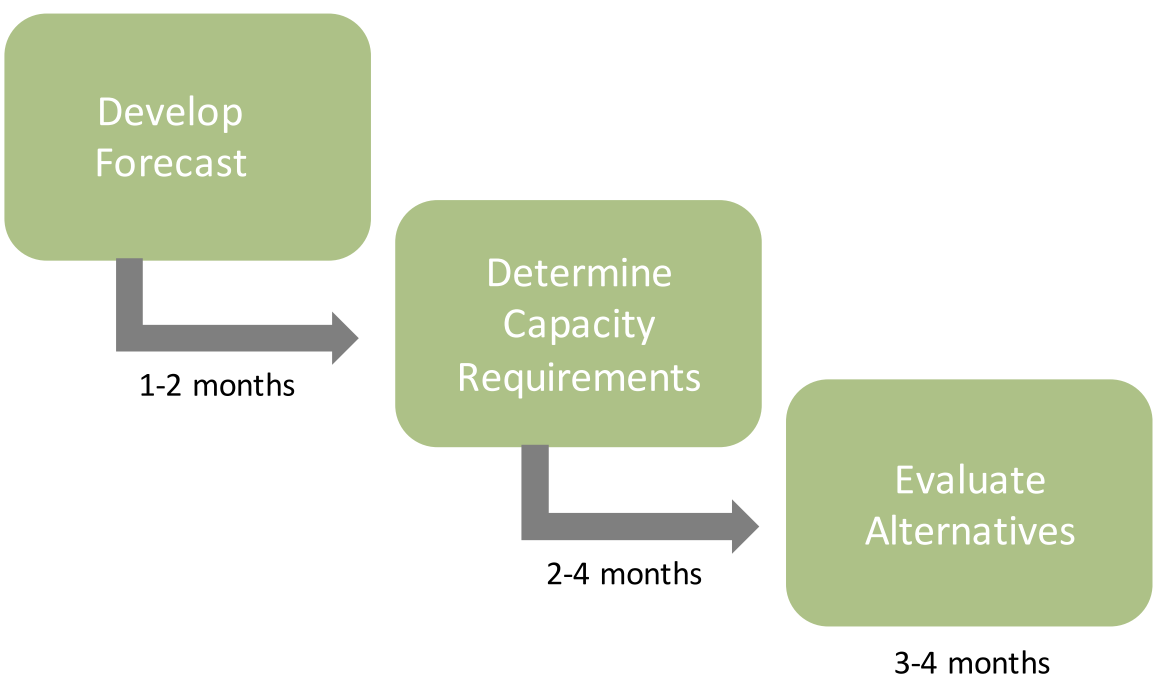
FIGURE III-1: TRADITIONAL DISTRIBUTION SYSTEM DESIGN



Source: ICF International

While the modeling is certainly complex, the distribution planning process has been relatively straightforward as shown in Figure III-2.

FIGURE III-2: TRADITIONAL ANNUAL DISTRIBUTION PLANNING CYCLE



The Companies, like most distribution utilities, have an annual planning cycle that corresponds to the annual budgeting process. The distribution planning process takes approximately 6-10 months. It begins with the load forecast and identifies anticipated distribution capacity and operating deficiencies, and applies the models to determine the most efficient mitigation plans to address projected deficiencies. Distribution planning analyses examine recent peak summer period experience and system stresses including operating conditions on substation transformer banks and other conditions. They require detailed modeling of the entire distribution system under both normal operating conditions and prescribed contingency conditions to evaluate system resiliency. In most cases, these studies identify low cost investments such as capacitor and regulator installations and voltage conversions solutions to resolve planning criteria violations.

2. *Implications of High DER Penetrations on the Distribution Planning Process*

The distribution planning process has served the Companies and our customers well for the past several decades, extending back to the post World War II economic expansion. The most significant changes in the electric industry have occurred in the generation and transmission sector and in the establishment of regional wholesale markets. With the recent growth in DER, the Companies must respond by transforming our distribution system planning approach. With low DER penetration, there has been little need to examine aggregate DER penetrations, impacts on the demand forecast, or the impact on circuit power flows. Distributed generation, in particular, introduces complexities attributable to two-way power flows and dispersed intermittent generation supply points on radial distribution systems originally designed only to serve loads. The larger distributed generation projects (>300 kW) have the most significant impact on planning because the Companies' radial system was neither designed nor configured to accommodate these projects located at disperse points throughout the network. Most of these projects will require their own detailed planning study in order to identify whether system reinforcements are required for interconnection.

A re-engineering of the distribution planning process is required in order to: (1) explicitly reflect the impact of DER on circuit load profiles used in planning studies, and (2) consider DER as a potential solution when making decisions related to the design of the network. Accordingly, we are redesigning our distribution planning process to achieve the following objectives:

- Incorporate DER into a new “Integrated System Planning” process to develop a platform for new energy products and services while assuring distribution system resiliency, reliability and safety;
- Provide planning results that indicate and encourage location of DER in the most beneficial locations on the distribution system;
- Improve DER interconnection studies by applying advanced modelling tools and approaches;
- Enhance demand and energy forecasting approaches to incorporate DER penetration;

- Incorporate DER into capital planning processes to identify areas where ("NWA[22] should be compared to traditional utility investments;
- Develop processes and methods to solicit, evaluate, and procure NWA where they are preferred to traditional utility investments; and
- Plan for a high DER penetration future by developing probabilistic planning tools and approaches.

Detailed load flow analyses will remain the fundamental tool for distribution planning. They are relied upon for compiling system information to specify the models, conduct all types of planning studies including evaluations that consider large load additions, and for performing interconnection studies for large generation projects. The validity of load flow study results will depend upon the granularity of and accuracy of system data, the accuracy of net load and DER forecasts, advances in modeling software and refinement of planning methods and supporting analyses. The Companies propose to update our GIS -based model to capture the physical asset and electrical data associated with existing DER and implement governance protocols to keep the GIS database current as new DER connects to the system. We are also repurposing the GIS data to serve as a central repository that will support both the Integrated System Planning and Grid Operations functions, thus eliminating duplication of effort required to maintain two separate models.

The new ISP process will also transition from an "annual" activity to an ongoing activity, with studies performed periodically throughout the year as required to process interconnection requests and to communicate beneficial locations, hosting capacity, and locational DER values (when adopted). The frequency of these updates will need to balance the effort required to perform them and their value to DER providers.

The quality of planning analyses will improve over the next several years as more granular data becomes available through network automation and other platform investments, and as utility planners gain experience understanding how DER performance (both new connections and the behavior of existing DER.) For example, the DER forecast of must reflect the various types and characteristics of DER (e.g. distributed generation, targeted energy efficiency, demand response, storage, or plug-in electric vehicles) throughout the network. The quality of the DER forecast should improve after the first few years as actual DER performance data is acquired, analyzed, and reflected in forecasting model parameters and common approaches are developed through the Supplemental DSIP process.

The transformation of the distribution planning function will be enabled by technology platform investments and associated systems that provide more granular information including load data enabled by AMI telecommunications, DER performance data, and distribution system

[22] An NWA is comprised of one or more third-party DER that comprise an integrated solution to a localized distribution reliability or system load issue that allows the utility to avoid or defer the need for a traditional utility investment.

performance data. As noted in Chapter II, a small percentage of the Companies' substations currently have SCADA which acquires real-time substation and circuit data. The Companies are proposing investments in addition to the existing automation plan in the approved rate plan that will accelerate acquisition of real-time substation and distribution circuit information to support grid operations and improve the quality of planning studies. Investments in data analytics will support several ISP processes including the ability to estimate hosting capacity by circuit, evaluate the performance of new storage technologies, forecast DER and net loads, and incorporate probabilistic approaches throughout the integrated system planning process. The Companies are also developing a geospatial DER database to track the location of DER by circuit that will support Grid Operations and Market Enablement as well as ISP functions.

B. The Integrated System Planning Process

This Initial DSIP also addresses the business process improvements required to provide baseline ISP capabilities. Several ISP processes and associated common Joint Utility approaches will be addressed in the Supplemental DSIP. For example, stakeholders participating in the Supplemental DSIP process will be addressing a common utility methodology to calculate hosting capacity by circuit. As common approaches and methods are developed through the Supplemental DSIP, we will integrate these findings into our planning methods.

The Companies' approach to the DSP "roadmap" has been to develop a clear vision of the desired "end-state", objectively assess our current capabilities relative to the end-state; and then identify technology investments and other activities (together, "enablers") that achieve the desired end-state capabilities. The ISP transformation is presented in Figure III-3.

FIGURE III-3: PATH TO THE ISP END-STATE

Current State		Enabling Investments and Initiatives		ISP End State
• Limited real-time system data • Planning methodologies and models do not explicitly reflect DER • Limited data that defines either utility facilities or DER • Deterministic planning methodologies and supporting tools • Planning models forced to rely on "rule of thumb" assumptions to accommodate missing data • Modelling requires significant level of manual intervention • Simple division-wide regression analysis for demand and energy load forecasting	+	• Technical platform & automation investments compile real-time substation and feeder data to support planning and operations • AMI collects premise data that reveals DER & system performance • Data quality initiatives enhance the accuracy of physical and electrical data represented in GIS • Advanced planning tools support more complex ISP analyses • Increased collaboration with 3rd contribute to better data inputs and model specifications	=	• Perform planning studies based on granular system and premise data integrated within in a completely specified and validated GIS database • Automate planning processes for increased efficiency • Advanced planning tools and associated competency development • Reliable and more granular forecasts of demand and DER • DER and NWAs are explicitly considered as options effective option to optimize system & feeder design & operations

The future ISP process requires enhancements to data, modeling capabilities, and planning processes to improve forecasts and planning studies that will support integration of DER solutions into electric system planning and provide system data to market participants.

Existing system and asset data is insufficient in scope, granularity and quality to meet the future needs of the ISP function. The Companies propose investing in technologies and methods that will expand the acquisition of system data and customer metered data, govern and improve quality and leverage the analytical tools required to apply new planning methodologies. These various gaps are being addressed in parallel to achieve valid results and produce valid and reliable DSP system data necessary to support the ISP core function.

ISP Requirements

- **Data** – Both physical/electrical (wire sizes, phase spacing, equipment impedances, capacities, and field settings) and time-sequence (peak load, minimum load, load profiles).
- **Modeling** – Engineering calculations of impedances, capacities, and settings in per-unit, customer and DER load characteristics.
- **Engineering Study Processes** – Forecasts of load, DER and system changes – e.g. reliability, hosting capacity, interconnections, system efficiency.

The Companies' are already considering DER as an alternative solution to traditional utility investments with the development of two Requests for Proposals ("RFP") for NWA. These two potential NWA projects provide the first opportunity for the Companies to draft, execute, and administer a new form of contract with the DER providers of non-utility solutions. While developing reliable methodologies, tools, and data[23], the Companies have been assessing the provision of information and insights to DER providers. Although much work remains to be done, the Companies have begun to perform analyses required to identify and communicate beneficial locations and insightful information. In the future, we anticipate that beneficial locations will encompass locations amenable to interconnections, and areas where DER can provide distribution system relief and/or system efficiency. Locational values will send the appropriate price signals to DER developers. In the interim, the Companies are reluctant to publicly provide information to third parties until we are reasonably confident in the quality of the data and results and can present them with sufficient confidence so that DER providers can rely on them for decision-making. We expect that our investments in methodologies, data, and tools described in this DSIP will steadily improve over the next few years enabling us to provide increasing amounts of insightful information to third parties.

The Companies provide current results of our beneficial locations analysis in the Initial DSIP as Appendix B. Due in the lack of sufficient data on the vast majority of circuits, the Companies' are not able to provide initial capacity results at this time.

While the Companies have great confidence in our forecast of demand and energy at the corporate and division level (i.e. for NYSEG and RG&E), we have not yet developed a forecast constrained by DER penetration at the substation or circuit level.[24] The Companies are working expeditiously to validate the location and capacity of connected DG to serve as the appropriate "cast-off" point for a DER forecast. We are also developing advanced DER database capabilities to support a robust DER forecast methodology.

Our "end-state" ISP process, based on current DSIP requirements, is presented in Figure III-4.

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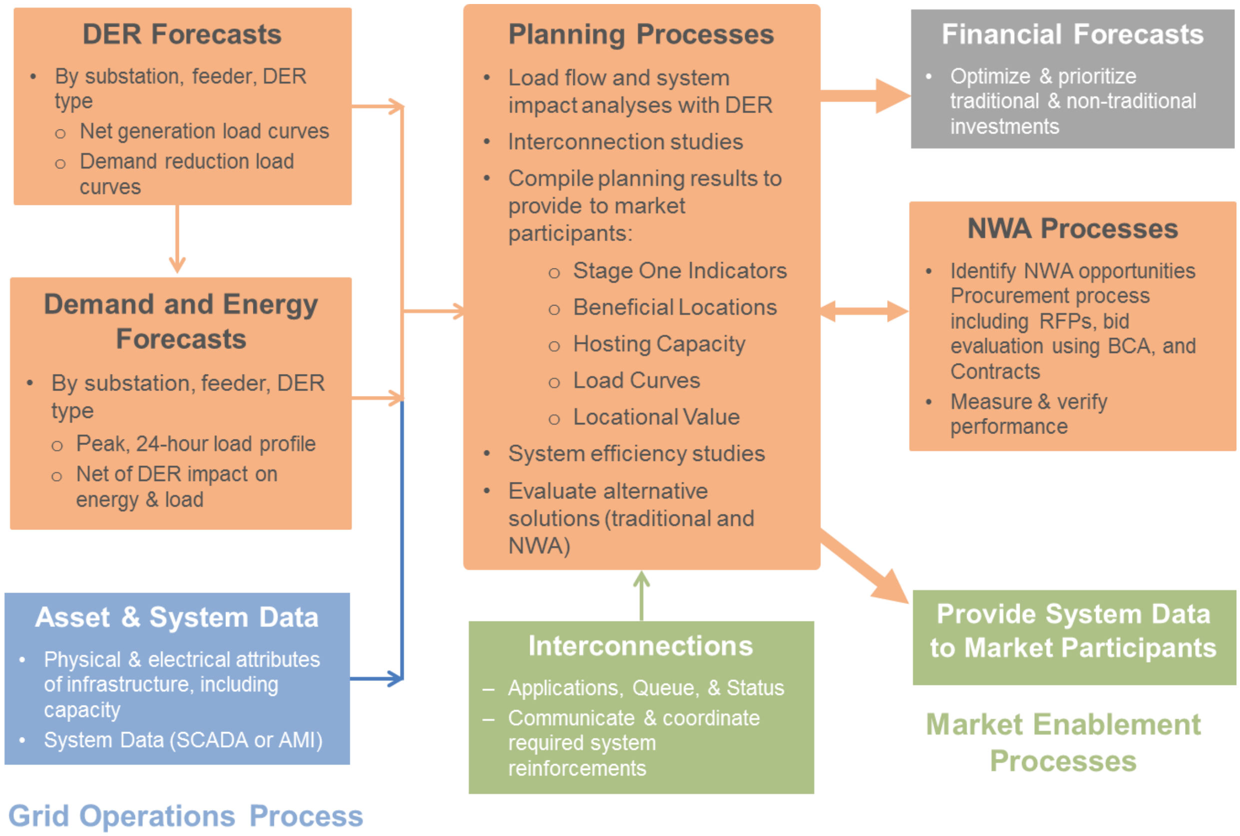
[23] This is consistent with the guidance provided in the DSIP Order: "The first phase will require the utilities to provide a base level of data, including information related to forecasts, planned investments, and operating systems, and a description of their system planning practices in an Initial DSIP filing. These Initial DSIPs will identify the limitations of current utility operations and the tools that can and should be developed to reliably operate a distribution system with high DER penetration levels. Attachment 1, pages 3-4.

[24] A division is defined as a major operating center within a company. The Companies submit sales forecast data to the Commission at the division level.

FIGURE III-4: INTEGRATED SYSTEM PLANNING PROCESSES



C. Capability Enhancements

The Companies are developing capabilities in six distinct areas in order to perform ISP functions that accommodate high DER penetrations:

(1) **Integrated System Planning with DER:** *redesign the distribution planning process (and supporting models) to reflect connected DER and the potential impacts of new DER, utility-owned storage as a grid asset (i.e. not on a customer premises), and consideration of micro grids;*[25]

(2) **Beneficial Locations, Hosting Capacity, and Locational DER Value:** (a) *identify high-priority locations where DER could provide distribution system relief, (b) calculate "hosting capacity" at the distribution substation and circuit level, and (c) estimate the locational value of DER to the distribution network;*

[25] A microgrid is a local energy grid with the ability to disconnect from the utility distribution system and operate autonomously.

(3) **Demand and Energy Forecasting with DER:** *enhance demand and energy forecasting methodologies and tools to incorporate the impact of DER on the baseline demand and energy forecasts and produce forecasts at a more detailed level (e.g. at the substation or circuit level[26]);*

(4) **Capital Planning with DER:** *incorporate the impact of DER, including the potential for NWA, into the development of the annual capital forecast;*

(5) **Procurement of Non-Wires Alternatives:** *(a) identify, and evaluate NWA opportunities, and (b) procure and manage NWA-related DER solutions; and*

(6) **Probabilistic Integrated System Planning:** *define and implement probabilistic and scenario-based planning techniques that capture uncertainties related to DER penetration and performance.*

Each of these capabilities will be addressed in detail in the remainder of this chapter. A brief description of each and the Companies' current capabilities are presented in the following table.

TABLE III-1: INTEGRATED SYSTEM PLANNING: CURRENT CAPABILITIES

Capability	DSP Requirements	Current Status
1. Integrated System Planning with DER	• Integrate CYME upgrade to reflect DER performance in load flow analyses, including interconnection studies • Consider DER as a potential capacity solution • Finalize updated planning criteria • Revise planning criteria to accommodate DER	• Load flow analyses based on available utility asset and system data (excludes DER) • Distribution planning does not consider DER as a capacity solution • Perform interconnection studies that identify necessary system reinforcements to connect them
2. Beneficial Locations, Hosting Capacity, and Locational DER Value	• Complete NYSEG/RGE Distributed Interconnection Guide Map – areas where DER are not easily accommodated on the distribution system • Refine methodology for identifying beneficial locations • Customize and apply hosting capacity methodology recommended in the Supplemental DSIP • Locational DER Value will be addressed REV proceedings	• NYSEG/RGE Distributed Interconnection Guide Map completed on June 1, 2016 • Interim beneficial locations based upon percentage rating criteria for substation transformers and circuits • A valid and reliable forecast of hosting capacity by substation or circuit does not exist.

[26] A distribution substation is connected to the transmission system and lowers the voltage level. The circuit (or "circuit") transmits power from the distribution substation to a load area where it is then connected through service transformers to circuits that deliver power to customer premises.

Capability	DSP Requirements	Current Status
3. Demand and Energy Forecasting with DER	• Develop valid methodology to forecast DER at a granular level • Refine and apply methodology to reflect DER forecast in the demand and energy forecast	• Validating the connected DER data base • Preliminary demand and energy forecast by Division (i.e. NYSEG and RG&E) • Forecasting of DER is completed at a corporate level
4. Capital Planning with DER	• Describe the process used to identify potential NWA projects • Propose an improved screening process • Explain how the Companies will maximize the integration of DER and avoid or defer traditional investments	• Identified seven additional potential projects that may be amenable to NWA that are included in the DSIP • Working with Joint Utilities and Stakeholders through the Supplemental DSIP process to define common suitability criteria, enhancing the previous "screening process"
5. Procurement of Non-Wires Alternatives	• Apply BCA methodology to NWA proposals • Refine and update BCA handbook as necessary data becomes available	• RFP process has been applied to one NWA and a second RFP is pending • NWA Procurement and EM&V approaches will be tested with initial NWA • BCA Handbook filed at the same time as this Initial DSIP filing; procedures for applying the BCA under development • BCA has not yet been applied to final NWA portfolios
6. Probabilistic Integrated System Planning	• Not addressed in Initial DSIP	• Probabilistic distribution planning is not required at this time and additional system data will be required to support these analyses • Methodology to be discussed in Supplemental DSIP

As noted with respect to the procurement of NWA, the Companies have filed their BCA Handbook on June 30, 2016.

1. ISP with DER

a) <u>Roadmap and Near-Term Initiatives</u>

As shown in the following roadmap, accurately reflecting the impact of connected DER on system planning studies requires investments in new modeling technologies, validation of existing databases, and training for distribution system planners on the use of new modeling tools. These new capabilities will be tested as part of the ESC project.

TABLE III-2: INTEGRATED SYSTEM PLANNING WITH DER

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Upgrade CYME Modeling Capabilities Integrate new CYME modules, and automate the modeling of DER and each Distribution Circuit.		
Validate Connected DER Validate information that defines connected DER for modeling purposes and update the DER Database.		
Enhance Quality of System Data for High DER Penetration Circuits Obtain valid system data and implement a data governance plan: ISP currently relies on limited availability of actual Physical/Electric and SCADA/Metered data on the Distribution System, requiring reliance on assumptions and default data.		
Incorporate DER into Load Flow Methodologies Revise ISP modeling methodologies and update Distribution Planning Criteria to accommodate high DER penetrations.	**Incorporate Grid Storage and Microgrids into ISP Processes** Revise ISP Processes and Load Flow methodologies.	
Procure Analytics Software Estimating Hosting Capacity and performing probabilistic planning analyses will require new software and/or upgrades to the current software. Vendors are currently developing software to meet future industry requirements.		
Competency Development Train Distribution Planning Engineers to utilize upgraded software tool to execute expanded DSP modeling and reporting responsibilities.		
ESC Integrated Systems Plan Enhance quality of system data and develop a DER and circuit forecast for the 14 circuits in the ESC, develop an Integrated System Plan and determine Hosting Capacity; communicating results in a heat map.		

The Companies utilize CYME[27] for distribution planning analyses. CYME is a suite of software tools that allow planners to simulate existing conditions on distribution circuits and predict the effects of changes in load. The Companies are implementing one of these tools, the CYME Gateway solution, and additional CYME modules to improve ISP planning processes. These CYME capabilities require accurate data for connected DER and distribution system flows.

[27] CYME is the trademark name of a suite of power engineering software tools offered by Eaton Corporation.

As noted in the roadmap, the ESC will test certain ISP capabilities (e.g. including assessments of the impact of DER on the system, determining DER hosting capacity). A DER Developer Portal will share this value-added data with third parties to support DER market penetration and policy goals.

One of the important applications of the ISP process is the performance of interconnection studies, particularly for interconnection requests from large generation projects and for smaller generation projects on circuits that are operating near or at hosting capacity limits. The new ISP process and availability of more granular data will improve the quality of these interconnection studies. Improvements to the overall interconnection process are discussed in Chapter IV.

b) Updates to Distribution Planning Criteria

The Companies rely on a set of criteria to drive decisions that affect the design of the network. These criteria ensure that the network will meet reliability, power quality, safety and other established service quality attributes. If these criteria might otherwise no longer be met in any part of the system, it requires that a system improvement is necessary. New projects are evaluated and prioritized based on their impact on system criteria with some criteria having greater weight (e.g. addressing safety concerns) depending on the particular circumstances.

The ISP team has reviewed the existing distribution planning criteria and determined that new criteria will be needed to address DER output and energy profiles and other considerations related to incorporating DER into the ISP process. Updates to the Companies' distribution planning criteria are provided in Appendix C.

2. *Beneficial Locations, Hosting Capacity, and Locational DER Value*

a) Roadmap and Near-Term Initiatives

"Beneficial locations" are locations based on specified substations or circuits where DER may provide value to the distribution network from new infrastructure deferral, system reliability, and/or system efficiency benefits. Beneficial locations may also refer to locations that provide value in wholesale markets as indicated by wholesale market prices when they become available at a more granular locational level than are currently available.

The ISP function is responsible for estimating available hosting capacity at the substation or circuit level and for calculating and publishing the locational value of DER at various points throughout the Companies' service area. Hosting capacity and Stage 1 indicators can be used to provide DER developers with a better understanding of less favorable locations for DER. The Companies are working with other utilities and stakeholders as part of the Supplemental DSIP process to develop a common methodology for hosting capacity. The locational value of DER will be addressed in the next stage after further policy guidance is provided.

The roadmap to identify beneficial locations and calculate hosting capacity is presented below.

TABLE III-3: BENEFICIAL LOCATIONS, HOSTING CAPACITY, AND LOCATIONAL DER VALUE

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Beneficial Locations Identify locations where DER would potentially defer or avoid infrastructure investments or provide reliability or operational benefits.		
Distributed Interconnection Guide Map Areas where DER have a greater likelihood on not being easily accommodated on the distribution system		
Common JU Hosting Capacity Methodology Work with the Joint Utilities and Stakeholders on a Common Hosting Capacity methodology as part of Supplemental DSIP.	**Estimate Distribution Substation & Circuit Hosting Capacity** Implement the agreed-upon methodology and establish an update procedure.	
Interim Substation & Circuit Hosting Capacity Calculation Methodology Continue efforts to develop and apply a valid interim hosting capacity methodology.		
Portal – Provision of data to Market Participants - High DG penetration areas Once the JU Supplemental Hosting Capacity methodology is determined, first assess those circuits with high levels of DER penetration for Hosting Capacity, and post these on maps on a web-based portal. Provide basic system data	**Portal – Provision of data to Market Participants - System wide** As improved circuit data becomes available, assess all circuits on our system, and post this on maps on the web. Provide basic system data.	
	Calculate & Share Distribution Locational Value Work with the Joint Utilities, NYISO, & Stakeholders to develop a common methodology for more granular locational marginal pricing.	

Through a recently-appointed interconnections "Ombudsman," the Companies are working to address challenges related to management of a growing interconnections queue throughout New York. The Stage 1 indicators are maps that identify areas where DER are not easily accommodated on the distribution system. This can be used to aid customers and developers on locations to avoid for large (greater than 300kW) DER systems due to the potential for high interconnection costs.

The Companies are severely constrained in their ability to produce valid hosting capacity results at this time due to the lack of granular system data on the overwhelming majority of our approximately 2,000 circuits. This gap, as further discussed below, is being addressed through technology projects described in Chapters VI (SCADA, DA, ADMS and other technology projects) and VII (AMI).

b) Beneficial Locations

As initial indicators of beneficial locations, the Companies have reviewed historical loading information on all distribution substation transformers and distribution circuits. Table B-1, Table B-2, Table B-3, and Table B-4 in Appendix B list specific areas in the Companies footprint where there is an impending or foreseeable delivery infrastructure upgrade need and thus DER would have more immediate delivery infrastructure avoidance value. Table B-1 and Table B-2 show transformers with a "percentage rating" of 80% or greater. The transformer "percentage rating" was calculated by dividing the 2011-2015 five-year average summer peak load by the transformer MVA rating. The results include the service characteristics (name, location,) of 45 transformers (6.6% of all transformers) with a percentage rating of 80% or greater. Table B-3 and Table B-4 show circuits with a percentage rating of 80% or greater. The circuit "percentage rating" was calculated by dividing the 2015 peak load by the circuit Mega-Volt Ampere ("MVA") rating. The results include the service characteristics (name, location) of 102 circuits (6.0% of all distribution circuits) with a percentage rating of 80% or greater. Transformers and circuits below the 80% percentage threshold rating are not included since they have no delivery infrastructure need for "years to come" which has been estimated to be at least greater than ten years. The Companies view the identification of these substations and circuits as valid information at this time, in advance of more sophisticated analyses that will leverage the future availability of more granular system and load data as well as other upgrades to our analytical capabilities.

c) Hosting Capacity

The New York utilities have adopted the following definition for hosting capacity[28]:

> *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 is location dependent, circuit and/or substation specific and time varying. Currently, most hosting capacity studies focus primarily on the impacts of PV on utility distribution

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[28] "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State", Energy Power Research Institute, June 2016. Page 2.

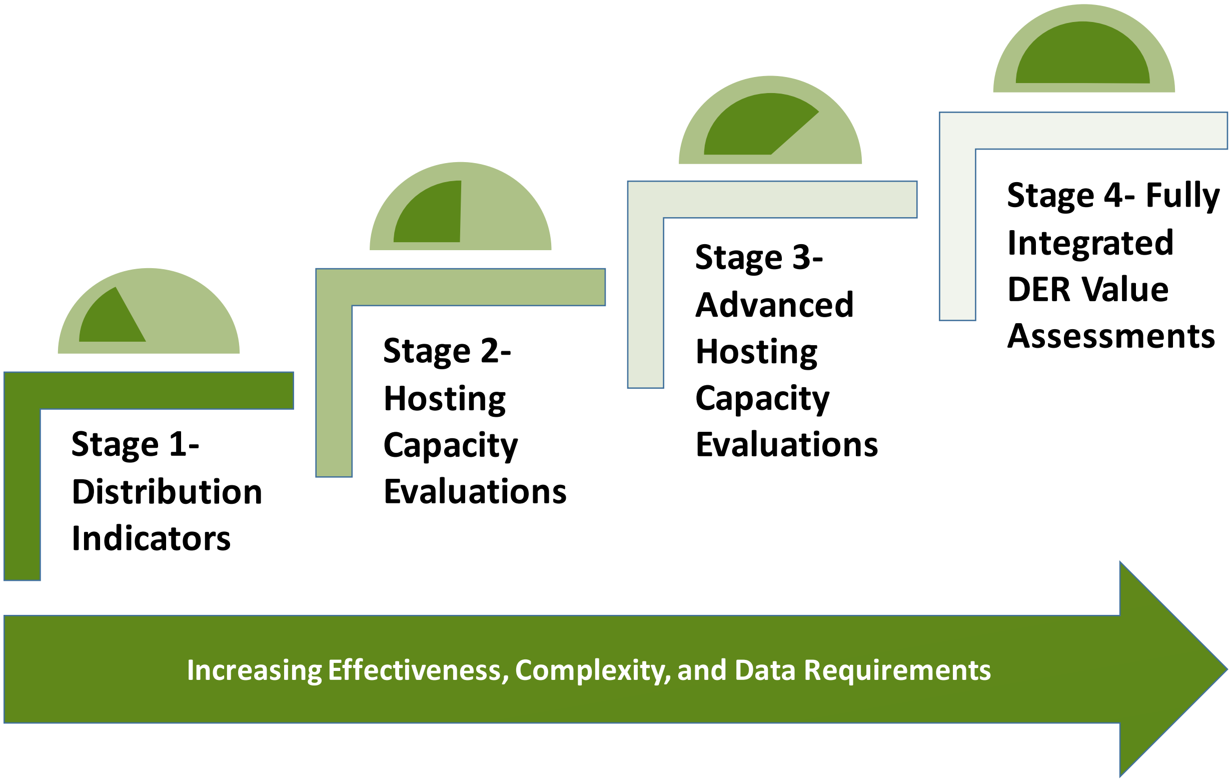
systems with the baseline requirements that the cumulative impacts should not violate voltage, thermal, power quality, reliability and other quality of service attributes. Estimating hosting capacity is complex and depends on many factors including whether or not DER is controllable, the number of existing DER installations and their variability in size, the profile of all of the DER currently located on the circuit, and the specific points along the circuit where DER are located, including the size of the DER at the ends of circuits.[29] Given these many factors, hosting capacity is properly expressed as a range, rather than as a single point estimate. There is also the practical consideration of how frequently to update and communicate estimates of hosting capacity by substation and circuit given that the inputs to the calculation change as new DER and load are connected.

An immediate priority of the Supplemental DSIP is acceptance of a common methodology that the utilities can apply to calculate hosting capacity. This effort is being supported by a White Paper prepared by the Electric Power Research Institute ("EPRI"), entitled, "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State."[30] EPRI has developed the four-stage roadmap in Figure III-5.

[29] When calculating hosting capacity, it may be appropriate to reflect certain DER projects that technically remain in the interconnection queue but are in the advanced stage of development and certain to be interconnected.

[30] "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State", Energy Power Research Institute, June 2016. Page 2.

FIGURE III-5: FOUR-STAGE ROADMAP



Source: Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State", Energy Power Research Institute, June 2016. Page 2.

The Supplemental DSIP will also examine whether it will be possible to increase hosting capacity on a circuit by enhancing the ISP process in the future.[31] The Companies' Flexible Interconnect Capacity Solution Demonstration Project, discussed in Chapter V, is an example of one approach which may achieve this objective. The DSIP Guidance encourages the expansion of existing or proposed new demonstration projects to study this issue. The Supplemental DSIP will also consider common approaches that utilities could use when requested by developers to upgrade circuits to support increased DER (vs. expansion for reliability purposes) and cost recovery mechanisms to support such expansions.

As noted above, the Companies have been assessing whether it is possible to develop an interim approach to hosting capacity that would produce valid and reliable results that could be relied on for investment purposes by the Companies and DER developers. This has been challenging because estimating hosting capacity requires modeling of an entire distribution network, populated with reasonably accurate load profiles and other data. No reliable results have been yet to be determined. Efforts to model hosting capacity are continuing and the Companies' approach will be reassessed as Supplemental DSIP discussions start to produce results.

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[31] Final DSIP Order, p. 45.

This challenge applies to efforts to produce interim estimates and does not relate to the Companies' efforts to develop the data and models to produce valid integrated system planning results by the end of the Initial DSIP period.

3. Demand and Energy Forecasting with DER

a) Roadmap and Near-Term Initiatives

The Companies have historically reflected DER (e.g. energy efficiency, demand response, and the impact of rooftop solar and other customer-owned generation or storage) in demand and energy forecasts by assuming that past DER are captured in the econometric methodology and subtracting an estimate of the impact of future demand-side programs. This net forecasting methodology has been adequate for relatively modest DER penetrations but needs to be revised to reflect higher DER penetrations and the emerging need to forecast any DER at a circuit or substation level to support ISP analyses. Thus, more complex future modelling approaches must be expanded to consider both customer demand and energy, in addition to DER supply and energy forecasts. This approach will ultimately lead to a more comprehensive understanding of the impacts of each DER on the distribution system and energy sales forecasts.

Forecasting DER that is offered by third parties presents unique challenges as compared to forecasting DER resulting from utility or NYSERDA programs. These challenges relate to the design of a forecasting methodology and specification of key assumptions that will drive the results. For example, customer decisions to connect DER are driven by economic and other considerations. The important economic assumptions relate to the amount of compensation that will be provided DER owners for the energy they deliver to the grid and for any other value that merits compensation.[32] The economic parity of DER as compared to supply service will depend on market conditions that are beyond the control of all stakeholders, including fuel prices, tax policies, government incentives and equipment cost trends. The receptiveness of customers to third-party offerings is also a source of uncertainty although experience over the next few years will help inform this relationship.

The roadmap to perform demand and energy forecasts that reflect DER is presented Table III-4.

[32] The Companies asked solar developers during three outreach conference calls whether they would be able to provide information regarding their forecasts that would inform the Companies' DER forecast. Developers indicated that they are not in a position to provide such information until there is an enhanced definition regarding future compensation to DER, including locational value.

TABLE III-4: DEMAND AND ENERGY FORECASTING WITH DER

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Maintain DER Database The DER Database will provide information that will support quantitative forecasting techniques		
DER Penetration Forecasting Develop initial methods to forecast DER penetration by technology type, refining the methodology and updating parameter estimates as more data becomes available.		
Interim Demand and Energy & DER Forecast Methodology Develop an interim methodology to support forecasts in advance of a methodology that relies on granular system and meter data.		
	Demand Energy & DER Advanced Forecast Methodology Derive and refine methodologies that leverage available system, customer, and DER data (including SCADA and AMI) to produce valid forecasts of DER and demand and energy (net of DER) at a granular level (e.g. substation and/or circuit)	

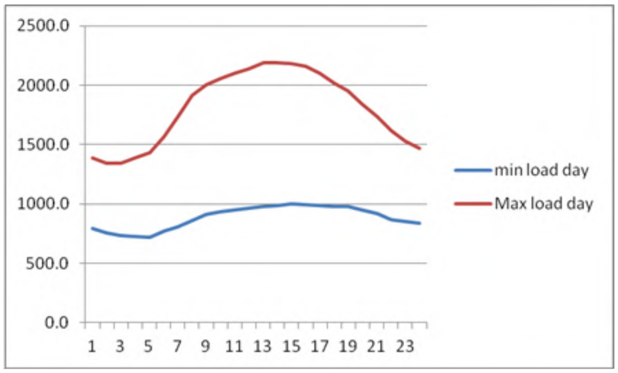
b) Demand and Energy Forecast

The Companies produce an annual forecast of demand and energy for NYSEG and RG&E divisions, by county within each division, and further disaggregated by customer class (e.g. Residential, Commercial, Industrial, Municipal, Lighting, etc.). This forecast supports a diverse set of regulatory and financial purposes. This high-level forecast employs class-specific econometric models and forecast assumptions regarding economic growth, prices and other determining factors that are relevant to each customer class. The econometric models incorporate historical weather as measured by heating and cooling degree-days and produce energy forecasts that assume “normal” weather based on the most recent 10-year average conditions. The number of customers and use-per-customer are estimated separately for the residential and commercial classes. An adjustment is made to account for distribution line losses. Load shape forecasts are developed for each customer class based on historical daily, monthly, and seasonal and monthly load data.

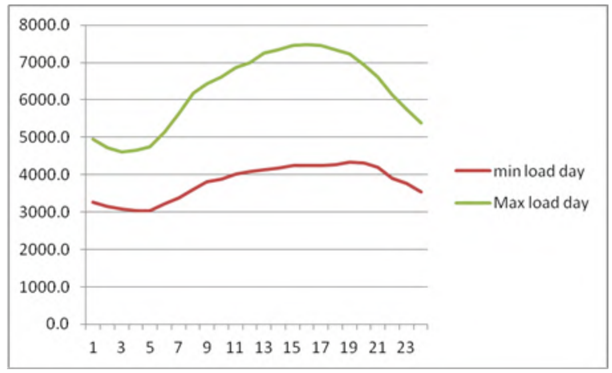
A considerably more granular forecast at the substation and circuit level is required to support new ISP responsibilities. The Companies have not yet produced a valid and reliable forecast of demand and energy at the substation and circuit level due to insufficient data. However, the Companies have developed a “Distribution Analysis Portal” that produces an estimated circuit load profile for approximately 70% of our circuits. This tool also allows for the manual extraction of peak day and minimum load day curves. These estimates will become more reliable as we collect more granular circuit demand information. New models will be developed and validated when sufficient data exist. Sample peak day and minimum load day estimated curves for two circuits are illustrated in Figure III-6: Sample Estimated Peak-Day and Minimum Load-Day Curves, below.

FIGURE III-6: SAMPLE ESTIMATED PEAK-DAY AND MINIMUM LOAD-DAY CURVES

Circuit A



Circuit B



c) <u>DER Forecast</u>

The Companies have not produced a disaggregated forecast of DER at this time. Factors such as hosting capacity that would constrain regional DER forecasts down to the substation and circuit level need to be developed. In the interim, we are compiling, validating and storing data on connected DER to create a valid GIS based DER database. This data will be essential to develop a valid DER forecast methodology, estimate the parameters, specify assumptions that drive the forecast, and will likely serve as the “cast-off” point for annual updates of the DER forecast.

The Companies anticipate focusing their attention on econometric modeling techniques because decisions to connect DER are driven by economic factors as well as by engineering and other factors. Econometric models require data to estimate model parameters and forecasts of “explanatory” variables to produce the DER forecast. The Companies will be collecting customer usage, DER performance, and other data to support this effort. The validity of econometric models and the resulting forecasts will improve each year as the historical data set expands.

d) <u>Demand and Energy Forecast with DER</u>

The Companies will be able to reflect DER in the demand and energy forecast after we are able to develop a valid and reliable DER forecast at a corresponding level of granularity to the demand and energy forecast without DER.

4. Capital Planning with DER

a) <u>Existing Capital Planning Process</u>

The Investment Planning group prepares the plan with input from our Finance group egarding overall investment levels ("top-down") and input from each area of the Companies that plans, manages, or delivers projects ("bottom-up").[33] The CIP is designed to advance the Companies' strategic directives subject to overall spending guidance for each year and prioritization guidance.[34] The planning process starts with the bottom-line level of capital investment for each business line. The Investment Planning group prepares the detailed and prioritized list of projects and annualized cash flows of both active and newly proposed projects.

The Company-specific Distribution line-of-business plans reflect the current distribution planning criteria, discussed above in this chapter. The plans also reflect the Companies' Asset Management program with respect to the need for replacement of existing infrastructure in order to maintain safe and reliable customer service in an environmentally responsive manner. Input may also be received from Distribution Operations and Maintenance. This analysis provides a systematic, sustainable and coordinated effort to optimally manage the life cycles of assets and their associated performance, risks and expenditures.

The electric distribution business, which is most relevant with regard to the DSIP and for consideration of NWA, categorizes projects among six groups:

(1) **Mandatory:** statutory and regulatory compliance projects such as highway relocations; industrial, commercial, and residential line extensions; service connections; storm restoration and street lighting projects.

(2) **System Capacity**: projects to ensure the system has sufficient capacity to meet the demands of customers as distribution transformers or circuit ratings increase.

(3) **Asset condition**: projects and programs necessary to replace assets based on health, obsolescence and their anticipated end of life, such as batteries, breakers, insulators.

(4) **Reliability**: projects necessary to maintain the continuity and quality of service to customers such as the "red circuit program" based in worst performer circuits/circuits.

(5) **Efficiency**: projects and programs that are focused on improving the delivery of energy or business processes such as automation.

(6) **Strategic**: projects that address corporate strategic direction such as smart grid projects.

[33] The bottom-up forecast reflects input from each of the Companies' 13 divisions.

[34] Project prioritization is based on the "Iberdrola USA Capital Investment Prioritization Strategy". See page 31 of the Companies' 2016 CIP.

The final CIP is reviewed by a team of senior executives to verify and validate that the prioritization is appropriate.

b) Changes to the Current Capital Planning Process to Incorporate NWA

The capital planning process has been changed to consider the potential impact of NWA. The Distribution Planning group will apply a set of "suitability criteria" to identify potential distribution system NWA projects which may be amenable to NWA.[35,36] These criteria are being refined as part of the Supplemental DSIP process consistent with direction that has been provided by the Commission, and it is expected that future DSIPs and future NWA project development will utilize the common suitability criteria being developed through the Supplemental DSIP process.

The suitability criteria for selecting potential projects for NWA have been applied to the subset of electric distribution projects that address system capacity problems. These projects comprise 13% of the Companies' electric distribution budget. More significantly, the nine projects[37] that we have identified as being amenable to an NWA and satisfy the suitability criteria comprise over half (54%) of the total budget attributable to projects that were candidates for an NWA. Traditional utility projects that did not satisfy the suitability criteria will remain in our capital budget.

The changes to the distribution planning process to accommodate NWA have been reflected in the Companies' Distribution Planning Manual, attached as Appendix C. The ISP function will apply the NWA suitability criteria to determine whether a DER could solve the problem and defer or eliminate a traditional capital project. The ISP function will then communicate this information to the NWA Group, including the minimal amount of MW required to defer the project per year, to begin the NWA solicitation process.

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[35] In the January 21, 2016 BCA Framework Order, the Commission directed the utilities to use a broader and more flexible set of screening criteria than they had proposed in their comments. In the Final DSIP Order, the Commission indicated that the utilities "should propose such an improved screening process in their Initial DSIP filings, addressing the concerns expressed by the Commission in its BCA Framework Order" [p. 40].

[36] NWA screens are currently being referred to as "suitability criteria". In advance of the Supplemental DSIP, the Companies are applying the following set of suitability criteria: traditional utility capacity solution is estimated to be $1 million or greater; required start of construction is far enough in the future to allow contracting and construction of the NWA project or the traditional construction alternative project; (Note this is the screen which was the most modified from the originally-proposed screens; in modifying this screen, the Companies believe we have a significant opportunity to collaborate with developers and learn from early NWA procurement projects what are minimum time horizons); represents a project need with improvements that are not based on asset condition; has a NWA project load reduction of less than 20% of the total peak load in the area of need and for which the project is not needed to meet a customer in-service date; and project costs do not include a customer-related contribution. The Companies are using these modified screens or criteria in this first DSIP, and will continue to work through the Supplemental DSIP process to develop criteria which are inclusive and workable.

[37] The nine projects identified include the Java and Station 43 projects which are already underway.

Each April 1st the Companies will file a CIP that (1) identifies potential NWA and includes an estimate for the traditional utility solution in the CIP, and (2) replaces a traditional utility project cost estimate with an NWA cost estimate if the Companies have executed an NWA contract within the prior 12-month period.

c) Roadmap and Near-Term Initiatives

The evaluation of how NWA may be used as an integral part of the Companies' capital planning process is presented in Table III-5. It should be noted that although the roadmap begins in 2017, the efforts to identify, solicit and review NWA projects began in mid-2015. Thus, substantial progress has already been made in each of these areas.

TABLE III-5: NWA INCORPORATION IN CAPITAL PLANNING

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Identify Projects Potentially Amenable to an NWA Solution Modify the Capital Planning process to identify planned projects amenable to NWA. Distribution Planning and the NWA group will identify the types of investments for which NWA might be effective as an alternative. For projects where NWA's are candidates, determine NWA requirements.		
Reflect the Outcome of NWA Solicitations in the CIP Update the CIP to reflect traditional utility projects that are impacted by an NWA selection.		
Improve Capital Planning Process to Incorporate DER • Modify cash flows or investments to reflect NWA selections • Update in-service date to reflect chosen DER solution • Update assets to be modified / installed by DER developer		

As part of the capital planning process, and consistent with policy direction, potential NWA will be identified after applying a set of "suitability criteria" that are being refined as part of the Supplemental DSIP process.[38] The Companies have developed and are applying initial suitability

[38] In the January 21, 2016 BCA Framework Order, the Commission directed the utilities to use a broader and more flexible set of screening criteria than they had proposed in their comments. In the Final DSIP Order, the Commission indicated that the utilities "should propose such an improved screening process in their Initial DSIP filings, addressing the concerns expressed by the Commission in its BCA Framework Order" [p. 40]. NWA criteria are currently being referred to as "suitability criteria."

criteria for identifying potential distribution system NWA projects.[39] It is expected that future DSIPs and future NWA project development will utilize the common suitability criteria being in the Supplemental DSIP process.

The changes to the distribution planning process to accommodate NWA have been reflected in the Companies' Distribution Planning Criteria, presented in Appendix C. Distribution planners will apply the NWA suitability criteria to determine if DER could potentially address the problem and defer/eliminate a large traditional wires project. In order to execute the NWA solicitation process, the distribution planners will then communicate this information to the NWA Group, including the minimal amount of MW required to defer the wires project per year.

As part of the selection of NWA bids, the Companies will apply benefit-cost tests based on the BCA Handbook methodology[40] to the most qualifying NWA proposals that are submitted in response to RFP.

d) Identification of current (2016) and Future NWA Projects

In compliance with the Track 1 Order, the Companies were required to identify at least one portion of their system in need of upgrades that might be amenable to NWA. The May 1, 2015 filings included the nature, scale, timing of the need, and the geographical area affected, with enough specificity for potential market participants to develop proposals. The Companies identified and filed an identification two potential NWA projects on May 1, 2015: Java Station and Station 43.

Java Station is an electric substation located in the eastern portion of NYSEG's Lancaster Division in Western New York. The substation is comprised of one Transformer serving two distribution circuits. NYSEG seeks potential NWA projects to accomplish the following objectives:

- Establish sufficient quantities of DER into the area served by Java Substation to reduce the peak loading on the individual transformer bank to below its nameplate rating of 5 MW.

[39] In advance of the Supplemental DSIP, the Companies are applying the following set of suitability criteria; traditional utility capacity solution is estimated to be $1 million or greater; has a required start of construction in not less than 24 months and optimally at least 36 months in the future; represents a project need with improvements that are not based on asset condition; has a NWA project load reduction of less than 20% of the total peak load in the area of need and for which the project is not needed to meet a customer in-service date; and project costs do not include a customer-related contribution.

[40] Although the Companies will have filed their BCA Handbook on June 30, 2016, at the same time as this Initial DSIP filing, as of the time of initial Java Station NWA bid review, no handbook was available for use. Therefore, the NYSEG/RG&E NWA team has worked closely with the Companies' representatives on the JU BCA Handbook team to utilize as much information as is presently known which may later be incorporated into the BCA Handbook. Early NWA pilots (including Java and potentially Station 43, depending upon the actual filing date of the BCA Handbook and its acceptance) will not have the benefit of a fully developed BCA Handbook and therefore the BCA screens will not exactly match those which are likely to come later after the adoption of the final BCA Handbook.

- Establish sufficient quantities of DER to address power quality issues that exist on the Java 280 circuit.
- Establish sufficient quantities of DER to address the potential risk of failure of the existing transformer.

Station 43 is an RG&E electric substation located just north of the intersection of Wyand Crescent and Merchants Road in the Town of Webster, New York. The substation is comprised of two transformers, each serving three distribution circuits. In this project, RG&E seeks potential NWA to accomplish the following objectives:

- Establish sufficient quantities of DER into the area served by Station 43 to reduce the peak loading on the individual transformer banks #3T and #4T to below their nameplate ratings.
- Establish sufficient quantities of DER to restore the combined N-1 contingency to 100% availability.

We applied the initial set of criteria proposed by the Joint Utilities in their comments on the BCA White Paper[41] to the distribution projects solving system capacity problems, in the 2016 CIP, resulting in a list of 9 potential projects[42] (including Java Station and Station 43) which may be amenable to future NWA projects. The additional seven projects are:

- RG&E Station 117: Replace #1 Transformer Bank and convert 3 circuits to 12Kv;
- RG&E Station 46: Replace #3 and #4 Transformer Banks;
- NYSEG Crafts: Add 2nd Transformer and 4th 13.2kV Feeder Position;
- NYSEG Hilldale: 115kV source, add transformer bank, 2nd 12kV Distribution Feeder;
- NYSEG Holland: Replace Transformer Bank;
- NYSEG Orchard Park: Add a 2nd Transformer; AND
- NYSEG West Davenport Substation: Replace Transformer.

e) Five-Year Historical Capital Spending

The Companies' five-year historical capital spending (2011-2015), organized by categories specified in the DSIP Guidance [p33] is presented in Appendix D.

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41 The selection of NWA was performed prior to completion of the BCA Handbook.

42 Although these 9 projects (including the Java Station and Station 43 projects) have been identified as potential NWA projects, they may not all result in NWA RFPs, due to potential changes in timing, system loading, lessons learned through the Java Station and Station 43 pilot NWA RFPs and other potential variables which may affect their suitability for NWA RFP and the Companies' ability to successfully execute a large number of NWA projects in the near future.

f) Five-Year Capital Forecast Capital Budgets

The April 1, 2016 CIP does not include the costs for AMI deployment and DSP technology investments. The 2016 CIP included several investments that are related to system automation. The incremental costs associated with all DSIP investments are presented in Chapter VIII.

The combined forecast, organized by categories specified in the DSIP Guidance [p33] is presented in Appendix E.

5. Procurement of Non-Wires Alternatives

Once potential NWA have been identified, the focus shifts to execution of a market test to determine whether there is an NWA that would be superior to the optimal traditional utility solution. This is a competitive RFP procurement, contracting, and contract administration exercise. It also requires application of the BCA framework as part of the process used to differentiate between proposals and ultimately to select between the leading proposal and the traditional utility solution.

a) Roadmap and Near-Term Initiatives

TABLE III-6: PROCUREMENT OF NON-WIRES ALTERNATIVES

<table>
<tr><th>Near-Term Initiatives
(2017-2018)</th><th>DSP 1.0
(2019-2021)</th><th>DSP 2.0
(2022+)</th></tr>
<tr><td>NWA Governance
Establish management and governance of the end-to-end NWA process.</td><td></td><td></td></tr>
<tr><td colspan="2">Determine if the Best NWA Solution is Superior to the Utility Solution
Analyze proposals using bid and technical specifications and apply the BCA Handbook methodology to remaining proposals to determine the most effective solutions based on a comparison of the NWA and utility solution.</td><td></td></tr>
<tr><td></td><td>NWA Procurements
Develop, design, and implement procurement of NWA utilizing tariffs.</td><td>Implement Storage and Microgrids in addition to NWA & DER
Once integrated systems planning methodologies to evaluate energy storage and Microgrids are developed, incorporate them in our plans as appropriate.</td></tr>
<tr><td colspan="2">NWA Effectiveness Evaluation
Hire independent evaluation contractor to conduct NWA Portfolio evaluations, providing access to individual project records, developer staff, and other data to conduct the evaluation in conformance with the Companies and NYSPSC guidelines on data confidentiality and privacy.</td><td></td></tr>
</table>

b) NWA Procurement Process

The NWA Group within Asset Management and Planning is responsible for managing RFP processes that solicit third-party solutions, and for administering the contracts with successful third-party bidders. The NWA RFP and administrative responsibilities are new utility responsibilities and the Companies anticipate learning a great deal as it executes its first two NWA projects for The Java Station (NYSEG) and Station 43 (RG&E). The Companies also engage in discussions with the other New York utilities to share lessons learned including participation in Supplemental DSIP stakeholder discussions.

The Companies have designed and implemented an initial RFP process that is based on prior supply-related processes. Since this is a new type of solicitation with unique attributes, the Companies provided Staff with a draft of the first (Java Station) RFP and an opportunity to comment before issuance.

An NWA RFP related to the Java Station area of need that was described above in Section III.C.4.d was released on February 8, 2016. An outreach plan was put into action with the issuance of the RFP. The outreach plan targets customers, interest groups, local officials and the public. The Companies anticipate executing a contract with one or more winning bidders in Q4 2016 or Q1 2017.

An NWA RFP related to the Station 43 NWA opportunity described in Section III.C.4.d will likely be released during Q3 2016. A list of over 100 potential bidders has been developed based on previous reliability services RFP lists, REV demonstration project information, learning meetings with vendors, energy efficiency and demand response procurement experience.

The Companies will utilize the BCA Handbook[43] methodology to evaluate benefits of deferring wires alternative projects as compared to the NWA proposals. The analysis reflects costs identified in the bid proposals, utility infrastructure costs identified through the Companies' budgeting process, and externality costs and benefits as defined in the BCA Handbook. This analysis will be performed for each project that conforms to the prerequisite bid requirements and that meets the technical essentials identified as part of the process and the subsequent technical review. The Societal Cost Test ("SCT") test will be the primary test used to distinguish the successful project, although additional BCA tests will be applied and reported. The projects will be ranked and those with the most cost-effective SCT ratings that meet and/or exceed the economic and reliability criteria will be selected for negotiation.

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[43] Although the Companies will have filed their BCA Handbook on June 30, 2016, at the same time as this Initial DSIP filing, as of the time of initial Java Station NWA bid review, no handbook was available for use. Therefore, the NYSEG/RG&E NWA team has worked closely with the Companies' representatives on the JU BCA Handbook team to utilize as much information as is presently known which may later be incorporated into the BCA Handbook. Early NWA pilots (including Java and potentially Station 43, depending upon the actual filing date of the BCA Handbook and its acceptance) may not have the benefit of a fully developed BCA Handbook and therefore the BCA screens will not exactly match those which are likely to come later after the adoption of the final BCA Handbook.

The Companies are at an early point in the development of NWA procurement processes, and expect to undergo significant learning and adaptation of processes during the first two years of NWA project experience, leveraging lessons learned from the Java Station RFP experience. The Energy Supply Group, working with the NWA Program Manager, cooperatively developed a Request for Proposals used for the Java Station release. The Energy Supply Group has experience managing RFP and procurement processes to acquire energy and reliability services and this expertise, including supporting documents utilized in the RFP development. The Companies decided to utilize an RFP, rather than an RFI, to send a clear signal to potential developers that the Companies are ready to procure resources and not simply soliciting information or interest. The Java Station RFP was released on February 8, 2016 with the following schedule:

- February 8, 2016 Issue RFP
- February 19, 2016 Pre-bid conference (20+ attendees)
- April 29, 2016 RFP responses due
- May 26, 2016 Short list of bidders notified
- By December 31, 2016 Complete technical review, conduct negotiations contract and file with Commission
- January 1, 2018 Resource In-Service Date

The schedule for the Java NWA RFP has been flexible due to the pilot nature of the process and the learning gained while completing steps in the process and it possible that upcoming dates may change.

In addition to the RFP document, the bid package released included:

- NWA Letter of Intent – explaining why the RFP was released;
- NWA Form of Agreement – draft contract;
- NWA Bid Data Request from – Exhibit C which is a template for the technical information required in the bid;
- NWA Commission Filing – Attachment B – copy of the May 1, 2015 filing; and
- NWA Confidentiality Agreement – Attachment D – which is required to be signed and returned prior to the release to potential bidders of the load information for the Java Station, and will also protect the confidentiality of the bid documents.

c) <u>Future NWA Procurements</u>

The issuance of an NWA RFP will be accompanied by an outreach plan that focuses on customers, local officials, interest groups, and the public, and includes a press release sent to trade publications and local media. The plan includes briefings on the RFP, a set of frequently asked questions, and establishment of a telephone line for messages and responses regarding the RFP.

RFPs for NWA bids require communication of system information that may not be routinely provided to third parties to enhance the quality of the bids that are received. This might include, for example, the amount of load reduction and associated timing being requested in order to defer or avoid a traditional utility solution.

NWA RFP procurement packages also identify requirements for EM&V processes for NWA projects. Projected requirements for NWA project and portfolio EM&V are based on information required to support ISP, Grid Operations and Interconnections processes. Requirements are based upon industry best practices, NYSEG and RG&E's experience with similar evaluation efforts for energy efficiency programs, and CMP's experiences with Non-Transmission Alternative projects. The RFP procurement package will also identify the performance measurement (metering) requirements. Measurement of generation supplied or other planned changes to the operation and flow of electricity through the distribution system is essential for effective and safe connection and subsequent reliance on the NWA resources. Measurement is required on a near real-time basis with both immediate and historical (stored) data needs.

The RFP schedule incorporates screening, benefit-cost testing, project selection, and negotiations. Following development of a viable NWA project, the NWA Team will review the project status with Staff, including the development of an implementation plan.

d) NWA Operation, Measurement and Verification, and Evaluation

An NWA Operating Manual will include sections for NWA Procurement, Commissioning, Operation, and Evaluation, Measurement and Verification. The NWA Operating Manual will refer to other NYSEG/RG&E manuals, processes and bulletins including the Distribution Planning Criteria document (MT 1.61.00); Bulletin 86-01, Requirements for the Interconnection of Generation, Transmission and End-User Facilities Distribution Planning Standards and other documents that may be included as the Operating Manual is further developed. Commissioning plans for NWA will be developed as resources are contracted and constructed. An Operations and Maintenance plan will be developed for each NWA Project based on the specific requirements for each project.

EM&V: Each NWA contracted project will have an EM&V plan specific to the resources under contract. The EM&V plan is a document that defines project-specific EM&V methods and techniques that will be used to determine performance for a specific NWA contracted project. The plan should include all EM&V options needed to address all of the NWA measures installed at the facility. In a long-term contract, it is very important to ensure that all assumptions, procedures, and data are recorded properly so they may be easily referenced and verified by others. EM&V activities may include site surveys, energy measurements, metering of key variables, data analyses, calculations, quality assurance procedures, reporting, and other activities. In the future, project-specific EM&V plans should be included as part of each NWA RFP response.[44] An EM&V plan specific to each project will be required in each NWA Agreement. The contents of a project-specific EM&V plan should provide an overview of the NWA project and verification activities. Contents will include objectives of the verification activities; defining the EM&V option and techniques to be used for each measure; identifying key physical characteristics of the facility or installation, system, and NWA resource(s) to be installed; defining the critical factors that affect the performance of the system; and define the baseline conditions.

NWA Portfolio Evaluation: The NWA Group will develop a Portfolio Evaluation Work Plan that identifies how the NWA Portfolio will be evaluated and the steps to be taken to conduct the evaluation. At a minimum, the evaluation work plan shall include evaluation scope and tasks, including proposed approach, sampling plans, activity time line and budget. NYSEG and RG&E will be responsible for hiring independent evaluation contractors to conduct NWA Portfolio evaluations, providing access to individual project records and databases, and several other relevant tasks. Evaluation activities that require an independent evaluation contractor shall be secured using a competitive bidding process, and shall be limited to costs not to exceed 5% of the value of the NWA portfolio being evaluated. It is anticipated that each NWA Project will be evaluated at least after one full year of operation, and periodically thereafter with the portfolio of projects).[45]

e) Coordination with Energy Efficiency and Demand Response Programs

Future NWA projects may coordinate with existing energy efficiency ("EE") and DR programs in an effort to maximize cost-effective opportunities in order to achieve targeted load shedding and permanent load reduction as needs are identified. DR and EE resources may be encouraged to participate in both DR programs and NWA projects, as long as there is no opportunity for double counting of the same resource contribution.

6. Probabilistic Integrated System Planning

The new ISP process will reflect several new categories of assumptions that are subject to a considerable degree of uncertainty. These assumptions related in particular to expected DER penetration and DER performance, including intermittency. For this reason, it is appropriate to

[44] Although the M&V plan was not a requirement for the Java NWA RFP, and may also not be a listed requirement in the upcoming Station 43, as the Companies gain experience and have the opportunity to provide more guidance to developers in the procurement process, it is expected that the M&V plan will become a required part of NWA proposals.

[45] There are four evaluation tasks for the NWA Portfolio which will likely be included in ongoing NWA Portfolio Evaluation: The evaluation tasks include: 1) resource and portfolio record keeping verification, 2) determination of persistence of individual projects and technologies (i.e. projected lifetime project output / energy savings / demand reduction), 3) measurement of project output and energy savings as specified for the project in the NWA RFP, and 4) ex-post benefit / cost (BCA) testing of the NWA Portfolio.

consider an ISP methodology that explicitly reflects these uncertainties through scenario analyses, probabilistic, or other techniques. However, as noted in the roadmap that follows, it is appropriate to gain further experience in REV before finalizing and applying a probabilistic approach that reflects uncertainty.

TABLE III-7: PROBABILISTIC INTERGRATED SYSTEMS PLANNING

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
	Determine Probabilistic Planning Methodology & Apply to High Penetration Circuits Work with the Joint Utilities & Stakeholders to define a methodology for Probabilistic Integrated Systems Planning, and apply to high penetration circuits.	

IV. Market Enablement

A. Introduction and Overview

Market Enablement is the core DSP function that will stimulate product and service transactions enabled by the DSP. Customers will benefit from access to their detailed usage and billing information and the ability to share it with DER providers. The Market Enablement function will also share planning and other system information with DER providers that will help providers decide where to target their marketing efforts. Secure sharing of accurate system and customer data with market participants, including end-use customers, supports rational economic decisions at every stage of the product development cycle. These efforts will leverage the information systems being developed by the Companies to compile, store, retrieve, and communicate large volumes of granular data on a timely basis, including data that will be available from AMI.

As the market for DER products and services evolves, the Companies will experience increases in the volume and complexity of DER-related billing and will need to "settle" multiple party (*e.g.* DSP, DER provider, and end-use customer) transactions. More complex tariff-based options such as TVP will require changes to billing systems. At some point in the future, organized distribution markets may form in New York and the DSP will have a role to serve in billing and settling these transactions. While this may be a few years away, distribution market transactions, and associated billing and settlement, should be considered as technology and information system plans are developed. For example, our upgrade from the current CRM&B is one of several integral components of our AMI Plan for establishing a foundation that will accommodate more complex transactions and support cash management activities.

Market Enablement will provide customer education and outreach efforts to inform customers of new product and service offerings and the evolving role of the Companies as the platform service provider. This function will contribute to the success of the DSPP through collaboration with third parties to address their needs (*e.g.* more efficient interconnection processes) and taking into consideration evolving customer demands. As discussed in Chapter V, the Companies hope to learn as much as possible about working with third parties to engage customers through the ESC, Energy Marketplace (*Your Energy Savings Store*), and Community Energy Coordination demonstration projects. The ESC provides an opportunity to test TVP options, new data portals, and third-party solutions, including GBC or a similar product.

B. Capability Enhancements

The development of a successful Market Enablement function will require enhancement of our capabilities in seven distinct areas:

(1) **Customer Care Processes and Systems:** *Integrating platform technologies with relationship management and billing tools to enhance the customer experience, while delivering timely and accurate invoices to end-users;*

(2) **Customer Data and Portals:** *Improve data access platforms and ability to provide data to customers and DER providers, with Energy Manager as our initial platform, as well as integrating other data provision functions such as GBC;*

(3) **Sharing Customer Data with Customers and DER Providers:** *Provide timely and accurate customer usage and other relevant data, consistent with the Companies' security and privacy requirements;*

(4) **Outreach, Marketing, and Sales:** *Communicate new products, services and utility-sponsored programs to target audiences to engage customers and increase participation in these programs;*

(5) **Sharing System Data and Information with DER Providers:** *Provide DER providers with timely access to system data;*

(6) **DSP Markets:** *Participate in efforts to develop statewide transactive markets for products and services that could be efficiently provided through organized market mechanisms; and*

(7) **Interconnection Processes:** *Streamline interconnection processes to provide grid reliability and optimization and accommodate an increasing penetration of DER.*

Each of these capabilities will be addressed in detail in the remainder of this chapter. A brief description of each and the Companies' current capabilities are presented in the following table.

TABLE IV-1: DSP REQUIREMENTS AND CURRENT CAPABILITIES

Capability	DSP Requirements	Current Status
1. Customer Care Processes and Systems	• Enhance billing systems and related customer care processes to accommodate new tariff offerings (e.g., TVP), and a large volume of DSP and DER transactions provided in collaboration with DER providers.	• Credit customer bills for DR participation • Automation of straightforward net energy metering billing • Spreadsheets for more complex net energy metering ("NEM") billing
2. Customer Data and Portals	• Develop portals and data retrieval capabilities to provide customers easy access to usage data, integrating tools such as GBC	• Mandatory Hourly Pricing ("MHP") customers can obtain hourly data • An energy services company ("ESCO") can obtain hourly data on MHP customers through a secure File Transfer Protocol ("FTP") site • Customers can obtain monthly usage from the Companies' websites
3. Sharing Customer Data with Customers and DER Providers	• Develop efficient methods of securely sharing customer data • Provide granular data to customers with AMI	• Current methods of sharing customer data comply with the Companies' security and privacy requirements • Plans to provide granular data to ESC customers with AMI are underway

Capability	DSP Requirements	Current Status
4. Outreach, Marketing, and Sales	• Improve customer engagement and participation in utility programs • Inform customers of the respective roles of the DSP and DER Providers	• Sales and marketing programs promote current utility products and services (i.e. Distribution Level Demand Response and Energy Efficiency) • Planning and developing outreach and education plans is underway for the ESC and demonstration projects
5. Sharing System Data Sharing with DER Providers	• Provide third parties with system data and information that contributes to interconnections and associated investment decisions.	• DER Providers receive some system information through the interconnection Standardized Interconnection Requirements ("SIR") process
6. DSP Markets	• Track and forecast participation in DER markets • Additional requirements will be established in future policy orders.	• Initial markets based on NWA RFP's and tariffs for demand response. • Additional development in *Your Energy Savings Store* and Community Energy Coordination demonstration projects.
7. Interconnections Processes	• Improve and streamline the interconnection process and sub-processes	• Large queue for interconnection requests being addressed through improvements made over the past year • Working with the Interconnection Ombudsman

1. Customer Care Processes and Systems

The Customer Care Processes and Systems capability addresses the need for the timely and accurate production and delivery of bills to all end-use customers in the DSP environment. Timely and accurate bills contribute to customer satisfaction and eliminate effort required to resolve billing issues. This process utilizes several information systems including customer metering databases and IT systems that store meter data and produce the bills. It also relies on billing and collection representatives that are trained to address any unique billing aspects for DER products and services and aware of the customer experience with DER.

a) Roadmap and Near-Term Initiatives

The Customer Care Processes and Systems capability development efforts are presented in the following roadmap.

TABLE IV-2: CUSTOMER CARE PROCESSES AND SYSTEMS

<table>
<tr><th>Near-Term Initiatives
(2017-2018)</th><th>DSP 1.0
(2019-2021)</th><th>DSP 2.0
(2022+)</th></tr>
<tr><td colspan="3"><u>Competency Development:</u>
Implement a formal training to address customer inquiries; processing of applications for enrollment in a DSP-market product or service (including interconnect); billing and balancing processes; and reconciliation.
• Deliver training to broad spectrum of employees to ensure adequate knowledge within the company to support anticipated growth.
• Increase bench depth of expertise in development of complex spreadsheets.</td></tr>
<tr><td colspan="3"><u>Processes and Procedures:</u>
Develop detailed process and procedures within the Customer Care team and among the other departments within NYSEG/RG&E supporting billing and associated processes.
• Create workflows and responsibility charts.
• Map out processes that have a touch point among departments to fully understand the entire process from start to finish. Review and revise procedures as programs evolve to ensure streamlined processes.</td></tr>
<tr><td><u>Process Owner & Supporting Staff:</u>
Create a team that is adequately staffed with the experience and expertise to execute day-to-day activities (customer inquiries, application, interconnect, timely and accurate bills)</td><td></td><td></td></tr>
<tr><td colspan="2"><u>Customer & Billing System Changes to Support AMI:</u>
Integration of AMI functionality with systems used to bill and provide services to customers. Define and deliver processes for on-demand meter reading, develop a rate model for billing rate configuration, integration of systems for access to meter reading data, and enhancement of multi-channel functions to support Smart AMI processes.</td><td></td></tr>
<tr><td><u>DER Billing & Settlement Systems Assessment:</u>
Identify Billing & Settlement systems enhancements to accommodate increased DER</td><td colspan="2"><u>Implement DER Billing & Settlement System:</u>
Implement enhanced Billing & Settlement software or modules to accommodate increased DER.</td></tr>
</table>

As participation in DSP and DER products and services increases, it is necessary to train existing and new staff to effectively manage complex billing processes and produce accurate bills. The training program will address advanced analytics and alternative pricing mechanisms. It is likely that customer billing will evolve in a manner that requires new end-to-end customer relationship and billing processes to be designed, tested and implemented. These processes will need to be automated to support high penetrations of DER, including integration with the DER and Market Management System to manage rate programs, customer contracts, DER communications, and performance as well as leveraging the Companies' websites to accommodate self-service account management functions.

The new billing and settlement processes will be developed and integrated with an upgraded CRM&B system in order to accommodate increasingly complex transactions and to support cash management activities. This technology investment is described in greater detail in Chapter VI.

2. *Customer Data and Portals*

The Companies anticipate the need to respond to large volumes of requests for customer data from customers that are interested in new products and services, as well as customer requests to share these data with DER providers and ESCOs. Currently, customers with time-of-use meters can access hourly usage information through a vendor portal; other customers can access monthly usage information through the Companies' websites. In addition, ESCOs serving our customers can obtain monthly customer usage data using the Electronic Data Interchange ("EDI") protocol, and they are able to obtain hourly customer usage through a secure FTP site.

a) Roadmap and Near-Term Initiatives

These processes will change with the launch of *Energy Manager* and adoption of GBC (or similar advanced data portal) capable of providing sub-hourly usage data for AMI customers and their ESCO suppliers. *Energy Manager* is being designed as a one-stop portal for customers that are interested in engaging with the Companies for a variety of energy-oriented services including accessing data, viewing energy usage analytics, obtaining usage cost estimation, seeing weather forecasts, energy education, and energy efficiency tips. It will eventually encompass the functionality that is being tested in *Your Energy Savings Store*, the Energy Marketplace REV demonstration project that will be included as part of the ESC.

The Customer Data and Portals capability development efforts are presented in the following roadmap.

TABLE IV-3: CUSTOMER DATA AND PORTALS

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Your Energy Savings Store: Test the Energy Marketplace demonstration concept in the ESC.	***Your Energy Savings Store* Full Rollout** Implement full rollout of *Your Energy Savings Store* based on lessons learned from the Energy Marketplace demonstration project.	
***Energy Manager*: Assess & Procure Alternative Data Portal Platforms:** Introduce the *Energy Manager* Customer data portal in the ESC. Organize and implement a plan to improve web service and Data Access Management skill sets based on lessons learned in the ESC.	***Energy Manager*: Data Portal Platform Implementation** Begin Implementation of Data Portal Platform with Energy Smart Community and update as necessary.	

b) Green Button Connect

GBC, or a similar product, is an integral element of the AMI Plan (*Chapter VI*). Raw meter data will be housed in a Meter Data Management System ("MDMS"). A database reporting function will translate raw data into a format that can be accessed by customers. Customers will also be able to allow registered DER providers to have access to their data through a secure portal. DER providers will be able to download batches of customer data that they are authorized to access.

The Companies will collaborate with other New York utilities to support the development of common protocols to be used by DER providers to access AMI usage data. The Companies will test these concepts in the ESC beginning in the second and third quarter of 2017 based on the first phase of ESC meter installations. Within a year, the portal will be rolled out to other regions as the system-wide AMI Plan is implemented. Competitive bidding will be used to select between GBC and alternative solutions.

Although these processes will be automated to the extent possible, we anticipate having to develop and train staff to handle inquiries from customers and DER providers regarding use of the portals and interpretation of the data. Most importantly, customers and DER providers will have access to the customer usage data that informs their energy decisions, including options to engage DER.

c) *Energy Manager* and Your Energy Savings Store

The Companies' Maine affiliate, CMP, is currently implementing *Energy Manager* as the one-stop shopping portal for its customers. The Companies' will benefit from this experience but will still need to engage in several development activities including training resources to support the portal, tailoring back-end processes that gather and synthesize raw data before it can be securely shared with third parties, and subsequent integration of *Your Energy Savings Store*, the Energy Marketplace REV demonstration project that is currently in development. The suite of functions will be designed to integrate all customer options, including participation in utility-sponsored energy efficiency and demand response programs in a way that minimizes customer confusion. Testing *Your Energy Savings Store* features through the ESC will lead to better system-wide rollout of *Energy Manager*.

Customers and market participants will be able to download usage data from the portals, as shown in Figure IV-1.

FIGURE IV-1: *ENERGY MANAGER* PORTAL ILLUSTRATION

This represents the user interface providing the customer with a graphical presentation of recent energy usage and point-and-click access to Green Button or a similar product.

d) <u>Transition of Existing Utility DER Programs</u>

In addition, the Companies our customers can use the portal to engage with our utility DER programs, including energy efficiency and demand response programs. The Companies' current energy efficiency suite of offerings includes traditional utility incentive driven programs in the residential, multi-family and non-residential market sectors. These programs will continue to evolve and be updated through ETIP filings. We intend to modify existing programs and offer new utility-sponsored programs to leverage the availability of more granular AMI data and to respond to evolving customer needs.

Energy efficiency offerings will be included in demonstration projects such as *Your Energy Savings Store* and integrated within the *Energy Manager* customer portal to be launched within the ESC. This functionality will provide customers with the ability to obtain straightforward information and advice on energy use and then use the same portal to access third-party and utility products and services that help them save on their energy bills.

The evolution of energy efficiency programs will be influenced by the working groups formed within the recently established Clean Energy Advisory Council ("CEAC"). The working groups are addressing the coordination of utilities with NYSERDA, increased reliance on markets to deliver energy efficiency, alternative approaches for the delivery of energy efficiency services to low- and moderate-income ("LMI") customers, energy efficiency best practices, and development of voluntary energy efficiency investment models.[46]

The Companies' demand response programs will be enhanced by leveraging AMI data to help increase enrollment. Current demand response programs rely on either the installation of hourly meters, or obtaining and installing a qualified thermostat/temperature control device. Customers with an AMI meter will be able to enroll in demand response programs without having to acquire additional equipment. Customers may also choose to obtain ancillary devices that will facilitate their participation in a demand response program. For customers that choose to participate in thermostat/temperature control device demand response programs, the AMI meter will provide a more accurate view of the customers' participation in demand response events and provide a more precise incentive payment. Finally, AMI will support the ability to participate in demand response as new TVP and Critical Peak Pricing ("CPP") products are offered.

3. Sharing Customer Data with Customers and DER Providers

While the portal will automate as many data-related services as possible, the Companies anticipate forming a small but dedicated customer response organization that interacts with customers, DER providers and other internal departments that interface with customers and DER providers regarding customer data issues.

a) Roadmap and Near-Term Initiatives

The Companies will develop processes for requesting, gathering, validating, protecting, and securely transmitting data to customers and DER providers. The Customer Data and Portals capability development efforts are presented in the following roadmap.

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[46] Additionally, the Low & Moderate Income Clean Energy Initiatives Working Group established within the CEAC is intended to evaluate alternative approaches for the delivery of energy efficiency and other services to LMI customers. The outcome of the activity of this group, as well as initiatives under development at other AVANGRID companies, will help inform future LMI program development in NY.

TABLE IV-4: SHARING CUSTOMER DATA WITH CUSTOMERS AND DER PROVIDERS

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Customer Data Aggregation Develop a method to quickly and properly identify, access, aggregate, validate, and deliver data, preferably through an automated process.		
Define Granular Customer Data Requirements Develop a secure method for customers to obtain their usage information and share it with DER providers on an opt-in basis.	**Automate Provision of Granular Data** Develop a long-term strategy to consistently and automatically provide more granular data to a larger audience in a secure manner for customers that select this option.	
Develop & Implement New Processes and Procedures Develop detailed processes and procedures to execute data sharing responsibilities. Create workflows, timeline and responsibility charts.	**Self-Serve Platform** Provide online access to pre-authorized developers for relevant, properly classified and secured data elements to that help them market and connect DER.	

The Companies' implementation approach to sharing customer data is to (1) automate data sharing to the extent possible, (2) comply with security and privacy safeguards, and (3) standardize the approach to responding to further requests for information. Providing usage data that is aggregated over a pool of customers will certainly require significant development effort in order to comply with privacy and other concerns. With regard to the third prong of the strategy, the Companies will prepare to administer customer requests by identifying resources for inspecting third-party requestor credentials, classifying data availability, and consolidating data requirements across related initiatives.

b) <u>Sharing of Customer Data</u>

DER providers require customer data to develop product and service offerings both to provide value to customers and to efficiently target their marketing efforts and investments. The Companies' first priority is to provide customers with access to more granular AMI data that will allow them to control their energy usage and bills. The Companies must obtain customer authorization before sharing any customer data with third parties, including usage data and "personal identifiable information" ("PII"). Per Commission order, customer data can only be released to third parties on an opt-in basis.[47]

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[47] See the Commission's Track 2 Order, May 19, 2016, p. 147.

Customers must have ready access to their own information. They currently have access to a variety of electronic energy data through password-protected Company websites (www.nyseg.com and www.rge.com). These data include:

- Contact information, financial institution for billing, tax jurisdiction, and tax district;
- Up to 24 months of electric usage, electric demand (demand classifications only), and gas usage;
- Bill balance and payment history;
- Electric meter number, gas meter number, electric POD ID, gas POD ID, and the next meter reading date;
- Gas and electric rate codes;
- Electric Supply Choice (utility supply or specific ESCO) and history; and
- Electric and gas grid location information (*i.e.* ISO Zone, gas pipeline region).

The Companies have participated in several Commission-organized technical conferences that have addressed policies and enabling technologies relating to the exchange of customer data. These conferences have explored ways to make customer data available to the market with the focus on adopting a statewide standard, such as GBC. Several stakeholders expressed the viewpoint that GBC has limited value in the absence of AMI. The Companies are proposing to implement AMI (*Chapter VI*) which introduces the potential of leveraging the capabilities of GBC to make customer information available to third parties.

Data security is a priority under any approach. There is general agreement that there is value in providing aggregated customer data to DER suppliers (*e.g.* load profiles on a circuit or behind a substation) that masks individual customer data, although whether the utilities can charge a fee that compensates them to provide this service has not yet been resolved.

The Companies and certain stakeholders support the adoption of the DataGuard Voluntary Code of Conduct[48] as a minimum voluntary data protection standard for New York that can be met by several data transfer approaches, including GBC's "*My Data*" portal. The *My Data* portal empowers customers and encourages engagement by allowing them to select which vendors can obtain customer usage data and for how long. The Companies also support the development and installation of a "Restful API" solution that can be made available to customers through Company websites, by leveraging GBC's "*Download My Data*" and *My Data* features.

Additional data, including data with greater granularity, will become available over time. These data types can be broken out into three categories:

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[48] The DataGuard code of conduct can be downloaded at: https://www.smartgrid.gov/document/voluntary_code_conduct_vcc_final_concepts_and_principles

(1) Additions that can be made without new software: Data that can be added without AMI and new software can be implemented with existing IT resources or contractors. Resources for customers and third parties can be placed on the Companies' websites for viewing with other account-level information, including:

- Availability of customer's individual ICAP tag value (as a proxy for demand);
- Base and weather sensitive load values to estimate seasonal daily usage; and
- Circuit and ISO Sub zone.

(2) Additions that can be made with GBC in connection with AMI: AMI and associated software will allow customers to access interval data (hourly or 15-minute data). Similarly, third party vendors will be able to access hourly or 15-minute load data in addition to coincident and non-coincident demand levels at points on the distribution system.

(3) Additions that can be made with other software, such as *Energy Manager* with AMI: Additional optional software packages can help customers compare their usage patterns to those of their neighbors to encourage conservation and energy- and cost-saving behavior. Some packages can gather and communicate consumer behavior data to third parties, such as changes in demand that are derived from corresponding changes in weather.

c) Transmission of Authorized Customer Information to ESCOs and Other Third Parties

EDI is currently the primary means of communicating customer information to ESCOs and other vendors. After being qualified to access data through EDI, ESCOs are allowed to submit an "historical usage" request for customer information, including 12 months of historical electric and/or gas usage. ESCOs must submit requests and each customer's "Point of Delivery ID" ("POD ID") – essentially equivalent to an account number – in order to receive customer-specific information. Vendors have to request the POD ID, as there is no existing method for customers to proactively make their POD ID available to vendors. GBC and other software solutions would resolve this issue. Historical customer data transferred via EDI is delivered overnight (*i.e.* with a one-day turn/around). This data includes:

- Customer service address;
- Electric or gas indicator;
- Sales tax district used by the distribution utility;
- Rate service class;
- Electric load profile reference category or code;
- Usage type (kWh or therm);
- Reporting period;
- Type of consumption (actual, estimated, or billed);
- 12 months of usage; and

- Meter number.

Customer usage (kWh, kW, var) is available on a monthly basis after meters are read and provided in “bill quality” format, rather than providing “raw” meter readouts. Customers with interval meters obtain hourly usage data and other customer data via a web portal as the data files are too large to rely on transfer via EDI. This data is measured in 15-minute intervals but provided as meter-read data to preserve the granularity of data that is not presented on the customer bill. GBC is designed to handle a significant amount of data and granularity. GBC uses a Restful API platform (such as .XML) making data available for extraction in a standardized format. Vendors must request data one customer at a time, although the Companies are exploring enhancements that would permit batch requests from ESCOs for customer data for multiple customers.

The Companies, acting as the DSPP, will provide ESCOs with access to hourly or 15-minute level consumption data starting in 2018 (for the Energy Smart Community). The DSPP will initially (2018) provide ESCOs hourly customer usage data via GBC for participants in the Energy Smart Community pilot. The data will be available one day after it has been downloaded and validated (*i.e.* passes billing quality validation algorithms in the billing system). Customers who are metered/billed on an hourly basis will have hourly data displayed. Customers who are measured on 15-minute level intervals will have that data displayed. Currently, there is no viable technological solution that would allow us to retrieve, validate, and post data in less than one day. A near real-time solution does not currently exist. Once AMI is available statewide, starting in 2020, the hourly or 15-minute level data will be made available for all customers in a similar fashion to those in the Energy Smart Community.

d) <u>Charging for the Provision of “Value-Added” Customer Data</u>

The Companies will provide “basic” data services that are included in the cost of service relied upon to establish tariffed rates. These include services that are available to all customers, and rely on systems, processes and human resources that support all customers. It is certainly conceivable that third parties may request “value-added” services that are of interest to a small number of third parties and/or require incremental investment to provide. For example, these services may require some customization or analysis in order to provide insights that third parties value. They could also be more granular than basic data. In cases where customers request information that is more detailed and/or more frequent than basic required data, the Companies may propose a value-added service charge to provide these data. The Companies have not yet determined which new services may warrant a fee, whether to charge a fee for these services, nor whether the fee will be value-based or based primarily on the incremental cost to provide those services. Under no circumstance will PII be provided as part of a fee-based service. Value-added services will involve an aggregation of customer data that is provided in a manner that precludes the ability to identify individual customers, a legitimate concern of all customers but particularly for medium and large business customers.

At the current time, the Companies consider the following as basic data services:

- Non-interval - Cumulative kWh, net or accumulated kWh, max recorded kW (if a demand meter is present). If a customer is on a TOU rate, summed usage in TOU periods is considered basic service.
- Interval - Energy use (kWh, net or accumulated kWh, kW, kvar) at program intervals specific to the customer's meter, as well as cumulative kWh, min/max kW, kvar. If a customer is on a TOU rate, summed usage in TOU periods is also basic data.
- Common data examples (regardless of meter type): historical consumption, historical billing amounts (total dollars, supply charges), customer tariff, and service location.

Value-Added Data Service examples include:

- Non-interval- Data that has been custom-extracted, compiled and/or transformed to show usage over a longer time period than the standard 13-24 months (*i.e.* 36+ months of billed individual energy use history), aggregated data, comparative use with class average TOU kWh if being provided to third parties (and when available).
- Interval-data that is delivered more frequently than basic data, or has been custom-extracted, compiled and/or transformed to show usage over a longer time period than the standard 13-24 months (*i.e.* 36+ months of billed individual energy use history), aggregated data, comparative use with class average. Other value-added and analytics-based offerings could include comparing peak day use patterns, variances in actual versus expected usage profiles etc. TOU kWh, TOU kvar if being provided to third parties (when available).
- Common data examples, regardless of meter type, include (where available): reported outages, power quality data, customer complaints regarding voltage/power quality, historical power factor, coincident and non-coincident customer peak.

4. Outreach, Marketing, and Sales

This effort focuses on a continuous expansion of existing utility-sponsored DER programs, including energy efficiency and demand response. Additionally, engagement through outreach programs will intensify as the implementation of new innovative rate structures and capabilities associated with AMI are introduced in the ESC. The launch and expansion of the *Your Energy Savings Store* will also provide a significant initial and ongoing opportunity for customer engagement. As the market matures, the Companies recognize that there will be a transition to a greater reliance on market-based approaches for programs that demonstrate economic viability.

The Outreach, Marketing and Sales capability development efforts are presented in the following roadmap.

TABLE IV-5: OUTREACH, MARKETING, AND SALES

<table>
<tr><th>Near-Term Initiatives
(2017-2018)</th><th>DSP 1.0
(2019-2021)</th><th>DSP 2.0
(2022+)</th></tr>
<tr><td colspan="3"><u>Outreach and Education</u>
Continuous development and expansion of outreach & education plans to customers enrolled in:
• Existing REV-related Programs (e.g. Energy Efficiency, DLDR, Community Choice Aggregation);
• ESC programs: (e.g. Energy Manager, TVP);
• Demonstration Projects (Your Energy Savings Store, Community Energy Coordination).</td></tr>
<tr><td colspan="3"><u>Training Programs</u>
Develop the appropriate program specific training that can be provided to customer facing employees.</td></tr>
<tr><td><u>Organizational Assessment</u>
Identify organizational gaps and inefficiencies in order to provide comprehensive and consolidated outreach & educational programs to customers.</td><td></td><td></td></tr>
</table>

5. Sharing System Data with DER Providers

The Companies will provide several types of system information that provides intelligence that DER providers can rely upon to make investment decisions. Rather than provide “raw” system data, the Companies will provide the results of planning analyses in order to offer information that is ready to be used. This includes Stage 1 indicators, beneficial locations, hosting capacity and the results of planning studies. However, as discussed in Chapter III, the Companies will only provide such information once it is considered to be valid and reliable. The Companies will also describe any analyses that have been performed in order to enable third parties to properly use the information, perhaps in combination with other sources of intelligence that they have developed and that are proprietary to the particular third party.

a) <u>Roadmap and Near-Term Initiatives</u>

The System Data Sharing with DER Providers capability development efforts are presented in the following roadmap.

TABLE IV-6: SHARING SYSTEM DATA WITH DER PROVIDERS

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Identify System Data Elements Identify both "basic" and value-added system data that will be provided to DER providers		
	Incorporate Supplemental DISP Outcomes Adjust the list and definition of system data based on Supplemental DSIP outcomes.	
Transfer Protocols Develop protocols to securely transfer system data to authorized DER providers.		
	Incorporate Supplemental DISP Outcomes Automate data transfer to the extent possible.	

The Companies, other New York utilities, third parties, and other stakeholders are developing a common methodology to develop several categories of system data as part of the Supplemental DSIP Process. These data include Stage 1 indicators, beneficial locations, hosting capacity, and other pertinent basic system data.

As part of the Advanced Planning Tools technology project (described in Chapter VI), the Companies are developing of a DER Developer Web Portal. Information will be exported in a geospatial view to produce a DER heat map, which will be made available to external third-party providers. The DER Developer Web Portal will provide a platform for the Companies to communicate beneficial locations for DER deployment to external service providers, and to accept interconnection requests from potential DER developers. In order to gain access to the future portal, DER providers must meet cyber security requirements and access the data via a secure login. As part of an overall effort to cultivate and manage relationships with third parties, the Companies will share this information with DER providers, consistent with infrastructure security and cyber security requirements.

The Companies are committed to implementing standardized functions and processes to support a high penetration of DER, multiple transactions, and numerous third parties. The Companies have been developing data sharing capabilities and protocols in order to share data with validated third parties for the Community Choice Aggregation ("CCA") and Community DG programs, and has initiated plans for sharing data with microgrid developers through NY Prize. Current efforts are focused on security and encryption protocols that must be used in the management of shared data.

DER providers rely on results of planning studies and system data to inform their marketing and investment decisions and to develop solutions that increase the overall efficiency of the network while also providing value to end-use customers. The Companies contemplate that most information will be made available to all authorized DER providers and that the cost to provide these services will be recovered through base tariff rates. However, there may be requests for "one-off" special studies by a single DER provider that require incremental effort that benefits that sole provider. In these instances, the Companies will propose a fee-based service, consistent with the guidance that has been provided in the Track 2 Order. These services could include the results of special load flow analyses that examine a subset of the service area. DER developers have emphasized the need for circuit-level data to assess opportunities and propose market-based solutions.[49] It is evident that modeling circuit performance for DER interconnections, reliability assessments, and operational performance monitoring require accurate data at the circuit-level. Similarly, modeling and forecasting future customer usage and DER impacts rely on accurate SCADA and metered time-sequence data. Over time, it is conceivable that certain fee-based services will be of use to many DER providers and could transition to tariff services.

The ISP function will determine the availability and accuracy of historical and forecasted system data and information and parallel efforts will occur to determine how to present this information to DER developers. Certain types of data the Companies expect to provide to developers can be seen in Table IV-7. Some of these data are not available today, but availability will increase over the term of the DSIP with the implementation of additional telecommunications and data acquisition. Increased granularity of system data, particularly with respect to geospatial and time dimensions, will contribute to more efficient DER offerings, solutions and investments.

[49] In fact, these data are foundational for multiple DSP objectives, including Grid Operations and Integrated System Planning in addition to Market Enablement.

TABLE IV-7: SYSTEM DATA AVAILABLE TO THIRD PARTIES

Data Field	Data Availability
System Load Forecast	Public - DSIP Filing
System Voltage	Public – FERC Form 1
System Reliability	Public – Annual Reliability Report
Substation Load	SIR – Pre-Application Report
Substation Voltage	SIR – Pre-Application Report
Voltage at Point of Common Coupling	SIR – Pre-Application Report
Substation Reliability	All DER Providers[50]
Circuit Load	SIR – Pre-Application Report
Circuit Voltage	SIR – Pre-Application Report
Circuit Reliability	Public – Annual Reliability Report
Stage 1 Indicators	Public – Distributed Interconnection Guide Map Website
Minimum Day Load Curve by Substation (Estimated)	All DER Providers
Minimum Day Load Curve by Circuit (Estimated)	All DER Providers
Peak Day Load Curve by Substation (Estimated)	All DER Providers
Peak Day Load Curve by Circuit (Estimated)	All DER Providers
Circuit peak demand forecast	SIR – Pre-Application Report
Circuit statistics (incl. ID, voltage, length, min and max load, min and max noon load, min and max daily energy)	SIR – Pre-Application Report
Substation Bank Capacity	SIR – Pre-Application Report
Aggregate existing distributed generation on the circuit (kW)	SIR – Pre-Application Report
Aggregate queued distribution generation on the circuit (kW)	SIR – Pre-Application Report
Distribution Capital Investments	Public – Capital Investment Plan in DSIP Filing

The Companies are investing in distribution automation and AMI that will provide valuable system data to improve the quality of load flow analyses and support the provision of both basic and value-added services to third parties. The first priority at this time is obtaining comprehensive

[50] The Companies are developing a process to securely provide these data to DER providers. The Supplemental DSIP will identify data subject to fees.

physical/electric and SCADA time-sequence circuit data through the Energy Smart Community. Secondary priorities include:

- Circuits with high existing or expected DER penetration from either a capacity or number-of-DER interconnection perspective;
- Circuits that routinely experience less-than-nominal reliability performance; and
- Circuits with a large number of protective devices or voltage control equipment.

6. DSP Markets

It is contemplated that the initial DSIP period will involve transactions for new products and services based on utility tariffs, RFPs and contracts for NWA, and competitive products and services offered by DER providers. The DSP will become a buyer of services from customers and DER providers, become a seller of services to DER providers (including system data services discussed above), and partner with DER providers in some circumstances. However, it is also contemplated that after a period of years, the DSP may offer services that are transacted through organized markets. In order to encourage efficiency, it is likely that these markets will be designed to operate at a statewide basis, similar to the operation of NYISO markets. From the definition of each “product” to billing to settlement, these markets will be complex to design and implement. Additional complexity will surround the development of a comprehensive set of rules and protocols governing participation in the markets.

Thus, transactive DSP market mechanisms are expected to develop in the longer-term, and are not directly addressed in the near term initiatives in this initial five-year Initial DSIP. However, certain design activities should begin during the Initial DSIP period and the Companies will be active participants and contributors to those efforts in the future.

The DSP Markets capability development efforts are presented in the following roadmap.

TABLE IV-8: DSP MARKETS

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
	Integrated Data Marketplace Functionality: Intersection of Outreach and Education, Data Portals and Provisions, and *Your Energy Savings Store* functionalities.	
DSP Market Pricing Product Development: Begin to refine and further develop products that could be provided by transactive DSP markets, leveraging knowledge from the REV demonstration projects and the ESC.		
Functionality Deployment in the ESC: Deploy programs / policy components being implemented in the ESC for DER availability, AMI, SCADA, etc. and derive lessons learned to inform DSP market development efforts.		

In the interim, the Companies will work collaboratively with third parties to identify, communicate, and execute opportunities for DER. These opportunities include NWA, provision of new third-party products and services, support for third-party services through platform services, and delivery of Company-sponsored programs that fill a market need at least during a transitional period. These latter programs include energy efficiency programs, which remain dependent on utility participation, and DER programs targeted to LMI customers.

As part of the Supplemental DSIP effort, the Companies are working with the other New York utilities and stakeholders to develop common approaches to interactions with third parties in order to facilitate market entry, lower the costs of their participation in the market, achieve lower costs for new products, and support a higher penetration of DER.

7. Interconnection Processes

a) Context: Surge in Applications in 2013-2015

Streamlining the interconnection process will contribute significantly to achievement of the Companies' overall interconnection goals:

- Connect viable DG projects as expeditiously as possible;
- Maintain the integrity of the distribution network; and
- Objectively calculate and fairly assign responsibility for interconnection costs.

The Commission has appropriately taken a holistic view to promoting DER. This includes a directive that the Companies identify beneficial locations and more recently through the efforts of the Ombudsman, publish maps that identify areas where DER are not easily accommodated on the distribution system. These policy initiatives should help eliminate proposals that have no viable chance of connecting to the grid, yet that remain in the queue for months or years.

Many of the larger (> 300 kW) projects that are currently in the Companies' interconnections queue are may be duplicate applications or in some cases, projects that will not move forward. The Companies will seek to work with Staff and DER developers over the next few months to reduce the projects in the queue, which will in turn improve the efficiency of the interconnections process for all parties.

b) Actions Taken to Streamline the Interconnections Process

The Companies have invested considerable effort, with success, in reducing the surge in the applications queue during the latter half of 2014 and continuing through 2015.

TABLE IV-9: INTERCONNECTION APPLICATIONS (2012-2015)

2012	2013	2014	2015	2016 (Jan-April)
529	689	1,395	2,778	1,201

In fact, the Companies received more interconnection requests in the fourth quarter of 2014 than in the entire year of 2013. Average processing time rose from six months for projects in the 25 to 300 kW size range in 2013 to 31 months the following year (falling outside of SIR requirements), but have dropped back down to six months due to improvements that the Companies have made to their interconnection processes.[51]

These improvements include adding staff to the Distribution Planning function and making several process improvements to manage application data requirements, monitor and report status relative to SIR compliance deadlines, and streamline the technical review process for inverter-based projects that are less than 300 kW.[52] The Companies began using the CYME model to perform voltage/flicker analyses which has produced fewer restrictions on system sizing.

The Companies have been working on an Interconnection Portal for the past year. Phase I went live on December 15, 2015. The portal allows applicants to submit applications, including all attachments, through the web-based portal. DER developers can also track the status of their applications through the portal. Enhancements were added on May 2, 2016 to incorporate the new SIR that addresses a pre-screening report, the Preliminary Screening Analysis, and the Supplemental Screening Analysis.

[51] Average processing time for larger projects (300kW to 2MW) have also started to drop but are declining more slowly, perhaps due to the increasing percentage of applications within this category.

[52] For projects of 25kW and less, analysis limited to verifying UL 1547 compliant inverters. For projects from 25kW to 300kW, analysis is limited to verifying UL 1547 compliant inverters and assessing the service transformer size.

The queue is also being addressed through the Ombudsman process with stakeholders working together with Staff and NYSERDA to improve the queue and overall interconnection process. A technical working group is focused on improvements to interconnection technical issues that will ultimately be reflected in revisions to the Commission's SIRs. The Companies generally maintained compliance with SIRs until mid to late 2014, and have since made considerable efforts to improve processes and analytical tools to restore compliance.

Phase II of the Interconnection Portal Process is scheduled for implementation in the third quarter of 2016 and will include correcting issues identified by solar developers in the Phase I portal. Phase II will also include additional project development, the ability to track project expenditures and construction costs, online application fee payment options, and hosting capacity maps. Phase III (2017-2019) will include an initial EPRI benchmarking study to assess feasibility and benefits of automation.

c) Present Challenges

While progress has been made many challenges remain. Application volumes remain high, with a dramatic increase in more complex projects (1 to 2 MW) over the past two years. Large projects require more complex and time-consuming analysis. Application patterns are difficult to predict, which presents challenges to planning resources within the interconnection function. The steady addition of connected DER also requires the ISP function to update model specifications to reflect current circumstances before they can perform detailed interconnection studies.

The rural nature of much of the Companies' service territory also presents challenges to the interconnection process. The low voltage, single-phase circuits frequently require expensive upgrades to enable interconnections. These circuits were designed to deliver energy to customers, but were not designed to deliver distributed generation to the transmission system.

The Companies are making progress in automating the interconnection for small projects (< 300 kW). A lot of discussion has been devoted to whether it is possible to increase automation that would apply to larger projects. EPRI produced a report that expressed many reservations about this prospect.[53]

d) Roadmap and Near-Term Initiatives

The Interconnection requirements capability development efforts are presented in the following roadmap.

[53] "EPRI Gap Prioritization of Opportunities and Challenges", October 2, 2015.

TABLE IV-10: INTERCONNECTION PROCESSES

Near-Term Initiatives (2017-2018)	DSP 1.0 (2019-2021)	DSP 2.0 (2022+)
Assess Interconnection Requirements Additional procedures are required to promote grid optimization and ensure small-scale generation sources can reliably connect to the grid.		
Phase II Portal Adds capabilities to address developer feedback, provide additional project detail, support on-line fee payments, and add hosting capacity maps and "heat maps"		
Phase III Portal Add additional automation capabilities based on EPRI assessment.		
Improvements Based on Technology Investments AMI, CYME Gateway, ADMS, and other technology investments will increase the quality of data, including connected DER to improve interconnection studies.		
Assess Staffing Requirements Monitor queue progress and continue to add staff to the Interconnections group.		

The Companies are also increasing the coordination between ISP and the interconnections group to monitor, identify and implement improvements to the processes related to detailed interconnection studies for larger projects.

C. Cyber Security and Privacy

The Companies take the protection of customer and system data extremely seriously, and will continue to aggressively pursue cyber security at DSP. The Companies have established *Cyber Security Risk Management Framework* and a *Cyber Security Charter & Policy*, which are implemented and managed by the Companies' Corporate Security Organization. This organization is responsible for physical security, cyber security and privacy.

The cyber security framework, charter and policy, along with associated rules and corporate procedures support a governance program for the protection of customer and employee information/data. The governance program and associated controls were developed using industry-standard best practices in addition to legal and regulatory obligations.

The Corporate Security Program focuses on people, processes, and technology to address security and privacy requirements. The charter and policy define a companywide approach to (and acceptance of) the Corporate Security Program, and provides a set of rules, processes, and procedures that must be followed in the management and oversight required to meet the Companies' corporate, legal, and regulatory responsibilities with regard to the protection of information- and system-based infrastructure and associated corporate assets.

The Corporate Security Program controls and protects information related to customers, employees, and the Companies' transmission and distribution infrastructure. A discussion of this program, including a collection of existing cyber security rules, standards, and practices that apply to the Companies, appears in Chapter II.

V. Energy Smart Community and Demonstration Projects

The Companies have developed an Energy Smart Community Project (referred to throughout this DSIP as the "Energy Smart Community" or the "ESC") to serve as a test platform for initiatives and technologies that will be required for the Companies to serve as the DSPP.

The Companies are also implementing a suite of REV demonstration projects that, along with the ESC, are designed to address key policy objectives:

- The development of ESC creates new opportunities for using data to test the DSP, promote DER, and increase system efficiency, reliability, and resiliency, while also creating value for customers and the market;
- The development of an energy marketplace branded *Your Energy Savings Store* (the "Energy Marketplace" demonstration project) will create customer value and reduce carbon emissions;
- The development of a more flexible interconnection process (the Flexible Interconnect Capacity Solution or "FICS" demonstration project) will increase the number of large projects that are able to interconnect on acceptable economic terms; and
- The use of a community-based energy asset planning process (the Community Energy Coordination or "CEC" demonstration project) that considers DER procurement will enhance fuel and resource diversity and animate the market of energy products and services.

Each of these projects is described in the sections that follow.

A. Energy Smart Community

The Companies are testing a variety of innovative initiatives, including customer and community engagement methodologies and an AMI pilot project, through the ESC. The primary objectives of the project include the following: (1) test and prove the functionality of Foundational Platform Technologies; (2) develop new capabilities and processes that support the evolution of the DSP; (3) create and test new rate designs that support system efficiency; (4) identify new methods for creating value for customers; (5) identify new methods for engaging with the market; (6) create an environment of collaboration; and (7) support and inform a clean energy policy.

Successful deployment of the ESC will require investments and development in people, processes, and technologies to gain experience and lessons learned. Leveraging a small-scale environment to build knowledge and expertise will aid the Companies' transition to serving as the DSP operator on a larger scale.

The Companies have selected the Ithaca region as the host location for the ESC. Tompkins County represents a diverse base of customers that is broadly representative of the Companies' larger service area. In addition, the County has established comprehensive energy and sustainability plans that are aligned with statewide energy policy principles. The Energy Smart Community will enable Ithaca and Tompkins County to make significant strides toward their energy and sustainability goals. Ithaca is the home of Cornell University, a major research institution that has made significant commitments to energy and sustainability goals through its Climate Action Plan, research initiatives, local collaborative initiatives with entities in the Ithaca region, and through its Atkinson Center for a Sustainable Future. Leaders from these institutions and organizations have engaged with the Companies and act as partners in the Energy Smart Community. These partnerships will further the contributions made by the ESC to support clean energy policy.

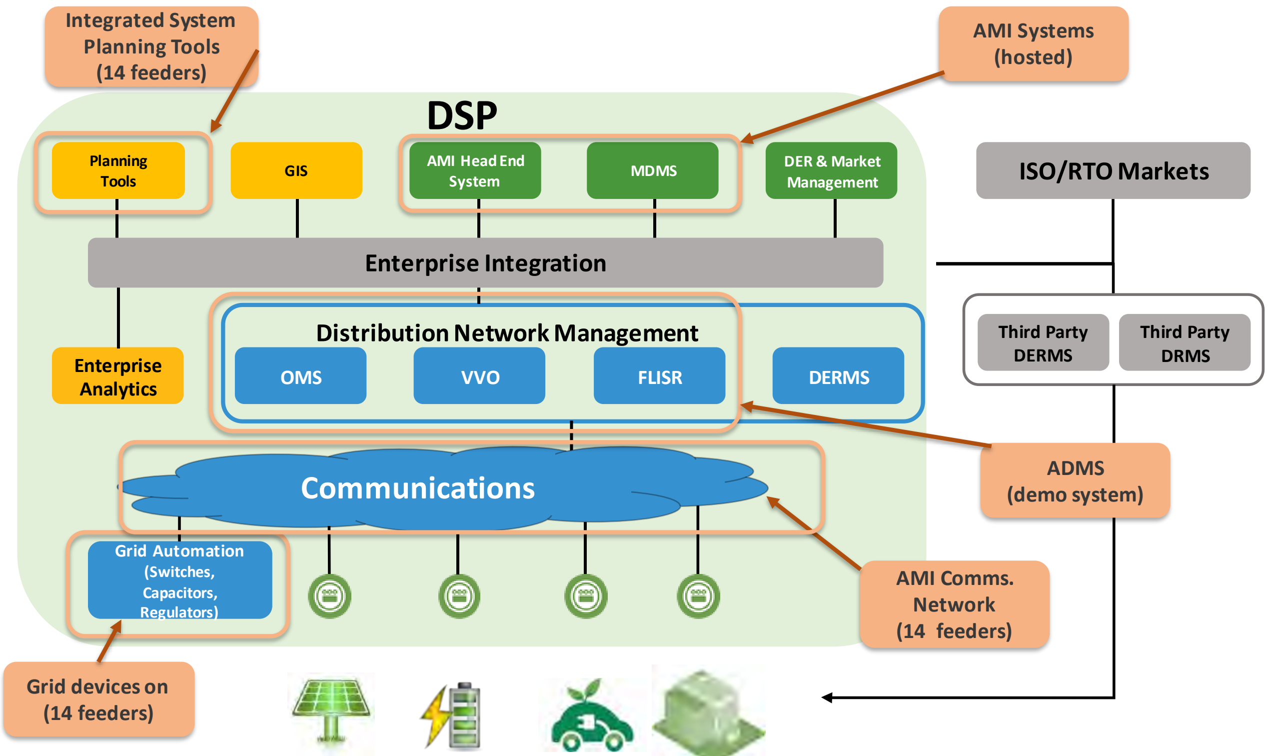
The ESC scope consists of program elements that address the three key core functions of the DSP operator: (1) operate the grid efficiently and reliably, (2) implement new processes and tools for integrated distribution system planning, and (3) support customer and third-party engagement in market operations. Some program elements will be designed, implemented, and managed by the Companies without significant involvement of community or market partners. These elements will involve the integration of foundational investments in technologies and systems that will allow the Companies to test DSP capabilities. Other program elements will build on the collaboration already taking place between the Companies and leaders in the community. Finally, several program elements will leverage market partners interested in proposing market-based solutions to address customer and system needs. These program elements will serve to foster an environment of collaboration.

ESC elements focused on Grid Operations include the following projects: implementation of distribution automation, VVO, deployment of AMI and associated telecommunications infrastructure, and implementation of early phases of the ADMS. The DSP must evolve its grid operations capabilities to enable it to maintain a secure and flexible distribution network. In addition, Grid Operations must be capable of managing demand-side resources, providing real-time network and load monitoring, fault detection and isolation, automated circuit and line switching, and Volt/var optimization. Each of these functions will be tested on a small scale within the ESC before deployment throughout the system in order to gather experience.

The Companies plan to automate all circuit head breakers, voltage regulation devices, reclosers, tie switches, and sectionalizing switches in the ESC. The Companies will leverage the advanced capabilities of smart meters for near real-time monitoring of DER output and status. In addition, as part of the VVO scheme, smart meters will be used to interface with smart inverters to provide voltage and var set points.

Figure V-1 illustrates the ultimate DSP functional block diagram with the projects to be implemented in the ESC indicated.

FIGURE V-1: ESC PROJECTS MAPPED TO BUSINESS AREA (2017-2018)



Source: EPRI with AVANGRID analysis

Integrated System Planning components of the ESC include: DER and load forecasting, calculation of Hosting Capacity, DER Performance Analysis and Assessment and a DER Developer Portal. Implementation of ISP within the ESC will provide a range of benefits: online access to necessary information that supports DER developers and local government planners to support the development of community energy plans and processes to enable third-party participation in market solutions including new products and services, energy efficiency and demand response services.

Market Enablement features of the ESC will identify new methods of creating value for customers engaging with the market. These features include: customer education programs, the use of innovative rates and billing practices, customer analysis and segmentation, and the implementation of an online energy platform and marketplace. The ESC will test approaches to helping customers understand the value of available programs and specific means to control their energy costs. Most importantly, the ESC rate design collaborative will provide a test bed for new rate designs (e.g. time-varying rates) that will help confirm the value of AMI. The ESC will also develop opportunities for market partners to gain access to new markets, retail customers, and the data needed to effectively engage those that will most benefit from energy services. The Companies will collaborate with third-party market providers to support participation in the marketplace and to provide access to data that will inform the evolution of a more robust market for energy products and services.

B. REV Demonstration Projects

The Companies have initiated a series of REV demonstration projects in compliance with the Order Adopting Regulatory Policy Framework and Implementation Plan ("Track 1 Order").[54] These projects are described below.

1. Energy Marketplace

The Energy Marketplace ("EM") will be an RG&E-branded e-commerce site, *Your Energy Savings Store*, which will provide both an innovative customer experience and a meaningful business opportunity for RG&E and its partners. EM was designed to test market engagement approaches and to stimulate market development. The site will bridge the gap between DER products and RG&E customers by providing information to help customers understand and manage their energy use, shop for and purchase energy related products and services, and efficiently connect DER providers with potential customers. The EM enables the Companies to test market concepts and lay the foundation for DSP markets through a better understanding of the required investments in new processes and services for customer engagement and market animation. The EM will allow the Companies to transform into a "transactional platform provider." The EM platform can be adapted to fit the Companies' evolving customer programs, ranging from new energy efficiency programs (market-based options), geo-targeting incentives to support NWA solutions, to financed energy management storage and generation.

<u>Development Status:</u> On April 15, 2016 RG&E filed its Energy Marketplace Demonstration Project Implementation Plan with the Commission. The Implementation Plan reflects comments and recommendations from the Staff assessment report issued March 15, 2016 and RG&E's revised proposal originally submitted to Staff July 1, 2015 and updated January 26, 2016.

RG&E completed its project kickoff meeting with Simple Energy on April 22, 2016. Coordination efforts are currently underway to allow the Energy Efficiency and Demand Response programs to utilize the Energy Marketplace as a distribution channel for each program's initiatives. RG&E is also coordinating between the EM and CEC projects in order to use the Energy Marketplace portal to connect customers with Service Providers. Marketing, branding and customer communication campaigns are currently under development with a soft launch planned for mid-July 2016, with a full launch expected at the end of July, 2016.

2. Flexible Interconnect Capacity Solution

The Flexible Interconnect Capacity Solution ("FICS") tests a new model for interconnecting large-scale controllable DER to the grid. "Controllable" encompasses the ability of the utility to potentially curtail the delivery of electricity generated by a DER to the distribution network. The

[54] Case 14-M-0101 — Proceeding on the Motion of the Commission in Regard to Reforming the Energy Vision, February 26, 2015, at 155-116, 132.

traditional interconnection process requires investments in network facilities (network reinforcements) necessary to accommodate the maximum rated capacity of proposed DER or otherwise limit the capacity that can be interconnected. FICS is a key component of supporting Grid Operations as it moves from supporting traditional utility-scale generation sources to an expansion of support for variable DER.

The Companies are testing whether the ability to manage the delivery of electricity generated by a DER to the grid can lead to a less expensive and potentially faster interconnection alternative to traditional infrastructure upgrades. The FICS concept has been proven by ScottishPower, a Company utility affiliate that serves over 5 million customers in the United Kingdom, and we are looking to build upon this valuable experience. The solution allows the Companies to leverage the distribution system to support a "platform-as-a-service" business model.

FICS will also allow the Companies to leverage the distribution network to support a “platform-as-a-service” business model. As FICS moves from a pilot to full implementation, the Companies will assess the viability of the solution and various methods to prove economic value that will support the business case to scale FICS across the service territory. FICS will scale based on the business case proving it is operationally feasible to curtail DER assets during constrained periods (thermal or voltage).

Development Status: In Q1 2016, the RG&E and NYSEG project team submitted its Implementation Plan and evaluated proposed DER in the interconnection queue for each company to identify FICS candidates, engaged the developers of the leading candidate DER, and conducted a broader stakeholder engagement to advance its proposed FICS platform-as-a-service business model.

The project team held kickoff workshops with representatives across the Companies’ organization involved in DER interconnection and operations, including Transmission Services, System Planning and Protection, Operations Technologies, Energy Control Center Operations, and Customer Service. The project team has actively engaged DER developers to evaluate interest in FICS participation as well as external interconnection stakeholders and industry experts to further evaluate and develop the FICS platform-as-a-service business model.

In its Demonstration Project Q1 2016 Report, the Companies evaluated over 400 DER interconnection studies and identified two leading candidates in the NYSEG service territory as the for the initial FICS demonstration scope: a 2 MW solar PV farm and a 450 kW farm waste biodigester. The Companies are currently on track to commission the first FICS site in Q4 2016 and expect to commission the second site in Q1 2017. In Q2 2016, the project team remains focused on modeling, data gathering and analysis, initial design, and the final design for the project.

3. Community Energy Coordination

The CEC demonstration project will test an innovative approach to reducing customer barriers to the adoption of DER in the NYSEG service territory. The CEC demonstration project is testing whether the Companies can enable community DER related energy goals by taking on the following specific roles within the DER value chain: engaging with community stakeholders; leverage brand with customers as a sales agent for DER; market coordinator for DER by efficiently connecting suppliers with prospective customers. It is expected that all of these roles in the value chain will reduce the cost of DER and increase the number of the Companies' customers engaging in the DER market.

Development Status: NYSEG submitted its Implementation Plan for the CEC project February 4, 2016. NYSEG has partnered with Taitem Engineering to assist with delivering community facilitation and market coordination functions. NYSEG will work to identify DER of interest to the community, solicit interest in DER by marketing directly to customers, and then present identified and qualified customer leads to eligible suppliers.

The project was launched in November 2015 and will be implemented in six phases:

- Phase 0: Development of the implementation plan and contract with project partner (Completed);
- Phase 1: Planning and Community Engagement;
- Phase 2: Project Planning and Market Solicitation;
- Phase 3: Customer Solicitation;
- Phase 4: Market Animation; and
- Phase 5: Evaluation.

Since the launch of the project, NYSEG has reviewed municipal master plans to identify community energy goals across Tompkins County and has conducted over forty meetings with relevant stakeholders to gather input about project offerings and design. The project team has evaluated various options for online platforms and formed a community advisory board with members representing municipalities, local organizations and engaged citizens.

Based on input received from stakeholder meetings, NYSEG has selected three DER to promote: Residential Energy Efficiency, Residential Solar PV, and Community DG. The project team has developed an initial business model and project design based on the input received from conducted stakeholder meetings.

The Implementation Plan includes twelve months of work in 2017 not originally provided for in the July 1, 2015 filing. The project will conclude in December 2017 due to a delayed start and additional time allocated for planning, market solicitation, and construction.

C. ESC and Demonstration Projects: Contributions to REV Policy Goals

As illustrated in Table V-1, below, the ESC and the Companies' demonstration projects will provide opportunities to develop best practices and lessons learned for implementing innovative technology solutions throughout the Companies' service area. The ESC project will include deployment of 12,000 electric smart meters to support telecommunications infrastructure to serve all customers on the 14 footprint circuits.

TABLE V-1: ESC AND DEMONSTRATION PROJECT CONTRIBUTIONS TO REV POLICY GOALS

	Create Customer Value	Animate Markets for Energy Products and Services	Enhance Fuel and resource diversity	Reduce Carbon Emissions	Improve System Efficiency	Raise System Reliability and Resiliency
Grid Operations	• ESC: Improved consumption and interval data through AMI meters • ESC: Operating the system efficiently to ensure affordability	• ESC: Granular system data needed for future transactive markets • ESC: Testing DERMS to support markets	• ESC, CEC: Support increased penetration of clean renewable resources	• ESC, CEC, EM, FICS: Innovative technology partnerships	• ESC: Full deployment test of ADMS for advanced system modelling and control • ESC: Improved system efficiency through VVO • ESC: Peak reductions from innovative rates and AMI	• ESC: Reliability improvement and Outage detection • ESC: Fault location and automated system restoration
Integrated System Planning	• ESC: Access DER our results of planning studies, system data and preferred DER locations	• ESC: Hosting capacity • ESC: A geospatial view of the beneficial locations for DER will be made available to developers	• ESC and FICS: Community Energy plans and goals • ESC: Hosting capacity will support efficient deployment of DG	• ESC: Results of planning studies will improve DER integration • ESC: DER performance analysis and assessment will build transparent models to support DG for planning	• ESC: Using advanced planning data and studies to uncover opportunities • ESC: Leveraging detailed system data for peak load reductions	• ESC: Probabilistic planning studies for increasing penetration of DER • ESC: Hosting capacity and results of planning studies will direct DG developers to optimal locations

	Create Customer Value	Animate Markets for Energy Products and Services	Enhance Fuel and resource diversity	Reduce Carbon Emissions	Improve System Efficiency	Raise System Reliability and Resiliency
Market Enablement	• ESC: Test innovative rate designs and billing formats • ESC, CEC, EM: Interactions through digital channels • ESC, CEC, EM: Increased customer choice • ESC, CEC, EM: Assess LMI needs and potential solutions • ESC, CEC, EM: Analytics and segmentation support targeted messaging	• ESC, CEC, EM: Digital Marketplace with third-party vendors • ESC: New market partnerships through the ESC pipeline • ESC: Improved understanding of energy use and costs • ESC: Innovative rate designs • ESC, CEC, EM: Analytics, segmentation will increase efficiency of DER markets	• Community Energy Coordination demonstration project • ESC: AMI enabled DER marketplace	• ESC, CEC, EM, FICS: Partnerships for new services for a clean energy future • ESC, CEC: Provide customers with clean energy choices through marketplace • ESC, CEC, EM, FICS: Support for market participants will increase utilization of clean energy resources	• ESC: Leveraging analytics to provide information to improve communications • ESC, CEC, EM: Improved education and communications • ESC: Innovative Rate Design incentivizes resource utilization at times that maximize system efficiency	• ESC, EM: New programs for energy efficiency and demand response • Flexible Interconnect demo. project

D. LMI Customer Engagement

The demonstration projects and ESC will assess opportunities to engage with LMI customers on a more comprehensive level to reflect LMI DER considerations. Our approach will also address, to the extent feasible, barriers to and opportunities for engaging with LMI customers, reflecting those identified by the Clean Energy Advisory Council.

E. Pipeline of Future Demonstration Projects

The Companies have developed an Innovation Pipeline process they will use to develop supplemental demonstration projects that will be included in the ESC. This process is designed to leverage the ESC as a test bed environment for supporting a portfolio of innovative demonstration projects, ensuring that it maximizes resources to realize compounded value for the Companies becoming the DSP. The Pipeline process will also serve to increase the value realized within the ESC by leveraging access to 'utility-of-the-future' investments, research and development, and innovation efforts being undertaken by the Companies' utility affiliates.

At this time, the Companies have identified opportunities for new demonstration projects that will be used to explore components of the Companies' plans for the DSP and Smart Integrator roles that will mature over the course of DSIP planning period. The Companies are currently in the initial planning and ideation stages, focused on business models and potential partnerships in three areas: electric vehicles, dynamic load control, and energy storage demonstration concepts. The Companies will file for approval for proposed new demonstration projects pursuant to the process established by the Commission in the Track 1 Order.[55]

The Innovation Pipeline process is designed to be transparent to ensure that internal and external stakeholders are able to understand how best to engage in the project development process. This transparency will also help to set and maintain realistic expectations for demonstration outcomes and success. A milestone "gate" approach will involve an iterative process to ensure that (1) the Companies assess opportunities holistically, (2) solutions are meeting real needs, (3) solutions are viable, and (4) solutions are aligned with long term DSP strategy.

To ensure the ESC maximizes investments and advancements that take place throughout the electric industry, the demonstration project development process will continue to engage the market in its efforts to develop innovative solutions to challenges on the distribution system. By partnering with third parties, the ESC will be better able to manage risk, optimize available resources, and develop more robust markets for new energy products and services.

[55] Case 14-M-0101. Order Adopting Distributed System Implementation Plan Guidance, April 18, 2016. Case 14-M-0101. Order Adopting Regulatory Policy Framework and Implementation Plan, February 26, 2015.

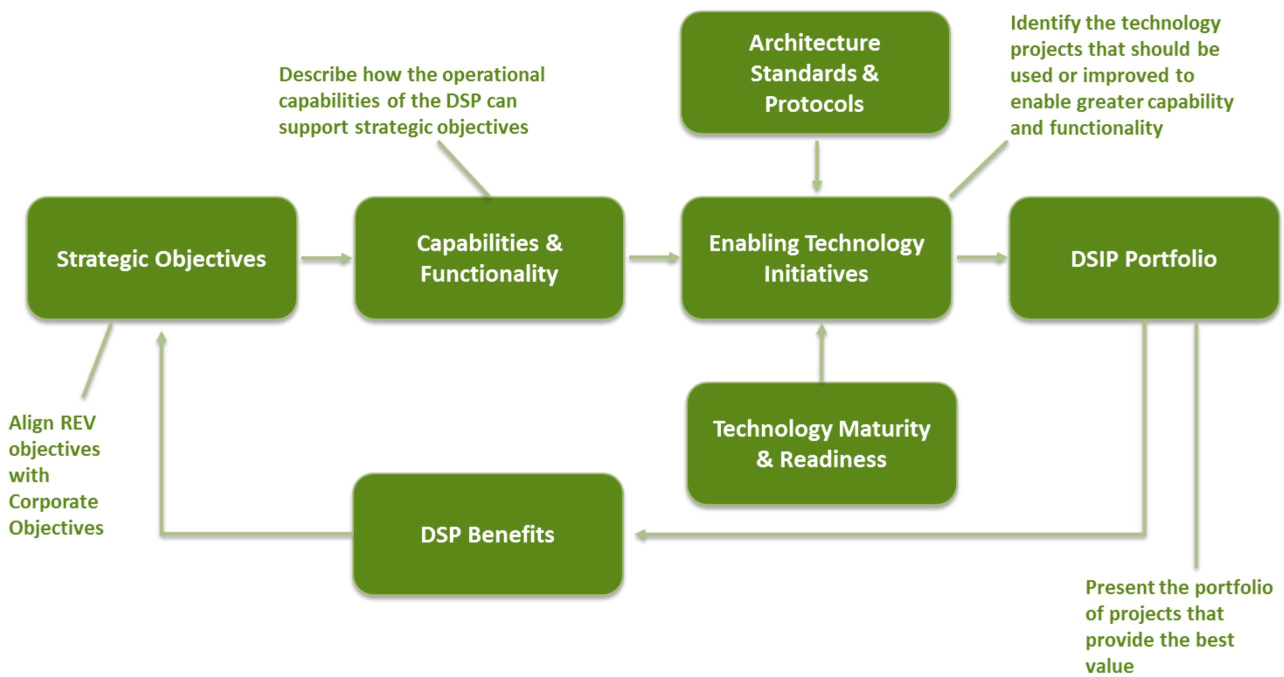
VI. Technology Platform

A. Technology Approach

Advanced technology will enable the DSPP to maintain safe, reliable and efficient operations while supporting the ability to connect and integrate significant DER. The Companies have identified five foundational technologies that work together to support the three core DSP functions: Grid Operations; Integrated System Planning; and Market Enablement.

As shown in Figure VI-1, the Companies applied a "Line-of-Sight" methodology that starts with the DSPP objectives, defines all of the necessary capabilities, determines the foundational technologies, and establishes a set of specific technology projects that together will enable the greatest capability improvements and associated functionalities. The Commission recognized this approach in its Track 1 Order.[56]

FIGURE VI-1: LINE-OF-SIGHT APPROACH TO TECHNOLOGY IMPLEMENTATION



Source: Bridge Energy Group

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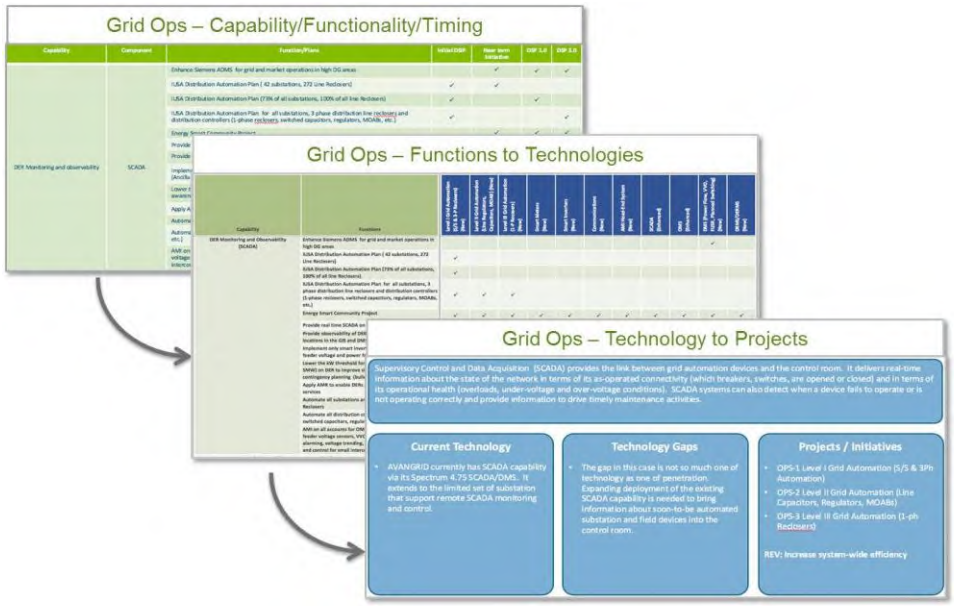
[56] The Commission's Track 1 Order, citing the Straw Proposal issued by the Platform Technology Working Group, noted that, "[t]he Report includes a preliminary list of DSP market functionalities to guide the development of technology protocols, and states the importance of *a clear line of sight from policy goals to functionalities to technology investments*." Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), Page 94, emphasis added.

Figure VI-2 describes how the Line-of-Sight methodology follows a logical path from (1) the three core DSP functions and required capabilities to (2) identification of certain “foundational technologies” to (3) specific technology projects.

FIGURE VI-2: MAPPING FUNCTIONS TO FOUNDATIONAL TECHNOLOGIES TO PROJECTS



The DSP functions and capabilities described in Chapters II-IV drive our technology investments. This initial step identified the processes and technologies that will be needed to support these functions in order to effectively plan, monitor, and control the grid of the future. The assessment considered emerging industry trends and the potential impacts of these trends on the physical grid design and how the Companies will manage our responsibilities as a DSP. Grid Operations requires new technologies to accommodate high DER penetrations and to monitor and operate the distribution system on a real-time basis in order to maintain power system stability, power quality, resiliency, and reliability of service to every customer throughout the Companies’ service areas. ISP requires more granular information including load data enabled by AMI telecommunications, DER performance data, and distribution system performance data in order to perform planning studies and provide system data and insights to market participants. Finally, Market Enablement requires technology enhancements to engage customers in new products and services communicate customer and system data securely to market participants, and to support more complex customer support functions, including billing.

1. *Five Foundational Platform Technologies*

Assessing the implications of these new requirements as an integrated whole, the Companies identified five foundational technologies that comprise the “Foundational Platform Technology” that enables the DSP:

(1) **AMI:** an integrated set of technologies that collect interval energy usage data through smart meters, validate and store the data in a database, provide customers access to their own meter data through a web portal, and provide behind-the meter monitoring and control capabilities;

(2) **Distribution Automation:** an integrated application of technologies that enables the automated or centralized control of power quality, reliability and flow conditions on circuits;

(3) **Telecommunications & IT:** systems that enable communication between network and customer equipment and Companies’ systems to comprise the technology platform;

(4) **Advanced Distribution Management Systems:** a set of systems that help manage and control the network, optimize network performance, respond to outages, and support the integration of DER; and

(5) **System Analysis and Planning Tools:** customized tools that utilize data compiled by Companies’ systems and databases and perform complex analyses to support all three core DSP functions.

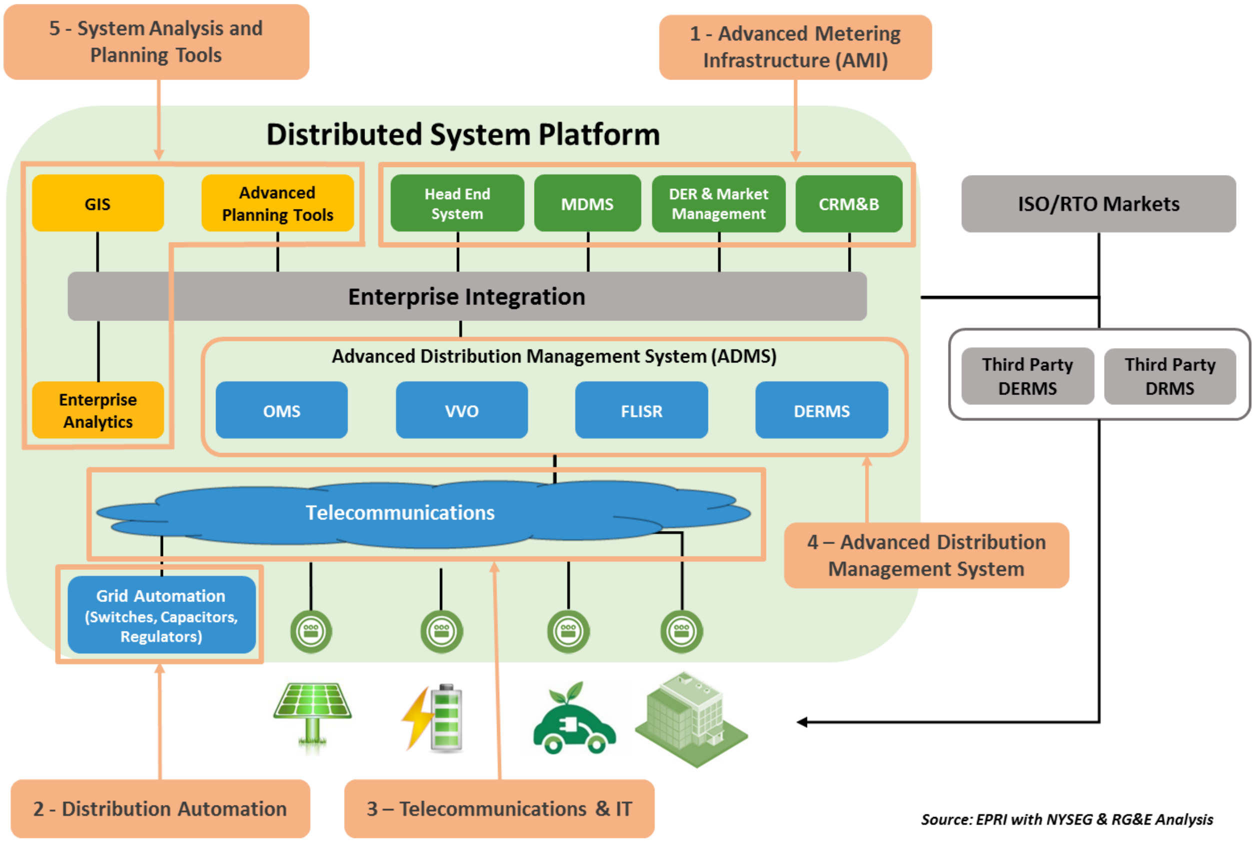
Two automation-related investments (the initial phase of DA, and certain telecommunications investments) were included in the Companies’ recent rate case and in the 2016 five-year capital plan. The initial phase of DA is a foundational investment because it will allow the Companies to monitor and control the distribution network in ways that improve reliability, resiliency, service quality, service flexibility, and operational efficiency – desirable outcomes that respond to observed increases in intermittent resources.

The Companies intend to implement and test each of these five Foundational Platform Technologies, scaled as appropriate, in the ESC in order to validate assumptions, assess capabilities, and establish plans to expand to full-scale implementation.

2. *DSP Technology Structure*

When combined with enhancements to approximately fifteen existing technologies (identified in Figure VI-3 by solid coloring), the five Foundational Platform Technologies form the comprehensive technology platform to support the DSP. This figure provides an overview of the key grid architecture elements and identifies their interaction with the markets, third-party service providers, and distributed energy resources.

FIGURE VI-3: TECHNOLOGY STRUCTURE OF THE COMPANIES' DSP

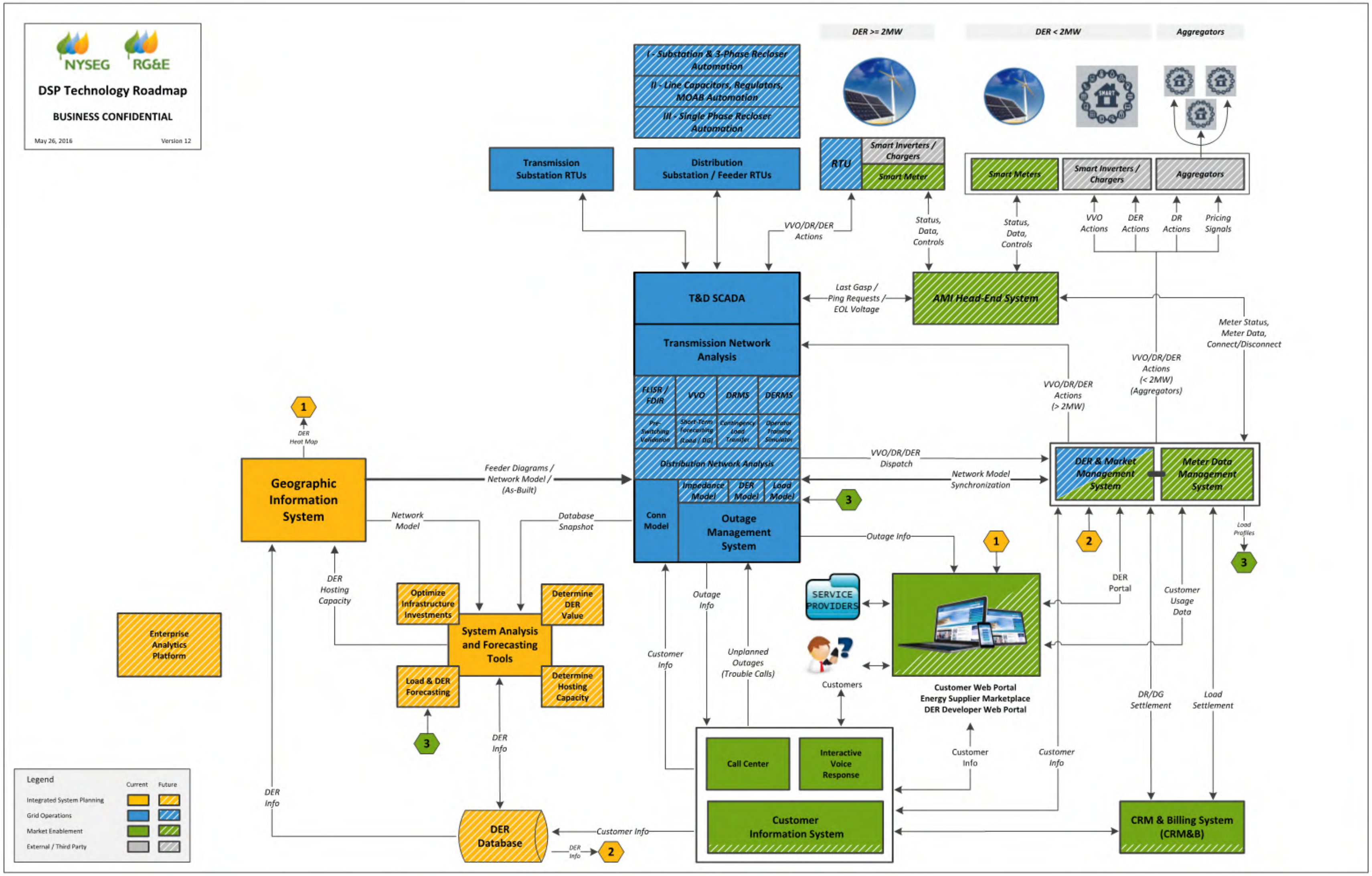


Source: EPRI with NYSEG & RG&E Analysis

Some of the existing technologies will require enhancements and upgraded linkages to other technologies and systems. These systems include work and asset management systems, customer information and billing systems, and several existing systems designed to manage a traditional network. Thus, several systems may support a single function or capability, or an individual system may support multiple functions and capabilities. For example, the increased monitoring and observability into the distribution network through AMI, grid automation, and the ADMS will enable grid operators to manage the grid and optimize DER under both normal conditions and outage events, and provide increased operating flexibility and efficiency. These tools will be supported by a common secure and scalable telecommunications network.

A more comprehensive mapping of the relationships and connections among the many existing and new systems that comprise the Foundational Platform Technology is presented on the following page.

FIGURE VI-4: DSP TECHNOLOGY ROADMAP



3. *Telecommunications and IT*

The Companies currently operate a number of application-specific telecommunication networks within and between the Companies. The separate telecommunication networks are comprised of a mix of networking technologies, including wireline and cellular telephone services, radio and fiber optics. The network technology elements are loosely woven together to support the basic connectivity needs demanded for operational services such as Telecontrol, Teleprotection and Telemetering. Operational voice services are provided over the collective network to electric substations and gas gatehouses for voice coordination of activities.

Operating the DSP will have significant implications for the Companies' telecommunications strategy and specific technology decisions. The Companies anticipate implementing a private or a hybrid public/private network to fully implement a smart grid network, and constructing a broadband telecommunications backbone as a foundational element of the smart grid. This will be necessary to achieve the two-way telecommunication that underlies most smart grid functionality, and cost efficiencies would be achieved by avoiding a piecemeal approach to deployment.[57]

As shown in Table VI-1, the telecommunications approach can be segregated into the three primary capabilities that will be required.

TABLE VI-1: TELECOMMUNICATIONS AND IT PROJECTS AND DESCRIPTIONS

Project	Description	Contributions to DSP
DA Telecommunications	Multi-layer topology of high-speed backhaul and wireless for communication with grid automation devices. Leverages AMI infrastructure.	Supports full spectrum of DSP use cases including interval meter reading, outage management, DA, and DER integration. Network also supports telecommunications to distribution network sensors and controls as well as devices that are owned by third parties.
AMI Telecommunications	Neighborhood Area Networks ("NAN") comprised of private radio, cellular and power line communications technologies.	Supports several utility platform functions including new products and services that are responsive to time-varying pricing ("TVP") signals. Provides data to support several grid operations and system planning functions, including OMS.
DER Telecommunications	Telecommunication network for interfacing to behind-the-meter devices - gross (vs. net) consumption, generation and storage, potentially control signals to DER	Necessary to measure demand response and DER loads; enables control of DG.

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[57] The Companies have shared these perspectives in comments submitted in Case 10-E-0285.

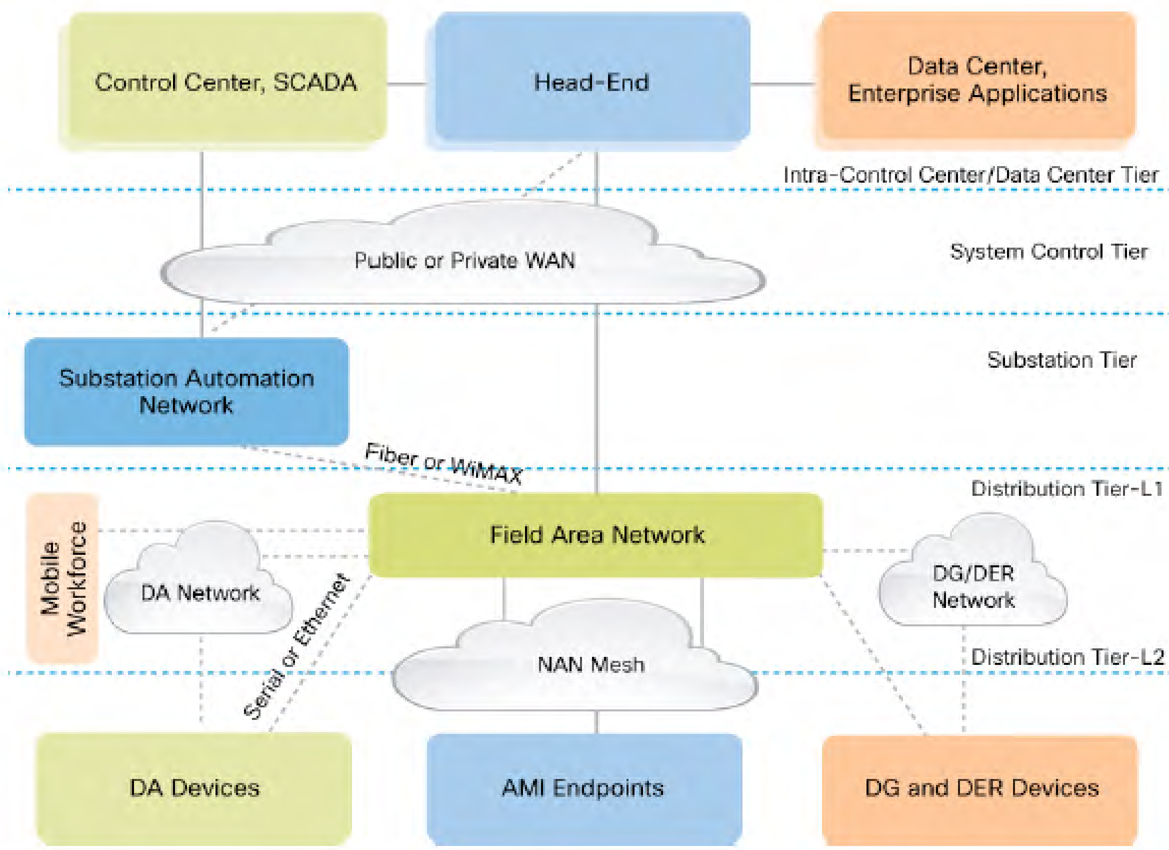
The Companies will address telecommunications needs through a multi-tiered network approach, including use of NAN, FAN, Wide Area Networks ("WAN"), and virtual network overlays to achieve REV goals.

NAN: NAN will address AMI telecommunication with the meters, and facilitate behind-the-meter capabilities envisioned for DER support. NAN solutions today can be comprised of private radio, cellular and power line telecommunications technologies. Build-out of NAN will occur in the context of the AMI solution rollout.

FAN: Field-Area Networks ("FAN") will consolidate telecommunications from the NAN to take-out points on the WAN. Field area networks are expected to consist of broadband radio to address combined needs of metering and grid automation. The DA plan is presently being executed to create and leverage FAN infrastructure.

WAN: Wide-Area Networks ("WAN") will transport data to/from the regional network gateways to/from the data centers. It is anticipated that WAN will consist of a mix of technologies from third party and utility owned networks. Third-party networks may include broadband Ethernet and Internet Protocol/Multi-Protocol Label Switching services. Private network technologies are expected to be based on Ethernet over utility owned fiber optic and microwave links. The WAN will continue to grow and evolve. Service locations, quantity and types of services, and timing of project needs will drive the pace and breadth of the WAN evolution. An intercompany, high capacity Carrier Ethernet core network links RG&E and NYSEG control centers and customer contact centers within the New York data center.

FIGURE VI-5: TELECOMMUNICATIONS TECHNOLOGY PROJECTS



Source: CISCO, http://www.cisco.com/c/dam/en_us/solutions/industries/docs/energy/C11-696279-00_cgs_fan_white_paper.pd

Virtual Networks: Virtual networks will be overlaid on the NAN/FAN/WAN based on data traffic classification and flows. Data that requires low latency performance will be afforded priority access over the links. Data flows between source and destination equipment/systems will be enforced by explicit rules in accordance with systems security policy and practices. Data sessions will be authenticated per device and per user. Data will be protected in storage and in transit through various levels of encryption.

The Companies will integrate customer and third-party metering and telecommunications equipment through utilizing smart meters as a conduit for interfacing between customer/third-party meters and telecommunication equipment. The interface will be utilized for monitoring and communicating operating set points. Envisioned functionality includes interval metering of smart inverter AC output, conveying operating mode (e.g. power factor control, voltage control, etc.) and set points for the selected operating mode.

B. Distribution Automation and DSP Projects

1. Portfolio of Distribution Automation and DSP Projects

The final step in the Line-of-Sight methodology is the definition of five specific DA and DSP projects, as distinct from AMI that is discussed in Chapter VII. These five projects are presented in Table VI-2: Portfolio of Distribution Automation and DSP Projects. Since technology changes rapidly, the Companies have collaborated with our global Iberdrola Networks peers to leverage lessons learned and solicited information directly from industry vendors to assess the status of products and/or services currently available on the market in support of the DSP functions.

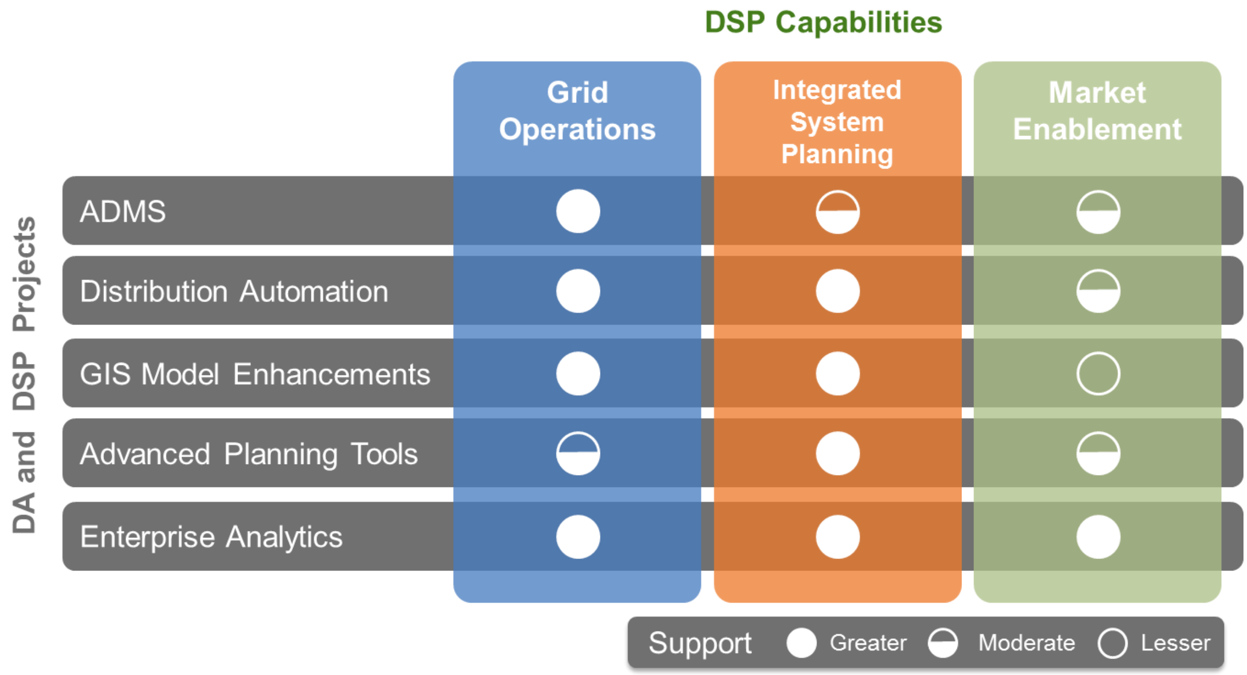
Each DSP function was then mapped to one or more commercially viable technologies that could support the function, and a technology roadmap was developed to address the monitoring, telecommunications, information technology ("IT") and operational technology ("OT") systems needed to support the DSP functions. A technology roadmap was used to identify specific projects to ensure the technology was introduced in a logical manner, taking into account availability of data, maturity of the technology, and interdependencies between the projects.

TABLE VI-2: PORTFOLIO OF DISTRIBUTION AUTOMATION AND DSP PROJECTS

Technology Project	Description
Advanced Distribution Management System (DA)	Expand the Siemens Spectrum system to include distribution power flow, VVO, DR, DERMS, FLISR. The ADMS will enable DER visibility and control and support DER transactions.
Distribution Automation (DA)	Automate the line regulators, capacitors, sectionalizers, tie switches and single-phase reclosers to enable control over network facilities.
GIS Model Enhancement (DSP)	Enhance the GIS grid model to provide DER and impedance data for planning and operations to enable and enhance interconnections analysis, hosting capacity analysis, circuit optimization, Volt/var control, and other functions.
Advanced Planning Tools (DSP)	Provide the capability to determine the DER hosting capacity in a manner consistent with the other New York Utilities, accurately forecast load, incorporate distributed generation and energy storage into Integrated System Planning, and implement a DER Developer Web Portal to communicate system data and accept interconnection requests.
Enterprise Analytics Platform (DSP)	Develop a comprehensive Enterprise Analytics Platform to fully leverage the vast quantities of granular system and customer data that supports our vision for Data Management, Business Intelligence, and Advanced Analytics.

The support each of these projects will provide to the three core DSP functions are illustrated in Figure VI-6, below.

FIGURE VI-6: DISTRIBUTION AUTOMATION AND DSP PROJECTS, DSP CAPABILITIES



2. Advanced Distribution Management System

The ADMS is comprised of the several interrelated systems that are required to operate a high-DER penetration network and is estimated at this time to require an investment of approximately $24.7 million, as illustrated in Table VI-3, below. A key capability of the DSP is the ability to plan, monitor and control all DER connected to the distribution grid in order to ensure the reliability and resilience of the network. The objective is to consider all distributed energy resources connected to the distribution grid, regardless of size, for voltage and var support for system efficiency, reliability, and safety. This will require that the DSP be aware of all DER in the system, grid connection, potential grid contributions, control capabilities (e.g. direct control or through third-party providers, telecommunication protocols), and market program incentives or constraints that may impact the ability to control the resources.

TABLE VI-3: ADMS PROJECT COSTS BY CATEGORY

($ Millions, 2016)

	2017	2018	2019	2020	2021	Total
IT Hardware Purchase & Installation	-	-	$0.08	-	$0.08	**$0.16**
Software Purchase & Installation	-	-	$8.40	$8.01	$8.16	**$24.58**
Total	-	-	**$8.48**	**$8.01**	**$8.24**	**$24.74**

The ADMS will provide real-time circuit optimization, DER monitoring and control and enhance our existing capability to provide applications such as:

- Power flow, which improves visibility into the state of the network;
- Demand response, which can reduce peak demand and resolve capacity issues;
- DER control, which can control distributed generation and storage to improve voltage quality; and
- FLISR that employs SCADA–enabled switches at key points in the distribution system to detect outages, isolate the faulted areas and restore service. These capabilities reduce and improve reliability.

The ADMS tool suite also enables study-mode and advanced pre-switching validation. This enables more informed decision-making by the grid operator.

ADMS includes a DERMS that manages distributed generation, energy storage, demand response, and other DER technologies, including commercial aspects. The DERMS will be supported by a DER database that stores the location, interconnection details, type, capacity, charging/discharging rate, monitoring and control capabilities, planned connection date, and connection status among other information. DERMs can increase the efficiency of DR programs, improve circuit voltage profiles, and contribute to peak shaving. To do this effectively, DERMs needs to be aware of the location and electrical characteristics of the devices on the network that contribute to load, generation, and storage in order to ensure power quality, and to enhance energy efficiency.

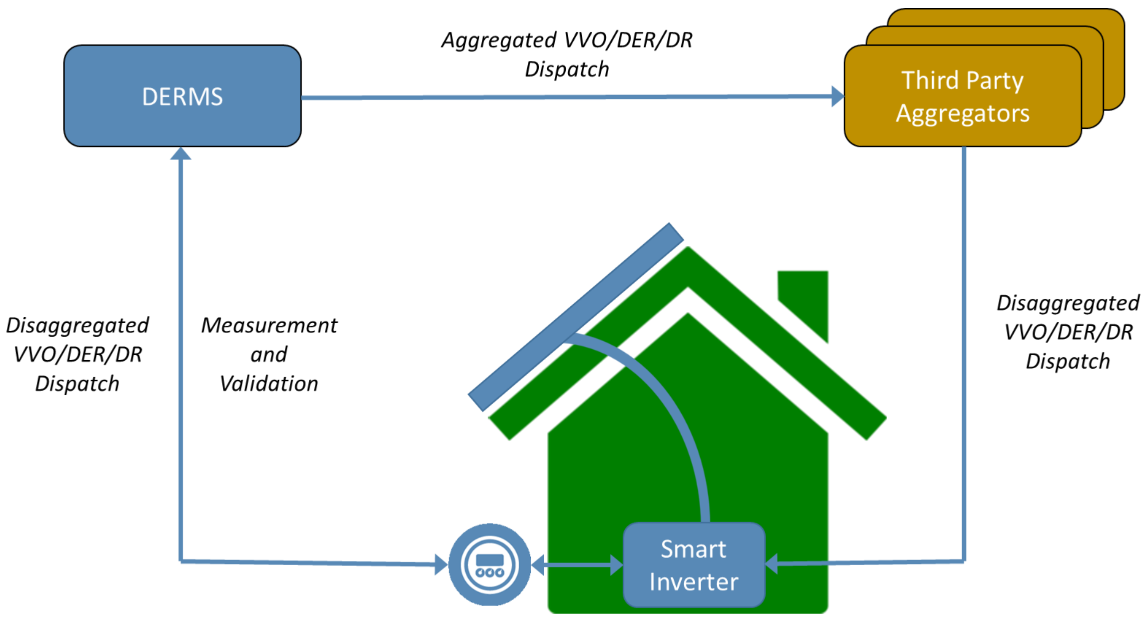
More specifically, the DERMS will provide the following capabilities:

- **Customer Engagement and Enrollment**: This will provide the ability to create and manage programs and constraints for all customer classes, for both economic and reliability dispatch, as well as integration with a future CRM&B System for managing customer and third-party service provider enrollment.
- **Aggregation**: This will provide the ability to create DER groups for DER management. It is envisioned that DER groups will be the primary dispatch mechanism of the ADMS/DERMS based on the grid architecture (voltage control zones, etc.).

- **Dispatching and Scheduling**: Resources will be dispatched from the ADMS on an aggregated/group basis; the DERMS will disaggregate the dispatch and issue the appropriate controls - either directly to the customer through the smart meter, or to third-party service providers.
- **Settlement**: DERMS will be tightly integrated with the MDMS to automate billing and settlement for both load and generation. This will provide the capability to track the service requested (watts, volts, vars) of each third party, and validate that the requested service was provided.

DERMS will also have the flexibility and scalability to interact with third parties (i.e. individual customers or aggregators) for voltage and var control services related to DER.

FIGURE VI-7: DERMS CONSTRUCT



The ADMS will support the ability to perform VVO to reduce overall energy consumption and peak demand and improve voltage quality. VVO optimizes circuit performance and reduces line losses. It manages circuit level voltage in response to the varying load conditions by controlling transformer Load-Tap Changers ("LTC") and voltage regulators. Optimized capacitor switching allows for enhanced power factor correction. DER are also planned to be part of the VVO control scheme.

The VVO plan is based on Level II automation plan implementation because it is dependent on the automation of line regulations and capacitors to incorporate grid-side resources into the VVO scheme. A VVO algorithm will be designed that corresponds to the operating requirements of the Companies' system. The plan contemplates that smart meters will provide voltage sensing to support VVO and also anticipates the participation of DER in providing voltage and var services. Smart inverters on DER will allow voltage and var set points to be implemented as necessary to avoid counteracting the contribution of grid-side resources in the overall VVO scheme.

The deployment of VVO will begin in the ESC project. This project will include automation of grid-side voltage and var resources on the ESC's fourteen distribution circuits. End-of-line smart meters in ESC will be used for voltage sensing. DER in the ESC will be requested to provide voltage and var support services. VVO will expand across the Companies' service territory based upon Level II automation, DER penetration, and smart meter implementation. Expanded implementation of smart meters will provide end-of-line voltage sensors to VVO control scheme for all circuits.

3. Distribution Automation

The Companies have been implementing the first phase of DA (Level I), and are planning two additional phases in this Initial DSIP. DA elements are comprised of smart sensors, reclosers, regulators, capacitor banks, processors, and supporting telecommunications networks that allow the distribution utility to control flows on circuits in response to system flows and events. For example, DA will enable automated circuit switching capability whereby we can diagnose problems remotely (without sending a crew) and then re-configure the network to either prevent an outage[58] or isolate a fault to the smallest possible impact area and restore power to the rest of the circuit, contributing to more efficient, safe, and expedient restoration of service.

The Companies' vision is to have all distribution controllers automated, and we have been moving toward that goal since 2010 by purchasing only automation-ready controllers, electronically-controlled reclosers and switched capacitor banks. Automating these devices will provide SCADA visibility, alarm notifications, and remote control capabilities to grid operators resulting in reduced customer outage minutes and fewer field crew truck rolls. The Companies are executing the DA plan in three phases.

TABLE VI-4: DA PROJECTS AND DESCRIPTIONS

Project	Description	Contributions to DSP
Level I DA	Automate all substations and three-phase reclosers.	Reduce the scope and frequency of power outages, and improve the operational and energy efficiency of the distribution system. Automating the line regulators, capacitors, and motorized air breaker switches will support VVO, circuit optimization, and power restoration applications.
Level II DA	Automate all line regulators, capacitors, and strategic switches.	
Level III DA	Automate all single-phase reclosers.	

[58] With automatic sectionalizing and loop schemes, there is a potential to isolate to a faulted section of the sub-transmission network with no customer connections.

The Companies are currently executing on Level I of the plan, as described in detail in the Companies' five-year CIP. In order to improve system reliability, resiliency, and efficiency of the distribution grid, the Companies are planning a three-stage grid automation program. Level I includes automation of all substations and three-phase reclosers. The automation of substation and three-phase reclosers will provide remote visibility of these devices to SCADA and OMS. This initiative will allow the system operator to view alarm notifications and unplanned operations, and allow remote control of these devices to restore outages in a timely manner. This will result in faster outage response, reduced outage minutes, reduced truck rolls, and reduced on-site crew time for restoration activities. The Level I implementation schedule will be adjusted to prioritize the automation necessary to implement the ESC project.

Level II and Level III automation is incremental to our prior DA investments that were included in the 2016 CIP, and are estimated at this time to cost $190.2 million. See Table VI-5, below.

TABLE VI-5: DA PROJECT COSTS BY CATEGORY

($ Millions, 2016)

	2017	2018	2019	2020	2021	Total
Network/Telecommunications Equipment	$9.23	$10.76	$11.17	$11.43	$11.71	**$54.29**
Distribution Automation Devices	$22.95	$27.25	$27.89	$28.55	$29.23	**$135.86**
Total	**$32.18**	**$38.01**	**$39.06**	**$39.98**	**$40.93**	**$190.15**

Level II includes line regulators, line capacitors, and gang-operated switches to enable Volt/var optimization, optimal circuit switching, and FLISR applications. Level III automation includes single-phase reclosers to further increase situational awareness and granularity of control. This phase would complete the grid-side vision. Integration of real-time DER monitoring and control would complete the overall vision of distribution automation and optimization. See Table VI-6 and Table VI-7 for the three-phase recloser automation plan and substation automation plan, respectively.

TABLE VI-6: THREE-PHASE RECLOSER AUTOMATION PLAN

3-Phase Recloser Automation Summary - NY (SCADA Mates are included)								
Year	NYSEG			RG&E			Automation Completion Percentages	
	Total automated at YE	Planned #/yr	% complete at YE	Total automated at YE	Planned #/yr	% complete at YE	NYSEG	RG&E
2014	95		16%	158		62%	16%	62%
2015	112	17	19%	182	24	71%	19%	71%
2016	157	45	26%	236	54	93%	26%	93%
2017	244	87	41%	255	19	100%	41%	100%
2018	357	113	60%	255	0	100%	60%	**100%**
2019	508	151	85%	255	0	100%	85%	100%
2020	595	87	100%	255	0	100%	100%	100%

TABLE VI-7: SUBSTATION AUTOMATION PLAN

Substation Automation Summary – NY								
Year	NYSEG			RG&E			Automation Completion Percentages	
	Total automated at YE	Planned #/yr	% complete at YE	Total automated at YE	Planned #/yr	% complete at YE	NYSEG	RG&E
2014	250		53%	122		72%	53%	72%
2015	251	1	53%	122	0	72%	53%	72%
2016	256	5	54%	124	2	73%	54%	73%
2017	265	9	56%	132	8	78%	56%	78%
2018	275	10	58%	147	15	86%	58%	86%
2019	290	15	62%	151	4	89%	62%	89%
2020	314	24	67%	159	8	94%	67%	94%

Level II and Level III automation will begin in the Ithaca area as part of the ESC project. This will include gang-operated switches for circuit optimization and FLISR. The automation of voltage regulators and capacitors will allow the operator to perform VVO from the control room, adjusting settings on both types of devices based on real-time information collected from the field.

The automation of capacitors will allow the operator to manually reduce losses through improvement of the power factor, reacting to the real-time var flows, by remotely adjusting capacitor bank settings, as opposed to sending crews to configure capacitor banks to a fixed setting annually or seasonally.

The automation of voltage regulators will allow operators to exercise manual or rule-based CVR based on real-time voltage readings along the circuits. CVR for short periods of time achieves peak reduction to resolve capacity deficiency emergencies or to reduce capacity payments, and/or to defer capacity additions/upgrades.

CVR for longer periods of time achieves energy conservation by improving voltage profiles over a wider range of generation and load conditions. Regulator and capacitor automation, along with the implementation of the ADMS and integration of DER, will yield significant results for VVO. Adding end-of-line voltage sensors from smart meters, as discussed in Chapter VII, will yield an even higher level of optimization.

The automation of strategically located switches, serving as tie switches and sectionalizing switches, will allow operators to operate these devices from the control room, thereby (1) restoring power more quickly to customers who would otherwise have to wait for crews to be dispatched to the site of these switches, (2) eliminating the need for crews to travel to operate these devices during planned and unplanned outages (typically twice per outage, once to switch to the abnormal configuration and later to switch back), and (3) performing remote circuit switching to optimize the grid based on varying load and DER output scenarios (e.g. light load during periods of high DER output).

Customers can expect better voltage quality as a result of the availability of voltage data from regulators and capacity banks on the distribution system. These data and the ability to remotely control voltage at these sites provide the ability to maintain voltage more reliably between the industry standard limits, ensuring better operation of customer electric equipment.

The Level III initiative to automate the single-phase reclosers will provide SCADA visibility, alarm notifications, and remote control capabilities to System Operators resulting in reduced customer outage minutes and fewer field crew truck rolls. This provides further granularity of grid control and better outage isolation capabilities.

4. GIS Model Enhancement

The Companies currently maintain a connectivity model of the distribution network in its GIS sufficient for the OMS application, but it is not sufficient for advanced distribution management applications such as distribution power flow, Volt/var optimization, DERMS, etc. In addition, we need to be aware of the location and electrical characteristics of the distributed energy resources on their network that contribute to load, generation, and storage in order to plan effectively, to ensure power quality, and to enhance efficiency. The Companies do not currently have an enterprise-accessible repository for storing information about existing and planned DER installations. As such, additional data needs to be populated in the GIS, such as impedance model and DER model information, to support these functions. In addition, the quality of the existing data must be improved in order to ensure accurate power flow and Volt/var results. This will provide a single complete and accurate model of the distribution network for the purposes of distribution planning and real-time operations.

The Companies plan to make the existing GIS the system of record for both system planning and real-time operation tools, aligning the model of the GIS with the needs of the systems it serves, expanding existing interfaces with those systems and putting in place governance to ensure that changes made to the distribution network in the field are corrected in the system or record and reflected in the model in a timely manner. This applies to other corporate systems as well. Having the GIS serve as a central repository will eliminate the duplication of effort that would otherwise be required to maintain the separate distribution planning and real-time operations models. The total estimated investment to enhance the GIS model is $26.9 million, as illustrated in Table VI-8.

TABLE VI-8: GIS MODEL ENHANCEMENT PROJECT COSTS BY CATEGORY

($ Millions, 2016)

	2017	2018	2019	2020	2021	**Total**
Software Purchase & Installation	$7.45	$6.29	$6.48	$6.67	-	**$26.88**

5. Advanced Planning Tools

Advanced planning tools refer to analytical methods and tools required to support new DSP requirements. There are three current requirements for advanced planning tools and more may be added over time.

(1) **DER Developer Web Portal:** The DER Developer Web Portal will provide a platform for the Companies to communicate beneficial locations for DER deployment to external service providers, and to accept interconnection requests from potential DER developers.

(2) **Hosting Capacity:** The DSP must be able to determine the amount of DER that can be accommodated without impacting power quality or reliability under existing control and infrastructure configurations, referred to as hosting capacity. In order to enable the determination of hosting capacity into the planning process, we plan to integrate additional tools. This information will be exported in a geospatial view to produce a DER heat map, which will be made available to external third-party providers through the DER Developer Web Portal.

(3) **Load Forecasting:** The results of planning studies are key drivers for utility decisions to reinforce the distribution system. Accurate planning studies require accurate load forecast data and, with the increasing penetration of DER, accurate DER forecast data. The Companies' existing forecasting tools extend to load only, and do not utilize the AMI meter data that will soon become available. This initiative will identify, assess and adopt a commercially available load and distributed generation forecasting tool.

The total estimated investment to develop advanced planning tools is $4.2 million. See Table VI-9, below.

TABLE VI-9: ADVANCED PLANNING TOOLS PROJECT COSTS BY CATEGORY

($ Millions, 2016)

	2017	2018	2019	2020	2021	Total
Software Purchase & Installation	$0.44	$0.10	$2.78	$0.89	-	**$4.22**

6. Enterprise Analytics Platform

The Enterprise Analytics Platform ("EAP") is being designed as a platform for collecting, collating and analyzing the large amounts of data that will be acquired by new technologies. We anticipate developing algorithms to translate various data into actionable information and intelligence that can be relied upon to inform planning, investment and policy decisions. Thus, the EAP will serve as the DSP engine, and provides access through a data warehouse and user interface functions. It will support a wide range of analyses, projects, and applications by combining and analyzing data from different Company databases. We are currently estimating that we will invest $11.6 million to develop the EAP, as illustrated in Table VI-10.

TABLE VI-10: ENTERPRISE ANALYTICS PLATFORM PROJECT COSTS BY CATEGORY

($ Millions, 2016)

	2017	2018	2019	2020	2021	Total
IT Hardware Purchase & Installation	-	$3.30	$0.60	-	-	**$3.90**
Software Purchase & Installation	$0.64	$4.28	$2.73	-	-	**$7.66**
Total	**$0.64**	**$7.58**	**$3.33**	**-**	**-**	**$11.56**

Data and analytics are foundational to performing as the DSPP. The "smart" revolution is exponentially compounding the amount of grid and customer data utilities generate. The development of the DSP platform will introduce a range of new data in the Companies' service area, including sub-hourly customer consumption data, status information from grid devices, interval measurements of service conditions on distribution circuits, and a growth in DER information. As the volume of data collected increases in magnitude and diversity through the platform investments, the Companies recognize the importance of leveraging data management, business intelligence, and advanced analytics to extract insights from this data in order to help move the business and the market toward a future of informed, proactive and agile decision making. The Companies have developed an analytics prototype for ISP as an initial test of the EAP concept.

The Companies will develop a comprehensive analytics platform to optimize the analytics capabilities and associated disciplines involved in acquiring, managing, transforming, validating, and utilizing data to be collected through the DSP platform. The strategy will focus on enhancing existing processes and reporting, establishing robust governance to ensure data quality for internal and external users, and deploying new toolsets in a structured, thoughtful approach. Analytics will play a key role in each of the three DSP core functions, as outlined below.

Grid Operations: The DSP must operate the grid in a safe and reliable manner as high penetrations of DER are realized. Analytics will be fundamental to enabling intelligent, rapid, and precise control via monitoring and telecommunication infrastructure throughout the distribution system and operating automated solutions across the system.

Integrated System Planning: In an effort to foster a more dynamic and flexible distribution system, the Companies plan to utilize more diverse data sets to better forecast demand, load shape, and DER penetration, and the effects that these factors will have upon grid operations and system efficiency. By bringing together system topology and connectivity (GIS), interval customer consumption (AMI), circuit-level visibility (SCADA), and asset information (property records/SAP), analytics will allow system planners to gain an unprecedented view into the dynamics of the distribution system to manage planning for the complexity of DER integration and two-way power flow. The Integrated Capacity Analysis, as described Distribution Resource Plans[59] filed by the California Investor-Owned Utilities on July 1, 2015, is a prime example of how new layers of analytics fed by granular system data can present views into the distribution system that further the business' and market's understanding of the system's capabilities.

Market Enablement: Data collection and sharing are key factors in achieving REV. Collection, analysis, and sharing of system and data are essential to achieve robust customer engagement and market animation. The Companies will use analytics toolsets to leverage multiple data sources to develop insight and present findings in an intuitive, meaningful format (i.e. geospatial, dashboard, etc.).

[59] Filed in compliance with guidance issued in California Public Utilities Commission Docket No. R.14-08-013,

VII. Advanced Metering Infrastructure Business Plan

A. Introduction

This AMI business plan identifies the various investments that comprise AMI, describes how it will be deployed, and describes the value it will provide to our customers and communities. AMI is the centerpiece of the Foundational Platform Technology the Companies need in order to serve as the DSPP and support the core DSP functions. AMI is essential to the Companies implementation of the "Smart Integrator" future utility model and leverages the Corporation's strengths as a global technology and innovation leader in the energy sector. Investment in AMI is aligned with the vision of our corporate entity and our commitment to carbon reduction, clean energy, energy efficiency, and technology innovation.

This business plan provides our current assessment of AMI deployment to approximately 1.8 million meters throughout our service territory. It presents an implementation schedule of smart electric and natural gas meter installations in both service territories, and describes the key systems that are required to support the acquisition and analysis of data collected by AMI meters. It also identifies innovative rate options. The plan includes a benefit-cost analysis that has been performed consistent with the Commission's BCA order.[60] Finally, the Companies propose an initial set of performance metrics that will measure the value provided by AMI deployment.

A key element of our strategy is to leverage AMI to facilitate the development of DSP capabilities and, most importantly, enable and test new rate designs that will encourage customer and community participation in energy markets and in actively managing their energy use. The Companies will institute a collaborative to address new rate designs within the ESC Project, aligning these new programs with REV objectives for customers and communities.[61] The collaborative for considering rate design initiatives within the ESC Project is also anticipated to address the deployment of AMI beyond the ESC territory. The business plan includes our proposed customer outreach and education programs that we will test and refine as part of the ESC, following collaboration with service providers and other stakeholders. This includes a proposal to implement GBC functionality through the *Energy Manager* web-based tool.

The AMI deployment will consist of six key elements:

(1) An integrated system of smart meters (both electric and natural gas) that capture customer usage data and other characteristics at defined intervals;

(2) A telecommunications network and associated IT infrastructure for acquiring meter and field device data, and enabling DA;

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[60] DSIP Order, Attachment 1, page 12.

[61] New York Public Service Commission. Order in proceedings 15-E-0283 and 15-E-0285, June 15, 2016.

(3) A Head-End System (“HES”) for data collection and monitoring and control of the telecommunication system;

(4) An MDMS to store and process massive quantities of meter data;

(5) An enterprise analytics platform for turning raw data into intelligence that can inform decisions by customers and the utility; and

(6) An upgrade from the existing SAP CCS to an SAP Customer Relationship Management & Billing (“CRM&B”) system that will increase customer engagement and satisfaction by providing more comprehensive billing options and improving outage management.

As illustrated in Table VII-1, AMI works alongside other foundational technologies to support the three core DSP functions and enable required DSP capabilities. It will support Market Enablement by providing granular usage information necessary to optimize value to customers including such options as demand response, energy efficiency, and storage. It will also enable TVP and other innovative rate structures. By enabling these products and services, AMI will allow customers to better manage their electricity usage and energy bills.

AMI supports Integrated System Planning and Grid Operations as well. It will provide a high resolution, real-time view of conditions on the system that will enable grid operators to manage the grid and optimize DER under normal circumstances, and respond to outages in emergencies. AMI supports substation and circuit data acquisition that is required to improve Integrated System modelling and accurately measure the results of distribution system efficiency and peak load reduction programs. These results will be used for to produce more accurate forecasts of demand and energy, locational value, hosting capacity, and other distribution planning studies.

TABLE VII-1: AMI SUPPORTS THE THREE CORE DSP FUNCTIONS

Core DSP Function	AMI Functionality
Grid Operations	Granular AMI interval data will improve load profiles, as well as load and DER forecasts; The telecommunications network will be used to monitor and control distribution automation equipment and to interface with DER smart inverters to support DER management. (Smart meters will serve as gateways to the behind-the-meter DER.) Integration with OMS will provide last gasp communications during outage events.[62]
Integrated System Planning	High-resolution AMI data will improve the accuracy of load flow analysis, hosting capacity, and other planning analyses These data will improve the quality of forecasts of demand and energy and will provide required data for DER locational value. AMI data will broaden the scope of potential data analytics to support investment decisions.
Market Enablement	The compilation, storage, retrieval, and transfer of large volumes of granular data on a timely basis support rational economic decisions at every stage of product development cycles. An upgraded CRM&B system will accommodate new and more complex transactions, innovative rate designs, and improved engagement.

As described in Section F, the AMI business case is net positive by a significant margin with due consideration of both operational and societal benefits. From an operational perspective, AMI improves the efficiency and execution of traditional utility functions such as meter reading, field services, customer service, outage management, and meter-to-cash processes. In addition, AMI is expected to enhance the distribution system's efficiency through CVR, and will produce a net reduction in carbon emissions.

B. AMI Technology and System Investments

The main components of the AMI system are designed and integrated to support the Companies' Foundational Platform Technology approach. Specific AMI system components are described below in Table VII-2. Associated system interfaces are described in greater detail in Appendix G, which contains a comprehensive illustration of the Companies' platform technology investments and AMI program considerations.

[62] The Companies' affiliate, CMP, has integrated its OMS and AMI systems and has begun to realize the operational benefits of this technology.

TABLE VII-2: AMI ELEMENTS

AMI Element	Contribution to DSP
Meters as sensors	State-of-the-art metering technology will allow the Companies to measure hourly or sub-hourly energy usage (kWh), demand (kW), and voltage at customer sites. It will enable the Companies to respond quickly when there is an outage or adverse device condition. The meters will perform analytical processing to identify inefficient loads and aggregated DR.
Telecommunications network	The AMI telecommunications network is a multi-layer, wireless topology for high-speed backhaul that supports a full spectrum of DSP use cases including interval meter reading, outage management, DA, and DER integration. The network also supports telecommunications to distribution network sensors and controls as well as devices that are owned by third parties (e.g. smart inverters and generation equipment).
HES	The HES is the “data administrator” and “first stop” for smart meter information. In addition to receiving and validating the authenticity and accuracy of meter data that is stored in a data management system (described next), the HES schedules routine administrative tasks such as reporting and device discovery, helps monitor the health and security of the network and its thousands of devices, and interfaces with the GIS to support trouble shooting when there is a problem with a meter or network device.
MDMS	The purpose of an MDMS is to simplify the IT processes that operate behind the scenes of an AMI deployment and to evaluate the AMI system’s performance. The Companies’ MDMS will also enable the Companies to store and process large quantities of metered data while maintaining uniformity, efficiency, and reliability of the data. The MDMS can flag data collection problems (e.g. gaps, overlaps, and redundancies of data) and features an auditable process to maintain reliability of these data.

AMI Element	Contribution to DSP
Enterprise Analytics Platform	The EAP translates raw data to information and intelligence to support decision-making. In effect, the EAP serves as the DSP engine, and provides access to data and intelligence through warehouse user interface functions. The EAP supports a wide range of analyses, projects, and applications by combining and analyzing data from different sources and eventually reporting it out in formats that support decision-making
CRM&B System Upgrade	Upgrading the existing SAP CCS to a CRM&B system will provide an individualized customer experience, which the Companies expect will increase customer engagement and satisfaction. The CRM&B component of the AMI system will enable more comprehensive billing options and the flexibility to report price and billing data to customers on the fly. It will also enable TVP rate design programs, improved outage management, and faster response times for service change requests,

The planned Upgrade of the Companies' existing CCS to a CRM&B system will facilitate several key customer and operational benefits. These include enabling self-service features, processing on-demand meter reads, execution of remote commands (i.e. disconnection, reconnection of service, etc.), outage detection, and many others. Furthermore, the upgraded CRM&B system will enable the Companies to automate a variety of processes that are currently completed manually by Customer Service personnel. This will prevent errors resulting in more efficient operations, and will enable the Companies to standardize processes and technologies across utility affiliates.

The Companies are currently planning procurement processes for the components of its planned AMI system. In March 2016 a Request for Information ("RFI") was distributed to technology vendors to gather pricing data and assess interest in the industry to respond to the Companies' specific needs in New York. Preliminary AMI cost estimates presented in Table VII-3 and throughout this DSIP are based on the responses to this RFI. The schedule and plan for deployment, which are informed by data obtained through the RFI process, are described in greater detail throughout the remainder of this chapter.

TABLE VII-3: CAPITAL AND O&M COSTS OF THE COMPANIES' AMI PLANS

(2016, $ millions)

	2017	2018	2019	2020	2021	Total
O&M	$ -	$6.9	$9.9	$11.1	$10.3	**$38.2**
PMO Capital	12.6	13.0	13.3	13.7	14.2	**66.8**
IT Capital	58.0	59.1	-	-	-	**117.1**
Hardware and Installation	-	42.9	114.9	106.2	55.9	**320.0**
Total	**$70.6**	**$121.8**	**$138.2**	**$131.0**	**$80.4**	**$542.0**

C. System-Wide AMI Deployment Plan

1. Project Management and Governance

A robust governance model is a fundamental requirement for mobilization and execution of the Companies' AMI plan. Effective governance will provide the framework for the successful integration of interdependent technology components and processes. There are two essential components of the governance structure the Companies will apply during the AMI deployment both in the ESC, and at scale throughout the Companies' service area. First, the project governance structure will address processes and practices that pertain to the project and its interaction with other corporate elements. Second, the project governance structure will address the roles of external stakeholders.

As part of the detailed planning for AMI, the Companies will establish a robust internal governance structure to address:

- Executive visibility into and control over program evolution and outcomes;
- Appointment of an AMI Program Lead;
- The delineation of roles for a Program Leadership Team, an Executive Steering committee, and an External Stakeholder Advisory Committee;
- Clear and well-understood responsibility and decision-making authority for all program teams;
- Effective oversight of (and insight into) program progress and direction, including the capability to identify and execute necessary adjustments in the face of internal and external events and changes;

- Appropriate processes and turn-around time for decision making, so that the AMI program schedule and deliverables remain on track;
- Effective identification and communication of AMI program element-level risks and issues, and development of related mitigation strategies and/or action plans; and
- Consistent line-of-sight into AMI deployment controls and documentation.

Project management will develop through weekly project team meetings, in which metrics will be reviewed and strategies developed to address any problems that arise. These meetings will likely include key project leads and market partners.

A Program Leadership Team will consist of individuals providing program guidance and support from the following departments: IT, Business Transformation, Operations Technologies, General Counsel, Finance/Regulatory, Engineering, Field Operations, Customer Services, and Electric Distribution. This structure will provide the Companies the opportunity to receive and incorporate feedback and input from the internal stakeholders group, allowing for a more transparent management process. Guidelines for the Program Leadership Team will require it to oversee and make decisions regarding high-impact, or large budget and scheduling decisions.

The governance structure will predominantly consist of primary and sub-project groups dedicated to specific program areas, such as cyber security and meter testing. In addition to these groups, there will be specific management (i.e. non-leadership) and support teams reporting directly to various leadership teams and the AMI Program Lead. The Companies will also designate special groups within this governance structure for specific tasks, such as responsibility for managing key vendor relationships.

A Risk Management Tracking and Mitigation Plan is a key feature of the governance framework. This plan is designed to provide necessary auditing and oversight of the entire program throughout implementation, including extensive and standardized reporting to ensure status tracking and transparency. The risk log will be reviewed monthly by the Program Lead team and reported periodically to the Commission. The Companies will seek to establish frequent meetings with the Commission to convey status of the AMI implementation.

2. Vendor Selection and Management

As discussed in Section B, above, the Companies are conducting a thorough vendor selection process in order to select the critical technology vendors for the program. The Companies' governance framework will effectively address and manage various considerations pertaining to the selection and participation of technology vendors not limited to: risk mitigation; frequent reporting and standing meetings; and current and future delivery costs. The Companies will strategically evaluate the reputation, abilities and offerings of each vendor in its selection processes.

3. *Cost Management and Mitigation*

The Companies will draw from lessons learned from CMP's deployment in order to implement an effective cost management and mitigation strategy. The Companies will also consider including contract terms that will ensure their liability or exposure is minimized on AMI Program procurements. These include contract terms such as system and route performance incentives, liquidated damages, one-time installation cost per site (i.e. network installation), deferred payment of firmware maintenance fees, and setting a Network Equipment Cost Cap that is not to be exceeded.

4. *Phased Rollout of AMI*

The ESC project will serve as a test bed for the DSP and as the first phase in the full deployment of AMI. Deployment throughout the remainder of the Companies' service area is planned to commence in 2018 and will be complete in approximately four years, as illustrated in Table VII-4.

TABLE VII-4: THE COMPANIES' ADVANCED METERING DEPLOYMENT PLANS

	2018	2019	2020	2021
NYSEG	20%	40%	30%	10%
RG&E	0%	30%	40%	30%

5. *Customer and Market Engagement Plan*

The success of the AMI Program will depend on the awareness, engagement, and participation of customers and other stakeholders. For customers, enhancing knowledge of tools that support efficient management of energy bills will require thoughtful, thorough, and relevant communication that encourages customers to make informed decisions about how and when they consume and produce energy. The Companies believe it is a key role of the DSPP to make a connection between the different aspects of the energy system in a way that will be meaningful for customers. The Companies will develop a comprehensive Communications Plan using experience it has gathered from similar projects and technology deployments. The Companies will use a variety of channels to engage each set of stakeholders, and to promote active engagement in the development of the specific program elements the AMI deployment will support.

The Companies will strive to minimize complaints and achieve a high level customer satisfaction by installing meters with less than a five-minute disruption of service and no need for the customer to be present. There will be a number of "hard to access" accounts, but the Companies will handle these accounts with special care by using direct mail, phone calls and appointments to ensure an efficient process.

Based on industry experience, the Companies plan to meet with civic leaders prior to beginning to deploy meters in a new city or town. Internal staff from the key account team and an external public relations firm will meet with elected officials and community leaders 75 days prior to the first installation of meters in a community in order to describe the benefits of smart meters and the installation process. The goal of these briefings is to ensure that the community is prepared for installation in advance, and knows what to expect.

The Companies will create a webpage to support the smart meter initiative consisting of an overview of the program and frequently asked questions. Approximately 35-40 days prior to installation, all customers will receive a mailing with instructions for opting out of a smart meter. All direct mailing and responses will be tracked. The installation vendor will be responsible for contacting “hard to access” customers to schedule appointments for smart meter installation.

Following the installation at each business and residence, the technician will leave a door hanger behind letting the customer know that a smart meter was installed and describing the benefits of using a smart meter. Following the installation, the Companies will promote the use of its energy portal (*Energy Manager*) using a variety of communications channels.

6. *Cyber Security and Privacy Plans*

The Companies are committed to implementing a secure and reliable AMI system. To this end, the Companies are developing an AMI-specific Cyber Security Plan (“CSP”) to describe and document plans to address physical and cyber risks. The Companies will leverage existing government standards and the Companies’ cyber security policies and procedures in the CSP. The plan will consistently adapt and document the security controls unique to the Companies, and will respond to evolving cyber security trends in the industry and requirements in New York State. The objective of the CSP is to integrate cyber security controls and requirements into day-to-day work activities to safeguard the Companies from cyber threats. The plan will reflect the Companies’ commitment to the protection of customer and system data from disclosure or harm.

The CSP is based on a set of guiding principles for protecting the privacy and security of customer and system data:

- Assess, identify, monitor, and mitigate risks at each stage of the AMI deployment lifecycle.
- Use established cyber security criteria for vendor and device selection.
- Ensure adherence to the relevant cyber security standards and/or best practices (identified in the CSP) in support of meeting AMI cyber security standards.
- Establish and maintain an organizational chain of accountability to senior management that provides ongoing support for cyber security.
- Continually assess and document the impact of the AMI Business Plan on critical grid control functions with which the AMI system will interface or connect.
- Continue to evaluate policy, procedural, and security mitigation approaches and controls at each phase of the deployment lifecycle.

- Implement controls for event logging, monitoring, alarming, and notification to protect customer information and improve the Companies' response to threats.

The Companies plan to use the National Institute of Standard and Technology ("NIST") risk-based assessment approach to select the cyber security controls that will be implemented for the AMI systems and the CSP. The NIST risk-based approach includes four key activities:

- Categorization of the system;
- Risk and vulnerability identification;
- Classification of the impact of the risks to the system; and
- Selection of appropriate security controls.

The CSP reflects the NIST SP 800-30 nine step methodology, which consists of characterizing the enterprise, identifying threats, identifying vulnerabilities, analyzing existing and planned security controls, determining likelihood of events occurring, analyzing impacts, recommending controls, and documenting results of cyber security events.

The Companies will emphasize a training plan that covers our policies, rules, and procedures for data protection. The goal of the training program is to raise awareness of the risks of cyber threats, train personnel to detect and recognize threats as they occur, and educate personnel on their roles and responsibilities in the case that incidents materialize. This training program focuses on the need to integrate cyber security controls, requirements, and vigilance into day to day work activities.

Please refer to Chapter IV for additional discussion of the Companies' plans to protect the privacy and security of customer and system data in their role as DSP.

D. Leveraging AMI to Support Market Engagement and Pricing Options

The Companies propose to implement *Energy Manager*[63] as the portal to engage customers in utility and third-party options that will help them manage their energy bills. It will eventually encompass the functionality that is being tested in the Energy Marketplace REV demonstration project. AMI will also support innovative rate structures, which will initially be explored through the ESC.

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[63] *Energy Manager* is a customer energy portal in use at CMP. The Companies will draw on the experience from Maine in its customization and deployment of the *Energy Manager* solution in New York.

1. Energy Manager

The Companies plan to implement the *Energy Manager* customer portal in New York to provide customers with a convenient method of accessing their energy usage data, obtaining key messages about the state of the energy system, and connecting with vendors (at the customer's selection) offering innovative energy products and services. The *Energy Manager* portal is a secure energy information management system with functionalities that are equivalent to the GBC "My Data®" standards.

Residential customers with an AMI meter that would like to download their data or provide it to specific product and service vendors will enroll in the *Energy Manager* portal. Once enrolled, customers will have access to the most recent 13 months of their usage data. Commercial and Industrial customers will be able to log into their secure online profile to access *Energy Manager* for Business, from which they can download either their usage or demand data into a Microsoft Excel or .XML file that follows the Green Button standard.

The Energy Manager portal is discussed in greater detail in Chapter IV (Market Enablement).

2. Innovative Rate Structures

The Companies' plan to offer TVP options to consumers. More than four decades of empirical research demonstrates that many consumers can and will enroll in TVP tariffs and will reduce usage during higher-priced periods relative to usage under traditional tariffs. TVP can lead to significant reductions in societal costs over time by reducing the need for high-cost peaking generation or reducing or delaying transmission and distribution capacity investments.

A major impediment to customer participation in TVP has been the high cost of metering on an individual customer basis. This is especially true for mass market consumers such as residential households and small commercial businesses. Full deployment of AMI will provide low cost opportunities for customers to better manage their energy costs and, in the process, improve the economic efficiency of the electricity system by choosing and responding to prices that more accurately reflect the cost of electricity supply.

The benefits of TVP pricing derive from the fact that prices more accurately reflect costs and customers will respond to TVP price signals. Economic efficiency is improved when customers shift from high price/cost time periods to lower price/cost time periods. Speaking generally, the benefits of TVP (discussed in greater detail below and in Appendix G) are a function of the number of enrolled customers, the load shapes of customers prior to enrollment, the price responsiveness (or price elasticity of demand) of enrolled customers, and the structure of the TVP tariff (e.g. prices by rate period). These factors drive the change in usage by rate period, which, in turn, drive the benefits that can be achieved in the form of avoided generation, transmission, and distribution capacity investments, reductions in fuel costs, and reductions in carbon emissions.

A variety of TVP structures have been tested in pilot programs and deployed by utilities around the country. The Companies plan to host a collaborative discussion with stakeholders to determine specific TVP programs, but expects that rate options evaluated in the ESC and eventually deployed across their service area include the following:

Time of use ("TOU")	Prices vary by time of day every weekday (and perhaps on weekends and holidays)
CPP	Prices vary by time of day only on days with exceptionally high demand. (Consumers are typically notified of critical peak events one day in advance.)
TOU-CPP	This design combines the two options above, with prices varying on all days but where peak period prices are higher on CPP days than on the typical weekday.
Day-type Variable Pricing	A set of TOU prices are established and communicated to consumers upon enrollment where prices by rate period vary across three or four different day types (e.g. low price days, moderate price days, high price days, critical price days) and consumers are told prior to each day what price schedule will be in effect on the following day.
Real Time Pricing ("RTP")	Prices change hourly in response to market conditions.

The Companies' TVP rate designs will be implemented and tested in the ESC. TVP programs will then be introduced throughout the Companies' service area in a manner that reflects lessons learned from customer engagement and participation from the ESC.

E. The Role of AMI in the Energy Smart Community Project

The Companies' ESC project, designed to be a test bed for the Companies' future DSP role, will include the installation of 12,000 smart meters,[64] along with the technology necessary to test new rate designs and programs that increase the efficiency of the electric system along the supply and delivery chain, including on customer premises. The experience gained during the ESC will reinforce and build on the smart grid experience from the deployment conducted by the Companies' affiliate, CMP.

The ESC project is proposed as a test bed for the DSP and as the first phase in the full, service territory-wide deployment of AMI. It is designed to provide insight and lessons learned to identify

[64] The estimated cost of AMI deployment in the ESC is $10 million. Cost recovery for the ESC project is addressed in the Companies' June 15, 2016 rate case decision.

and utilize the most effective energy solutions. A broad array of AMI-enabled products and services will be tested by the ESC project including TVP and other rate designs, customer access to their usage data through a web portal, and other programs that may be developed. Rate design will be discussed with stakeholders before a tariff filing is made. The initial rate design programs may be limited if significant system changes are required to enable billing. The ESC is likely to include subsequent rate design proposals developed after initial experience is gained. The ESC project will also serve as a test bed for the business use cases of the technology platform, including granular AMI and network sensor measurements, to model and simulate changing load based on complex algorithms and predictive analytics to inform hosting capacity and other models that are required to perform system planning. These same data will allow the Companies to monitor DER performance and test VVO.

F. Measuring the Success of AMI

The Companies have developed metrics to track and evaluate program performance, costs, and benefits in order to ensure AMI deployment is implemented in an efficient and effective manner, and that customers benefit from the investment. These metrics will be crucial for the development of the program and for responding to issues that are likely to arise, particularly during the initial rollout for early adopters.

In its Final DSIP Guidance Order, the Commission requires that the Companies include proposed metrics to measure the value associated with the AMI deployment, as well as measurements related to customer engagement and participation in new programs, outage management and other system operations impacts, and environmental benefits.[65] The Companies have identified a set of impact metrics designed to track the benefits expected to be realized from deploying AMI, and divided them into three primary categories: (1) AMI Deployment, (2) Customer and Environmental Impacts and (3) Operation and Maintenance ("O&M")Impact metric. The first category, displayed below in Table VII-5, will track the progress of the AMI deployment and progress made in the deployment of AMI with respect to installed units, correctly functioning technology, and budget performance.

TABLE VII-5: AMI DEPLOYMENT METRICS

Metric	Description
AMI electric meter failures	Proportion of installed devices that are faulty
AMI gas module failures (including tin/welded case and remediated meters)	Number of AMI Gas module failures including Tin/Welded Case and Remediated meters

[65] DSIP Guidance at p.59.

Metric	Description
Proportion of meters deployed	Progress according to planned pace of deployment
Proportion of network devices deployed	Progress according to planned pace of deployment
Proportion of budgeted dollars spent on implementation	Program cost performance
Proportion of budgeted O&M costs spent to support the AMI system	Program cost performance
Proportion of deployed meters reporting daily	Comparison of actual functionality to planned performance
Proportion of reporting meters with complete data	Comparison of actual functionality to planned performance

The second category of metrics provides measurements of the impacts of AMI regarding the participation of, and benefit to, customers as well as the environment benefits associated with the AMI deployment. These are displayed below in Table VII-6. The Companies intend to particularly track and evaluate metrics related to the TVP initiative. This will include monitoring the number of customers enrolled in the TVP Pricing Programs and the number of customers using the *Energy Manager* web portal. These metrics will help the Companies evaluate their TVP offerings with respect to customer participation and engagement. This information will enable the Companies to gain insights that will improve future products and services. Additional metrics will indicate the environmental benefits of the CVR program and operating efficiencies of the AMI system.

TABLE VII-6: CUSTOMER AND ENVIRONMENTAL IMPACT METRICS

Metric	Description
Customers using the AMI Portal *(Energy Manager)*	% of customers with AMI meter who log into portal to view usage information over a TBD interval (3 months, 1 year etc.)
Customers targeted with energy saving messaging - All	% of customers targeted with messages regarding their energy savings tools, personalized usage and or savings tips
Customers targeted with energy savings messaging - Low Income	% of customers targeted with messages regarding their energy savings tools, personalized usage and or savings tips

Metric	Description
Near Real Time Data	Number of customers who have access to near real time data via the web after AMI meter installation
Customer knowledge of AMI	Awareness survey related to AMI benefits and features
Targeted Energy Forum Presentations	Number of presentations provided; target two per year
Number of community organizations contacted	Number of organizational events attended where information on AMI plan features and benefits will be provided
Reduction in vehicle fuel consumption and vehicle emissions	Reduction in vehicle fuel consumption and vehicle emissions due to reduction in manual meter reading costs, reduction in false outages and reduction in number of field visits during outages to confirm a customer has power
Environmental benefits due to CVR	Provide energy savings and corresponding emissions reductions

The third category of metrics, displayed below in Table VII-7 addresses the Commission's directive for metrics tracking outage management and system operations. This group of metrics will allow the Companies to accurately track, monitor, and evaluate system operations with the goal of ensuring that improvements continue to be realized.

TABLE VII-7: O&M IMPACT METRICS

Metric	Description
Outage Duration reduction	Reduction in Outage Duration
Emergency response labor reduction	Number of single outages for a large storm that were determined remotely via AMI eliminating the need to send a crew or call to confirm power restoration
Number of false outages resolved through AMI	Number of false outages that were found through AMI that the Companies did not have to send a crew or call to confirm
Estimated Bills - AMI accounts	% of accounts with bills which are estimated
Reduction in manual meter operations costs	Track avoided meter operations O&M costs and report
Number of Distributed Resources with AMI Meter	Percent of Distributed Resources with AMI Meter

The Companies will begin reporting on Build Impact metrics at the time AMI deployment begins (i.e. early 2018). Reporting on Customer and Environmental and O&M Impact metrics will begin one year after the first meter is deployed (i.e. early 2019).

G. AMI Benefit-Cost Analysis

The Companies have completed an extensive assessment of the benefits and costs of its AMI plan. Table VII-8 summarizes the present value of benefits, costs, net benefits, and the benefit/cost ratio for five specific and quantifiable benefit streams that AMI makes possible: operational savings; reduction in outage duration and customer costs associated with AMI-OMS integration; reduction in capacity and energy costs and carbon emissions from implementation of opt-in TVP; usage alerts and feedback to customers; and CVR/VVO. Implementation of AMI and AMI-enabled programs and services is estimated to produce societal benefits of $736 million in present value terms over the first 20 years of the investment at a total cost of $603 million. The net benefits of $133 million produce a benefit cost ratio of approximately 1.2 using the Societal Cost Test, indicating that the Companies' AMI plan presents a sound investment.

TABLE VII-8: 20-YEAR PRESENT VALUE OF AMI BENEFITS AND COSTS

(2016, $ Millions)

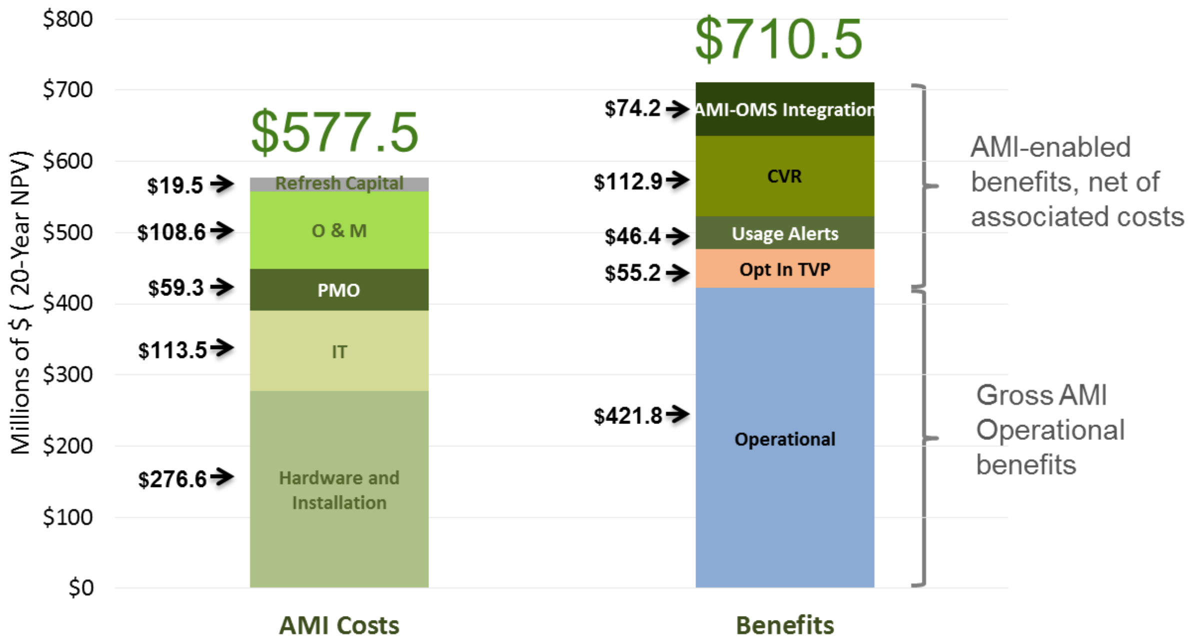
	Category	Societal Cost Test
AMI Operational Business Case	Benefits	$421.8
	Costs	$(577.5)
	Net Benefits	$(155.8)
	B/C Ratio	0.73
AMI-OMS Integration	Benefits	$74.2
	Costs	-
	Net Benefits	$74.2
	B/C Ratio	-
CVR/VVO	Benefits	$112.9
	Costs	-
	Net Benefits	$112.9
	B/C Ratio	-
TVP (opt-in scenario)	Benefits	$73.5
	Costs	$(18.2)
	Net Benefits	$55.2
	B/C Ratio	4.03
Usage Alerts	Benefits	$53.2
	Costs	$(6.8)
	Net Benefits	$46.4
	B/C Ratio	7.78
Total	Benefits	$735.6
	Costs	$(602.6)
	Net Benefits	$133.0
	B/C Ratio	1.22

Specific benefits and costs are described below. A comprehensive discussion of the AMI System Benefit Cost Analysis can be found in Appendix G.

1. AMI Deployment Costs and Benefits

Figure VII-1 compares the costs of AMI with the sum of (1) gross AMI operational benefits and (2) AMI-enabled benefits, net of associated costs. All values in the figure are presented in present value terms from 2018 (when deployment begins) through 2040 (when the last installed meters reach their assumed 20-year life), expressed in 2016 dollars.

FIGURE VII-1: 20-YEAR PRESENT VALUE OF SOCIETAL BENEFITS AND COSTS



a) <u>Costs</u>

The Companies distributed an RFI to AMI technology vendors in March of 2016 to gain a better understanding of the likely costs of AMI deployment. The deployment cost elements were derived from RFI responses and are described in greater detail in Section C of Appendix G.

- Hardware and installation costs of $276.6 million account for nearly half of the 20-year Net Present Value ("NPV") of deployment costs. This category includes new replacement meters; a telecommunications network with hardware components for transmitting information throughout the distribution network; and engineering and installation labor costs.
- The IT budget of $113.5 million (20-year NPV) includes forecast hardware, software, and integration costs. These costs include HES and MDMS hosting, implementation of the CRM&B upgrade, and provision and support for a customer web portal.

- The Project Management Organization cost category, representing $59.3 million (20-year NPV) includes labor costs for personnel that will be needed for approximately five years (the 4-year deployment plus pre- and post-deployment periods).
- O&M costs of $108.6 million (20-year NPV) include marketing and customer communications, fixed overhead, any incentives for customers enrolling in specific programs, and other variable costs of the AMI deployment.
- Refresh capital totaling $19.5 million over 20 years includes the cost of device failures that are expected to occur on approximately 0.5% of electric meters and gas modules due to electronic malfunctions. It also covers planned replacement of network devices throughout the 20-year life of the AMI system.

b) Benefits

Operational Savings

Operational savings of $421.8 million are derived from lower costs associated with meter reading, field services, and billing and call center costs; avoided meter replacement costs (i.e. replacement of legacy meters with like technology); reduced storm restoration costs; reduced cash requirements; and lower losses as a result of more efficient meters.

Opt-In TVP

The $55.2 million in net benefits associated with TVP pricing reflect the fact that prices more accurately reflect costs and customers respond to TVP price differentials. Economic efficiency is improved when customers shift from high price/cost time periods to lower price/cost time periods. The aggregate benefits are primarily a function of the number of enrolled customers, the load shapes of customers prior to enrollment, the price responsiveness (or price elasticity of demand) of enrolled customers, and the structure of the TVP tariff (e.g. prices by rate period) being examined. These factors drive the change in usage by rate period which, in turn, drive the benefits that can be achieved in the form of avoided generation, transmission and distribution capacity investments, reductions in fuel costs and reduced carbon emissions.

Usage Alerts

The Companies' AMI system will provide opportunities to improve economic efficiency and support the objectives of REV by offering TVP options and information feedback services to consumers (e.g. "usage alerts"). TVP will lead to $46.4 million in net cost savings over twenty years by reducing the need for high-cost peaking generation or reducing or delaying transmission and distribution capacity investments. TVP also gives consumers greater opportunities to reduce their energy bills by shifting from higher to lower cost time periods.

CVR

Advances in sensors, telecommunications, optimization models, and control technologies have made it possible to monitor voltages and adjust voltage regulating equipment and capacitor banks in near-real time, while ensuring that voltage levels remain within the desired range for all customers. VVO systems make quick adjustments to voltage and reactive power levels within distribution circuits to address real-time system needs. Because of their real time monitoring and response, they enable delivery of power at lower voltage levels, thus saving power – a concept known as CVR. CVR is expected to result in net savings of $112.9 million over 20 years.

AMI-OMS Integration

The integration of AMI with the OMS will save an anticipated $74.2 million over 20 years. AMI-OMS integration will reduce outage durations in two ways. First, smart meters send a last-gasp message to the OMS system, which will be received much more quickly than would a call from a customer. Second, outage location can be identified through analysis of last gasp messages. This reduces the time associated with a crew traveling to a circuit to locate open devices themselves. Operational efficiencies reduce outage duration and, therefore, reduce customer outage costs.

c) Customer Benefits Not Reflected in the BCA

The Companies' AMI plans will result in additional savings that are not quantified in this financial business case. In particular, deployment of AMI has the potential to address fairness issues in that it can help to align costs that are currently socialized across all customers with customers that impose those costs. There are three kinds of socialized costs that AMI can address:

- **Theft of Service:** While it is difficult to quantify, there is undoubtedly some theft of service in the Companies' service territory and the revenue the Companies would have collected from the individuals responsible for theft is effectively socialized and collected from customers who pay for the service they receive. AMI provides tamper alarms and measures usage profiles at the customer level that can be reviewed for reasonableness to identify and address potential theft.
- **Meter Inaccuracy:** Not all meters are 100% accurate and some of the existing electromechanical meters in the service territory do not accurately measure all the electricity that is delivered to customers. Customers with these "slow" meters are not billed for all the energy they receive; the amount of shortfall from these customers is socialized over the entire customer base. New AMI meters would reduce the frequency of meter accuracy and malfunction problems.
- **Write-offs and Consumption on Inactive Meters:** The Companies incur write-offs of bills for customer non-payments. The Companies must also cover energy use on inactive accounts where deliveries occur but there is no customer of record to charge for the service. In both of these cases, the Companies socialize the revenue shortfall. With AMI meters, inactive accounts and shut-offs for non-payment can be processed more efficiently thereby reducing write-offs.

H. Contribution of AMI to Our Customers and Society

The AMI plans will allow the Companies to achieve significant customer value and it will make significant contributions to the Companies' objectives for operations in the future as the DSP. These contributions are illustrated in Table VII-9.

TABLE VII-9: AMI CONTRIBUTION TO POLICY GOALS AND THE COMPANIES' OBJECTIVES

Objective	AMI's Enabling Effect
Create Customer Value	• AMI will offer customers increased visibility into energy usage. DER customers will be able to view and optimize the bi-directional flow of power. • Customers will be able to receive offers for innovative energy- and cost-saving programs by sharing their high-resolution usage information with vendors that they can screen and approve. • AMI allows the introduction of Time Varying Rates, which provide an opportunity to capture bill savings by eliminating energy consumption or shifting it to less expensive periods.
Animate Markets for Energy Products and Services	• AMI and its associated telecommunications infrastructure will enable the utility to provide detailed assessments of system conditions that can be alleviated by non-traditional energy solutions.
Enhance Fuel and Resource Diversity	• AMI provides an opportunity to develop a detailed view of system conditions and load patterns, allowing for targeted DER solutions that improve the diversity of fuel sources used for energy generation in the state.
Reduce Carbon Emissions	• Customers will have access to detailed, time-based usage information from AMI. These data can be used to drive energy demand from peak to off-peak periods, reducing the need to dispatch inefficient, fossil-based generation resources. • Detailed system-status also enables 3rd party market vendors to target specific customers with opportunities to acquire carbon-free DG.
Improve System Efficiency	• By providing efficient price signals that reflect state policy, AMI supports the transition of on-peak load to off-peak hours, increasing the efficiency of the state's generating resources.
Raise System Reliability and Resiliency	• Detailed information concerning the state of the distribution grid at discrete locations will improve the Companies' ability to identify system and hardware constraints, and preemptively address reliability issues with preventive maintenance and effective capital planning.

Objective	AMI's Enabling Effect
	• Integration of AMI with OMS raises the Companies' ability to quickly detect and respond to outage events, raising system reliability.

AMI will integrate with existing systems and drive new business processes, increase automation and efficiencies, and provide new data sources to enhance service and efficiencies for customers, markets, and the Companies. It will provide customers, market participants, and utilities with increased visibility and resolution with regard to energy usage and flow, increased knowledge of energy system status and health, and enhanced efficiencies and reliability through situational awareness and system automation.

VIII. Financial Impacts and Cost Recovery

The Companies present their plans for recovering costs for foundational investments and DSIP implementation, taking into consideration their recently approved 2016 Rate Plan and Commission requirements. The 2016 Rate Plan requires that a separate AMI collaborative will take place, and a more detailed review of the AMI cost recovery associated with that full deployment will be discussed as part of that collaborative process. The Companies intend to make a separate filing regarding the AMI rate recovery, an associated rate impact analysis, and the proposed rate design. The separate filing will help form the basis for discussions during the AMI collaborative.

The DSP and AMI investment project plans described in this DSIP are preliminary, and will be updated to reflect the results of stakeholder input, competitive bidding outcomes where appropriate, and other detailed planning activities. Updates will form the basis of specific requests for project approval and associated cost recovery.

The Companies will begin the implementation phase of this DSIP's objectives upon receiving approval for the plans described here, including the approach for recovery of the incremental costs associated with these plans and costs associated with the required AMI foundational investment. The Companies require timely and complete cost recovery of these investments in order to build the DSP on financially viable terms.

A. DSP Implementation Costs (2017-2021)

The transition from legacy operations to serving as the DSP operator entails incremental investments during this initial DSIP implementation period from 2017 through 2021. Some capital and O&M costs, including those for AMI, which has a multi-year deployment calendar, will extend beyond this five-year planning horizon. A major component of this DSIP is the AMI plan described in Chapter VII. As required by the Commission, the Companies have included benefit-cost analyses to support the objectives, development actions, costs, and benefits of the AMI deployment proposal.[66]

The capital and O&M costs associated with the plans described in this DSIP require the Companies to balance a set of competing priorities: financial considerations (e.g. ratepayer impacts); the need to invest in order to provide new, innovative, and market-based services; and the anticipated benefits to customers and society at large of realizing the REV proceeding's objectives.

The Companies' 2016 Rate Plan includes in delivery rates the costs associated with certain REV investments that are being made to support the DSP, the ESC, and some "incremental"

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[66] DSIP Guidance Order, BCA Framework Order. The AMI BCA analysis is introduced in Chapter VII and described in detail in Appendix G.

foundational investments required to build DSP capabilities.[67] As noted above, the recovery mechanism associated with a system-wide rollout of AMI will be addressed in an AMI collaborative. These AMI costs are not included in the recently approved delivery rates, and will be subject to Commission review and approval at a future date.

The Companies have initiated many of the near-term initiatives necessary for the transition to the DSP role.[68] Some near-term initiatives and capability development activities will incur incremental costs over and above those already included in delivery rates. These initiatives are shown in Chapter VI, Technology Platform.

B. Cost Recovery

The Companies have organized DSIP costs into five categories for cost recovery purposes, described in Table VIII-1.

TABLE VIII-1: CATEGORIZATION OF DSIP COSTS BY RECOVERY APPROACH

Cost Recovery Categories	
Included in Current Rates	(1) Investments that were included in the Companies' planned capital expenditures in the 2016 Rate Plan and also reflected in the 5-Year Capital Plan, approved by the Commission on June 15, 2016; (2) Capital investments in the ESC and associated ESC O&M expenses were also reflected in the approved 2016 Rate Plan;
To Be Recovered Through a Rate Adjustment Mechanism or other approved mechanism	(3) The revenue requirement impact of "Incremental" DSIP and all other REV-related expenses and investments until such time as the expenses and investments are included in base delivery rates, along with incremental O&M expenses that are not currently being recovered through rates. The Companies' approved 2016 Rate Plan allows for these costs to be recovered through the Rate Adjustment Mechanism ("RAM") subject to annual thresholds being met for total RAM-eligible costs. To the extent the RAM is insufficient to recover incremental REV costs on a current basis the Companies may request Commission authorization of a temporary surcharge that would allow for the current cash collection of the incremental REV costs until such costs are included in delivery rates; (4) Costs to plan, and perform REV demonstration projects - as indicated in the REV Track 1 Order, Companies are allowed to defer, for future recovery, all incremental costs associated with REV demonstration projects. The Companies' 2016 Rate Plan allows for these costs to be recovered through the RAM subject to annual thresholds being met for total RAM-eligible costs. To the extent the RAM is insufficient to recover incremental REV costs on a current basis, the Companies may request

[67] New York Public Service Commission. Order in proceedings 15-E-0283 and 15-E-0285, June 15, 2016.

[68] Near-term initiatives and capability development are discussed in Chapters 2-6.

Cost Recovery Categories		
		a temporary surcharge that would allow for the current cash collection of the incremental REV costs until such costs are included in delivery rates.
Cost Recovery yet to be Determined	(5)	AMI investments associated with a full rollout of AMI (i.e. over and above AMI investments that are included in the ESC). The Companies will make a separate filing with the Commission for AMI costs recovery and will be discussed in the AMI collaborative.

The 2016 Rate Plan provides for recovery of certain REV-related costs that have already been identified in the 5-year Capital Plan (investments) or otherwise included in 2016 Rate Plan revenue requirements. These are Category 1 investments and expenses.

The 2016 Rate Plan also provides for recovery of costs associated with the Companies' ESC (Category 2), comprised of an estimated $18 million of capital expenditures and $7.6 million of O&M expenses over the three-year term of the plan. The Companies further agreed to seek to limit AMI capital expenditures within the ESC to $10 million and to apprise Commission Staff and interested parties if these expenditures are forecast to be in excess of $11 million.

The 2016 Rate Plan provides for incremental DSIP and REV-related investments and expenses (Category 3), explicitly permitting recovery of certain incremental costs, including those attributable to NWA-related activities, through a RAM. This RAM is subject to an annual cost recovery cap of $19.3 million for NYSEG Electric and $11.4 million for RG&E Electric. The Companies will submit RAM Compliance Filings on April 1st of each year that reflect RAM-eligible deferrals and associated costs as of December 31st of the preceding year. Cost recovery through the RAM will occur during the 12-month period beginning on July 1st, after Commission review and approval. RAM-eligible costs that exceed the annual cost recovery cap will be deferred and carried forward to the next year. The RAM is fully described in Appendix S of the 2016 Rate Plan. Initial DSIP costs that are approved by the Commission from this filing will be eligible for recovery through the RAM. However, the RAM also is intended to collect other deferred costs including major storms, property taxes, and NYSEG Electric Pole Attachment revenue requirements.[69] To the extent the RAM is insufficient to recover incremental REV costs on a current basis; the Companies may request Commission authorization of a temporary surcharge that would allow for the current cash collection of the incremental REV costs until such costs are included in delivery rates.

The Track 1 Order provided for the deferral of "the revenue requirement impacts of incremental costs of REV demonstration projects" until their next rate plan.[70] The Order capped revenue requirement impacts at "0.5 % of delivery service revenue requirement or the revenue

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[69] Appendix S of the NYSEG and RG&E Rate Plan details the components and operation of the RAM. The Commission approved the 2016 Rate Plan on July 15, 2016.

[70] Track 1 Order, page 116.

requirement associated with capital expenditures of $10 million, whichever is greater."[71] The Companies are recording these costs consistent with this direction, and intend to recover these costs (Category 4) through the RAM.

Pursuant to the terms of the 2016 Rate Plan, the revenue requirement attributable to a system-wide rollout of AMI (Category 5) will not be recovered through the RAM. Rather, this would be the subject of discussion in an AMI Collaborative required by the 2016 Rate Plan as well as a separate filing before the Commission.

[71] Ibid.

Appendix A: Stakeholder Engagement

The Companies have engaged stakeholders in the preparation of this Initial DSIP seeking feedback, input, and insights from a range of interested parties as contemplated in the DSIP Order. The Companies' objectives for stakeholder engagement include contributing to stakeholder understanding of complex issues, resolving issues to the degree possible, and providing stakeholders with an opportunity to share their perspectives and comment on the Companies' approach to the DSIP. The Companies are proponents of educating stakeholders, conducting outreach, and actively communicating with external parties.

In an effort to engage key constituencies on the many complex topics associated with markets, engineering, utility operations and new technologies, the Companies have met and will continue to meet with community groups, environmental groups, economic development organizations and agencies, vendors, developers, local and state elected and municipal officials, energy task forces, and key customers.

Stakeholder Engagement in connection with our DSIP filing has consisted of seven activities. The meeting agendas were tailored to meet the interests of each audience.

(1) **Initial DSIP Stakeholder Workshop:** We held an all-day workshop in Geneva on June 9, 2016. Our DSIP team leaders presented an overview of our DSIP and engaged stakeholders through questions and comments, and in follow-up communications.

The workshop provided an overview of the Companies' plans for this Initial DSIP, and specific aspects of the DSIP including technology projects, AMI, system planning implementation, Energy Smart Community, non-wires alternatives, and data provision. Parties to the case and members of the Joint Utilities' Advisory Group were invited, representing DPS Staff, DER providers, large customers, small customers, consumer groups, public power, environmental groups, marketers, the wholesale market, and utilities. Twenty-four stakeholders participated and provided feedback for consideration in the development of this Initial DSIP. The stakeholders participated actively, feedback and comments on several areas including natural gas grid impacts, greenhouse gas emissions energy efficiency programs, data security, clarification of new software and terms, AMI, and how the Energy Smart Community was selected. The participants also inquired about how they could help and what information could they provide to aid the planning processes. Following the workshop, stakeholders suggested that further collaboration including periodic webinars, website resources, additional customer communication, and community meetings would be greatly appreciated. There was a broad consensus that "yes," the session was worthwhile and informative. Stakeholders expect that the Companies will continue on-going dialog with this stakeholder group after this Initial DSIP is filed.

(2) **Outreach to Solar Developers:** The Companies held three one-hour webinar conference calls with groups of DER developers on June 15, 2016 to address several issues in more detail than had been addressed in the Workshop.

Thus, these conference calls were designed to facilitate an understanding and discussion of the NYSEG/RG&E Initial DSIP Filing, including an overview of the future utility model, our approach to and content of the filing, system planning improvements, interconnection improvements, the interconnection guide maps, and provision of system data. Our goal was to have solar developer participants understand the “what,” “why,” and “how” of the filing, solicit stakeholder feedback and discuss items such as the provision of data and information sharing. The webinars were structured to allow for discussion and dialog. All solar developer groups were engaged and interested. Questions and comments were thoughtful and reflected a desire to understand the Companies’ information and the desire to have the Companies understand the developers concerns and needs.

Overall feedback from stakeholder outreach and engagement indicated that solar developers want to be involved, and want to have the opportunity to influence future decisions. They indicated that this was a great first step, and a useful experience that answered many open questions and concerns. In the future, they requested that circuit and substation data be provided in the pre-application for interconnections, that further explanation of the interconnection guide maps would be needed, advanced knowledge of future capabilities for ADMS, and to share the methodology for screening for NWA. Interconnections process concerns included: linking billing to DG applications, non-actioned projects in the queue, and transparency for forecasting viable projects.

(3) **Outreach to Energy Smart Community Stakeholders:** Members of the ESC program team made a presentation to a Tompkins County Climate Protection Initiative meeting on June 24, 2016 that was attended by representatives of several regional environmental and economic development groups.

(4) **Outreach to Public Officials:** The NYSEG Public Affairs team met with several State Senators and Assemblymen/women either individually or in small groups to brief them on the status of REV and our DSIP filing, address any questions, and invite feedback. We also met individually or by teleconference with several elected local and municipal officials as well as several elected local and municipal officials. In addition to the timing of the filing, we described the major components of the filing, explained its relationship to REV and other REV initiatives, and discussed the potential impact it will have on customers. We also explained that there would be an opportunity for public comment as part of a broader review process.

(5) **Outreach to Large Customers:** NYSEG Marketing and Sales representatives held several individual meetings with large customers to brief them on the status of REV and our DSIP filing, address any questions, and invite feedback. We addressed the same issues as addressed in the outreach to public officials, with somewhat greater attention paid to the impact on customers.

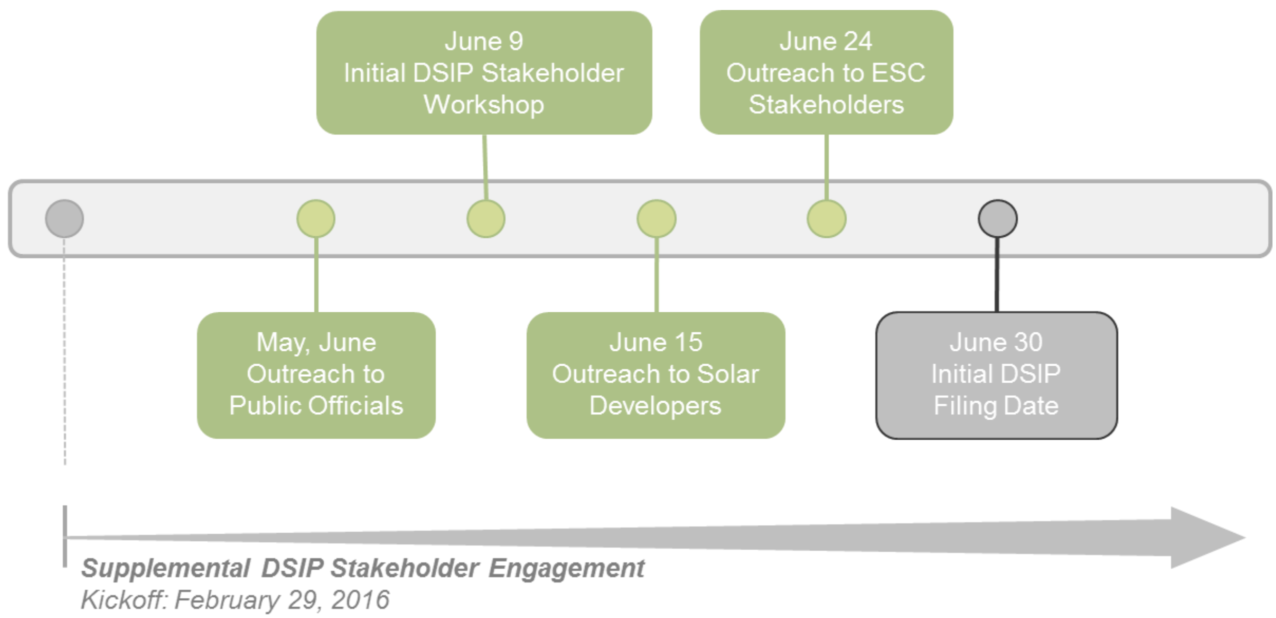
(6) **Participation in the Supplemental DSIP Stakeholder Engagement Process:** The Companies are active participants in the Supplemental DSIP engagement process, along with other New York utilities. The first such meeting was held on February 29, 2016 and the Joint Utilities filed a Supplemental DSIP engagement work plan on May 5, 2016.

Although this process has only begun in earnest within the last two months, the Companies have learned a great deal from stakeholders regarding their perspectives on topics that are also addressed in our Initial DSIP.

(7) **Less Formal Stakeholder Engagement:** We engage with our stakeholders on a variety of issues on a regular basis and apprise them of DSIP-related activities.

A summary timeline is presented in Figure A-1.

FIGURE A-1: STAKEHOLDER ENGAGEMENT TIMELINE



Overall, we have leveraged these numerous communications to inform key stakeholders about our upcoming DSIP filing and obtain feedback on the issues that are most important to each of them. These efforts will continue throughout the DSIP review process and into the implementation phase.

Appendix B: Beneficial Locations

The Companies have reviewed historical loading information on all distribution substation transformers and distribution circuits. The following tables list specific areas where there is an impending or foreseeable delivery infrastructure upgrade need, and thus DER would have more immediate delivery infrastructure avoidance value.

Table B-1, and Table B-2 show transformers with a "percentage rating" of 80% or greater. The transformer "percentage rating" was calculated by dividing the 2011-2015 five-year average summer peak load by the transformer MVA rating. The results include 45 transformers (6.6% of all transformers) with a percentage rating of 80% or greater.

TABLE B-1: NYSEG DISTRIBUTION SUBSTATION BENEFICAL LOCATIONS

Division	Substation	Transformer Bank
Binghamton	Glenwood #1 4.8 kV	SUB-TRF 3-1667KVA
Binghamton	Glenwood #2 4.8 kV	SUB-TRF 3-1667KVA
Brewster	Dingle Ridge 4.8 kV	3-1917(5751KVA 3PH) TRF
Lancaster	Wales Ctr 4.8 kV	SUB-TRF 3-1667KVA
Mechanicville	Stillwater 4.8 kV	SUB-TRF 3-833/0/0/933KVA
Lancaster	Silver Creek 4.8 kV	SUB-TRF 1-7.5/9.375MVA
Brewster	Amenia 4.8 kV	3-1667/1917 KVA
Elmira	Bulkhead #2 12.5 kV	LTC-TRF 1-7.5/9.375/10.5MVA
Lancaster	Orchard Park 4.8 kV	SUB-TRF 3-2.5/3.125MVA
Lancaster	Sloan 4.8 kV	LTC-TRF 1-7.5/9.375MVA
Brewster	Crafts 13.2 kV	1-12/16/20/22MVA,TRF,LTC
Lancaster	Java 4.8 kV	SUB-TRF 3-1667KVA
Lancaster	Dick Rd 1 - 4.8 kV	LTC-TRF 1-7.5/9.375MVA
Lancaster	Holland 4.8 kV	SUB-TRF 1-5.0/6.25MVA
Liberty	Hilldale 12.5 kV	SUB-TRF 3-2.5/2.8/3.5MVA
Mechanicville	Crooked Lake 4.8 kV	SUB-TRF 3-833/0/0/933KVA
Auburn	Weedsport 4.8 kV	SUB-TRF 3-1667KVA
Binghamton	Whig St 4.8 kV	LTC 1-2.5/3.125/0/3.5MVA
Brewster	West Patterson 13.2 kV	3-2800KVA (8400 3PH) TRF
Hornell	Arkport 4.8 kV	SUB-TRF 3-1000KVA
Liberty	Old Falls 12.5 kV	LTC-TRF 1-12/16/20MVA
Oneonta	Bridgewater 4.8 kV	SUB-TRF 3-667KVA
Auburn	Swift St 4.2 kV	SUB-TRF 3-1667KVA
Binghamton	Morningside 4.8 kV	SUB-TRF 3-1667KVA
Elmira	Kane St 4.8 kV	SUB-TRF 3-1667KVA
Geneva	Clyde 4.8 kV	SUB-TRF 3-2500KVA
Ithaca	Trumansburg 4.8 kV	SUB-TRF 3-1667/1917KVA
Liberty	Concord 4.8 kV	SUB-TRF 3-2500KVA
Oneonta	Earlville 12.5 kV	SUB-TRF 3-2500/2800KVA
Oneonta	Sand St2 4.8 kV	SUB-TRF 3-1667KVA
Oneonta	W. Winfield 12.5 kV	SUB-TRF 3-1667/2147KVA

TABLE B-2: RG&E DISTRIBUTION SUBSTATION TRANSFORMER BENEFICAL LOCATIONS

Division	Substation	Transformer Bank
Rochester	51	SUB-TRF1-6.25MVA
Rochester	43	SUB-TRF3-6.25MVA
Lake Shore	192	SUB-TRF1-1.5MVA
Rochester	71	SUB-TRF2-10.5MVA
Canandaigua	127	SUB-TRF1-14MVA
Rochester	53	SUB-TRF1-4.5MVA
Canandaigua	156	SUB-TRF2-1.5MVA
Rochester	46	SUB-TRF1-6.6MVA
Rochester	22	SUB-TRF1-6.25MVA
Rochester	69	SUB-TRF1-22.4MVA
Rochester	46	SUB-TRF3-6.25MVA
Lake Shore	210	SUB-TRF1-5.25MVA
Rochester	43	SUB-TRF4-6.25MVA
Lake Shore	217	SUB-TRF1-7MVA

Table B-3 and Table B-4 show circuits with a percentage rating of 80% or greater. The circuit "percentage rating" was calculated by dividing the 2015 peak load by the circuit MVA rating. The results include 102 circuits (6.0% of all distribution circuits) with a percentage rating of 80% or greater.

TABLE B-3: 2015 NYSEG DISTRIBUTION CIRCUIT BENEFICAL LOCATIONS

Division	Substation	Circuit
Lancaster	Silver Creek 4.8 kV	179
Lancaster	Silver Creek 4.8 kV	180
Binghamton	Glenwood #1&2 4.8 kV	685
Binghamton	Center Vil 4.8 kV	248
Elmira	West Elmira 4.8 kV	111
Geneva	Lehigh St#2 12.5 kV	602
Lockport	Transit St-4 4.16 kV	113
Oneonta	River Road 4.8 kV	103
Binghamton	Vestal #1 4.8 kV	714
Ithaca	Candor 4.8 kV	722
Binghamton	Sanitaria 4.8 kV	211
Geneva	Clyde 4.8 kV	202

Division	Substation	Circuit
Lancaster	Silver Creek 4.8 kV	178
Brewster	Bedford Hls 4.8 kV	225
Brewster	Bedford Hls 4.8 kV	227
Ithaca	Valois 4.8 kV	719
Oneonta	N. Norwich 4.8 kV	12
Lancaster	Sloan 4.8 kV	231
Plattsburgh	Clintonville 12.5 kV	456
Oneonta	Sidney 4.8 kV #1	145
Brewster	Goldens Bank #113.2 kV	418
Hornell	Arkport 4.8 kV	220
Lancaster	Hamburg 1&2 - 4.8 kV	293
Liberty	White Lake 12.5 kV	290
Mechanicville	Stillwater 4.8 kV	215
Oneonta	BouckVille 4.8 kV	12
Oneonta	Colliersville 4.8 kV	12
Oneonta	Cooperstown 4.8 kV	123
Oneonta	Morrisville1 4.8 kV	106
Oneonta	River Road 4.8 kV	102
Lancaster	Springbrook 12.5 kV	495
Lancaster	Wende 12.5 kV	442
Plattsburgh	Beekmantown 4.8 kV	133
Auburn	Genoa 4.8 kV	603
Brewster	Dingle Ridge 4.8 kV	277
Plattsburgh	West Chazy 4.8 kV	136
Binghamton	Chenago Br 4.8 kV	741
Brewster	Peach Lake #2 4.8 kV	249
Geneva	Clyde 4.8 kV	201
Geneva	Clyde 4.8 kV	203
Hornell	Naples 34.5 kV	566
Oneonta	Birdsall St #1 4.8 kV	82
Brewster	Amenia 4.8 kV	154
Geneva	Seneca ordinance 4.8 kV	207
Lancaster	Dick Rd 1 - 4.8 kV	393
Lockport	Vine St. 4.16 kV	102
Brewster	Amawalk 13.2 kV	453
Liberty	Hilldale 12.5 kV	225
Oneonta	Sidney 4.8 kV #1	146

TABLE B-4: 2015 RG&E DISTRIBUTION CIRCUIT BENEFICAL LOCATIONS

Division	Substation	Circuit
Rochester	89	212102
Rochester	16	49902
Rochester	62	38012
Rochester	109	519502
Rochester	41	43102
Rochester	62	38312
Rochester	114	251902
Rochester	419	516412
Rochester	43	47002
Rochester	33	37802
Rochester	136	529502
Rochester	92	216702
Rochester	42	29902
Rochester	92	216602
Rochester	418	527002
Rochester	47	29002
Lake Shore	193	22602
Rochester	83	223802
Rochester	29	45502
Rochester	89	521802
Rochester	114	252002
Rochester	16	48202
Rochester	49	27002
Rochester	40	213502
Rochester	72	44002
Rochester	101	255002
Rochester	89	521902
Rochester	16	49802
Rochester	14	43702
Rochester	83	218002
Rochester	40	42802
Rochester	104	515702
Rochester	49	46602
Canandaigua	144	291302

Division	Substation	Circuit
Canandaigua	168	519002
Rochester	420	218302
Rochester	66	48702
Rochester	85	222902
Rochester	126	522502
Rochester	89	522002
Rochester	62	38112
Rochester	112	252302
Canandaigua	144	291402
Rochester	103	221402
Rochester	1	33602
Rochester	76	210102
Rochester	55	524002
Rochester	112	253402
Rochester	43	210402
Rochester	38	36702
Rochester	81	222602
Rochester	42	219402
Rochester	19	220902

Appendix C: Distribution Planning Manual Additions

The Companies' Networks Distribution Planning Manual will be updated to include processes for evaluating DER and incorporating DER/NWA options to the overall distribution planning process. These new elements of the manual are described below.

A. DER Capacity Factors

A new Section 7.3 of the Distribution Planning Manual will reflect DER Capacity Factors. DER capacity factors are used to de-rate the alternating current ("AC") ratings of the DER to determine the expected sustainable and reliable distribution load relief of the specific DER installation. The capacity factor is defined as the ratio of the DER's actual output over a period of time, to its potential output if it were possible f to operate at full nameplate AC capacity continuously over the same time period. DER capacity factors from the U.S. Energy Information Administration ("EIA")[72] are:

Contracted Demand Response	= 100%
Nuclear Power Plant	= 90%
Battery Storage	= 90%
Coal Power Plant	= 64%
Natural Gas Power Plant	= 42%
Hydroelectric dam	= 40%
Fuel Cell	= 40%
Biomass	= 34%
Wind Farm	= 30%
Solar	= 26% (ISO New England)[73]

The Peak Availability Factor is defined as the ratio of the amount of time that the DER is able to produce electricity over a distribution circuit's peak load period of time, divided by the amount of time in the period. In the absence of interval load data specific to the point of interconnection of the DER being evaluated, the use of the following typical daily peak load curves, as shown in the figure below:

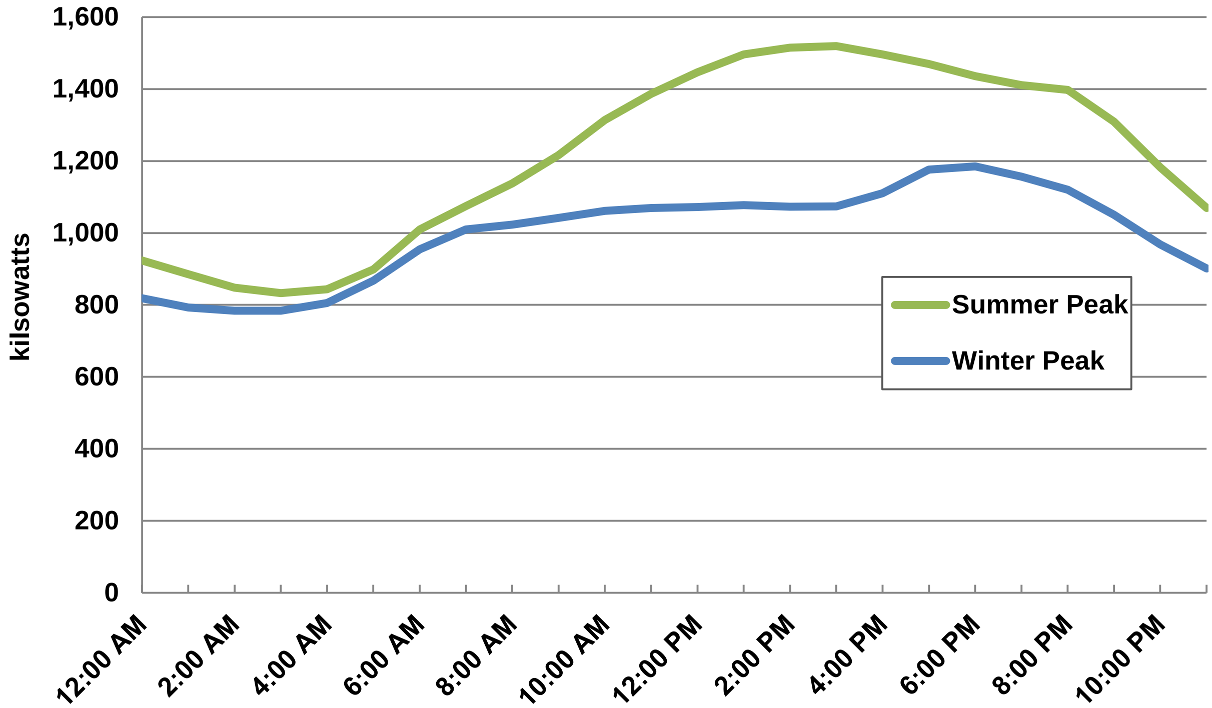
- Summer daily peak period of 12:00 pm to 6:00 pm.

[72] U.S. Energy Information Administration. Electric Power Annual 2009, Revised April, 2011.

[73] The 26% ISO New England factor is being adopted by Electric Distribution Planning. National Grid's extensive PV analyses validate this factor, which is used in its assessments as well. The Companies' Transmission Planning departments has adopted this factor for its NTA project evaluations.

- Winter daily peak period of 3:00 pm to 9:00 pm.

FIGURE C-1: SUMMER VERSUS WINTER PEAK



Example Calculation: A 2 MW (full AC rating) solar PV array has been successfully approved for interconnection to the distribution system, all contributions for required system reinforcements have been paid, and construction of the array is scheduled for the current calendar year. For the evaluation of any capital investment projects being planned for the distribution circuit and substation to which the array is being connected, the following impact to peak loading must be taken into consideration:

- Summer Peak Availability = 100% as the PV is expected to generate in the summer between the hours of 7:00 am and 7:00 pm.

  Summer Peak Impact = 2 MW x 0.26 x 1.0 = 520 kW expected summer peak reduction.

- Winter Peak Availability = 33% as the PV is expected to generate in the winter between the hours of 7:00 am to 5:00 pm.

  Winter Peak Impact = 2 MW x 0.26 x 0.33 = 172 kW expected winter peak reduction.

B. Incorporating DER into the Distribution Planning Process

A new Section 7.4 of the Distribution Planning Manual will reflect the incorporation of DER in the distribution planning process. The Companies' annual distribution planning process consists of a traditional five-step process incorporating current DER and forecasted DER plus identification of projects amenable to NWA (step 6 and 7):

(1) Identify the issue (issues are typically problems that fall outside of the established distribution planning criteria):

- Location
- Limiting elements
- Magnitude of issue
- Critical Load
- Load Curve

(2) Identify the goal of the solution (what should the solution accomplish)

(3) Identify the electric/wire alternatives (what electric solutions are available)

(4) Evaluate the electric alternatives (evaluations are made against established criteria and performance attributes)

(5) Select the best traditional alternative (the traditional wires solution that best meets the goal of the solution)

(6) Determine if generator/load reduction could solve the problem and defer/eliminate a large project according to NWA selection criteria

(7) To begin the process of DER solicitation proposals as alternatives to the recommended traditional wire solutions, communicate to the NWA Department projects amenable to NWA, including the minimal amount of MW required to defer the project per year.

The products of this annual process are the following:

- An Annual Distribution Issues Report which summaries the issues, lists the chosen solutions, and provides documentation of the overall condition of the Companies' distribution system.
- A five-year capital plan which provides the priority recommendations to be used by the Companies' Investment Planning Departments to develop the overall capital forecast for the Companies.
- A ten-year plan of locations and infrastructure where future system reinforcements are likely to occur due to current loading conditions and future expected growth.

Although the project solutions in this portion of the overall process include only traditional wire alternatives, two categories of DER are considered within the traditional planning process. First to be considered is the effect of the previously connected DER to the current year substation and circuit peak loads. As more unsolicited DER is added to the system each year, its actual effect on reducing the peak load of the specific distribution circuit and substation to which it is connected is factored into the planning process in the form of reduced annual peak loading. The total DER connected to the distribution system is tracked in various data bases, and is available for review by the Distribution Planner at the distribution circuit and substation levels. As the analysis for capital projects is reevaluated each year, the effect of this peak load reduction can lead to the postponement and delay of capital projects.

Second, any DER which has committed to connect will be evaluated for potential peak load reductions using the DER factors defined in Section 7.3. For this Distribution Planning purpose, the commitment to connect will consist of a successful CESIR study, payment of any applicable system reinforcement project costs required for interconnection and an expected in-service date within the current calendar year or expected project phases in future years. Once satisfied, the Distribution Planner will factor the proposed DER into the project and, if necessary, alter the year of need to reflect the impact of the proposed DER on the expected peak loads under evaluation.

Following the above DER and distribution system evaluation, the list of capital projects produced by the Distribution Planning Department is communicated to Investment Planning for inclusion within the overall capital planning process. The projects are then evaluated by System Engineering and Electric Capital Delivery for the development of project costs and construction schedules. Those projects that meet the NWA selection criteria in Section 7.2 are communicated to the NWA Department to begin the process of DER solicitation proposals as alternatives to the recommended traditional wire solutions.

Appendix D: Five-Year Historical Capital Spending

Table D-1, Table D-2, Table D-3, and Table D-4 show the Companies' historical spending in distribution, substations transmission, telecommunication, information technology, and shared services.

TABLE D-1: NYSEG HISTORICAL SPENDING IN DISTRIBUTION, SUBSTATIONS, AND TRANSMISSION

NYSEG ($000)	2011	2012	2013	2014	2015
Distribution	93,118	89,827	90,357	82,863	58,574
Substations	41,166	47,704	48,160	62,244	75,920
Transmission	25,520	19,658	22,860	17,459	37,709
Grand Total	**159,804**	**157,189**	**161,378**	**162,566**	**172,203**

TABLE D-2: RG&E HISTORICAL SPENDING IN DISTRIBUTION, SUBSTATIONS, AND TRANSMISSION

RG&E ($000)	2011	2012	2013	2014	2015
Distribution	51,234	48,658	45,455	47,239	31,027
Substations	47,595	82,720	83,093	60,922	73,089
Transmission	3,468	11,070	12,749	20,403	4,717
Grand Total	**102,297**	**142,449**	**141,296**	**128,565**	**108,833**

TABLE D-3: NYSEG HISTORICAL SPENDING IN TELECOMMUNICATION, IT, AND SHARED SERVICES

NYSEG ($000)	2011	2012	2013	2014	2015
Telecommunication	664	1,736	1,742	2,324	6,233
Information Technology	4,276	5,887	10,931	18,315	11,166
Shared Services	14,619	11,526	11,620	15,024	17,088
Grand Total	**19,559**	**19,149**	**24,293**	**35,663**	**34,487**

TABLE D-4: RG&E HISTORICAL INVESTMENT IN TELECOMMUNICATION, IT, AND SHARED SERVICES

RG&E ($000)	2011	2012	2013	2014	2015
Telecommunication	92	36	1,756	783	3,780
Information Technology	3,877	2,985	6,161	9,273	6,329
Shared Services	12,681	10,708	11,853	10,824	11,711
Grand Total	**16,650**	**13,729**	**19,771**	**20,880**	**21,819**

Appendix E: Five-Year Forecast Capital Budgets

The Companies develop and file our five-year Capital Investment Plan ("CIP") for each Company (NYSEG and RG&E) and each of five lines of business, as shown in Table E-1 summarizing the five-year 2016 CIP forecast.

TABLE E-1: 2016 CIP BY LINE OF BUSINESS

$ millions	Electric Transmission	Electric Distribution	Gas	Generation	Common	Total
NYSEG	300.0	569.7	333.9	36.7	200.5	1,440.8
RG&E	600.4	295.8	260.6	52.8	108.3	1,317.9
Total	**900.4**	**865.4**	**594.5**	**89.5**	**308.8**	**2,758.7**

Table E-2 and Table E-3 show the Companies' five-year capital budgets for distribution, substations, and transmission.

Distribution Investments

NYSEG: The Distribution budget is relatively level over the forecast period, primarily due to Distribution Operations programs contained in this category. Changes relative to 2016 are due to some specific projects such as AMI installation as part of the Energy Smart Community project (2017), and ECC System Upgrade and Amenia Conversion projects (2019).

RG&E: The Distribution investment maintains a general annual increase that accounts for inflation. Since this segment of the budget is based on Distribution Operations programs, there are no particular projects that cause any significant increase or decreases in the budget.

Substation Investments

NYSEG: Substation investment (both transmission and distribution stations) is expected to gradually increase over the next five years. The largest drivers of this increase are due to substation modernization projects and the number of additional projects planned that affect transmission substations. The magnitude of the investment in substations is further impacted by upgrades/additions to several transmission substations such as Coopers Corners, Gardenville, and Fraser.

RG&E: The 2016 level of investment in Substations is very high due to the Ginna Retirement Transmission Alternative ("GRTA") and Station 23 New Downtown Source projects. Although not all of the GRTA and Station 23 projects are substation related, over 70% of the investment is being made within substations. This project has been included entirely in the substation category due to this reason. The GRTA project accounts for more than 65% of the substation budget while Station 23 accounts for more than 20% of the substation budget. The planned investment in GRTA reduces by 85% in 2017, while the Station 23 project investment is slightly higher during the same year. Overall, the 2017 budget is reduced with respect to 2016. Upon completion of these projects (GRTA in 2017, Station 23 in 2018), the Substation budget decreases significantly.

Transmission Investments

NYSEG: Major transmission changes (decreases) occur in 2018 and 2019, relative to 2016 levels. The primary drivers of these decreases are due to the completion of the Auburn Transmission Project in 2017. In 2020, transmission investment increases significantly, relative to previous years, due to the planned significant investment in the mandated FERC Brightline Project. Although investment in this program will be made starting in 2017 through 2019, the magnitude of the investment increases materially in 2020.

RG&E: The major driver of RG&E's increase in transmission investment in 2018 and 2019, relative to 2016, is the Rochester Area Reliability Project ("RARP"). An additional driver to the increase in transmission investment in 2017-2019 is the FERC Brightline projects. The decrease in Transmission investment in 2020 is due to substantial completion of RARP, and decreases in the FERC Brightline investment.

TABLE E-2: CURRENT FIVE-YEAR CAPITAL BUDGET FOR DISTRIBUTION, SUBSTATIONS, AND TRANSMISSION

($000)	2016	2017	2018	2019	2020	Total 2016-2020
NYSEG	**155,497**	**173,719**	**149,692**	**176,863**	**213,868**	**869,639**
Distribution	82,157	93,935	85,405	96,957	86,737	445,191
Substations	26,357	36,306	43,202	64,657	66,418	236,940
Transmission	46,983	43,478	21,085	15,249	60,712	187,507
RG&E	**220,427**	**199,511**	**172,296**	**152,520**	**150,820**	**895,573**
Distribution	38,682	43,197	47,177	51,237	52,288	232,581
Substations	157,263	81,842	28,740	17,812	46,491	332,147
Transmission	24,482	74,472	96,379	83,471	52,041	330,845
Grand Total	**375,924**	**373,230**	**321,988**	**329,383**	**364,687**	**1,765,212**

The table below shows the five-year capital budget for distribution, substations, and transmission broken down by detailed project listings for the Companies.

TABLE E-3: CURRENT FIVE-YEAR CAPITAL BUDGET FOR DISTRIBUTION, SUBSTATIONS, AND TRANSMISSION

($000)	2016	2017	2018	2019	2020	Total 2016-2020
NYSEG	**155,497**	**173,719**	**149,692**	**176,863**	**213,868**	**869,639**
Distribution	**82,157**	**93,935**	**85,405**	**96,957**	**86,737**	**445,191**
Amenia 2nd Bank and 13.2kKV Conversion - Brewster	-	-	3,000	7,000	-	10,000
Asset Condition - Red Health Index	11,250	12,000	12,750	13,500	15,000	64,500
Betterments	7,000	7,210	7,426	7,649	7,879	37,164
Distribution Line	14,500	14,935	15,383	15,845	16,320	76,983
Distribution Line Inspection	9,241	9,652	10,585	11,451	11,794	52,723
ECC System Upgrade	-	-	-	4,900	-	4,900
Electric Meters - Program	2,633	2,633	2,633	2,765	2,823	13,487
Energy Control Center Project in NY, Siemens DMS	700	-	-	-	-	700
Energy Smart Community REV Project	3,728	2,465	1,943	648	-	8,784
General Equipment Operations T&D	510	520	531	541	552	2,654
Glenwood - Replace Substation Transformers	1,000	-	-	-	-	1,000
Industrial Commercial	1,249	1,274	1,299	1,325	1,352	6,499
Java 2nd Transformer and 12 kV Conversion	-	-	-	-	489	489
Lifecycle Replacement - ECC/XECS systems	105	105	105	620	105	1,040
Lockheed Martin Remote Outage Visualization	1,000	-	-	-	-	1,000
Major Government Highway	2,040	2,081	2,122	2,165	2,208	10,616
Mobile Replacement #2 and #4	2,000	2,800	-	-	-	4,800
NYSEG Automation Projects	5,000	8,000	7,500	7,500	7,500	35,500
NYSEG Communications for Automation Programs	1,000	1,000	1,000	1,000	750	4,750
Organic Growth ECC/XECS systems	138	140	142	144	148	712
Red Circuit Reliability	4,000	4,120	4,244	4,371	4,502	21,237
Residential Line Extensions	8,000	8,240	8,487	8,742	9,004	42,473
Service Connects	2,787	2,843	2,900	2,958	3,047	14,535

($000)	2016	2017	2018	2019	2020	Total 2016-2020
Smart Grid / AMI for Energy Smart Community Project	-	10,000	-	-	-	10,000
Storm Restoration	1,326	1,352	1,380	1,407	1,435	6,900
Street Lighting	1,000	1,030	1,061	1,093	1,126	5,310
T&D - Switch Replacement Program	300	300	-	-	-	600
T&D Reject Pole Replacement	500	515	664	683	703	3,065
Telecom - Alarm Monitoring Refresh	150	-	-	150	-	300
Telecom - SONET Refresh	-	450	-	-	-	450
Substations	**26,357**	**36,306**	**43,202**	**64,657**	**66,418**	**236,940**
Telecom Bridges for new KGO BU Site	-	20	-	-	-	20
Transmission and Distribution Fault Indicators	250	250	250	-	-	750
Walden 35kV Conversion	-	-	-	500	-	500
West Varysburg 12kV extension	750	-	-	-	-	750
Chenango Bridge Substation 743 Regulation	250	-	-	-	-	250
Coopers Corners - Add Third 345/115kV Transformer	-	461	2,346	7,063	-	9,870
Crafts - Add 2nd Transformer and 4th 13.2 kV Circuit Position	-	-	-	-	1,666	1,666
Davis Road, Replace 115/34.5kV Transformers #2 and #3 with new LTC's	-	-	-	5,509	5,255	10,764
Dingle Ridge - Add Second Transformer and 13.2kV Conversion	1,045	4,555	-	-	-	5,600
Eelpot New 2nd 115 kV/34.5 kV Transformer	3,741	-	-	-	-	3,741
Erie Street, Add 3rd 115/34.5 kV Transformer	-	-	-	-	1,027	1,027
Fraser New 2nd 345 kV/115 kV Transformer and 115kV Bus Reconfiguration	100	2,607	4,968	8,224	-	15,899
Gardenville, Add 3rd 230/115kV Transformer	-	-	-	660	12,683	13,343
Geneva, Add Switched Capacitor Bank at Five Points Prison Substation	-	-	-	903	-	903
Hilldale 115 kV source, Transformer bank upgrade, 2nd 12 kV distribution circuit	-	-	8,192	2,516	8,000	18,708
Holland Transformer Replacement	-	-	-	-	115	115
Homer City Capital Breakers	500	500	500	500	515	2,515

($000)	2016	2017	2018	2019	2020	Total 2016-2020
Meyer New 2nd 115/34.5 kV Transformer	854	943	-	-	-	1,797
Oakdale Substation Reconfiguration Project	100	100	218	977	3,268	4,663
Old Fall substation - Install 2nd LTC Transformer	3,738	3,042	1,500	2,000	-	10,280
Orchard Park - Add a 2nd Transformer Bank	-	-	-	4,136	4,542	8,678
Perry Center Area New 34.5 kV Substation	100	500	800	1,019	-	2,419
South Perry New Substation	3,713	1,500	1,500	1,621	-	8,334
Stephentown New 2nd 115/34.5 kV Transformer	100	1,355	-	-	-	1,455
Stillwater Substation- Upgrade Transformer to 14MVA	2,454	3,410	1,000	1,500	-	8,364
Substation Automation Program	1,500	1,610	1,722	1,837	1,892	8,561
Substation Battery Replacement Program	1,167	1,190	1,214	1,238	1,263	6,072
Substation Circuit Breaker Replacement Program	2,667	2,718	2,785	2,869	2,955	13,994
Substation Insulator Replacement Program	-	950	950	950	500	3,350
Substation Modernization	-	2,218	5,032	5,000	13,500	25,750
Substation Program	1,428	1,457	1,486	1,515	1,560	7,446
Substation Silicon Carbide Replacement Program	500	500	250	250	-	1,500
Substation Transformer Distribution Replacement program	1,000	1,000	1,000	1,000	2,000	6,000
Substation Transformer Transmission Replacement program	1,000	1,000	1,000	1,000	2,000	6,000
Watercure Road - Second 345kV Transformer	100	180	1,239	1,253	-	2,772
West Davenport Sub - Replace sub transformer with non-LTC 7.5/10.5MVA unit.	-	-	-	2,827	3,677	6,504
Westover Goudey New Transformer and Cap Banks	100	471	2,000	4,529	-	7,100
Windham Substation 115 KV Capacitor Bank Addition	100	874	-	-	-	974
Wood Street - Add Third 345/115kV Transformer	100	3,165	3,500	3,761	-	10,526
Transmission	**46,983**	**43,478**	**21,085**	**15,249**	**60,712**	**187,507**
Auburn Transmission Project	35,416	20,322	-	-	-	55,738

($000)	2016	2017	2018	2019	2020	Total 2016-2020
Columbia County Transmission Project (Klinekill 115 kV)	1,988	8,303	6,135	-	-	16,426
FERC- Bright Line	4,000	10,000	10,000	10,000	53,722	87,722
Fraser-Gilboa 345kV 35 Line (GF5) Relay and Communication Replacement	397	-	-	-	-	397
General Equipment - Substations	153	156	159	162	166	796
Line 526, Rebuild Coddington-South Hill 34.5kV Line	-	-	-	200	700	900
Line 807 - Convert to 115kV Operation	424	-	-	-	-	424
Line 810, Rebuild Carmel-Adams Corners 46kV Line	-	-	-	-	386	386
Transmission Line	4,605	4,697	4,791	4,887	4,985	23,965
Mechanicville, Circuit 620, Install Static and Ground Wires	-	-	-	-	754	754
RG&E	**220,427**	**199,511**	**172,296**	**152,520**	**150,820**	**895,573**
Distribution	**38,682**	**43,197**	**47,177**	**51,237**	**52,288**	**232,581**
Automation Program	2,000	2,090	2,182	2,275	2,368	10,915
Betterments	3,000	3,060	3,121	3,184	3,247	15,612
Communications for Automation Programs	500	1,000	1,000	1,000	1,000	4,500
Distribution Fault Indicators	100	100	-	-	-	200
Distribution Line	5,000	5,150	5,305	5,464	5,628	26,546
Distribution Line Inspection	1,000	1,030	1,061	1,093	1,126	5,309
General Equipment - Operations T&D	255	260	265	271	276	1,327
General Equipment Blanket - Substations	102	104	106	108	110	531
Incremental Automation Projects	1,000	2,000	2,500	2,500	2,750	10,750
Industrial Commercial	2,585	2,636	2,689	2,743	2,798	13,451
Lifecycle Replacement - ECC/XECS systems	139	139	139	324	139	880
Major Government Highway	8,352	8,519	8,688	8,865	9,041	43,465
Meters	1,206	1,206	1,206	1,266	1,293	6,178
Minor Government Highway	353	360	367	375	382	1,837
Old Insulator Change out Program	750	750	750	750	773	3,773
Padmount Switchgear Replacement	300	300	300	300	309	1,509
Red Circuit Reliability	1,800	1,854	1,910	1,967	2,026	9,556

($000)	2016	2017	2018	2019	2020	Total 2016-2020
Residential Service Installation	2,784	2,839	2,896	2,954	3,013	14,486
RG&E ECC System Upgrade	-	-	-	2,100	500	2,600
RG&E Asset Condition - Red Health Index	3,750	4,000	4,250	4,500	5,000	21,500
RG&E Pilot Wire Replacement Program	200	1,891	4,439	-	-	6,530
Service Connects	1,445	1,474	1,504	1,534	1,565	7,522
Silicon Carbide Change out Program	150	150	150	150	155	755
Station 117 - Replace #1 Transformer Bank and convert 3 circuits to 12 kV operation.	-	-	-	5,100	6,306	11,406
Storm Restoration	306	312	318	325	331	1,592
Street Lighting	1,000	1,030	1,061	1,093	1,126	5,309
T&D Reject Pole Replacement	605	623	642	661	680	3,211
T&D Switch Replacement Program	-	318	328	338	348	1,332
Substations	**157,263**	**81,842**	**28,740**	**17,812**	**46,491**	**332,147**
Ginna Retirement Transmission Alternative and Fifth Bay - Station 80	106,004	15,514	-	-	-	121,518
Station 192 transformer/facilities upgrade	2,678	2,265	-	-	2,178	7,121
Station 23 - New Downtown 115 kV Source	37,070	40,859	7,313	-	25,000	110,242
Station 23-Transformer and 11.5 kV Switchgear	2,039	3,732	603	-	-	6,374
Station 262- New 115 kV/34.5 kV Substation	100	2,363	2,023	3,500	3,160	11,146
Station 43 - Replace #3 and #4 Transformer Banks.	4,500	2,785	-	-	4,500	11,785
Station 46 - Replace #1 and #3 Transformer Banks	-	-	-	2,920	-	2,920
Station 49 - Replace 34.5-11.5 kV Transformer - Rochester	100	2,755	2,000	-	-	4,855
Station 51 transformer/facilities upgrade and secondary source addition	-	4,000	5,316	-	-	9,316
Station 95 - Add Second 34.5/11.5 kV Transformer	1,273	-	-	-	-	1,273
Substation - Minor Capex Program	832	847	865	882	909	4,335
Substation Battery Replacement Program	1,000	1,020	1,040	1,061	1,082	5,204
Substation Circuit Breaker Replacement Program	1,667	1,702	1,723	1,729	1,781	8,603
Substation Modernization	-	-	1,856	1,719	1,700	5,275

($000)	2016	2017	2018	2019	2020	Total 2016-2020
Substation Transformer Distribution Replacement program	-	3,000	3,000	3,000	3,090	12,090
Substation Transformer Transmission Replacement program	-	1,000	3,000	3,000	3,090	10,090
Transmission	**24,482**	**74,472**	**96,379**	**83,471**	**52,041**	**330,845**
FERC- Bright Line	5,000	10,000	10,000	10,000	4,663	39,663
Mobile Substations #3 and #5	2,900	860	-	-	-	3,760
Mobile switchgear #4	1,137	-	-	-	-	1,137
Move circuits 904 and 905 from Double Circuit Towers to separate towers	-	8,000	10,000	-	-	18,000
RARP	10,987	41,372	55,429	66,632	36,685	211,105
Sectionalize 115 kV Circuit 917 (S7 - S418)	100	1,478	2,755	2,000	-	6,333
Station 168 Service Area Reinforcement	3,991	4,387	7,813	4,449	4,000	24,640
Station 70 - Auto sectionalization 115 kV Circuit 917	-	8,000	10,000	-	-	18,000
Stations 67 to 418 New 115 kV Transmission Line	-	-	-	-	6,296	6,296
Transmission Line	367	375	382	390	397	1,911
Total NYSEG and RG&E	**375,924**	**373,230**	**321,988**	**329,383**	**364,687**	**1,765,212**

Table E-4 and Table E-5 include the five-year capital budget for Telecommunications, IT, and Shared Services.

Within NYSEG, there are increases in the Telecommunication, IT, and Shared Services budgets over the five-year forecast. The most dramatic increases come in 2020 and are focused on the IT, while increases in both 2019 and 2020 focused on the Shared Services. In 2020, IT is planning a large upgrade to the Customer Service module of our Enterprise Resource Program. In 2019 within Shared Services, an increase in Security, specifically physical security, is driving the increase. In 2020, the major driver is Fleet. The NYSEG Fleet is aging, and the necessary funding in near term years was deferred within the current rate case. To do this, a significant level of funding is necessary in 2020 to ensure that the NYSEG fleet operates in a safe and efficient manner.

At RG&E, there is a general increase each year with the Telecommunication, IT, and Shared Services budgets over the five-year forecast. The most dramatic increase is focused in 2020. During this year, RG&E will also be upgrading the Customer Service module of our Enterprise Resource Program. Additionally, though to a lesser magnitude, RG&E’s increase in fleet is the same as NYSEG’s.

TABLE E-4: FIVE-YEAR CAPITAL BUDGET FOR TELECOMMUNICATIONS, IT, AND SHARED SERVICES

($000)	2016	2017	2018	2019	2020	Total 2016-2020
NYSEG	26,981	37,401	34,304	40,776	61,086	200,548
Telecommunication	3,191	3,526	4,222	4,547	4,952	20,463
IT	5,230	5,904	6,793	7,306	21,010	46,243
Shared Services	18,560	27,971	23,289	28,898	35,124	133,842
RG&E	18,559	18,316	19,942	17,765	33,705	108,287
Telecommunication	295	314	371	485	634	2,099
IT	2,612	2,854	3,236	4,141	13,935	26,778
Shared Services	15,652	15,148	16,335	13,139	19,136	79,410
Grand Total	**45,540**	**55,717**	**54,246**	**58,541**	**94,791**	**308,835**

TABLE E-5: FIVE-YEAR CAPITAL BUDGET FOR TELECOMMUNICATIONS, IT, AND SHARED SERVICES

($000)	2016	2017	2018	2019	2020	Total 2016-2020
NYSEG	**26,981**	**37,401**	**34,304**	**40,776**	**61,086**	**200,548**
NYSEG Telecommunication	**3,191**	**3,526**	**4,222**	**4,572**	**4,952**	**20,463**
Telecommunications Major	3,191	3,526	4,222	4,572	4,952	20,463
NYSEG IT	**5,230**	**5,904**	**6,793**	**7,306**	**21,010**	**46,243**
IT Projects - Asset Condition	1,632	2,041	2,638	3,517	4,000	13,828
IT Projects - Cyber Security	550	732	600	600	700	3,182
IT Projects - Efficiency	1,417	1,453	850	2,300	15,000	21,020
IT Projects - Group Initiatives	370	304	700	459	600	2,433
IT Projects - Mandatory	30	30	1,130	30	60	1,280
IT Projects - Reliability Risk	290	370	615	400	650	2,325
IT Projects - Strategic	941	974	260	-	-	2,175
NYSEG Shared Services	**18,560**	**27,971**	**23,289**	**28,898**	**35,124**	**133,842**
Auburn Service Center - building renovation	-	-	30	-	300	330
Binghamton Service Center - roof replacement	150	-	-	-	-	150
Elmira Service Center - building renovation	-	770	-	-	-	770
Fleischmanns - heating fuel conversion	-	-	125	-	-	125
Geneva - building renovation and consolidation	-	-	2,600	1.400	-	4000
Ithaca General Office - building separation for disposition	200	600	400	-	-	1,200
Johnson City Training Facitility - construct new fabric structure	150	-	-	-	-	150

($000)	2016	2017	2018	2019	2020	Total 2016-2020
Kirkwood General Office - cooling tower replacement	200	-	-	-	-	200
Lancaster Service Center - building renovation	40	450	-	-	-	490
Liberty - dock upgrade	200	-	-	-	-	200
Liberty - elevator upgrade	200	-	-	-	50	250
Liberty - HVAC upgrade	250	250	-	-	-	500
Major Facilities Projects	-	-	-	2,811	-	2,811
Mechanicville Service Center - building renovation	50	500	-	-	-	550
Noyes Island - drainage and paving improvements	450	-	-	-	-	450
Oneonta Service Center - building renovation	45	-	-	-	450	495
Plattsburgh - heating fuel conversion	500	-	-	-	-	500
Plattsburgh Facility - building renovation	100	500	-	-	-	600
Vestal Electric Meter Lab - building renovation	20	150	-	-	-	170
Walden - Facility Closure and Relocation	440	-	-	-	-	440
CRC/Self Service Improvement	-	-	265	237	-	502
Laboratory Equipment	200	171	-	-	200	571
Other Customer Service Projects	-	50	-	50	50	150
Facilities Minor Projects	1,778	2,055	3,161	2,628	1,500	11,122
Fleet - Light duty vehicle capital leasing program	-	-	-	-	4,598	4,598
General Equipment - Fleet	100	100	100	100	100	500
Transportation Equipment	5,452	5,900	6,900	7,900	20,000	16,152
Fire Protection	950	1,200	1,000	750	3,000	6,900
Physical Security	6,996	15,177	8,591	12,895	4,775	48,434
Video Conferencing Equipment	89	98	117	127	100	55,865
RG&E	**18,559**	**18,316**	**19,942**	**17,765**	**33,705**	**108,287**
RG&E Telecommunication	**295**	**314**	**371**	**485**	**634**	**2,099**
OT TELECOM MAJOR CAPITAL PROJECTS - LifeCycle	295	314	371	485	634	2,099
RG&E IT	**2,612**	**2,854**	**3,236**	**4,141**	**13,935**	**26,778**
IT Projects - Asset Condition	835	1,147	1,054	2,424	2,800	8,261
IT Projects - Efficiency	727	800	422	893	10,000	12,842
IT Projects - Group Initiatives	195	161	500	243	400	1,499
IT Projects - Mandatory	30	30	630	30	35	755
IT Projects - Reliability Risk	550	350	330	250	350	1,830
IT Projects - Security	275	366	300	300	350	1,591
RG&E Shared Services	**15,652**	**15,148**	**16,335**	**13,139**	**19,136**	**79,410**

($000)	2016	2017	2018	2019	2020	Total 2016-2020
West Ave - Lighting Upgrade	-	130	-	-	-	130
East Ave - 6th Floor Renovation	600	-	-	-	-	600
East Ave - South Façade Restoration	400	-	-	-	-	400
Eastern Monroe - Lighting Upgrade	110	-	-	-	-	110
Major Facitilities Projects	-	1,390	1,594	1,669	2,500	7,153
CRC/Self Service Improvement	-	-	500	-	-	500
Laboratory Equipment	239	128	23	391	400	1,181
Other Customer Service Projects	177	315	-	293	250	1,035
Facilities Minor Projects	2,417	2,234	2,837	4,127	3,500	15,115
Fleet - Light duty vehicle capital leasing program	-	-	-	-	2,213	2,213
General Equipment - Fleet	45	45	45	45	45	225
Transportation Equipment	4,936	4,970	5,074	5,181	9,361	27,129
General Equipment	277	322	432	678	725	2,434
Fire Protection	1,575	575	750	375	1,250	4,525
Physical Security	4,710	4,934	5,000	375	1,000	16,019
Video Conference Equipment	100	50	50	50	100	350
VoIP endpoint project (Phone System)	66	100	75		50	291

Appendix F: BCA Handbook

The Companies' BCA Handbook is being filed concurrently with this Initial DSIP.

Appendix G: AMI Benefit-Cost Analysis

A. Executive Summary

New York State Electric & Gas and Rochester Gas & Electric (hereafter referred to as the Companies) propose the implementation of an Advanced Metering Infrastructure ("AMI") that will be an essential foundational system in realizing REV goals to empower customers through new tools and information to effectively manage and reduce usage, establish and animate new markets to promote the implementation of DER's, and minimize environmental impacts of power generation and energy consumption. The AMI project will include installation of intelligent meters (both electric and gas), supporting telecommunications network and IT infrastructure, and software applications to process data and interact with field devices. In addition, the network will provide a telecommunications channel for distribution automation ("DA"), distributed energy resources ("DER") and Demand Response ("DR").

AMI implementation will generate a wide variety of benefits, many of which can be reasonably quantified while others are less tangible. Although the less tangible benefits, such as market animation, may ultimately be quite large, this document focuses on the tangible, quantifiable benefits and compares those with the cost of obtaining them through AMI deployment and implementation of customer programs that are enabled by AMI. The analysis summarized here examines the benefits and costs associated with the following investments, business process changes and programs enabled by AMI:

- **AMI Operational Business Case:** A comparison of the cost of implementing AMI and the operational savings that can be obtained in the form of reduced meter reading and field service costs, reductions in billing and call center costs, and others.
- **Time-varying Pricing ("TVP"):** Examination of the benefits (e.g. avoided capacity and energy costs, among others) of a time-of-use-critical-peak-pricing (TOU-CPP) tariff with the cost of implementing TVP under two enrollment scenarios, opt-in and default;
- **Behavioral Conservation:** A comparison of the costs and benefits, primarily in the form of avoided energy consumption and carbon emissions, from defaulting roughly half[74] of the Companies' residential customers onto a program that provides weekly usage alerts showing customers their usage and energy costs over the prior week and cumulatively since the start of the billing period;
- **AMI-OMS Integration:** Estimation of the benefits, in the form of reduced customer outage costs, resulting from the fact that AMI can provide quicker visibility into exactly where outages occur and also reduce outage restoration times;

[74] Those for which the Companies have email addresses.

- **CVR/VVO:** Covers the incremental reduction in energy use associated with conservation-voltage-reduction/Volt/var-optimization (CVR/VVO) when implemented in conjunction with full deployment of AMI.

Figure G-1 shows the primary costs and benefits associated with each of the programs and business process changes outlined above.

FIGURE G-1: SOCIETAL BENEFIT AND COST CATEGORIES FOR QUANTIFIABLE PROCESS CHANGES AND PROGRAMS ASSOCIATED WITH AMI[75]

AMI Operational Business Case	Time Varying Pricing & Information Feedback	AMI-OMS Integration	CVR/VVO
AMI COSTS Meters & related equipment Meter installation Network equipment & installation Project management IT hardware, software & integration	**COSTS** Program design & set up Customer recruitment Program administration Program evaluation	**COSTS** Software integration covered in AMI IT costs	**COSTS** CVR/VVO costs included in tech projects – there are incremental benefits from AMI but no incremental costs
AMI OPERATIONAL BENEFITS Meter reading Field services Billing & call center Avoided meter purchases Reduced storm costs Improved cash flow Reduced meter burden	**BENEFITS** Avoided G, T & D costs Avoided energy costs Reduced carbon emissions	**BENEFITS** Reduced customer outage costs Reduced carbon emissions (fewer truck rolls)	**BENEFITS** Avoided G, T & D costs Avoided energy costs Reduced carbon emissions

In addition to the societal benefits summarized above, a number of benefits were also quantified that can be categorized as equitable redistributions of costs among various stakeholders. These include reductions in theft and write offs and, fewer meter malfunctions and slow meters, and less consumption on inactive meters. These benefits are included in one or more of the additional benefit-cost perspectives summarized in the following section.

[75] Time Varying Pricing and Usage Alerts, which are analyzed separately, are combined in this figure because they have the same cost and benefit categories and to keep the size of the figure manageable.

1. *Benefit-Cost Analysis*

The BCA order[76] specified that benefit-cost estimates be developed based on three perspectives:

- **Societal:** 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? Note that this perspective is not focused on whether customers' bills will increase or decrease (which may depend upon their participation in the program), but rather whether the volumetric rate increases or decreases.

The societal test not only counts operational benefits to a utility, but it also includes benefits experienced by customers (e.g. reduced outage costs), 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). In the analysis, meter and network deployment occurs over a four-year period starting in 2018 while benefits continue to accrue over the assumed 20-year life of each new meter. The discount rate used for present value calculations is the Weighted Average Cost of Capital ("WACC") for each AVANGRID operating company. Since taxes are considered income transfers, which are excluded from the societal test, the after-tax WACC is used for the societal test (6.81% for NYSEG; 7.48% for RG&E) whereas the pre-tax WACC is used for the UCT and RIM tests (9.60% for NYSEG; 10.34% for RG&E). 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.

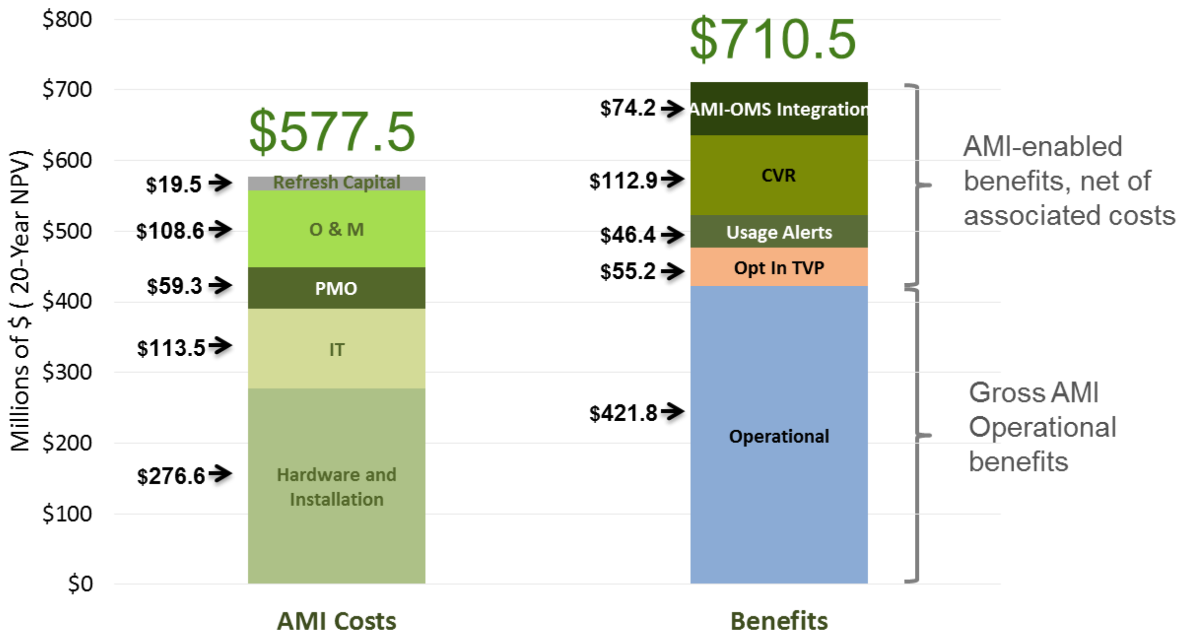
76 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d

2. *Summary of Results*

Figure G-2 summarizes the quantifiable societal costs and benefits associated with AMI deployment. All values in the figure are presented in present value terms from 2018 (when deployment begins) through 2040 (when the last installed meters reach their assumed 20-year life), expressed in 2016 dollars.

The Companies have approximately 1.8 million gas and electric meters that would be replaced during AMI deployment. Of these, roughly 1.2 million are electric meters and the rest are gas meters. In order to achieve some of the primary operational benefits associated with AMI deployment, especially avoided meter reading costs, both gas and electric meters must be replaced or retrofitted (gas only).

FIGURE G-2: PRESENT VALUE OF SOCIETAL BENEFITS AND COSTS



As seen in Figure G-2, AMI installation costs are broken down into five primary categories:

- Meter and network hardware and installation;
- IT hardware and software;
- Project management;
- Ongoing operations and maintenance of the system over the life of the AMI investment; and
- Refresh capital (e.g. annual replacement of failed meters plus replacement of IT hardware and network devices at several intervals).

Roughly 48% of the $578 million in costs over the life of the investment are comprised of meter and network hardware and installation. The $114 million associated with investment in and operation of IT systems and equipment includes costs for AMI head-end hosting, meter data management hosting, a new billing and customer relationship management system and integrating AMI with the OMS system. Roughly 10% of the present value of costs is associated with project management during the deployment phase and 19% of total costs are from ongoing operations and maintenance. The remaining 3% of total costs are associated with refresh capital.

During the meter deployment phase (including the year prior to initial deployment) from 2017 through 2021, the Companies estimate that cash outlays (non-discounted) will equal approximately $504 million for meter and network hardware and installation, project management and IT hardware and software. This is roughly $299 for each installed electric meter and $239 for each gas meter.

The present value of operational benefits from AMI deployment is estimated to equal $422 million, or roughly 73% of total costs over the life of the investment. Of this total, 48% ($202 million) comes from avoided meter reading costs and 24% ($100 million) comes from reductions in field service costs stemming from meter features such as remote connect/disconnect. Savings of approximately $41 million is estimated to come from reduced billing and call center costs and another $28 million in cost reductions stem from reductions in storm restoration costs due to more efficient management of crews through greater visibility into where outages occur and when they are restored. The remaining operational savings (roughly $51 million) are estimated to come from reduced meter purchases from the Companies existing replacement program, improved cash flow (through quicker read to bank timeline) and avoided network O&M (telecommunications) costs.

As seen in the right hand side of Figure G-2, the gap of $156 million between AMI costs and operational benefits are more than offset by the net benefits from AMI enabled pricing and programs such as usage alerts, improvements in reliability from AMI-OMS integration and conservation savings from CVR/VVO. TVP and usage alerts, with net benefits of $102 million, offset roughly two-thirds of the operational business gap.[77] The TVP benefits are based on an opt-in tariff in which 15% of residential and small and medium business (“SMB”) customers are enrolled on a TOU-CPP tariff. The usage alert program provides weekly updates on usage and costs via email on a default basis to roughly half of the Companies’ residential consumers.[78] The benefits shown in Figure G-2 represent avoided energy costs and carbon emissions for both electricity and gas behavioral conservation. Roughly 75% of total benefits for the TVP tariff arise from avoided generation capacity costs while the remaining benefits arise from avoided transmission and distribution capacity and avoided energy use and carbon emissions. If default TVP pricing—which currently is not approved in New York for residential consumers– could be

[77] Gross benefits from opt-in TVP and usage alerts combined are estimated to equal roughly $127 million, but these are offset in part by roughly $25 million in costs to market and operate these programs over the life of the AMI meters.

[78] The Companies predicts they will have email addresses on roughly 60% of its residential population by the time meter deployment begins in 2018.

implemented, TVP net benefits alone could equal nearly $179 million, which alone would cover the full operational business case gap.

The integration of AMI with OMS will reduce outage durations for a subset of outage types due to the ability to detect outages more quickly and through more effective management of outage restoration due to greater visibility into outage locations. Shorter average outage duration will reduce customer outage costs. The cost of AMI-OMS integration is already included in the $114 million in IT hardware and software costs discussed above. Outage cost reduction benefits are estimated to equal $74 million.

The final AMI-related benefit stream that is quantified has to do with the incremental reduction in energy use that can be obtained from CVR/VVO when AMI is fully deployed. The Companies estimate that AMI combined with CVR/VVO will reduce energy use by roughly 0.5% on average across all customer usage. This reduction would produce benefits with a present value equal to roughly $113 million, of which almost 73% is attributable to avoided energy costs and carbon reductions.

Combined, the quantifiable societal benefits of full deployment of AMI by the Companies are estimated to exceed the present value of costs by almost $133 million over the assumed life of the investment. With a societal benefit-cost ratio of over 1.2 and the fact that many intangible and hard-to-forecast benefits such as market animation and increased penetration of DER are not included in the analysis, the full deployment of AMI by the Companies is consistent with recently approved AMI projects in New York.

B. Introduction

The Companies propose to fully deploy AMI to obtain the substantial societal benefits quantified in the analysis documented here. AMI will also enable progress toward the REV objectives of empowering customers through new tools and information to effectively manage and reduce usage; animating new markets to promote the implementation of DER's; and reducing the environmental impact of power generation and energy consumption. The Companies propose to complete full deployment over the four-year period from 2018 through 2021.

AMI implementation will generate a wide variety of benefits, some of which can be reasonably quantified while others are less tangible. The largest category of quantifiable benefits is comprised of the operational savings that arise from AMI implementation. Examples include reduced meter reading costs, reduced field service visits associated with connections and disconnections, reductions in storm related costs due to better visibility into outage locations, reductions in billing and call center costs, among others. As seen later, the net present value ("NPV") of all of these operational savings offset roughly 71% of the cost of deploying AMI.

Another important benefit category stems from the fact that full deployment of AMI and integration of AMI with the Companies outage management system ("OMS") can reduce outage duration by shortening detection times and by more efficient deployment and management of crews through greater visibility into outage locations. Shortening outage duration reduces customer outage costs.

A third source of benefits stems from implementation of more economically efficient pricing and enhanced customer services that arise from access to the more granular and timely information that can be provided through AMI. These pricing strategies and enhanced information services 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.

The final quantifiable benefit from AMI addressed stems from the incremental reduction in energy use, demand and carbon emissions that can be obtained from conservation voltage reduction ("CVR")/Volt/var optimization ("VVO"). The Companies are proposing to implement CVR/VVO as part of their DSP platform. If AMI is deployed along with VVO, the benefits arising from CVR/VVO would be larger than if CVR/VVO was deployed independent of AMI.

1. *Benefit-cost Analysis*

The primary methodology used to assess the AMI investment and related programs is benefit-cost analysis ("BCA"). BCA 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 BCA is to provide factual insights, make tradeoffs transparent, improve the planning process and help maximize value. BCA 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 order[79] specified that benefit cost analysis should be undertaken from three perspectives:

- **Societal:** Do the benefits, including externalities, exceed the costs?
- **Utility**: Is the resource or program self-funding or are additional funds needed?
- **Ratepayer**: How does the resource affect rates? Note that this perspective is not focused on whether customers' bills will increase or decrease (which may depend upon their participation in the program), but rather whether the volumetric rate increases or decreases.

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[79] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d

The societal test not only counts operational benefits to a utility, but it also includes benefits experienced by customers (e.g. reduced outage costs), 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. Table G-1 and Table G-2 summarize the various costs and benefits that are included in each of the cost-effectiveness tests.

Of these three perspectives, the societal test is the most important from a public policy perspective and is the primary focus in this report. As long as net benefits are positive from a societal perspective, it means that society as a whole would be better off by implementing AMI and the complementary programs enabled by AMI, even if some societal members might gain while others lose. Under these circumstances, complementary policies can typically be implemented that reallocate the gains and losses so that most stakeholders are better off.

TABLE G-1: BENEFITS INCLUDED IN EACH BCA TEST PERSPECTIVE

AMI Component	Benefit Type	Benefit Category	Societal	Utility	Ratepayer
AMI	Avoided Capital	Avoided Meter Purchases	X	X	X
	Avoided O&M	Billing	X	X	X
		Call Center	X	X	X
		Field Work	X	X	X
		Improved Cash Flow	X	X	
		Meter Reading	X	X	X
		Reduced Meter Burden	X	X	X
		Reduced Storm Costs	X	X	X
		Avoided Network O&M	X	X	X
	Avoided Fleet Capital	Field Work	X	X	X
		Meter Reading	X	X	X
	Societal Benefits	Avoided Carbon due to Fewer Truck Rolls	X		
		Avoided Customer Outage Costs	X		
		Meter Accuracy Improvement			X

AMI Component	Benefit Type	Benefit Category	Societal	Utility	Ratepayer
	Transfer-Customer Equity	Energy Theft Reduction			X
		Delivery Write Offs			X
		Energy Write Offs			X
AMI Enabled Rates/Options	Avoided Capital	Avoided Transmission Capacity	X	X	X
		Avoided Distribution Capacity	X	X	X
	Customer Energy Supply Savings	Avoided Generation Capacity	X	X	X
		Avoided Wholesale Energy Costs	X	X	X
		Avoided Wholesale Natural Gas Costs	X	X	X
	Societal Benefits	Avoided Carbon due to Reduced Energy Use	X		
		Avoided Carbon due to Reduced Natural Gas Use	X		

TABLE G-2: COSTS INCLUDED IN EACH BCA TEST PERSPECTIVE

AMI Component	Cost Type	Cost Category	Benefit Cost Analysis Perspective		
			Societal	Utility	Ratepayer
AMI	Deployment Capital	IT Hardware	X	X	X
		IT Software	X	X	X
		Meters	X	X	X
		Network	X	X	X
		PMO	X	X	X
	Refresh Capital	IT Hardware	X	X	X
		Meters	X	X	X
		Network	X	X	X
	O&M	O&M	X	X	X

AMI Component	Cost Type	Cost Category	Benefit Cost Analysis Perspective		
			Societal	Utility	Ratepayer
AMI Enabled Options	O&M	Marketing Acquisition Costs	X	X	X
		Other Variable Costs	X	X	X
		Fixed Overhead Costs	X	X	X
		Participant Sign Up Incentives		X	X
	Lost Revenue	T&D Revenue Losses/ Customer Savings			X

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

- The meters are assumed to be deployed over a four-year period starting in 2018 and ending in 2021. The Companies' AMI deployment schedule is illustrated in Table G-3.

TABLE G-4: DEPLOYMENT SCHEDULE

	2018	2019	2020	2021
NYSEG	20%	40%	30%	10%
RG&E	0%	30%	40%	30%

- Each meter is assumed to have a 20-year life. As such, meters deployed in 2018 are assumed to produce benefits tied to meter deployment through 2037, meters deployed in 2019 are assumed to deliver benefits through 2038, and so on. Thus, the analysis period goes from 2018 through 2040.
- The present value of costs and benefits are discounted back to 2018 (when costs are first incurred) using the NYSEG and RG&E WACCas the discount rate. Since taxes are considered income transfers, which are excluded from the societal test, the after-tax WACC is used for the societal test (6.81% for NYSEG; 7.48% for RG&E) whereas the pre-tax WACC is used for the UCT and RIM tests (9.60% for NYSEG; 10.34% for RG&E). 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 inflation between 2016 and 2018. Annual labor inflation rates are assumed to equal 3% and all other costs are assumed to inflate by 2.1% annually unless stated otherwise in the discussion below.
- The annual growth in the NYSEG/RG&E customer population is assumed to equal 0.5%.

2. *Appendix Organization*

The remainder of this appendix is organized as follows. Section C summarizes the analysis for the operational business case, which compares the costs of AMI deployment with the operational savings that will be achieved once AMI is fully deployed. Section E summarizes the outage cost reduction benefits that can be achieved through the integration of AMI and OMS. Section F summarizes the net benefits associated with implementation of TVP. Section E analyzes the net benefits that can be obtained from information feedback programs that are enabled by AMI. Section G presents estimates of the benefits stemming from CVR/VVO implementation in conjunction with AMI and Section H provides a summary of all quantified costs and benefits associated with AMI deployment

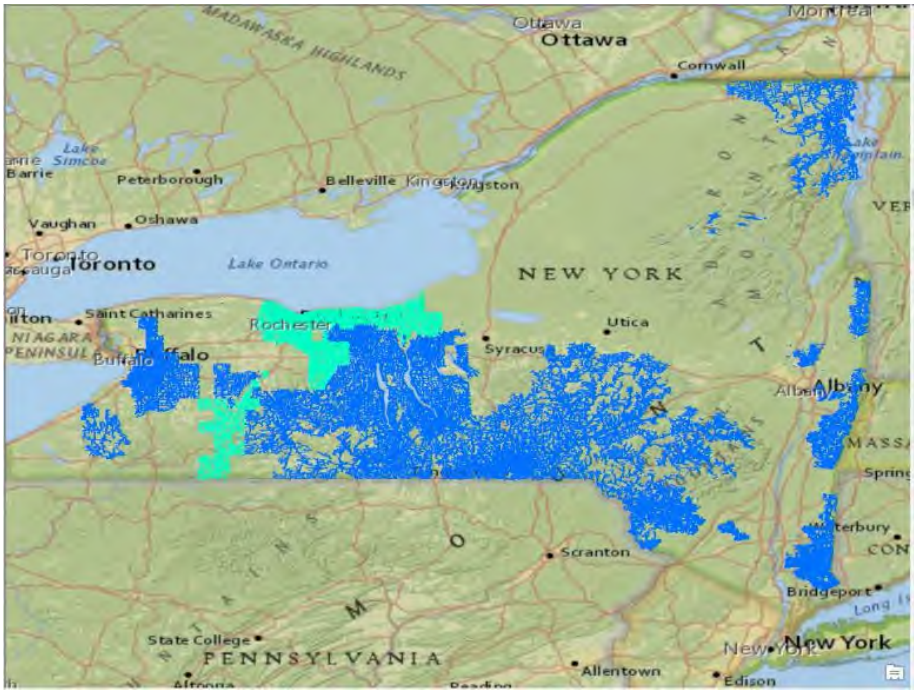
C. Operational Business Case

As seen in in Table G-5, the Companies have 1.8 million electric and gas customer meters across 21,000 square miles in New York, located in the RG&E and NYSEG service area. Roughly 45% of RG&E's meters are gas meters whereas only 22% of NYSEG's meters are gas meters. Figure G-3 and Figure G-4 provide maps of these meter locations within the state.

TABLE G-5: ELECTRIC AND GAS METERS

Meter Type	RG&E	NYSEG	Total
Gas Meters	296,533	260,574	557,107
Electric Meters	365,490	871,558	1,237,048
Total	662,023	1,132,162	1,794,185

FIGURE G-3: THE COMPANIES 1,237,048 ELECTRIC METER LOCATIONS



Note: Dark blue dots are NYSEG meters, and light blue dots are RG&E meters

FIGURE G-4: THE COMPANIES 557,107 GAS METER LOCATIONS

Note: Dark blue dots are NYSEG meters, and light blue dots are RG&E meters

The Companies have evaluated the costs and benefits of AMI technology that can provide the following capabilities:

- Delivered daily reads with a success rate of 99.5% for both electric and gas meters;
- Delivery of electric interval consumption data (hourly for residential customers and quarter-hourly for commercial customers) with a success rate of 99.0% and delivery at least four times per day;
- Execution of service connects and disconnects for electric residential and network meters with a 98% success rate (execution within 30 minutes);[80]
- Execution of on demand reads for gas and electric meters with a 98% success rate within 60 seconds;
- Home Area Networking (“HAN”) to facilitate customer interaction and management of their gas and electric service usage;
- Delivery of electric meter power-off and power-on requests to AMI head end within 15 minutes;
- Capability to reprogram meters over-the-air to adapt to new demand response rates that might evolve;
- Capability to monitor voltage with electric meters;
- Capability for a small percentage of electric meters (5%) to deliver 15-minute interval data every 15 minutes; and
- Capability to provide two-way telecommunications to distribution automation grid devices with low latency.

The remainder of this section discusses the costs and some direct benefits of deploying AMI with the above functionality across the Companies’ service area. These costs and benefits are discussed in six subsections: initial AMI deployment expenditures; AMI system operational costs; AMI system life-cycle refresh expenditures; operational savings; capital savings; and economic analysis of system costs and benefits. The economic analysis indicates that about 71% of the total life-cycle costs of AMI are offset by the operational and capital benefits that AMI generates and that are described here. AMI also supports other benefits, which are discussed in other sections of this appendix.

The seventh subsection below discusses impacts of AMI that improve equity or bill fairness by reducing the socialization of costs incurred by a few customers across the entire customer

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[80] The economic analysis of savings through reduced field work assumes the service connect/disconnect switch will be used in credit situations. Though currently not approved in New York, the use of the switch to replace field visits occurs in other states, and the assumption here is that requirements would change once AMI is fully implemented in New York.

population. These impacts represent $122 million (20-year NPV) of cost redistribution to improve fairness.

1. *Initial AMI Deployment Expenditures*

Table G-6 summarizes the projected expenditures to deploy AMI to all the Companies' customers. The total cost of roughly $503 million dollars over the five-year period from 2017 to 2021 represents estimated cash flows, adjusted for inflation where appropriate, not the present value of expenditures. The remainder of this subsection discusses each of the entries in Table G-6.

TABLE G-6: PROJECTED AMI DEPLOYMENT EXPENDITURES

($ Millions, unless otherwise identified)

Deployment Cost Element	Electric	Gas	Total
Meters and Installation	[redacted]		
Network			
IT			
PMO			
Total	$370.4	$133.4	$503.8
Meters	1,237,048	557,107	1,794,155
Cost per Meter	$299	$239	$281

a) Meter Equipment and Direct Installation

Meter equipment and direct installation costs account for [redacted] of total deployment costs. In March, 2016, the Companies issued an RFI to collect data from a range of AMI system providers and meter installers. Representative system and installation bids were used to produce the unit prices in Table G-7.[81] Electric meters include disconnect switches for residential and network meters, and Home Area Networking for meters to permit broadcasting of information from meters to customers.[82] In the description of customer service benefits below, the role of the disconnect switch in producing customer benefits is described more fully. The quantities in Table G-7 were

[81] For transformer-rated three-phase meters, the vendor-quoted price for self-contained three phase meters has been doubled, and represents a cost that might actually be incurred by internal company resources that could handle this segment of the AMI deployment.

[82] The analysis assumes the disconnect switch can be used for both reconnections and disconnections of service, reflecting how it is used at CMP in Maine. Using the switch only for reconnections would reduce the field service benefits described later on in the discussion.

developed from analysis of information in the Companies' Customer Information System ("CIS") and Meter Asset Management Databases. For gas customers, ordinarily a telecommunications module is installed on existing meters and no meter change out is required. However, the Companies identified 45,861 gas meters where the age and design of the meter indicated that replacement was prudent to avoid rework during the life of the AMI system. The [redacted] million difference between the [redacted] million in meter and installation costs in Table G-6 and the [redacted] million in Table G-7 includes make-ready work and inventory replacement as explained in the subsection below on other meter deployment costs.

TABLE G-7: METER EQUIPMENT AND DIRECT INSTALLATION COSTS

($ Millions, unless otherwise identified)

Equipment or Installation Service	Quantity	Unit Price ($)	Sales Tax Per Unit ($)	Contingency per Unit ($)	Total Expenditure
Single Phase Electric Meters	1,097,868	[redacted]			
Network Electric Meters	19,182	[redacted]			
Self-Contained Three Phase Meters	96,022	[redacted]			
Transformer-Rated Three Phase Meters	24,006	[redacted]			
Gas Meters	45,861	[redacted]			
Gas Telecommunication Modules	557,107	[redacted]			
Single Phase Electric Meter Installation	1,097,868	[redacted]			
Network Electric Meter Installation	19,182	[redacted]			
Self-Contained Three-Phase Meter Installation	96,022	[redacted]			
Transformer-Rated Three Phase Meter Installation	24,006	[redacted]			
Gas Meter with Integrated Module Installation	45,861	[redacted]			
Gas module Installation	511,246	[redacted]			
		[redacted]			

b) Network Equipment and Direct Installation Costs

The telecommunications network sends and receives information from the meters to the AMI operations center. The network cost estimate is based on the representative AMI system bid received by the Companies, which the representative vendor developed based on a review of all meter locations as part of a detailed propagation study. The network installation prices are based on experience at Central Maine Power ("CMP"), an AVANGRID operating company that previously deployed AMI, and include costs for a site visit prior to installation and make-ready work that might be needed. Make-ready work includes any needed secondary line extensions from transformers, and in 10% of the network locations, installation of a distribution transformer to support the network device.

The direct costs of the network are a relatively small part (approximately 2%) of overall deployment costs. However, additional network deployment costs, described below, are significantly higher than the direct equipment acquisition and installation costs of [redacted] million. The AMI network underlying the total cost estimate includes equipment costs of [redacted] million for network collectors and repeaters and [redacted] million for associated installation, including make-ready work. Make-ready work often includes tasks such as site surveying, running secondary lines to network devices, and adding pole-top extensions for device mounting purposes. In the development of these cost estimates, the installation costs have been escalated by 3% annually. In addition, a 15% contingency allocation reflects uncertainty surrounding the number of network devices that will be required and the unknowable installation challenges that may be encountered during deployment. The network equipment requirements on a dollars-per-customer basis are significantly less than they were for CMP's AMI system. This decrease reflects network design and technology advancements that have taken place over the last five years.[83]

c) Other Meter Deployment Costs

Approximately 8% of the overall deployment costs, or [redacted] million, result from support that is needed for the direct meter installation effort, including a refresh of the current meter inventory. Table G-8 summarizes these costs, which are estimated based on experience with AMI deployment at CMP. These cumulative costs are not discounted but do reflect inflation expected over the project time period. The AMI deployment cost estimate is escalated at 3% over the deployment period and anticipates that 1% of the installations will require meter panel repairs at an average cost of [redacted] each (based on CMP experience). While these expenditures are the customer's responsibility, deployment costs would actually be higher if the installation effort was held up waiting for the customers to take remedial action, and it is more efficient to proactively repair the meter panels to maintain installation efficiency. In addition, it is estimated that 15% of direct installations will require a revisit for trouble-shooting purposes that will cost an average of [redacted] per visit.[84] Costs for meter installation support and meter engineering support, two positions

[83] CMP deployed 625,000 AMI meters between 2010 and 2012, with an AMI system similar to the one used as a reference system in this estimate.

[84] It is prudent to include some revisit expenses, and this estimate is based on CMP experience, taking into account advancements in field tools and remote trouble shooting that have occurred since CMP installed its system.

that proved essential for successful deployment at CMP, are based on one full-time external support individual (costing [redacted] per hour) who will be present for the entire 4-year deployment period. The meter installation support individual will track and audit daily installation results from the AMI installation vendor and help to schedule trouble-shooting and meter panel repair efforts. The meter engineering support individual will help with meter testing, meter inventory auditing, and meter programming. Costs for meter installation and engineering support are escalated at 3% over the four-year deployment period.

Other meter deployment costs include replacement of the current meter inventory, which is assumed to equal 3% of the cost of meters for deployment. Finally, other meter deployment costs include an allowance of [redacted] per meter for seals and locking rings and a provision for A and C-based adaptors for 2% of the meters at a cost of [redacted] per adaptor.

TABLE G-8: OTHER METER DEPLOYMENT COSTS

($ Millions, unless otherwise identified)

Cost Element	Expenditure
Meter Panel Repair	[redacted]
Meter Revisits	
Meter Installation Support	
Meter Engineering Support	
Meter Inventory	
Seals and Adaptors	
Total Other Meter Deployment Costs	

d) Other Network Deployment Costs

Table G-9 summarizes other network deployment costs that are in addition to the direct equipment acquisition and installation costs discussed previously. These cumulative costs are not discounted but do reflect inflation over the project time period. These costs are roughly double the direct network equipment and installation costs. Table G-9 includes transformers for 10% of the network devices to support the installation when a location is required where a transformer is not already installed on the distribution system (based on CMP experience). A full-time network troubleshooter ([redacted]per hour for 160 hours per month in 2016$) for the four-year deployment period will help identify performance problems with the network and coordinate with the AMI system provider to develop solutions. Four full-time installation support individuals ([redacted]per hour for 145 hours per month in 2016$) for the four-year deployment period are included to help with equipment inventory management, to set up network devices and get them ready for installation, and to assist with inspections in the field and with installation issues that might arise with customers located near the installation sites. The resources in Table G-9 reflect experience gained during deployment at CMP, adjusted for the network performance improvements that have taken place throughout the AMI industry since 2012.

Table G-9 also includes [redacted] million (contingency included) for build-out of the Companies' telecommunications backhaul system to allow all network collectors to tie into it, so that backhaul telecommunications costs can be reduced (see section on operations and maintenance costs that follows). This build out not only reduces operations and maintenance costs, it also helps the Companies avoid operations and maintenance costs for distribution automation (see description of benefits).

TABLE G-9: OTHER NETWORK DEPLOYMENT COSTS

($ Millions, unless otherwise identified)

Cost Element	Expenditure
Transformers	[redacted]
Network Installation Support	
Network Troubleshooting	
Tier I Telecommunications Network Improvements	
Total Other Network Deployment Costs	

e) Project Management Office ("PMO")

Cost estimates for the project management office are based on labor costs for 35 individuals (14 employees whose positions would be backfilled, and 21 positions filled with staff augmentation from outside), most of whom will be needed for five years of service (4-year deployment and pre and post deployment service). In total, PMO costs represent 13% of total deployment costs. The aggregated costs in Table G-10 are not discounted and do not reflect inflation over the deployment time period, which results in the higher PMO cost reported in Table G-6. However, in the actual estimation of costs, an annual escalation rate of 3% was applied throughout the deployment period.

Beyond staffing costs, the PMO budget includes an AMI vendor management fee of [redacted] million, which covers network design, day-to-day project support, and detailed network installation assistance ([redacted] million). Thus, the [redacted] million direct costs or the network in Table G-9 are far exceeded by the $21.2 million of other network deployment costs (Table G-9: Other Network Deployment Costs and the [redacted] million of network installation support provided within the AMI vendor fee (Table G-10).

The PMO budget also includes a [redacted] million travel budget for 6 CMP employees to be in New York for the entire deployment period to share their AMI deployment experience and to contribute to the overall management effort (these employees will fill 6 of the 35 positions in the PMO). The

CMP travel budget includes [redacted] per week for each CMP employee. The budget also includes [redacted] million in professional fees for legal support and [redacted] in professional fees for external support for town meetings with customers prior to deployment. The included overheads on internal positions cover incremental costs of IT support, real estate, and administration for the CMP employees working on the project team.

The PMO budget also includes [redacted] million for customer communications, including updates on the project installation process by letter, email, and door hanger.

TABLE G-10: AGGREGATED PROJECT MANAGEMENT OFFICE COSTS

($ Millions, unless otherwise identified)

Project Management Office Cost Item	Total Cost
Internal Staff (13 Positions)	[redacted]
External Staff (20 positions)	
Staff Expenses	
Customer Communications Expenses	
AMI Vendor Professional Fees for Support	
Legal and Regulatory Support	
Total PMO Costs	$61.1

Note: Does not tie to Table G-6 because of escalation factors

f) IT Hardware, Software and Integration

Table G-11 shows the breakdown of IT expenditures associated with AMI deployment, which total $112 million in 2016 dollars, including 15% contingency. This cost estimate includes AMI head-end hosting, meter data management hosting, implementation of a new customer billing system and provision and support for a customer web portal. The IT integration effort links the MDM to the new customer billing system, and the AMI head-end to the MDM and the OMS. The budget includes [redacted] million for security considerations during the implementation and integration effort. The IT budget was developed internally with a team that included IT staff members who had implemented the CMP AMI project. It reflects experience gained at CMP, the particulars of the New York IT environment, and changes in hardware costs that have occurred since 2010 when CMP IT changes were implemented.

TABLE G-11: IT HARDWARE SOFTWARE AND INTEGRATION COSTS

($ Millions, unless otherwise identified)

Cost Element Description	Hardware	Software	Services	Total	Contingency	Total
Network Engineering and Security	[redacted]					
AMI Head End System						
Meter Data Management System						
GIS Integration						
Energy Manager Web Portal						
Alerts						
Integration						
Misc.						
Customer Billing System						
Total	[redacted]					$112.1

Note: IT expenditures are assumed to be split equally across 2017 and 2018 and are not escalated in this table. As such, the values in this table do not tie exactly to the summary in Table G-6.

g) Annual AMI Operations and Maintenance Costs ("O&M")

Table G-12 summarizes the cost of operating and maintaining the new AMI system, which is estimated to equal roughly [redacted] million annually (in 2016 $). The estimated budget includes costs for 24 staff members (12 for the AMI system, 9 for MDM, and 3 for data analytics), which represents about one-third of the O&M budget. Field troubleshooting and maintenance represents 10% of the budget, IT maintenance charges represent 42% of the budget and data telecommunications and facilities represent 12% of the budget. These estimates are based on experience with AMI implementation at CMP.

Specifically, the O&M budget includes [redacted] per year for network telecommunications to link the AMI network collectors to the AMI head-end. This expenditure will cover charges of [redacted] per month from each of the 50 backhaul points. It is assumed that the AMI collectors will connect to an existing telecommunications canopy over the service area, enhanced with incremental expenditures already described, and information will travel within the canopy to one of the 50 backhaul points.

The O&M budget includes annual field visits for 30% of network devices (based on CMP experience), completed at a cost of [redacted] per visit in 2016 dollars.

The field trouble-shooting budget includes twice what CMP currently spends for troubleshooting. Despite lower network equipment requirements per square mile in New York, the service territory is not contiguous and the higher trouble shooting budget is needed to provide adequate coverage in all service offices. The tower lease expenditures are the same as those currently incurred at CMP, reflecting an assumption that fewer towers per square mile will be needed in New York, due to lower network equipment requirements per square mile.

The O&M budget includes maintenance for computer hardware and software, assumed to be 20% of the initial costs of the computer software licenses and 5% of the initial costs of the computer hardware. These are typical fees incurred by the Companies on existing systems today.

The representative network design includes 13,571 cellular meters with 4g telecommunications cards to send and receive information over the public cellular networks. Public network telecommunications fees are assumed to be [redacted] per month for each meter, and these fees are included in the O&M budget.[85]

Finally, the operational costs include [redacted] of severance costs per person for [redacted] of the [redacted] positions in customer service that may be eliminated by AMI deployment ([redacted] million in total). Some of the employees impacted by AMI deployment are assumed to leave voluntarily or to move into other positions inside the company. These costs are not included in the summary in Table G-12, but are included in the cost estimate.

[85] The assumption of [redacted] per month per meter was suggested by an AMI vendor as representative of what might be negotiated today, and is significantly lower than historical rates.

TABLE G-12: ANNUAL OPERATIONS AND MAINTENANCE COSTS

($ Millions, unless otherwise identified)

Cost Element	Annual Cost	Comment
Operations Staff Cost	[redacted]	12 FTE's
MDM Staff Cost		9 FTE's
Analytics Staff Cost		3 FTE's
Network Telecommunications Backhaul		50 backhaul points at $60 per month
Cellular Meter Backhaul		[redacted] per month per Cellular Meter for 13,571 meters
Telecommunication Tower Leases		100% Current CMP Lease Expense Costs
Computer Hardware Maintenance		16% of Initial Hardware Expenditure
Computer Software Maintenance		20% of Initial Software Expenditure
RF Troubleshooting		200% of current CMP Troubleshooting costs
Network Field Maintenance		Trips to 30% of Network Devices per year at [redacted] per trip
Total Annual Expenditures	$8.9	

h) System Refresh Costs

The total life-cycle cost estimate for AMI includes three kinds of capital investments over the life of the system. First, it is expected that each year, 0.5% of electric meters and gas modules will fail due to electronic problems and will need to be replaced. This annual failure rate would also be expected with existing electric meters, but existing meters cost about [redacted] less than AMI meters (assumed not to escalate over the AMI life-cycle). As such, the annual meter refresh that occurs with or without AMI will be incrementally more expensive by [redacted] per electric meter with AMI. The incremental cost of replacing failed gas modules, including installation, is [redacted] per meter, representing the full cost of the module and the full cost of the trip to exchange the module. These incremental costs account for the [redacted] million in annual expenditures shown in Table G-13.

The system network refresh costs include expenditures of [redacted] million ([redacted] per network device in 2016 dollars) each year in 2026 and 2036. Originally, the network devices cost about [redacted] each to deploy (installation and equipment) but the refresh can be done at lower cost because swapping out batteries and communications cards in the existing installed devices can be done without the need for a completely new network device, site surveying, and site-make-ready work.

The system refresh costs include [redacted] million for 100% replacement of IT hardware each year in 2024, 2031, and 2038. This hardware supports four environments (Production, Test, Development, and Disaster Recovery). Computer hardware prices are expected to decline, but the original prices are used for projecting refresh costs, implicitly assuming the original expenditures will permit the acquisition of higher performing hardware that will help improve system operations.

TABLE G-13: AMI SYSTEM REFRESH COSTS

Refresh Expenditure Element	Refresh Cost	Comment
Annual Electric Meter and Gas Module Failures	[redacted] per year	Covers incremental costs of .5% electric meter and gas module failure rate each year
Periodic Network Refresh	[redacted] per Refresh	Covers revisits to network devices in 2026 and 2036
Periodic IT Hardware Refresh	[redacted] per Refresh	Covers IT hardware replacement in 2024, 2031, and 2038

2. *Operational Savings*

Full deployment of AMI for both gas and electric meters will produce substantial operational savings. Table G-14 summarizes the annual operational benefits (2016 dollars), which total $32.1 million. These benefits are described in more detail in the subsections below

TABLE G-14: SUMMARY OF ANNUAL OPERATIONAL BENEFITS

($ Millions, unless otherwise identified)

Benefit Area	Annual Benefits
Meter Reading	[redacted]
Field Customer Service	
Reduced Storm Costs	
Reduced Call Center Costs	
Reduced Billing Costs	
Improved Cash Flow	
Avoided Telecommunications Costs for Distribution Automation	
Total	$32.1

a) Savings in Meter Reading, Field Customer Service, Billing and Call Center

To estimate direct customer service savings, expenditures were first estimated assuming AMI is not in place. These expenditures include salaries, benefits, vehicles, and overtime, which total [redacted] million per year. Next, a review of how work would change with full deployment of AMI was conducted, utilizing interviews with call center and billing supervisors and detailed review of all field work orders in 2015. Projected savings were estimated based on a proportional reduction in work for all areas except Field Customer Service, where the expectation is less than a proportional reduction in staff because of the increased inefficiency of remaining work due to the reduced density of jobs. This analysis of all customer service benefits (meter reading, field services, billing, and call center) produced a savings estimate of [redacted] million per year as described in Table G-15. These estimates are based on the following assumptions and analysis:

- The new AMI system will read 99.5% of meters accurately each day. The 0.5% of meters that are not read for a billing cycle can be estimated with the expectation that reads will be available in the subsequent month. In rare instances where reads are missing for consecutive months, manual reads can be obtained with the remaining field service staff so that the entire meter reading staff can be released for other assignments.
- A review of field work completed in 2015 suggests that [redacted] of the current work will be eliminated as a result of deploying AMI. The estimated reduction in field staff is less than proportional to the work reduction because it is anticipated that the work not eliminated by AMI will involve more drive time per job and thus require more time to complete. Importantly, the savings estimates assume that the service connect/disconnect switch in residential and small commercial meters will be used to carry out all connection and disconnection work orders, including those that are related to credit and collections. This assumption anticipates a change in current Commission requirements for a site visit before disconnection occurs and projects instead the use of a combination of mail and phone contacts before the work is initiated.
- Savings in billing and call center activities occur because customer questions about billed usage, estimated bills and billing rework to address anomalies will drop dramatically after AMI implementation. Currently, customers receive bills every month but meters are typically only read every other month so the percent of total bills that are estimated is quite high. In addition, the manual meter reading process sometimes produces misreads, which can lead to call center inquiries as well as manual bill adjustments. In estimating call center savings, it was assumed that future staffing of the call center would reflect a greater number of call center representatives than are in place today, to address projected needs in fulfilling customer service expectations. If those increases are not undertaken, the AMI impact would be measured in the value of service improvements it brings about, rather than in headcount reductions.

The projected savings in Table G-15 have been reviewed and compared to experience at CMP, where AMI has been fully deployed for over 3 years. The savings estimates in percentage terms are somewhat higher than those observed at CMP. These differences are expected because of the much higher estimated-bill rate in New York and because of expected improvements in AMI technology that have emerged since the CMP system was designed in 2010. These savings are escalated at 3% throughout the project period.

TABLE G-15: ANNUAL CUSTOMER SERVICE SAVINGS

(Millions of 2016 dollars at full deployment)

Work Area	Projected Annual Expenditure without AMI	Projected Savings from Deploying AMI	Projected Positions without AMI	Projected Reduction in Positions Resulting from AMI
Meter Reading and Support	[redacted]			
Field Customer Service				
Billing				
Call Center				
All Work Areas				

b) Reduced Storm Restoration Costs

The Companies spent an annual average of $23 million for storm restoration over the last six years (overtime, external crews, meals and lodging). Assuming that 10% of this work can be reduced by using the AMI system to “ping” meters and direct the outage restoration crews more efficiently, annual projected savings would equal $2.3 million, as summarized in Table G-16. Over the project period, this cost is escalated at 3% per year.

TABLE G-16: ANNUAL REDUCED STORM RESTORATION COSTS

($ Millions, unless otherwise identified)

Statistic Description	Value
Average Annual Incremental Storm Costs 2010-2015	$ 23.1
Expected % Reduction in Incremental Costs due to AMI	10%
Expected Avoided Incremental Storm Restoration Costs	$2.3

c) Reduced Cash Requirements

AMI offers the opportunity to reduce the time between meter reading and bill mailing by 1.5 days. Effectively, this reduction will result in payments consistently being received 1.5 days earlier than before AMI. Table G-17 shows the $900,000 annual savings provided by this improvement.[86]

[86] This is not a one-time benefit. One way to describe it is that the payment terms for customers, including the delay from the meter read to the bill send out, are being reduced from 33-34 days to 31.5-32.5 days.

TABLE G-17: ANNUAL REDUCED CASH REQUIREMENTS

($ Millions, unless otherwise identified)

Statistic	Value
Annual Revenue	$2,106
Annual Cost of Capital	10%
Daily Cost of Capital	0.03%
Days from Read to bill reduced with AMI	1.5
Annual Cash Flow Savings	$0.9

d) Savings in Avoided Distribution Telecommunications Costs

An investment of [redacted] million dollars in backhaul telecommunications infrastructure is included as part of the AMI deployment costs (See "Other Network Deployment Costs" above). This investment enables the realization of only [redacted] per year in AMI telecommunications backhaul charges, but at the same time it supports reductions in distribution telecommunications costs in other parts of the Companies' network. In total, these additional savings equal [redacted] annually. There are six sources of these savings.

- Legacy telecommunication links to electric substations and gas gatehouses can be transformed to use the telecommunications network provided by AMI instead of the dedicated leased telephone circuits currently in use. There are presently 193 electric substation and 35 gas gatehouse station telecommunication channels leased at [redacted]/month on average. Annual savings of roughly [redacted] million are possible if these channels are migrated onto the telecommunications network provided by AMI. The savings are assumed to begin to be realized in 2022 and become fully realized by 2024.
- The field dispatch radio system consists of 45 tower sites throughout New York. The radio system communicates with the towers over leased telephone circuits. Those circuits cost [redacted] million annually based on 2014 actual expenses. 80% of those leased circuits could be eliminated due to service migration onto the telecommunications network provided by AMI once it is in place. These annual savings are assumed to begin to be realized in 2022 and become fully realized in 2024.
- 378 automated reclosers can be re-networked using the AMI telecommunications network rather than using existing cell modems, which would reduce costs by roughly [redacted] million per year.
- 407 additional reclosers that will be automated in the 5-year plan can use the telecommunications network provided by AMI instead of using cell modems at an annual cost savings of approximately [redacted] million.
- 120 substations currently automated can use the AMI telecommunications network instead of using cell modems, at an annual cost savings of less than [redacted]

- 1,000 additional reclosers, switches, regulators and capacitors will be automated over the next five years and could use the telecommunications network provided by AMI instead of using cell modems, for an annual savings of [redacted]

3. *Capital Savings*

a) Avoided Meter Purchases

The Companies plan to replace 1 million electric meters and 45,000 gas meters over the next 18 years due to concerns about age and performance. With AMI deployment, this replacement work will no longer be necessary. Table G-18 summarizes the expected savings of $3 million annually over the 18-year period when existing meters would have been replaced through the current meter upgrade program. This plan is part of the meter shop's work effort over the project period. This estimate assumes that installation labor costs escalate 3% annually while equipment costs remain constant.

TABLE G-18: ANNUAL AVOIDED METER COSTS

($ Millions, unless otherwise identified)

Avoided Cost Element	Value
Annual Gas Meter Replacements Avoided	[redacted]
Annual Electric Meter Replacements Avoided	
Annual Gas Replacement Installation Labor Avoided ($ per Meter)	
Annual Gas Meter Expenditure Avoided ($ per Meter)	
Annual Electric Replacement Installation Labor Avoided ($ per Meter)	
Annual Electric Meter Expenditure Avoided ($ per Meter)	
Annual Avoided Costs	

b) Avoided Fleet Capital Costs

Changes in the Customer Service Organization that are described above generate a significant reduction in operational expenses. In addition, the reduction of [redacted] positions in meter reading and field customer service generate capital savings related to the vehicles that are no longer needed. These capital savings amount to [redacted] per year, or about [redacted] per vehicle per year.

4. *Economic Analysis of AMI Costs and Operational Benefits*

The sum of AMI system costs (Deployment Capital, System Refresh Capital, and Operations and Maintenance Annual Costs) can be directly compared to the expected benefits described in above by discounting the costs and benefits over time to provide point estimates of lifetime costs and benefits, using the after-tax cost of capital that is appropriate for the societal cost test. Table G-19 shows the present value of costs for AMI deployment and Table G-20 shows the present value of benefits covered in this operational business case (additional benefits are discussed in subsequent sections). Net benefits and the benefit/cost ratio are shown in Table G-21.

The present value of costs over the forecast horizon equals $594 million and the present value of benefits equals $422 million. Put another way, the operational benefits offset roughly 71% of deployment and operational costs, including system refresh, over the assumed life of the investment. As discussed in subsequent sections in this appendix, additional benefits can be derived from AMI enabled programs and services, such as time-varying pricing, information feedback programs, integration of AMI with OMS and the incremental benefits of CVR/VVO attributable to AMI. The aggregate net benefits associated with these additional programs and investments are significantly greater than the negative net benefits summarized above.

TABLE G-19: PRESENT VALUE OF AMI IMPLEMENTATION AND OPERATIONAL COSTS

($ Millions, unless otherwise identified)

Cost Type	Cost Category	NPV ($m)
Deployment Capital	IT Hardware	[redacted]
	IT Software	
	Meters	
	Network	
	PMO	
Refresh Capital	IT Hardware	
	Meters	
	Network	
O&M	O&M	
Total		$(577.5)

TABLE G-20: PRESENT VALUE OF AMI OPERATIONAL BENEFITS

($ Millions, unless otherwise identified)

Benefit Type	Benefit Area	Total
Avoided Fleet Capital	Field Work Meter Reading	[redacted]
Avoided Meter Capital	Avoided Meter Purchases	
Avoided O&M	Avoided Network O&M Billing Call Center Field Work Improved Cash Flow Meter Reading Reduced Strom Costs	
All Benefits		$421.8

TABLE G-21: BENEFIT COST RATIO FOR AMI OPERATIONAL BENEFITS

Category	Value
Benefits	$421.8
Costs	$(577.5)
Net Benefit	$(155.8)
B/C Ratio	0.73

5. *Customer Benefits Not Reflected in the BCA*

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, thus reducing the socialization of certain kinds of costs from particular kinds of customers to the overall customer population. There are three kinds of socialized costs that AMI can address:

- **Theft of Service:** While it is difficult to quantify, there is undoubtedly some theft of service in the Companies' service area, 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%. 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.[87] 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.
- **Write-offs and Consumption on Inactive Meters:** Finally, the Companies currently write off bills that customers should have paid and also write off some consumption on inactive meters where deliveries occur but there is no customer of record to charge for the service. In both of these cases, the Companies socialize the revenue that would have been collected if the customer of record had paid their bills or if there had been no consumption on the inactive meter. With AMI meters, customers that do not pay can be shut off faster, reducing write-offs, and inactive meter consumption can be reduced because of the remote disconnect capability of AMI meters.

In addition to improving fairness by reducing socialization of costs and aligning costs with the customers that use the service, actual energy use can be lowered by reducing theft of service, write-offs and consumption on inactive meters as discussed below.

- Identifying theft of service can result in one of two outcomes: those responsible for the theft pay the Companies and continue to be customers, or those customers can drop off of the system. When they drop off, there is less electricity to produce, which can be valued at the avoided cost of energy production.
- When write-offs or consumption on inactive meters is reduced, through the faster execution of service termination orders or by cutting service on inactive meters, less electricity is produced.

In practice, it is difficult to quantify 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. Reducing theft, improving meter accuracy, and reducing meter malfunctions may be

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

detectable and observed as a reduction of the system loss factor. Write-offs and consumption on inactive meters are more measurable, but for clarity, the impact of reduced write-offs has been classified exclusively as a fairness benefit.[88]

In this analysis, we have addressed these fairness issues by working to quantify how socialization of costs might be reduced through implementation of AMI, and 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.

Assuming the existing meter population is under-registering consumption relative to AMI meters by 0.33% and that theft of service can be reduced by 0.25%, and applying those percentages to $1.6 billion of annual revenue (netting out revenues on large commercial customers and industrial customers where the metering is already sophisticated), results in a $9 million reduction of costs annually that are socialized across the customer base. Projected write-off reductions of $4.8 million per year are expected from AMI deployment. The present value of the revenue associated with the reduction in socialization of all of these impacts is $122 million, which is a substantial impact compared to the present value of $397 million in capital costs required to deploy AMI between 2018 and 2021. However, we characterize the $122 million as a rate impact, which reduces the socialized costs that customers see, rather than as a societal benefit of AMI. The clearer benefit is the value of improving the fairness of customer bills by $122 million and by reducing the kWh generated to some extent. Table G-22 summarizes the impacts discussed in this subsection.

TABLE G-22: AMI IMPACTS THAT IMPROVE RATE FAIRNESS

($ Millions)

Fairness Impact	20-Year NPV
Meter Accuracy	$30.2
Theft of Service	$42.6
Bill Write-Offs	$49.2
Total Fairness Impacts	$122.0

D. AMI-OMS Integration

As discussed in the main body of the DSIP, the Companies plan to implement an advanced OMS. The cost and functionality of the integration of AMI and OMS are discussed in the main body of

[88] The distribution portion of reduced write-offs has been tracked to understand the consequences for revenue requirements.

this filing. Enhanced visibility into outages provided by full deployment of AMI and integration of AMI with OMS provides substantial incremental benefits that are quantified in this section.

BRIDGE assessed how the integration of AMI with the Companies' OMS would reduce outage duration. BRIDGE's assessment found that AMI-OMS integration would reduce customer outage minutes in cases where an outage is evidenced by meters (as opposed to cases where the outage is evidenced by telemetry of the breaker tripping). When a non-telemetered component of the system fails and a utility does not have AMI integrated with OMS, the outage would typically not be identified until a customer called. For these types of outages, AMI-OMS integration improves reliability in two ways. First, smart meters send a last gasp message to the OMS system and that message is typically received more quickly than a call from a customer. Second, by analyzing the set of last gasp messages that are received, the outage can be located using prior knowledge of connectivity of the network to identify the open device. This reduces the time associated with a crew traveling to a circuit to locate the open device. These operational efficiencies reduce outage duration and, therefore, reduce customer outage costs.

To quantify the benefits of the reduction in outage duration, the following two assumptions were made:

- The time saved before an outage is confirmed is 3 minutes, the average time for a customer to call to report an outage; and
- The time saved identifying an open device is 12 minutes at NYSEG and 8 minutes at RG&E (NYSEG tends to have longer circuits).

BRIDGE assessed the outages of non-telemetered fuses and switches over the past three years (2013-2015) and estimated the total reduced customer outage minutes that would result from AMI-OMS integration. In total, BRIDGE estimated 6.7 million total reduced customer outage minutes per year for NYSEG and 1.4 million reduced outage minutes for RG&E.

Nexant analyzed historical outages and customer level data to estimate the customer value associated with these reductions in customer outage minutes, which is based on the total cost of outages with and without the reduction in outage duration associated with AMI-OMS integration. The difference between the aggregate cost with the reduced duration and the aggregate cost without the reduced duration is the benefit attributed to AMI-OMS integration. The remainder of this subsection provides a brief overview of the methodology used to quantify outage costs, summarizes the analysis that was done using that methodology in this specific application, and presents estimates of outage cost reduction benefits associated with AMI-OMS integration.

1. *Estimating Customer Outage Costs*

The preferred method for estimating customer outage costs is a survey that describes several hypothetical outage scenarios and asks customers to detail the costs that they would experience under those conditions, as described in the Electric Power Research Institute's Outage Cost

Estimation Guidebook.[89] Various parties have proposed alternative approaches for estimating customer outage costs. The strengths and weaknesses of each approach are described in a literature review conducted for the National Association of Regulatory Utility Commissioners.[90] As discussed in that review, customer surveys are the preferred method for estimating outage costs because they directly measure the costs that customers experience under a variety of outage scenarios without relying on the relatively weak assumptions that alternative methods use.

The primary drawback of surveys is that they require collecting detailed information from large, representative samples of residential, commercial and industrial ("C&I") customers. As a result, only a few of the largest utilities in the U.S. have conducted customer outage cost surveys. To address this barrier, the Department of Energy ("DOE"), Lawrence Berkeley National Laboratory, and Nexant have been working together for over a decade to make reasonable outage cost estimates readily available for utilities that have not conducted their own surveys. The first step in developing a national estimate of outage costs was to combine results from all of the outage cost surveys that were conducted using the methods outlined in the Outage Cost Estimation Guidebook. This aggregate statistical study, called a meta-analysis, was first done in 2003 (with results from 24 surveys) and then updated in 2009 and 2015 (with results from 34 surveys, including the original 24).[91]

2. *Analysis of Historical Outages*

In this analysis of the benefits of AMI-OMS integration, Nexant applied the econometric models from the 2015 meta-analysis of customer outage costs referenced above. These models consist of are the same equations that serve as the basis for the Interruption Cost Estimate ("ICE") Calculator, which is a publicly-available, online tool that estimates customer reliability benefits associated with user-specified reliability improvements that arise from smart grid and other types of investments.[92] In this instance, Nexant did not use the ICE Calculator itself because the reliability improvement from AMI-OMS integration applies to specific types of outages (those arising from non-telemetered fuses and breakers, as described above). Nexant analyzed those outage types specifically for the past three years (2013-2015), as in the BRIDGE analysis of reduced customer outage minutes. Nexant also linked this historical outage information with the Companies customer databases to customize the outage cost estimates to the specific circuits that were affected by each outage.

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[89] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

[90] Sullivan, M.J., and J. Schellenberg (2011). *Evaluating Smart Grid Reliability Benefits For Illinois*. National Association of Regulatory Utility Commissioners Report.

[91] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-6941E.

[92] Available here: http://www.icecalculator.com

Using customer level characteristics data, the econometric models produce outage cost estimates for various scenarios for each circuit at RG&E and NYSEG. Key inputs include customer class (residential, small C&I and medium and large C&I), usage (annual kWh), and industry type (for C&I customers only), since average outage costs vary significantly across these factors. These inputs vary with the distribution of customers at each circuit. The result is estimates for outage costs of various durations, seasons, and times of day, specific to the customer mix at each circuit. This information is combined with the database of historical outages.

Nexant received data on every outage that occurred in the Companies' service area for the years 2013 through 2015. This database contained key attributes of each outage, including date and time of the occurrence, outage duration, the circuit it occurred on, the number of customers affected by type, and the equipment that triggered the outage. To model the effect of AMI-OMS integration, Nexant identified outages that resulted from the tripping of a fuse or breaker that was not telemetered, and lasted longer than 3 minutes. These are the outages that stand to benefit from AMI-OMS integration. Then the actual duration of each relevant outage was reduced by 15 minutes for NYSEG and 11 minutes for RG&E,[93] which are the expected reductions in minutes per outage that result from AMI-OMS integration based on BRIDGE's assessment. This information was then combined with estimates of outage costs from the econometric models. The estimates reflect the customer mix on the circuit where the outage occurred, as well as the time of day, season, and duration of the outage.[94] The result is two cost estimates for every historical outage: one for the actual outage and another for the outage assuming the duration was reduced due to AMI. The costs are summed to yield aggregate values for each year with and without AMI-OMS integration, the difference of which is the aggregate annual benefit associated with AMI-OMS integration.

Table G-23 summarizes the annual benefit (in 2016 dollars) of AMI-OMS integration for each year of historical outages from 2013 through 2015 for each utility, assuming that AMI is fully deployed. On average, NYSEG benefits from avoided customer outage costs equal $5.25 million per year, and RG&E customer benefits equal nearly $1.1 million per year. The average avoided cost per reduced customer outage minute is similar for each utility ($0.78 for NYSEG and $0.75 for RG&E).

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[93] Or down to a minimum of 3 minutes for outages shorter than 18 minutes for NYSEG and 14 minutes for RG&E.

[94] Due to limitations in the underlying survey data from the meta-analysis, the econometric models cannot reliably estimate costs for outages longer than 16 hours (960 minutes). Therefore, outages longer than 960 minutes were capped at 960 minutes.

TABLE G-23: AGGREGATE BENEFIT OF AMI-OMS AVOIDED OUTAGE COSTS

($ Millions, unless otherwise identified)

Utility	Year	Outages of Non-telemetered Fuses and Breakers	Average Number of Customers per Outage	Benefits of AMI-OMS Integration		
				Reduced Customer Outage Minutes	Avoided Customer Outage Costs	Avoided Cost per Reduced Customer Minute (2016 $)
NYSEG	2013	10,748	51	8,287,755	$5.6	$0.68
	2014	11,029	38	6,304,095	$5.5	$0.87
	2015	9,990	37	5,585,865	$4.7	$0.83
	Average	**10,589**	**42**	**6,725,905**	**$5.3**	**$0.78**
RG&E	2013	3,235	45	1,592,811	$1.2	$0.75
	2014	2,951	42	1,367,047	$1.0	$0.75
	2015	2,947	42	1,372,338	$1.0	$0.76
	Average	**3,044**	**43**	**1,444,069**	**$1.1**	**$0.75**

To estimate the present value of the benefit over the lifetime of the AMI-OMS integration investment as it rolls out, the avoided customer outage costs of $5.3 million per year for NYSEG customers and $1.1 million per year for RG&E are scaled by the percent of AMI deployment in each year. The benefit over time is also scaled by the same population growth rate, inflation rate and discount rates that apply to other investments. This results in a present value of the avoided customer outage cost benefit due to AMI-OMS integration of roughly $62.7 million for NYSEG and $11.5 million for RG&E, for a total benefit of $74.2 million across the two companies.

E. Time Varying Pricing

The Companies' plan to fully deploy AMI provides opportunities to improve economic efficiency and support the goals and objectives of REV by offering TVP to consumers. More than four decades of empirical research has shown that many consumers can and will enroll on TVP tariffs and will reduce usage during higher-priced periods relative to usage under traditional tariffs in which prices do not vary across the hours of the day, days of the week and seasons. TVP can lead to significant reductions in societal costs over time by reducing the need for high-cost peaking generation or reducing or delaying transmission and distribution capacity investments. It also gives consumers greater opportunities to reduce their energy bills by shifting from higher to lower cost time periods.

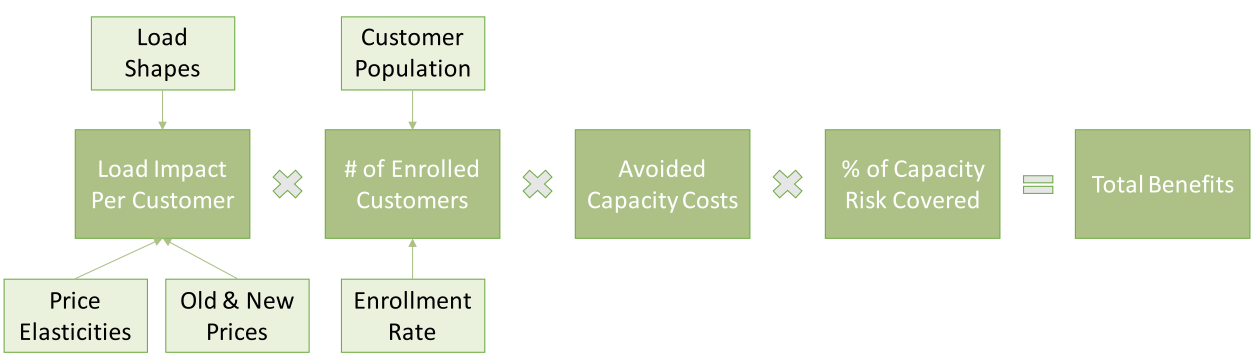
Historically, a major impediment to customer participation in TVP has been the high cost of metering on an individual customer basis. This is especially true for mass market consumers such as residential households and small commercial businesses. Full deployment of AMI will provide low cost opportunities for consumers to better manage their energy costs and, in the process, improve the economic efficiency of the electricity system by choosing and responding to prices that more accurately reflect the cost of electricity supply. In the New York Public Service Commission Order Adopting Regulatory Policy Framework and Implementation Plan (February 26, 2015), the Commission indicates that "REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale,…Customers, by exercising choices within an improved electricity pricing structure and vibrant market, will create new value opportunities and at the same time drive system efficiencies and help to create a more cost-effective and secure integrated grid." .

The remainder of this subsection provides a high level summary of the assumptions and analysis associated with estimating the net benefits of TVP based on two scenarios, one involving opt-in recruitment and the other involving default enrollment of customers. These scenarios are meant to be illustrative of what could be achieved from TVP and do not represent all of the potential options that would be enabled by AMI. Neither are they meant to suggest what the Companies should or would do in terms of pricing strategies once AMI is fully deployed. Nor are the costs underlying each scenario meant to necessarily reflect what the Companies' costs would be if they implemented a specific scenario. Nevertheless, the input values underlying the analysis are far from arbitrary. The data and assumptions used here are based on evidence from pricing pilots and programs implemented by other utilities combined with usage data and other key inputs that are specific to the Companies' customer populations.

1. *Conceptual Framework*

The benefits of TVP pricing derive from the fact that prices more accurately reflect costs and customers respond to TVP price differentials across rate periods. Economic efficiency is improved when customers shift from high price/cost time periods to lower price/cost time periods. The aggregate benefits are primarily a function of the number of enrolled customers, the load shapes of customers prior to enrollment, the price responsiveness (or price elasticity of demand) of enrolled customers, and the structure of the TVP tariff (e.g. prices by rate period) being examined. These factors drive the change in usage by rate period which, in turn, drive the benefits that can be achieved in the form of avoided generation, transmission and distribution capacity investments, reductions in fuel costs and reduced carbon emissions. Figure G-5 summarizes the main drivers of capacity benefits. A similar figure can be shown for energy benefits associated with TVP.

FIGURE G-5: KEY DRIVERS OF CAPACITY BENEFITS FROM TVP



One variable in the figure not mentioned above is the % of capacity risk covered. In brief, this factor recognizes that TVP impacts do not necessarily produce demand reductions during all hours when generation or distribution capacity relief may be needed. Load reductions that occur when system (or an individual distribution network) load is at or near its maximum will be more valuable than reductions that occur when there is plenty of available capacity. As an extreme example, reducing load during summer afternoon hours when peaking risk is high will have substantially higher benefits than shedding load on winter mornings. Conceptually, the benefits of time-varying pricing should be based on the contribution of load reductions in the hours when such reductions are most needed by the system. Factoring peaking risk into the calculation of benefits requires estimating the likelihood of peaks occurring for each hour throughout the year, which was done using historical data for NYSEG/RG&E.

2. *Rate Design*

The analysis presented here estimates the net benefits associated with two TVP deployment scenarios offered to the Companies' residential and SMB customers. Benefits stemming from the implementation of TVP for large commercial and industrial customers are not included because many of these customers already have interval meters and because TVP benefits from these customers could be cost-effectively obtained without full scale deployment of AMI. The base case scenario reflects the offer of TVP on an opt-in basis with an assumed steady state enrollment of 15% of the target population. The second scenario reflects default enrollment for residential and SMB customers and an assumed opt-out rate of 10%. While we realize that default pricing for residential consumers is not currently allowed in New York, analysis of the net benefits of default pricing provides a useful benchmark for comparison with the costlier opt-in scenario.

A variety of TVP structures have been tested in pilot programs and deployed by utilities around the country, including:

- **Time of use ("TOU") –** prices vary by time of day every weekday (and perhaps on weekends and holidays);
- **Critical peak pricing ("CPP") –** prices vary by time of day only on high demand days (consumers are notified, typically the day before, when a high demand day occurs);
- **TOU-CPP –** combines the two options above, with prices varying on all days but where peak period prices are higher on CPP days than on the typical weekday;
- **Day-type variable pricing –** a set of TOU prices are established and communicated to consumers upon enrollment where prices by rate period vary across three or four different day types (e.g. low price days, moderate price days, high price days, critical price days) and consumers are told prior to each day what price schedule will be in effect on the following day;
- **Real time pricing –** prices change hourly in response to market conditions.

In this analysis, for both the opt-in and default enrollment scenarios, we estimate the impact associated with a hypothetical TOU-CPP rate in which time-varying prices are in effect for all non-holiday summer weekdays and higher prices are in effect for 12 critical peak pricing days on average each year. Nexant sought to design a reasonable rate that followed general principles of cost recovery, economic efficiency, customer equity, and rate simplicity. To meet these objectives, the rates were designed with the following features:

- The **TOU peak period** portion of the tariff is based on marginal generation and energy-related costs;
- The **critical peak period** portion of the tariff is based on incorporating avoided generation[95] capacity costs into the relatively few hours that drive capacity needs, which occur on high demand days;
- **Revenue neutrality** for the average customer by discounting the base energy prices to offset the higher peak period pricing.

It is important to emphasize that the rates presented here are intended to be hypothetical, yet plausible based on Nexant's experience with TVP at other utilities. They are designed to illustrate the potential benefits that can be achieved by passing price signals through to consumers that more accurately reflect the cost of energy and avoided future capacity costs.

a) Rate Periods

TOU-CPP rates consist of a set of rate periods for two distinct days: normal weekdays (non-event days) and event days. On non-event days, we assume that a TOU pricing structure is in effect consisting of two rate periods: peak and off-peak. On an event day, a CPP adder is layered on top of the TOU price for all hours that fall inside the CPP window. An effective TOU-CPP rate will have peak periods that are well-aligned with the hours when system capacity is likely to peak.

To determine the hours for each TOU-CPP rate period, Nexant assessed the concentration of peaking risk associated with all hours of the year and then examined how much of the risk would be covered by various peak periods. A peak period from 11 AM to 6 PM would capture 94.4% of the historical generation peaking risk at RG&E and a peak period from noon to 9 PM would capture 89.3% of the peaking risk for NYSEG. Figure G-6 and Figure G-7 show the distribution of generation risk derived from system load at the Companies. At each IOU, the distribution of peaking risk is concentrated in July in mid-afternoon, with a somewhat later peak at NYSEG.

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[95] A case could be made for also incorporating transmission and distribution capacity into the CPP adder but, as seen below, the generation capacity adder alone leads to quite large peak-to-off-peak price ratios that drive significant reductions in peak period demand. Incorporating transmission and distribution capacity into the adder would create price ratios that exceed those that have been tested empirically. As such, larger adders would necessitate predicting demand reductions that go beyond what has been observed empirically which would introduce more uncertainty into the predicted values.

FIGURE G-6: NYSEG GENERATION RISK ALLOCATION

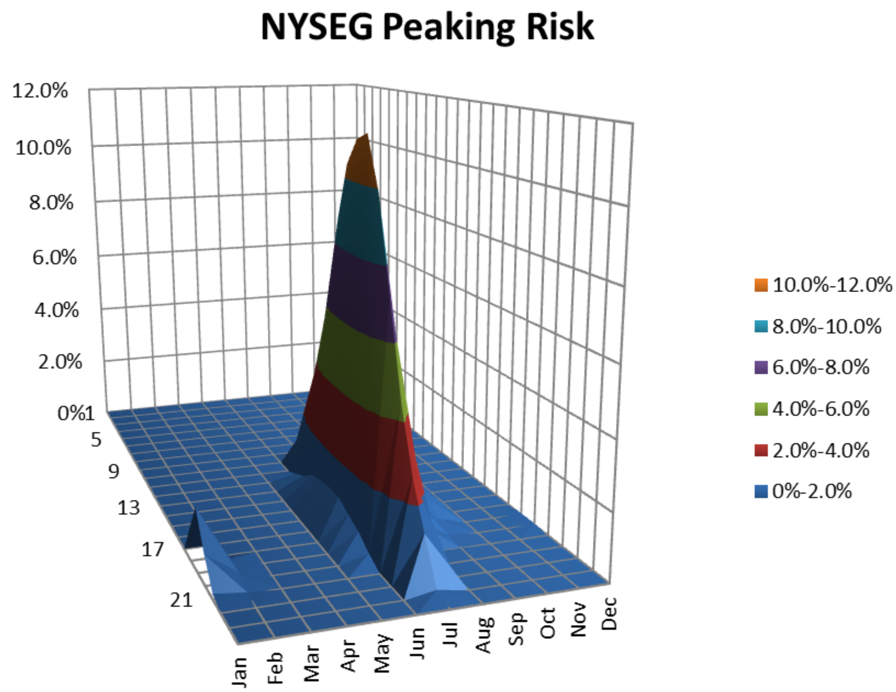
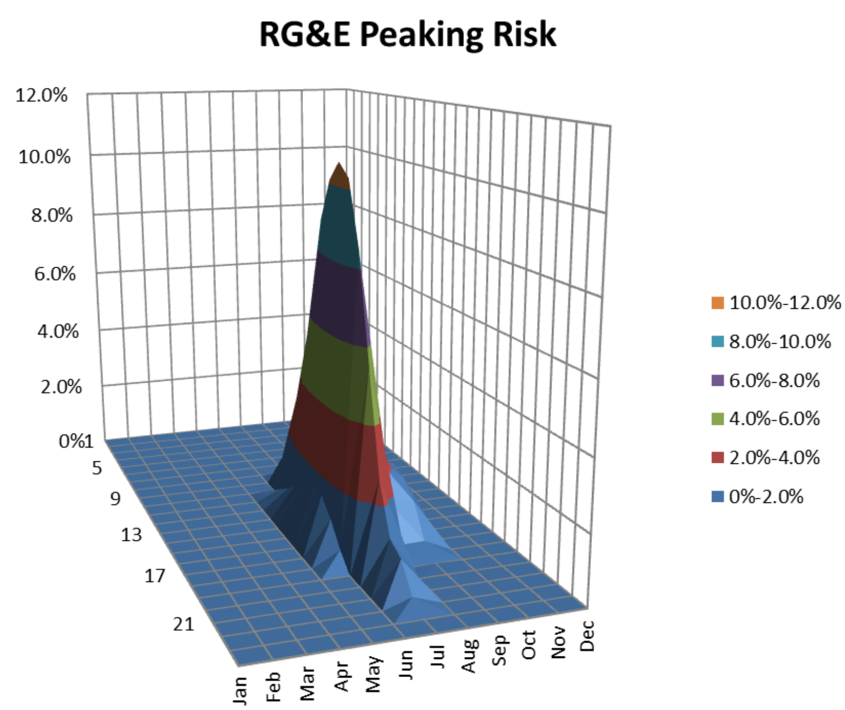


FIGURE G-7: RG&E GENERATION RISK ALLOCATION



b) Prices

After the rate periods were defined based on peaking risk, it was necessary to set prices that would be in effect during each rate period. The analysis assumed that both bundled and retail access consumers would have the same rate options. To develop these prices, we first determined market-based generation and energy-related costs for the TOU peak period during summer weekdays. We used NYISO day-ahead prices from summer, non-holiday weekdays to determine the economically efficient price signal (peak-to-off-peak price ratio) during the TOU peak period. The ratio of average peak to off-peak prices yielded a price ratio of 1.5.

After establishing the TOU peak-to-off-peak price ratio, CPP adders[96] were then determined assuming that 12 CPP events would be called on average during each summer. A key initial input in determining CPP adders is the avoided capacity cost values; we used 2020 avoided capacity costs of $68.60/kW-year for generation. Equation 1 shows the calculation of the CPP price adder based on the total avoided capacity costs, the number of CPP events, the length of the CPP period, and the percent of peaking risk captured.

$$\text{CPPadder\_gen} = \frac{\text{Avoided Generation Capacity Cost}}{\text{\# CPP days} \times \text{Length CPP Period}} \times \text{\% System Risk Captured} \qquad \textbf{(1)}$$

To determine the new TOU-CPP prices, we first took the TOU price signal and CPP adders as fixed and then discounted the off-peak price by a commensurate amount to reach a new rate that is revenue neutral.[97] This step necessitated calculating revenue under the current rate structure as well as revenue under the new, TVP structure, which required data on usage by time of day for the average customer within each customer class. We used a representative sample of 25% of residential customers within each IOU to calculate current revenue and solved for new prices that did not increase or decrease revenue, on average. In summary, the rates were calculated using the following steps:

- Calculate current revenue for the average customer using the variable portion of current prices;[98]
- Calculate the average customer’s usage in CPP, TOU and off-peak periods; and
- Solve for the TOU off-peak variable price that equates current revenue with revenue under the new prices.

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[96] By “adder,” we mean an amount that is added to the TOU price in each period within the CPP window on an event day.

[97] The TOU-CPP rate is revenue neutral compared to the standard flat rate if the revenue collected under both tariffs is the same, holding the consumption pattern for the average customer constant for both rates.

[98] Only the variable portion of current prices is used as the customer has no incentive to change consumption when fixed prices change.

Table G-24 shows the optimal rates by customer type for each operating company for the primary residential rates (SC1 for both companies and SC8 for NYSEG), along with the variable portion of the current flat rate that customers face. Note that the TOU peak-period prices are lower than the original flat rate prices for residential customers. We therefore elected to tie the TOU peak price to the variable portion of the current flat rate that customers face in order for the rate to be more reasonable.

TABLE G-24: OPTIMAL TOU-CPP RATES ($/KWH)

Utility	Residential Rate Type	Current Price	TOU Off Peak Price	TOU Peak Price	CPP Adder
NYSEG	SC1	0.102	0.062	0.094	0.640
	SC8	0.099	0.060	0.090	0.640
RG&E	SC1	0.098	0.060	0.089	0.771

Table G-25 shows the rates that were used in the analysis for each operating company. The TOU peak price is equal to the variable portion of the current flat rate that customers face. On normal weekdays, the peak to off-peak price ratio is roughly 1.7, which is slightly higher than the ratio of 1.5 used to calculate the optimal rates. On CPP days, the CPP peak to off-peak price ratio is 12 to 1 at NYSEG and 14 to 1 at RG&E. This is within range of the maximum CPP peak to off-peak price ratio of 14:1 for which pilot studies of load impacts in the region exist. This rate gives residential consumers a strong incentive to reduce peak period energy use on CPP days and a modest incentive to reduce it on average weekdays.

TABLE G-25: TOU-CPP RATES USED IN ILLUSTRATIVE BCA ($/KWH)

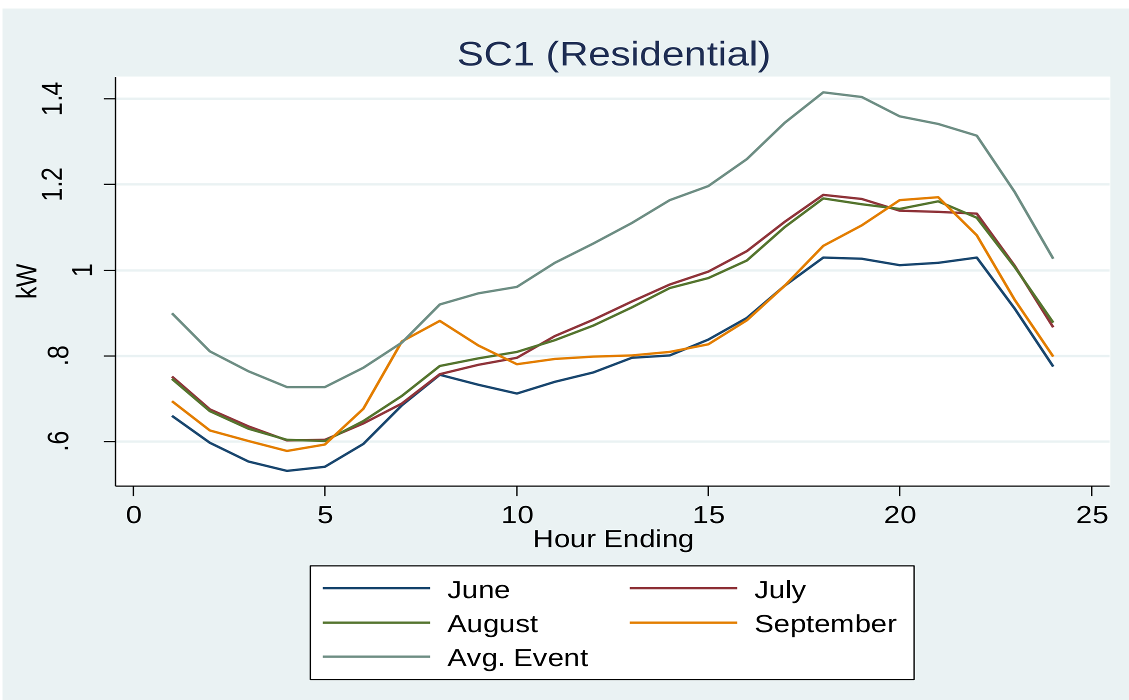
Utility	Residential Rate Type	Current Price	TOU Off Peak Price	TOU Peak Price	CPP Adder
NYSEG	SC1	0.102	0.059	0.102	0.640
	SC8	0.099	0.060	0.099	0.640
RG&E	SC1	0.098	0.060	0.098	0.771

3. *Price Responsiveness and Load Impacts*

After deriving a revenue-neutral TOU-CPP rate, the next step in the methodology is to predict how customers would adjust their energy usage behavior in response to that rate. This is a two-step process involving the estimation of reference loads and the use of a demand model to estimate how usage in each pricing period changes. The analysis assumes that both bundled and direct access customers face the same rates.

A key input to predicting demand reductions in response to TVP tariffs is the current load shape for customers who enroll on the rate. Electricity usage varies throughout the year as seasons/temperatures change and it is important to capture these differences in the reference loads because it has a direct impact on the magnitude of load reductions that can be achieved using TVP at different points in time. Unfortunately, the Companies do not have a dynamic load research sample that could be used to develop reference loads. A neighboring utility, NGrid, does, however, and NGrid gave permission to use their load shapes for this analysis. NGrid's load data was combined with the Companies' annual usage data to develop proxy load shapes for each customer segment. Figure G-8 shows the hybrid reference loads for the average weekday for each summer month and for the average CPP day for NYSEG's SC1 rate. As seen, loads on CPP days are much higher than on non-CPP days and reducing demand during peak periods on these days is a key driver of benefits from TVP rates. Similar profiles occur for the SC8 tariff and for the RG&E SC1 tariff.

FIGURE G-8: REFERENCE LOADS FOR NYSEG SC1 NON-ESCO CUSTOMERS



The second step in estimating load reductions from TOU-CPP rates is predicting how customers would respond to time-varying rates in each rate period. Estimating changes in demand that result from a change in price is a fundamental issue in economics and a large amount of research has been done to develop structural models of demand that capture customer preferences for goods and services based on their own price and the prices of any complementary/substitutable goods and services. Empirically, these preferences can be represented by elasticities, which relate changes in consumer demand to changes in explanatory variables such as prices and income. The Companies have not conducted any TVP pilots or estimated demand reductions associated with TVP rates in their service area, but many other utilities have.[99] The analysis presented here relied on elasticity estimates from Connecticut Light and Power's ("CL&P") Plan-It Wise Energy Pilot[100] for residential opt-in customers. The demand response for small business customers was based on analysis of TOU pricing in California and was assumed to equal a conservative 2%.

There have been very few pilots involving default enrollment into TVP. Customer inertia and lack of awareness would suggest that the average demand reduction per customer under default enrollment is likely to be less than the average for opt-in customers. Fortunately, one relatively recent, well designed pilot was done that allows for a good comparison of average reductions under default and opt-in conditions. The Sacramento Municipal Utility District's ("SMUD") Smart Pricing Options pilot[101] used a randomized control trial ("RCT") design to offer multiple tariffs, including a TOU-CPP tariff, to consumers based on both opt-in and default enrollment. The pilot revealed that, on average, load reductions for default customers were lower than for opt-in customers, but in aggregate, default enrollment produced much greater aggregate load reductions than did opt-in enrollment due to the much larger enrollment rate obtained under default compared with opt-in enrollment. The ratio of average load reductions for default compared with opt-in customers on the same rate in the SMUD study was 0.6. In the analysis presented here, for the default scenario, we applied that same ratio to the estimated load impacts for opt-in customers based on the CL&P pilot.

The reference loads and price elasticities discussed above combined with the rates shown in Table G-25 produce a load reduction of roughly 0.18 kW, or 14.3% on average for NYSEG's SC1 rate for opt-in enrollment. For default enrollment, the same rate would produce load reductions equal to roughly 0.11 kW, or 9%.

4. *Enrollment Rates*

Customer enrollment on TVP tariffs is influenced by a number of factors, including customer characteristics, enrollment strategy (e.g. opt-in versus default), rate characteristics and the marketing strategies and tactics used to encourage participation. Enrollment rates from SMUD's SPO pilot were used as input to the assumed enrollment rate of 15% for the opt-in and 90% for the default tariff. While SMUD's population differs from the Companies' and enrollment rates may differ, we believe that 15% enrollment is achievable if driven by extensive customer

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[99] A useful bibliography on the topic can be found at http://www.brattle.com/system/publications/pdfs/000/005/266/original/Dynamic_Pricing_Bibliography_4-15.pdf?1454955084

[100] See http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWise/$File/Plan-it%20Wise%20Pilot%20Results.pdf and http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2028178

[101] Stephen George, Jennifer Potter and Lupe Jimenez. *SmartPricing Options Final Evaluation*. September 5, 2014. See also SmartPricing Options Interim Evaluation. October 23, 2013.

research (this effort is factored into the cost analysis) that informs the development of plans for communicating with customers and educating them about the rate. However, in the interest of having estimates that are conservative, we also included a $25 signup incentive to overcome inertia and encourage enrollment. Market studies done at PG&E indicate that a modest sign-up incentive can double enrollment rates for CPP tariffs compared with marketing campaigns that do not pay incentives. There are also well known examples of much higher enrollment rates for TOU tariffs. Salt River Project and Arizona Public Service have roughly 25% and 50% of their customers currently enrolled on TOU rates after several decades of concerted marketing. Over roughly a three-year marketing campaign, Oklahoma Gas and Electric ("OG&E") has enrolled roughly 15% of their target population onto their SmartHours Rewards program. Given these observed enrollment rates from actual TVP tariffs offered by utilities, we believe that the assumption of a 15% enrollment rate based on extensive customer research and modest sign-up incentives is reasonable.

Both the opt-in and default scenarios assume that the TVP rates are rolled in as meters are deployed but with a one-year lag. The opt-in scenario also assumes that the 15% steady state enrollment rate is not reached until the third year in which the rate is offered and that only the top-three quartiles of consumers, based on annual usage, are recruited. This is an increasingly common practice with opt-in rates since low use consumers may not deliver benefits large enough to overcome the marketing costs associated with enrolling them. Once the steady state enrollment of 15% is obtained in the opt-in scenario, this is assumed to be maintained in all subsequent years by recruiting enough consumers to replace those who leave the program. There are two types of consumers who may leave a rate program, those who drop out because they don't want to be on the rate and those who close their account for any of a variety of reasons, including due to moving out of the service territory. In the analysis conducted here, we assume that customers who close their accounts but open a new account within each service territory will be defaulted onto the TVP rate that they were on before they closed the account. That is, once a customer enrolls on the TVP rate, we assume it follows them as long as they stay inside the service territory. As such, no recruitment costs are incurred from replacing them. Data from the Companies on customer churn combined with census data concerning the number of customers who move outside the territory and an assumed dropout rate of 2% per year were combined to produce estimates of replacement customers equal to 8.8% for NYSEG and 11.1% for RG&E.

5. *Costs*

The two TVP pricing scenarios outlined above have different cost assumptions associated with implementation that must be factored into the cost effectiveness analysis. Costs are assumed to vary over time according to three implementation stages. Stage 1 is the prelaunch period during which program design, launch preparation and development of all marketing materials would occur. Stage 2 is the ramp up period during which primary program recruitment would occur and stage 3 is the steady state period. For each rate scenario, stage 1 is assumed to last one year, stage 2 is assumed to last two years following the prelaunch period, and stage 3 covers the remaining years of the forecast period. Costs included in the analysis for each scenario include:

program design and administration; general marketing; customer specific acquisition costs; recurring engagement costs; and program evaluation. The cost assumptions for each category are detailed below.

The cost estimates included in this analysis are meant to be indicative of what might be needed to support each pricing scenario. Wherever possible, they are based on evidence from pricing pilots or programs that have been implemented by other utilities or on the Companies' costs for marketing campaigns for other programs.

a) Program Design and Administration

This category covers the cost of in-house staff assigned to manage the TOU-CPP program during the analysis period, including program development, the intensive ramp up period and the long-term steady state period. It also includes costs for outside consulting services during the prelaunch period.

During the prelaunch phase for both enrollment scenarios, we assume that a project manager and an assistant project manager will be needed half time for a year to get ready for program launch. The cost of an FTE project manager, fully loaded, is assumed to equal $162,000 per year ($81,000 for half a year), which is comprised of a base salary of $90,000 per year and 80% overhead rates.[102] The cost of an assistant is assumed to be $117,000 per year ($58,500 for half a year), with a base salary of $65,000 plus 80% overheads. We also assume that the Companies would require outside consulting services for design and implementation planning for both scenarios, at a cost of $200,000. Combined, the prelaunch costs for both scenarios are assumed to equal $339,500.

During the two-year ramp up period, we assume that program administration will require one fulltime project manager and a full time assistant project manager for both scenarios, at a cost of $279,000 per year. During the steady state period, under both scenarios, we assume the program can be operated by a half-time project manager and a full-time assistant project manager, at an annual cost of $198,000.

b) General Marketing

The general marketing cost category covers all marketing costs other than direct mail and other forms of customer-specific communication. During the prelaunch phase, this category covers development of all marketing materials, including customer-specific outreach materials such as direct mail letters and brochures. During the ramp up and steady state periods, this category covers general awareness and education for the default scenario. Mass media advertising is assumed to not be used for the opt-in scenario since this scenario involves targeting of customers

[102] Based on input from the Companies.

in the top three usage quartiles (since lower usage customers are less cost effective) and mass media advertising would invite inquiries from the lowest quartile customers.

General marketing costs during the prelaunch period are assumed to cover development of all marketing materials and strategies. This would likely include focus groups to develop sound messaging strategies for marketing and educational materials. During the buildup to its very successful SmartPricing Options pilot, SMUD obtained input from roughly 2,500 customers through 20 focus groups and four surveys to develop successful names for each rate plan, preferred messaging and channels of communication for various customer segments and educational materials in the form of welcome kits and other ongoing communication.[103] This extensive research was one of the key reasons why SMUD was able to achieve enrollment rates between 15% and 20% for their opt-in pricing plans and had a very low opt-out rate prior to enrollment of roughly 5% for their default plans. At a cost of roughly $15,000 per focus group and $50,000 per survey, this level of effort would cost approximately $500,000. Since the pricing scenarios analyzed here involve a single rate, we assume that the Companies would conduct 10 focus groups (covering different customer segments) and two surveys in support of development of marketing materials during the prelaunch period, at a total cost of $250,000, and that the cost would be the same for both the opt-in and default scenarios.

SMUD's development of marketing materials for the SPO pilot involved outside service costs of more than $600,000 for seven different pricing plans. Development of direct mail marketing materials and welcome kits for a single rate is assumed to require expenditures of $200,000 for each scenario (although the makeup of those materials would differ between the opt-in and default scenarios). In addition, for the default scenario, we assume there would be an additional expenditure of $400,000 for development of mass media advertising campaigns. In total, prelaunch expenditures for the opt-in scenario are assumed to total $450,000 and for the default scenario they are assumed to total $850,000.

General marketing cost assumptions during the ramp up period differ significantly across the two scenarios. As indicated above, mass media advertising cannot be used for a targeted campaign. On the other hand, mass media advertising would likely be a critical element of any large scale default scenario. In a recent campaign for a residential electric conservation program, the Companies utilized TV, radio, newspaper and digital channels for seven months at a cost of $625,000, or roughly $90,000 per month. We use this as the basis for the mass media awareness campaign for the default scenario and assume that the campaign would run for 10 months each year during the ramp up period.[104] Thus, the general marketing costs for the default scenario are estimated to equal $900,000 per year during the ramp up period (and 0 for the opt-in scenario, which will be marketed using direct mail only).

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[103] SmartPricing Options Interim Evaluation. October 23, 2013.

[104] Mass media campaigns during November and December are unlikely to be very successful as it is difficult to rise above the noise of holiday advertising.

During the steady state period, once again, no mass media advertising is assumed to be used for the opt-in scenario because of the targeting assumption. For the default scenario, we assume that the Companies would use mass media advertising for several months leading up to and during the summer months to remind people to watch for CPP notifications and to avoided peak-period energy use to keep their bills down. We assume that the monthly cost for this campaign would be half that of the more important and broader media outreach during the ramp up period. In summary, we assume that mass media advertising would be used for four months each year at a cost of $45,000 per month, for a total annual cost of $180,000 for the default pricing scenario.

c) Customer Specific Acquisition Costs

This category covers costs associated with customer acquisition for each pricing scenario. Four subcategories of costs are included here: customer-specific communication costs for materials such as direct mail; an enrollment incentive for the opt-in scenario; welcome kits that explain how the rate works and that educates consumers about the kinds of behavioral changes that could lead to lower bills; and the cost of processing a tariff change. There are no prelaunch costs in this category (materials development was covered under the general marketing category). Acquisition costs differ significantly during the ramp up and steady state periods and between the opt-in and default scenarios as explained below.

For the opt-in scenario, customer-specific communication costs are based on a direct-mail/email marketing campaign. Even though the Companies currently have email addresses on 45% to 50% of their customers and this percent is growing each year, we assume conservatively that the Companies would use email outreach for only 25% of the population and would use direct mail for the remaining 75% of the population. We also assume that each DM customer would receive 3 mailings over the course of the two-year ramp up period. The cost per mailing, $1.36, is based on inputs from the Companies from a recent direct mail campaign for an arrears management program.[105] In this recent campaign, the Companies paid $1.10 for printing and mailing for each direct mail piece, plus $0.26 for postage, bringing the total to $1.36. The Companies also recently paid $0.02 for each email in a recent marketing campaign.

The average cost per acquired customer for the DM/email campaign is a function of the enrollment rate. For example, if each customer targeted for enrollment received 3 direct mail pieces on average, and the enrollment rate was 5%, the average cost per enrolled customer would equal $81.60 (($1.36x3)/0.05). On the other hand, if the enrollment rate was 15%, the average cost per enrolled customer would be $27.20 (($1.36x3)/0.15). Based on the above costs and a 15% enrollment rate, the average cost per enrolled customer is $20.60 (=((3x$1.36x0.75) + (6x$.02x.25))/0.15)).

For the default scenario, we assume each customer would receive two letters indicating that they will be defaulted onto the rate prior to the rate transition, for a total cost per customer of $2.72.

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105 Email from Leona Michelson, dated 5/11/16.

The next subcategory of costs is for marketing incentives, which only applies to the opt-in scenario. Research by Nexant in conjunction with PG&E's SmartRate tariff[106] indicates that relatively modest sign up incentives in the range of $25 to $50 can significantly improve enrollment rates.[107] Although SMUD obtained high enrollment rates for all pricing plans without using incentives, and Arizona Public Service and Salt River Project have obtained enrollment rates in the 25% to 50% range over a long period of time without using incentives, we nevertheless assumed that a signup incentive of $25 would be needed to achieve an enrollment rate of 15%.

The third cost element tied to initial recruitment onto each rate is a welcome kit that explains the details of the rate and provides education and tips concerning how changes in the timing of electricity use can reduce bills. In SMUD's SPO pilot, the cost for welcome kits equaled $2.50 per enrolled customer. We use this value here.

The final customer acquisition cost is associated with processing tariff changes in the Companies' CIS and billing systems as customers begin transitioning to the new rate. This cost is difficult to estimate as it is tied to the business processes that each utility uses to make such changes, the percent of changes that are made by call center representatives ("CSR") versus business reply cards ("BRC") and other factors. Costs could also vary depending on whether they are handled one at a time or in bulk through overnight batch processing. Once again, we turn to the SMUD pilot for data on this activity. SMUD estimated that, for the opt-in pricing plans, each rate change would cost $29 in terms of CSR labor costs and administrative costs for BRC processing. We use this estimate here although we believe it could be quite high if many changes can be made through a self-service web portal.

For the default scenario, we assume that the cost of opting-out of the default rate would require the same amount of effort as it would take to opt-in to a rate plan under the other scenarios. This cost would apply to the assumed opt-out rate of 10% of the population. For the 90% of customers who are assumed to stay on the rate, we assume that these rate changes would be done using batch processing at a cost of $0.50/change.

In summary, the total cost per enrolled customer for the opt-in scenario is $77.10, which equals $20.60 per enrolled customer for marketing, $25 for incentives, $2.50 for the welcome kit and $29 for CSR and related costs associated with the rate transfer. For the default scenario, the total cost per enrolled customer equals $8.57, which is comprised of $2.72 for each customer for the two letters they will receive notifying them about the impending rate change, $2.50 for the welcome kit, CSR and related costs of $29 for each customer that opts out prior to being enrolled onto the rate (assumed to be 10% of customers) and $0.50 for batch processing for the 90% of customers who are enrolled onto the rate.

In order to maintain a steady-state enrollment of 15% in the opt-in scenario and 90% in the default scenario, customers who leave the tariff either because they close their account or wish to drop

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106 SmartRate is a critical peak pricing tariff with no TOU component.

107 See PG&E (February 29, 2012)

out, must be replaced. As discussed previously, we assume that customers who close their accounts but open a new account elsewhere within the Companies' service area would be defaulted onto the TVP rate that they were on before they closed the account. That is, once a customer enrolls on the TVP rate, we assume the rate follows them as long as they stay inside the service territory. As such, there are no customer acquisition costs associated with replacing these customers. On the other hand, customers who close their accounts and move outside the service territory must be replaced with someone who moves into the premise they vacated. For these replacement customers, we assume that they will be recruited onto the tariff at the time they open their account. Acquisition costs for these customers for the opt-in scenario would involve the cost of a welcome kit plus the sign-up incentive, for a total cost of $27.50 each. For the default scenario, only the welcome kit cost of $2.50 applies. Data from the Companies on customer churn combined with census data concerning the number of customers who move outside the territory and an assumed dropout rate of 2% per year were combined to produce estimates of replacement customers equal to 8.8% for NYSEG and 11.1% for RG&E.

d) Recurring Engagement Costs

This category covers annual costs per enrolled customer. Costs for programming and operating a notification system are included in the IT cost category for AMI so no additional notification costs are included here. In analyzing costs for SMUD's SPO pilot, this cost category included $1.50 per customer per year for additional CSR support associated with customer inquiries around CPP events and $1.20 per customer per year for additional mailings to remind customers about the upcoming event season and to provide tips about how to manage energy costs. While we believe that there may be additional calls associated with events or high summer bills in the early years of the program, we would expect these calls to dissipate after customers have been on the rates for several years. We also don't believe that reminders would need to be provided every year but would be useful periodically. We have included a cost of $1.50 per year per enrolled customer for the entire duration of the analysis to cover these additional costs, while recognizing that they might be higher in the early years and less in subsequent years.

e) Measurement and Evaluation Costs

The final assumed cost is meant to cover estimation of load impacts and process evaluations for the tariff programs. We assume these evaluations would be contracted out to an independent evaluator at a cost of $400,000 and each would be done every other year. They are entered into the model as an average cost of $200,000 each year.

6. *Avoided Costs*

The final input variables used in the TVP benefit-cost analysis are the avoided generation, transmission, distribution and energy costs used to value reductions in peak period energy use and load shifting behavior induced by the more accurate price signals incorporated in the TOU-CPP rates. Avoided generation capacity costs were based on an installed capacity ("ICAP") forecast produced by the spreadsheet model that is Attachment A to the BCA Order. This model produces ICAP values for several regions, including the Lower Hudson Valley ("LHV") and Rest of State ("ROS"). The value used for each customer segment of this study was a weighted average between the LHV and ROS forecasts, based on the percentage of the segment's summer usage in the Brewster division (which is in LHV) versus outside of Brewster. For RG&E, the avoided generation forecast was equal to the ROS forecast since Brewster is not a part of RG&E's service territory. Table G-26 shows the avoided capacity cost inputs used in the analysis.

TABLE G-26: AVOIDED GENERATION CAPACITY VALUES ($/KWH-YEAR)

Year	Avoided Generation Capacity Value at Distribution Level			
	RG&E	NYSEG SC1	NYSEG SC8	NYSEG SC2
2015	51.53	56.03	58.45	55.10
2016	73.89	78.76	81.39	77.75
2017	99.14	102.39	104.14	101.72
2018	102.39	106.15	108.18	105.37
2019	110.31	114.02	116.01	113.25
2020	114.93	118.56	120.51	117.80
2021	114.93	118.56	120.51	117.80
2022	114.93	118.56	120.51	117.80
2023	114.93	118.56	120.51	117.80
2024	114.93	118.56	120.51	117.80
2025	114.93	118.56	120.51	117.80
2026	114.93	118.56	120.51	117.80
2027	114.93	118.56	120.51	117.80
2028	114.93	118.56	120.51	117.80
2029	114.93	118.56	120.51	117.80
2030	114.93	118.56	120.51	117.80
2031	114.93	118.56	120.51	117.80
2032	114.93	118.56	120.51	117.80
2033	114.93	118.56	120.51	117.80
2034	114.93	118.56	120.51	117.80
2035	114.93	118.56	120.51	117.80

Avoided transmission capacity values were not available and were assumed to be $10/kW-year in real 2016 dollars.

Avoided distribution capacity values were taken from a NERA study of marginal cost of service, and were held constant in real 2016 dollars throughout the analysis period. The assumed value is $18.13/kW-year for NYSEG and $23.42/kW-year for RG&E.

Avoided energy costs were based on the Congestion Assessment and Resource Integration Study's ("CARIS") location based marginal prices ("LBMP"). These costs include environmental compliance costs including Regional Greenhouse Gas Initiative ("RGGI") compliance, which captures a portion of the cost of carbon. The forecast used in this study was a weighted average of the zonal LBMP values, based on the aggregate annual usage in each zone. Table G-27 summarizes the input values used for avoided wholesale energy costs.

TABLE G-27: AVOIDED WHOLESALE ENERGY COSTS ($MWH)

Year	Weighted Average Avoided Wholesale Energy Cost
2016	38.89
2017	38.50
2018	39.92
2019	42.36
2020	49.94
2021	51.70
2022	53.57
2023	54.41
2024 and beyond	55.73

Finally, avoided carbon values were based on the EPA's social cost of carbon ("SCC"), minus the pecuniary value associated with RGGI compliance, which is captured by the avoided energy costs. Estimates of this avoided carbon cost on a $/MWh basis were provided by the "Clean Energy Standard White Paper – Cost Study" which was issued by the New York State Department of Public Service.

TABLE G-28: VALUE OF CARBON EMISSION REDUCTIONS ($/KWH)

Year	Estimated SCC minus Pecuniary CO2
2017	0.0165
2018	0.0166
2019	0.0163
2020	0.0146
2021	0.0141
2022	0.0140
2023	0.0141
2024	0.0144
2025	0.0146
2026	0.0146
2027	0.0146
2028	0.0151
2029	0.0148
2030	0.0149
2031	0.0149
2032	0.0147
2033	0.0149
2034	0.0151
2035	0.0151
2036	0.0152
2037	0.0152
2038	0.0152
2039	0.0152
2040	0.0154

7. *Net Benefits for TVP Scenarios*

The benefit-cost analysis presented here compares the cost of implementing TVP pricing assuming meters are in place with the benefits achieved in the form of avoided capacity and energy costs and reductions in carbon emissions. Table G-29 shows the present value of societal costs, benefits and net benefits for opt-in and default scenarios for the Companies. The societal benefits in the form of reduced capacity and energy costs and lower carbon emissions far exceed the cost of implementation in both scenarios. For the opt-in scenarios, the present value of benefits exceeds costs by $55.2 million over the 20+ year forecast horizon. Transitioning New York residential and small and medium commercial customers to TVP tariffs could enable net benefits of more than $179 million. The benefit-cost ratio for the opt-in scenario is roughly 4 and the ratio for the default scenario exceeds 5, indicating that both programs would be cost-effective even if costs were much higher, enrollment was lower and average load impacts were less than the assumptions used in this analysis.

TABLE G-29: BCA ANALYSIS RESULTS FOR TVP SCENARIOS

Benefit/Cost Category	PV Over Life of Meters ($ million)	
	Opt-in Scenario	Default Scenario
Avoided generation capacity	$54.6	$164.5
Avoided transmission capacity	$4.5	$13.7
Avoided distribution capacity	$8.7	$26.4
Avoided wholesale energy costs	$4.6	$12.8
Avoided carbon due to reduced energy use	$0.9	$2.5
PV of Total Benefits	$73.5	$219.8
Marketing and acquisition costs	$9.5	$11.9
Other variable costs	$3.4	$20.3
Fixed overhead costs	$5.4	$9.0
PV of Total Costs	$18.2	$41.2
Net PV of TVP Program over meter life	$55.2	$178.6

Estimated net benefits for the opt-in scenario using the UCT and the RIM test equal $36 million and $35 million respectively, which is significantly less than the $55 million of the societal test. Neither test includes carbon benefits, which are small, and both tests include sign up incentives as costs. The RIM test also factors in lost revenue. The biggest difference, however, is due to the difference in discount rates used for the UCT and RIM tests compared with the societal test. Nevertheless, the benefit-cost ratio for TVP is still quite robust for both tests, exceeding 2.5 in both cases.

F. Information Feedback Programs

A wide variety of research has been done in the last decade concerning the potential impact on energy use resulting from more frequent and more granular access to information about energy use and behavioral changes than can be made to reduce energy use and bills. For example, numerous empirical evaluations of Home Energy Reports ("HERs"), which typically provide normative comparisons of usage and energy savings tips monthly on a default basis, show that sustainable annual energy savings of 1% to 3% are achievable. However, these products were developed and have primarily been implemented using conventional, monthly billing data, not the more granular and near real time AMI interval data.

In the last several years, a number of utilities, including CMP, have conducted well designed pilots studying whether weekly provision of usage data (with or without goal setting) reduces energy use. CMPs usage alert pilot offered weekly delivery of usage and cost data to consumers on an opt-in basis and showed that participants reduced annual usage by around 2.5%. However, this pilot also found that it was relatively difficult and costly to attract customers into the program.

In ongoing work done by Nexant for Southern California Gas Company ("SoCalGas"), weekly usage alerts have been delivered via email on a default basis to gas only customers for whom SoCalGas already had email addresses. An average reduction of roughly 0.7% was found in the initial winter for this program. The reduction increased to 1.2% in the second winter, as described in the most recent, publicly available evaluation of this program.

In the analysis summarized here, we estimate the benefits and costs associated with a usage alert program that would be implemented on a default basis for gas and electric customers for whom the Companies have email addresses. This analysis is meant to be indicative of the type of societal benefits that could be obtained through the more granular and timely data that will be available once AMI is fully deployed. The Companies currently have email addresses on between 45% and 50% of residential customers and this percent is growing each year. For this analysis, we assumed that the availability of email addresses will reach 60% of residential customers by the time meters are deployed and will remain at this level over the forecast horizon. We also assume that 10% of customers will opt-out of the default program. Given that this is a default rollout, the assumed energy savings is 0.75% of electric usage and gas usage (if applicable) for these customers.

The analysis assumes there are three types of usage alerts that customers may receive – electric-only, gas-only or both. Both current ESCO and non-ESCO customers are included in this analysis. The annual electricity usage for these specific customers is aggregated and applied to this conservation analysis for usage alerts. Data on gas usage was obtained from EIA while electricity usage data was obtained from the Companies.

The assumed cost of setting up the usage alert program is $500,000 and the ongoing program management cost is assumed to equal $50,000 per year. In addition, it is assumed to cost $0.72 per customer per year to send the weekly emails (equals $0.02 per email times 3 emails per month times 12 months). The cost estimates were based on the number of electric only, dual fuel and gas only customers in the NYSEG/RG&E service area.

The benefits associated with this program include avoided energy costs, avoided capacity costs and reduced carbon emissions. Table G-30 shows the present value of societal benefits, costs and net benefits associated with usage alerts, based on the societal cost test. As seen, the present value of net benefits for the two operating companies combined over the 20+ year forecast horizon equal roughly $53.2 million. Roughly one quarter of the total benefits come from reductions in gas usage (and gas related carbon emissions, which are not shown separately in the table but produce benefits of roughly $3.5 million). The benefit/cost ratio on this program is almost 8, indicating that even if costs were much higher or benefits lower, this program would still be very cost effective from a societal perspective.

TABLE G-30: SOCIETAL BENEFITS FROM WEEKLY USAGE ALERTS FOR GAS AND ELECTRICITY CUSTOMERS

($ Millions, unless otherwise identified)

Benefit/Cost Category	Present Value Over 20 Year Meter Life
Avoided generation capacity	$7.6
Avoided transmission capacity	$0.6
Avoided distribution capacity	$1.2
Avoided wholesale energy costs	$20.8
Avoided carbon due to reduced energy use	$12.3
Avoided wholesale gas costs	$10.7
PV of Total Benefits	$53.2
PV of Costs	$6.8
PV of net benefits over 20 year meter life	$46.4

G. CVR/VVO Benefits

One vital role of electric utilities is to ensure that electricity supply remains reliable, which requires maintaining customer voltages between 114 and 126 volts (120 volts ±5%). In most distribution systems, however, voltage levels vary across a circuit due to line losses. Customers located close to the source of a circuit usually receive voltage at levels higher than 120V while voltages are lower at the end of a circuit. Voltage set points flowing into circuits are often set manually based on summer peaking conditions when temperatures are hotter and line losses are higher. Stabilizing and reducing voltage levels within the tolerance range reduces power consumption without requiring any changes in behavior or equipment by customers.

Advances in sensors, telecommunications, optimization models, and control technologies have made it possible to monitor voltages and adjust voltage regulating equipment and capacitor banks in near real time, while ensuring that voltage levels remain within the desired range for all customers. VVO systems make quick adjustments to voltage and reactive power levels within distribution circuits to address real-time system needs. Because of their real time monitoring and response, they enable delivery of power at lower voltage levels, thus saving power – a concept known as CVR. A key advantage of CVR/VVO technology is that it can deliver energy savings and demand reductions without changes in customer behavior, without customer purchases, and without utility incentive payments.

The magnitude of demand reductions and energy savings that can be achieved through CVR/VVO depend on whether AMI is in place. Without AMI, a VVO system needs to be operated more conservatively – voltage levels cannot be lowered as much because of the lack of visibility of voltage for end use customers. With AMI, smart meters can communicate voltage levels to the VVO system, thus enabling incremental decreases in voltage levels while ensuring customer voltages remain within the desired range.

VVO technology has wide reaching potential and implications. Not only can it help achieve precise customer voltage control and provide substantial energy and demand savings, it can also enhance overall grid efficiency (by reducing line losses), improve power quality, and facilitate the integration of DER and electric vehicles.

Table G-31 summarizes the key inputs used to estimate the incremental CVR/VVO benefits attributable to AMI due to having voltage reads for individual meters. The incremental reduction of 0.5% for all hours of the year was provided by BRIDGE. Because the technology reduces energy use across nearly all customers for all hours it delivers a substantial amount of energy, peak demand, and carbon reductions, even though the percentage reduction is quite small. In aggregate, once AMI is fully deployed, the incremental CVR/VVO savings due to AMI is estimated to equal 120 GWh of energy, 23 MW of demand reductions, and 64,669 tons of avoided carbon per year, prior to accounting for population and load growth. The present value of these societal benefits over the life of the investment is estimated to equal $112.9 million (in 2016 dollars) across the Companies two jurisdictions. The present value of benefits for NYSEG equal $80.3 million and for RG&E, the estimate equals $32.6 million.

TABLE G-31: ESTIMATED MONETIZED SOCIETAL BENEFITS FROM CVR/VVO ATTRIBUTABLE TO AMI

($ Millions, unless otherwise identified)

Type of Metric	Metric	NYSEG	RG&E
Inputs	Annual Energy Consumption (MWh)	16,449,940	7,568,278
	Peak Demand (MW)	3,004	1,604
Assumptions	% Reduction Due to Voltage Reduction	0.50%	0.50%
Benefits per Year	Energy Savings (MWh)	82,250	37,841
	Reduced Peak Demand (MW)	15.0	8.0
	Reduced CO2 Emissions(tons)	44,291	20,378
Present Value Over Life of Investment	Avoided Gen Capacity Benefits	$17.6	$6.8
	Avoided Trans Capacity Benefits	$1.5	$0.6
	Avoided Distribution Capacity Benefits	$2.7	$1.4
	Avoided Energy Benefits (2016 $)	$45.0	$18.0
	Carbon Benefits due to Reduced Energy Use	$13.6	$5.8
	Total Societal Benefits	**$80.3**	**$32.6**

The present value of benefits for the Utility Cost Test equal $70.7 million and the net benefits for the Ratepayer Impact Test equal $37.8 million. Both of these perspectives exclude carbon benefits and the RIM test counts lost T&D delivery revenue from the lower energy sales as costs. Importantly, these alternative test perspectives also use a higher discount rate as explained in Section C, which substantially reduces the present value of benefits.

H. Summary of Benefits and Costs

Table G-32 summarizes the present value of benefits, costs, net benefits, and the benefit/cost ratio, for five sources of benefits that are enabled by AMI: operational savings; reduction in outage duration and customer outage costs associated with AMI-OMS integration; and reduction in capacity and energy costs and carbon emissions from implementation of opt-in TVP, usage alerts and CVR/VVO. Overall, implementation of AMI and AMI-enabled programs and services is estimated to generate net societal benefits of roughly $133 million. While the operational cost savings associated with implementing AMI fall short of the present value of costs for AMI deployment by about $156 million, the societal benefits (net of incremental costs) of $289 million from AMI enabled programs and business operations far exceed this operational benefit-cost gap. The overall benefit-cost ratio of 1.22 means that even fairly significant changes in assumptions and input values would still produce a positive case for full deployment of AMI. These results, combined with the fact that many intangible and hard-to-forecast benefits such as market animation and increased penetration of DER are not included in the analysis, makes it clear that full deployment of AMI at the Companies' New York service area is a very sound policy decision from a societal perspective.

TABLE G-32: 20-YEAR NPV OF AMI BENEFITS AND COSTS

(2016, $ Millions unless otherwise specified)

Category	Benefit Cost Analysis Metric	Societal Value Total
AMI Operational Business Case	Benefits	$421.8
	Costs	$(577.5)
	Net Benefits	$(155.8)
	B/C Ratio	0.73
AMI/OMS Integration	Benefits	$74.2
	Costs	-
	Net Benefits	$74.2
	B/C Ratio	-
Incremental VVO/CVR (Due to AMI)	Benefits	$112.9
	Costs	-
	Net Benefits	$112.9
	B/C Ratio	-
Opt-in Time Varying Pricing	Benefits	$73.5
	Costs	$(18.2)
	Net Benefits	$55.2
	B/C Ratio	4.03
Usage Alerts	Benefits	$53.2
	Costs	$(6.8)
	Net Benefits	$46.4
	B/C Ratio	7.78
All AMI (no DSP)	Benefits	$735.6
	Costs	$(602.6)
	Net Benefits	$133.0
	B/C Ratio	1.22

Table G-33 shows the benefits, costs and net benefits associated with the UTC and RIM test perspectives. Recall from Table G-1 and Table G-2 in Section B that each test includes or excludes certain costs and benefits. For example, both tests exclude carbon and avoided outage benefits and include customer incentives as costs, while the RIM test also counts lost revenue as a cost. It is also very important to note, as previously discussed, that the present value calculations for these two metrics use a significantly higher discount rate than the societal test perspective. This reduces the net benefit values relative to the societal test since many costs (especially the AMI deployment costs) are front loaded over the forecast horizon relative to the benefits, which tend to occur over a longer period of time. As such, the costs have a greater weight in the present value calculations than do the benefits when a higher discount rate is used. The impact of the different discount rates can be seen clearly in Table G-32 and Table G-33, which show the PV of benefits and costs side by side for each quantified benefit and cost category based on the post-tax (societal) and pretax discount rates. The tables also show how each quantified benefit and cost category discussed in this appendix map into each cost test perspective.

TABLE G-33: NPV OF AMI BENEFITS AND COSTS USING UCT AND RIM TESTS

(2016, $ Millions unless otherwise specified)

Category	Benefit Cost Analysis Metric	Utility Total	Ratepayer
AMI Operational Business Case	Benefits	$330.8	$418.0
	Costs	$(542.7)	$(542.7)
	Net Benefits	$(211.9)	$(124.7)
	B/C Ratio	0.61	0.77
AMI/OMS Integration	Benefits	-	-
	Costs	-	-
	Net Benefits	-	-
	B/C Ratio	-	-
Incremental VVO/CVR (Due to AMI)	Benefits	$70.7	$70.7
	Costs	-	$(32.9)
	Net Benefits	$70.7	$37.8
	B/C Ratio	-	2.15
Opt-in Time Varying Pricing	Benefits	$55.8	$55.8
	Costs	$(19.8)	$(21.2)
	Net Benefits	$36.0	$34.6
	B/C Ratio	2.82	2.63
Usage Alerts	Benefits	$34.1	$34.1
	Costs	$(5.4)	$(18.6)
	Net Benefits	$28.7	$15.6
	B/C Ratio	6.34	1.84
All AMI (no DSP)	Benefits	$491.4	$578.7
	Costs	$(567.9)	$(615.4)
	Net Benefits	$(76.5)	$(36.8)
	B/C Ratio	0.87	0.94

TABLE G-34: BENEFIT ESTIMATES FOR EACH COST TEST PERSPECTIVE

($ Millions, unless otherwise identified)

AMI Component	Benefit Type	Benefit Category	Societal	Utility	Ratepayer	NPV (Post Tax)	NPV (Pre-Tax)	Revenue Requirement
AMI	Avoided Capital	Avoided Meter Purchases	X	X	X	[redacted]	[redacted]	Yes
	Avoided O&M	Billing	X	X	X	[redacted]	[redacted]	Yes
		Call Center	X	X	X	[redacted]	[redacted]	Yes
		Field Work	X	X	X	[redacted]	[redacted]	Yes
		Improved Cash Flow	X	X		[redacted]	[redacted]	No
		Meter Reading	X	X	X	[redacted]	[redacted]	Yes
		Reduced Meter Burden	X	X	X	[redacted]	[redacted]	No
		Reduced Storm Costs	X	X	X	[redacted]	[redacted]	Yes
		Avoided Network O&M	X	X	X	[redacted]	[redacted]	Yes
	Avoided Fleet Capital	Field Work	X	X	X	[redacted]	[redacted]	Yes
		Meter Reading	X	X	X	[redacted]	[redacted]	Yes
	Societal Benefits	Avoided Carbon due to Fewer Truck Rolls	X			[redacted]	[redacted]	No
		Avoided Customer Outage Costs	X			[redacted]	[redacted]	No
	Transfer-Customer Equity	Meter Accuracy Improvement			X	[redacted]	[redacted]	No
		Energy Theft Reduction			X	[redacted]	[redacted]	No
		Delivery Write Offs			X	[redacted]	[redacted]	Yes
		Energy Write Offs			X	[redacted]	[redacted]	No

AMI Component	Benefit Type	Benefit Category	Societal	Utility	Ratepayer	NPV (Post Tax)	NPV (Pre-Tax)	Revenue Requirement
AMI Enabled Rates/Options	Avoided Capital	Avoided Transmission Capacity	X	X	X	[redacted]	[redacted]	Yes
		Avoided Distribution Capacity	X	X	X	[redacted]	[redacted]	No
	Customer Energy Supply Savings	Avoided Generation Capacity	X	X	X	[redacted]	[redacted]	No
		Avoided Wholesale Energy Costs	X	X	X	[redacted]	[redacted]	No
		Avoided Wholesale Natural Gas Costs	X	X	X	[redacted]	[redacted]	No
	Societal Benefits	Avoided Carbon due to Reduced Energy Use	X			[redacted]	[redacted]	No
		Avoided Carbon due to Reduced Natural Gas Use	X			[redacted]	[redacted]	No
Total			735.6	491.4	578.7			

TABLE G-35: COST ESTIMATES FOR EACH COST TEST PERSPECTIVE

($ Millions, unless otherwise identified)

AMI Component	Cost Type	Cost Category	Societal	Utility	Ratepayer	NPV (Post Tax)	NPV (Pre-Tax)	Requirements
AMI	Deployment Capital	IT Hardware	X	X	X	[redacted]		Yes
		IT Software	X	X	X			Yes
		Meters	X	X	X			Yes
		Network	X	X	X			Yes
		PMO	X	X	X			Yes
	Refresh Capital	IT Hardware	X	X	X			No
		Meters	X	X	X			No
		Network	X	X	X			No
	O&M	O&M	X	X	X			
AMI Enabled Options	O&M	Marketing Acquisition Costs	X	X	X			Yes
		Other Variable Costs	X	X	X			Yes
		Fixed Overhead Costs	X	X	X			Yes
		Participant Sign Up Incentives		X	X			Yes
	Lost Revenue	T&D Revenue Losses/ Customer Savings			X			No
Total			$(602.6)	$(567.9)	$(615.4)			