NYSEG RG&E

Appendix A:

Response to Staff Whitepaper 2018 DSIP Guidance

July 31, 2018

Contents

Acronyms

ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ANM	Active Network Management
BEV	Battery Electric Vehicle
BCA	Benefit-Cost Analysis
BIA	Business Impact Analysis
C&I	Commercial & Industrial
CA	Certificate Authority
CCA	Community Choice Aggregation
CDG	Community Distributed Generation
CEAC	Clean Energy Advisory Council
CEF	Clean Energy Fund
CERT	Computer Emergency Response Team
CES	Clean Energy Standard
CESIR	Coordinated Electric System Interconnection Review
CHP	Combined Heat & Power Facilities
CIP	Critical Information Protection
CMP	Central Maine Power
COBIT	Control Objectives for Information & Related Technologies
COM	Communications
COP	Cyber Security Plan
CRM&B	Customer Relationship Management & Billing System
CVR	Conservation Voltage Reduction
DC	Direct Current
DCFC	DC Fast Charging
DEC	Department of Environmental Conservation
DER	Distributed Energy Resource(s)
DER MMS	Distributed Energy Resource Market Management System
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DMS	Data Management System
DOE	Department of Energy
DPF	Distribution Power Flow
DR	Demand Response
DSE	Distribution State Estimator
DSIP	Distributed System Implementation Plan
DSP	Distributed System Platform
DSPP	Distribution System Platform Provider
ECC	Energy Control Center
EDI	Electronic Data Interchange
EEI	Edison Electric Institute
E-ISAC	Electricity Information Sharing & Analysis Center
EIA	U.S. Energy Information Administration
EM&V	Evaluation, Measurement & Verification
EMS	Energy Management System
EOP	Emergency Preparedness & Operations
EPRI	Electric Power Research Institute
ESC	Energy Smart Community
ESCC	Electricity Subsector Coordinating Council
ESCO	Energy Services Company
ESP	Electronic Security Perimeter
ESPI	Energy Service Provider Interface
ETIP	Energy Efficiency Transition Implementation Plan
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAT	Factory Acceptance Tests
FERC	Federal Energy Regulatory Commission
FICS	Flexible Interconnect Capacity Solution

Appendix A: 2018 DSIP Guidance Requirements

FLISR	Fault Location, Isolation and Service Restoration
GBC	Green Button Connect
GHG	Greenhouse Gas
GMEP	Grid Model Enhancement Project
HVAC	Heating, Ventilation & Air Conditioning
ICAP	Installed Capacity
ICS-CERT	Industrial Control Systems Cyber Emergency Response Team
IOAP	On-line Application Portal
IOS	International Organization for Standardization
IPWG	Interconnection Policy Working Group
IT	Information Technology
IPWG	Interconnection Policy Working Group
ITWG	Interconnection Technical Working Group
kW	kilowatt
LMI	Low- and Moderate-Income
LSRV	Locational System Relief Value
LTCS	Load Top Changers
M&C	Monitoring and Control
M&V	Measurement and Verification
MCOS	Marginal Cost of Service
MDMS	Meter Data Management System
MGMS	Microgrids Management System
MHP	Mandatory Hourly Pricing
MM&C	Measurement, Monitoring & Control
MOD	Modeling, Data & Analysis
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards & Technologies
NREL	National Renewable Energy Library
NWA	Non-Wires Alternative(s)
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSEG	New York State Electric & Gas Corporation
NYSERDA	New York State Energy Research and Development Authority
OMS	Outage Management System
OPF	Optimal Power Flow
OSG	Operational Smart Grids
OT	Operational Technology
PDS	Program Development System
PGP	Pretty Good Privacy
PHEV	Plug-in Hybrid Vehicles
PII	Personally Identifiable Information
PMO	Project Management Office
POD ID	Point of Delivery ID
PRC	Personnel Performance, Training & Qualifications
PSC	Public Service Commission
PSP	Physical Security Perimeter
PV	Photovoltaic
QAS	Quality Assurance System
REV	Reforming the Energy Vision
RFP	Request for Proposal
RFI	Request for Information
RG&E	Rochester Gas and Electric Corporation
RTU	Remote Terminal Unit
SAP	Systems, Applications & Products
SAT	Site Acceptance Tests
SCADA	Supervisory Control and Data Acquisition
SEEP	System Energy Efficiency Plan
SFTP	Secure File Transfer Protocol
SGS	Smarter Grid Solutions
SIR	Standardized Interconnection Requirements
SMSI	Smart Meter – Smart Inverter
SOX	Sarbanes-Oxley Act
SPSIP	Supplemental Distributed System Implementation Plan
T&D	Transmission and Distribution
TOP	Transmission Operations
TOU	Time of Use
TVP	Time Varying Pricing

UBP	Uniform Business Practices
UER	Utility Energy Registry
US-CERT	United States Computer Emergency Readiness Team
VDER	Value of DER
VO	Voltage Optimization
VVO	Volt/VAR Optimization
ZEV	Zero Emissions Vehicle

4 DSIP Update Topical Section Specifications

4.1 Integrated Planning

Introduction/Context and Background

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

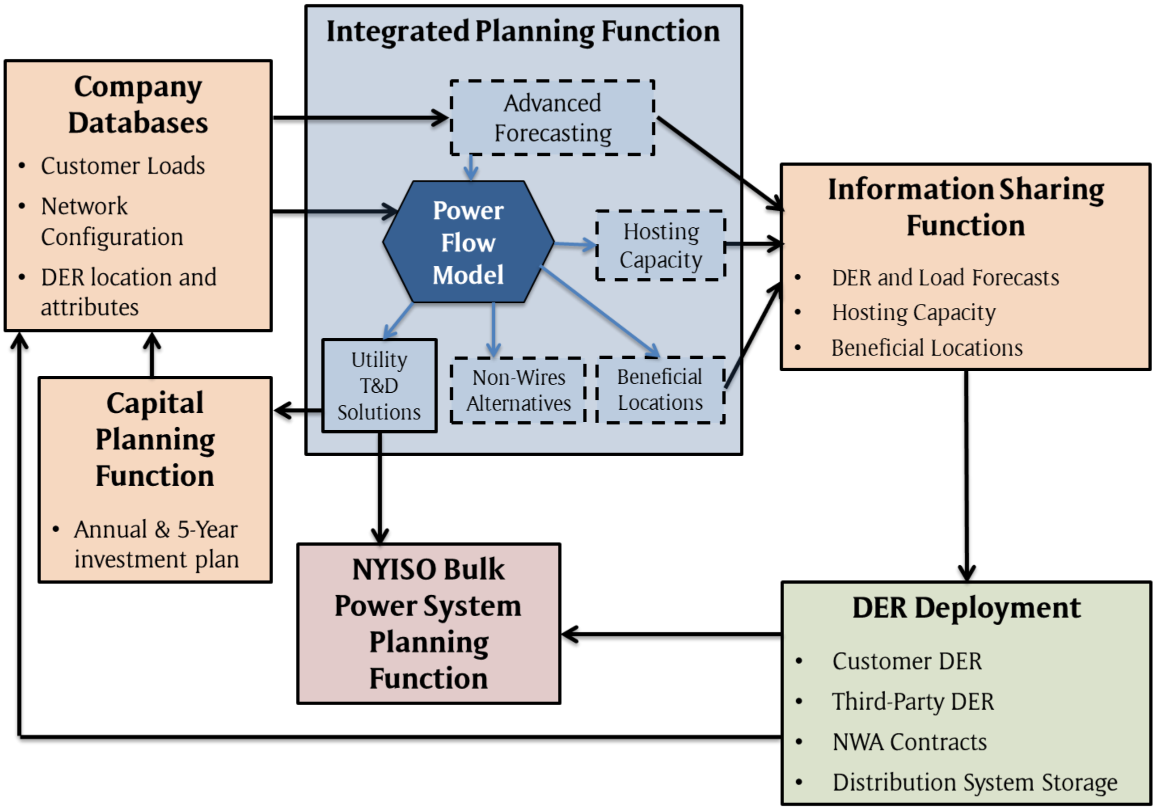
The Companies have made considerable progress since the filing of our 2016 DSIP to design and build the Integrated Planning function, working together with the Joint Utilities to deliver a consistent experience to market participants throughout New York.

We are building our Integrated Planning function to achieve the following outcomes:

- Maintain a safe, reliable, resilient network by making investments in distribution facilities and/or connecting new distributed energy resources (DER);
- Deliver value to customers over the long-term by enabling efficient investment decisions by the Companies and DER developers;
- Accommodate high levels of DER penetration, maximizing the contribution to customer value for any given amount, type, and location of DER;
- Communicate system information and insights to DER developers to inform their investment decisions; and
- Provide system information and insights to other AVANGRID functions to support their respective DSP responsibilities.

The Integrated Planning function and relationships between Integrated Planning and other business areas is presented in the Figure 4.1-1.

FIGURE 4.1-1: INTEGRATED PLANNING FUNCTION



We have made meaningful progress in each of primary areas of Integrated Planning: Advanced Forecasting, Utility Transmission and Distribution Solutions, Hosting Capacity, Non-Wires Alternatives (NWA), and Beneficial Locations. In addition to building the Integrated Planning function, we are sharing hosting capacity and beneficial locations insights with DER providers, and have been identifying, issuing and evaluating the results of NWA solicitations. We have also been working with the Joint Utilities to collaborate with the New York Independent System Operator (NYISO) to discuss integrated transmission and distribution planning processes, forecasting planning inputs and assumptions, and data resources.

Implementation Schedule and Investments plan

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

Our primary focus has been to continue to build a strong foundation in order to be able to integrate large quantities of DER into our Integrated Planning and Grid Operations functions. It will not be possible to achieve a long-term vision of optimizing DER and traditional utility assets to provide benefits to our customers and the grid unless we build a foundation that can manage DER and operational data, update our data sets and planning studies on a relatively frequent basis, and keep up with evolving DER technologies and customer responses to new products and services. The need for more granular data with respect to time and location dimensions is particularly critical. It will also not be possible to perform adequate probabilistic planning studies without data that has sufficient granularity and quality. Our Technology Platform, described in Chapter VIII of our 2018 DSIP Report, is being designed to provide the raw, granular, time-differentiated data required to support our three Distributed System Platform (DSP) Pillars Integrated Planning, Grid Operations, and Market Services.

While we are still in learning mode with respect to integrating DER through the Energy Smart Community (ESC) and other innovation projects, we have already begun delivering value to our customers, DER providers, and the grid. Along with the other Joint Utilities, we are providing hosting capacity maps with insights for every circuit on a web-portal. We have been executing NWA solicitations for potential NWA opportunities. Our initial 2016 DSIP filing and the Joint Utilities' Supplemental DSIP filing[1] identified probabilistic integrated planning as a future enhancement. The Companies have also been focused on granular load and DER forecasting, and our LoadSEER innovation project may inform the probabilistic planning methodology. We have installed 98% of the Advanced Metering Infrastructure (AMI) meters in the Energy Smart Community, with the remainder expected to be installed by early 2019. AMI provides the granular load data to support our ESC initiatives.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

Our plans for the next five years are presented in the Integrated Planning Roadmap (Figure 4.1-2). The short-term initiatives build upon our foundational efforts to date and are necessary stages before pursuing the long-term initiatives. We are focusing on improving our models and the quality of data inputs. This includes leveraging more granular customer usage, DER production, and operational performance data as they become available to perform more accurate and reliable planning studies. We will be able to identify and provide the most efficient solutions to address the needs of the network, including DER and NWAs.

[1] Filed November 1, 2016 in Case 16-M-0411.

FIGURE 4.1-2: INTEGRATED PLANNING ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)
Develop Forecasting, Hosting Capacity, and NWA Processes	Developed Forecasting, Hosting Capacity, NWA Processes	Improve Data Granularity and Quality Automate Data Processes (Innovation)	Automate Data Processes (System-wide)
Incorporate DER into System Planning	Shared System Data with Developers Integrated NWAs into Integrated Planning	Storage Innovation Projects Incorporate EE, EVs, and Energy Storage into Integrated Planning Forecast DER and Hosting Capacity (ESC)	Forecast DER and Hosting Capacity (System-wide)
Perform Scenario and Probabilistic Planning Analyses	Foundational System Investments to Improve Data Granularity and Quality	Research and Test Probabilistic Methodologies	Incorporate Scenarios and Probabilistic Planning Methodologies

By the end of the five-year period, we anticipate being able to deploy more advanced planning and data management tools. We will be able to incorporate probabilistic methods to evaluate the needs of the network and address them while maintaining reliability and service quality. This includes the development of Integrated Planning annual planning cycle analyses, while updating system data that will be shared with DER developers more frequently due to automation of Integrated Planning processes. This will connect the Integrated Planning forecasts to the annual and five-year capital plan, supported by robust analyses to support our investments that address both reliability and resiliency.

The five-year Integrated Planning development plan depends on the execution and timing of a number of foundational investments, most notably NYSEG and RG&E's plan to rollout AMI over a four-year period system-wide. We will be coordinating the Grid Automation plan due to the common telecommunications infrastructure. With respect to Integrated Planning, this will allow the Companies to begin using more granular data to perform advanced forecasting and hosting capacity analyses with better data.

The ability to evaluate the impact of DER integration and subsequently deploy DER more broadly also depends on the availability of more granular data and the functionality provided by the Grid Model Enhancement Project (GMEP) and Enhanced DER Monitoring and Control (M&C) projects.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks that relate to performance of the Integrated Planning function, and have taken measures to mitigate each risk, as shown in Figure 4.1-3.

FIGURE 4.1-3: INTEGRATED PLANNING RISKS AND MITIGATION

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality of data that is relied upon by the DSP to perform Integrated Planning functions	• NYSEG and RG&E are designing the GMEP Phase 1 project to incorporate governance and data processes and flows • Enterprise Data Platform deliverables are clearly specified, including data architecture, dictionary, flow diagrams, etc. • NYSEG and RG&E are performing a data governance/data quality pilot roadmap for DER integration • The Companies will build redundancy into AMI telecommunications infrastructure
2. **Cost Recovery:** Timely cost recovery is necessary to maintain financial strength	• Integrated Planning analysis cycle is connected to the five-year Capital Plan • Existing AVANGRID/NYSEG and RG&E financial controls will be maintained
3. **Customer Value:** DSP must be efficient and enable reliable, resilient, safe distribution service	• We are applying lessons learned from ESC and innovation projects to adjust and implement to scale • We advocate for REV policies that align with customer value • We are negotiating third-party performance contracts that ensure reliable service

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, *increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.*

DER developer needs are identified, discussed, and validated through the Joint Utilities' stakeholder engagement process. Several webinars and meetings have focused on Integrated Planning-related issues both before and since the Joint Utilities' Supplemental Distributed System Implementation Plan was filed and the formal Joint Utilities' stakeholder process was launched. These meetings have addressed Advanced Forecasting and Hosting Capacity issues. The stakeholder needs related to these topics are discussed in our 2018 DSIP Guidance Response Sections 4.2 (Advanced Forecasting) and 4.12 (Hosting Capacity), respectively.

Stakeholder engagement has contributed to actions that have already begun producing results. With respect to Integrated Planning and related activities, NYSEG and RG&E have developed circuit-level hosting capacity and made it available to third parties on a portal. The Joint Utilities are currently participating with Staff and stakeholders on regulatory approaches to providing location-specific-price-signals to attract DER to key locations along the grid to alleviate congestion and other issues.[2]

We also addressed Integrated Planning in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.[3]

Additional Detail

The utility's electric system plan must position the utility to timely integrate an increasing number and variety of DERs while maintaining or improving safety, reliability, quality, and affordability of service. Utility planning analyses based on known information and advanced forecasts will have to evaluate an increasingly complex and dynamic system environment where the combined behaviors and mutual effects of loads and supply resources can vary significantly.

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2 State of New York Public Service Commission, Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

3 Feedback received is reflected in this filing. The outreach effort included a daylong meeting held in our service area attended by over 70 stakeholders present, where we presented our DSIP and solicited and incorporated feedback. Participants included elected officials and representatives from a county planning department, sustainability coalitions, academic institutions, clean energy companies, solar organizations, New York Power Authority (NYPA), advocacy groups, engineering firms, innovation companies, and vendors.

Appendix A: 2018 DSIP Guidance Requirements

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities which support integrated electric system planning:

NYSEG and RG&E are building an Integrated Planning function that will accommodate large numbers of DER and NWAs, to be considered along with more traditional utility investments when planning the grid. We are focused in the near term on continuing to build foundational capabilities and processes that support the range of specific Integrated Planning functions (*e.g.*, advanced forecasting, hosting capacity, and procurement of NWAs).

1) *The means and methods used for integrated system planning.*

We are building three capabilities to perform Integrated Planning:

1) Develop Forecasting, Hosting Capacity, and NWA Processes;
2) Incorporate DER into System Planning; and
3) Perform Scenario and Probabilistic Planning Analyses.

We are also developing five functions within Integrated Planning:

1) Advanced Forecasting: granular forecasting of load and DER by location and hour of the year;
2) Utility Transmission and Distribution (T&D) Solutions: identifying areas of the grid that require an investment and determining if they can be addressed by a traditional grid investment, a non-wires alternative, by accelerated deployment of DER, or some combination of these;
3) Non-Wires Alternatives: procurement of non-wires alternatives through a competitive solicitation process;
4) Hosting Capacity: estimating the amount of DER in kW that can be accommodated by a circuit without adversely affecting reliability or power quality without the need for grid upgrades paid for by DER developers;[4] and
5) Beneficial Locations: identifying circuits on the grid where DER could help address constraints and potentially defer grid investments.

These five functions work together to achieve our Integrated Planning outcomes.

Integrated Planning's primary analytical engine is the Power Flow Model, a tool that relies on an up-to-date mathematical representation of the physical and electrical attributes of distribution infrastructure that comprise the network, system flow data from our Supervisory Control and Data Acquisition (SCADA) system and AMI, a forecast of loads by circuit, and the location and operational attributes of connected and forecasted DER.

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[4] Link to Hosting Capacity Portal

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

The means and methods identified in Subpart 1 enable NYSEG and RG&E to perform Integrated Planning functions. NYSEG and RG&E will work with the Joint Utilities to develop probabilistic forecasting methodologies that address the primary sources of uncertainty. Our planning studies will incorporate forecasts of all DER, and the power flow model will incorporate the location and other attributes of DER. This approach will capture the interrelated effects of various DER.

These DER forecast inputs depend on the behavior of third parties and customers in response to technical, economic, and other factors. While predictive behavioral models will certainly improve as historical data is available for estimation purposes, there will always be some uncertainty around assumptions used to produce forecasts as well as typical statistical variances. Scenario analyses can help determine how the uncertainty attributable to DER forecasts impacts planning results.

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

Quality of data is one of the major factors that contribute to the confidence we have regarding advanced forecasting results, including the forecasts of DER. Data includes historical energy usage data at the desired level of granularity (primarily time of use, peak load, and location), measurements of energy flows at various points on the distribution system, and the operating performance and other characteristics of installed DER. As these data improve in quality with the phased implementation of AMI and distribution automation and enhancements to DER databases, the confidence in forecasts of load, DER, and hosting capacity will improve.

In addition, we have identified quality of data as a primary risk factor in the Risk and Mitigation subpart above. We identify the steps that we are taking to address this risk and improve the data quality we rely on for Integrated Planning.

Finally, "Automate Data Processes" is included in our Integrated Planning roadmap to improve the timeliness of our Integrated Planning processes. We will test these processes before adopting them as part of the Integrated Planning process.

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

Sensitivity analyses typically estimate the impact on an outcome (or dependent variable) based on a change in an important assumption (or independent variable). They are most valuable when making decisions based on a forecast that may change significantly if one or more drivers are beyond the control of the utility and potentially subject to wide variation. NYSEG and RG&E anticipate that the DER and load forecast will be impacted by a number of assumptions including:

- The number, type, operating capabilities, and location of various types of DER, particularly where such forecasts depend on customer decisions in response to emerging technologies and/or offerings by third party DER providers;
- Weather conditions;
- Economic development activities and general economic conditions; and
- Environmental policy and market assumptions.

Each one of these factors is a candidate for sensitivity analyses. The applicability of particular sensitivity analyses will depend on the type of analysis being performed and the purpose of the analysis.

Particular planning decisions will consider base case as well as sensitivity analyses, with an explanation as to how various analyses contributed to the final decision.

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

Our Integrated Planning function will prepare work products (*e.g.*, hosting capacity forecasts, solutions to distribution system needs included as inputs to the NWA Suitability Criteria, etc.) throughout the year, and produce results that are reflected in our annual five-year capital plan. These work products will reflect the best available data, adjusting long-term forecast assumptions as trends emerge. It is conceivable that particular project or NWA procurement decisions could be accelerated, delayed, or reprioritized within a planning year in response to extraordinary developments (*e.g.*, the planned shutdown or expansion of a large load).

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

There is a direct relationship between "asset management" capital projects that reflect the need to address aging infrastructure and Integrated Planning. For example, a planned replacement of a 4kV distribution line can be upgraded to a 12kV line to increase hosting capacity if doing so will attract DER that is beneficial to the grid and accommodate future customers' needs, such as EV adoption or new or expanded facilities. NYSEG and RG&E have criteria that are used to make asset management decisions to explicitly consider opportunities to optimize the network by making incremental and economical enhancements to projects that benefit the grid and our customers.

There is a diverse collection of beneficial electrification opportunities that have the potential to reduce customer costs, improve the environment, improve productivity, contribute to economic development and improve workforce safety. These include residential and commercial heat pumps, electrification of forklifts and other industrial or warehouse equipment, commercial food service equipment, industrial processes, and heat recovery chillers in commercial and industrial facilities, and the electrification of transportation and increased reliance on electric vehicles (EVs). The Integrated Planning function will need to monitor these trends, including supporting government policy or Commission actions, and reflect them in load forecasts. Additionally, upgrade considerations must factor in DER procurement in order to realize the full benefit of distribution investment deferral value of the NWA, as detailed in the NWA Suitability Criteria.

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

NYSEG and RG&E consider energy efficiency as the first option when meeting customer demand. Energy efficiency actions that reduce demand during peak periods are more likely to lead to long-term savings from capital investments or NWA contracts that are driven by peak demand.

It is our practice to look for energy efficiency opportunities in areas that are potential NWA candidates. NYSEG and RG&E estimate the location and amounts of anticipated energy and peak load reductions when they are associated with an NWA. These are based on customer-specific assessments and we rely on them when defining the NWA requirements. Thus, we have targeted a few large customers located behind Station 51, a currently planned NWA, in an effort to identify energy efficiency and other demand-side actions that would reduce the peak demand that would otherwise need to be met by other NWA. In addition, energy efficiency programs are considered DER that can be used as part of an NWA solution. It is important to develop and target energy efficiency options to areas of the system that are expected to need investments to meet capacity needs as these will result in the greatest cost savings, an outcome that we expect to see in project-specific BCAs.

The sustained impact of past energy efficiency programs is reflected in the load forecasts, a practice that we and other utilities have applied for years. However, we anticipate that we can improve our ability to reflect locational energy efficiency in our databases and forecasts when we have AMI and other foundational investments in place. We further anticipate that applying new data analytics to customer usage data from AMI and other data from our own databases and public demographic information will allow us to target communications to customers that offer insights regarding energy efficiency opportunities and actions that they should consider.

See 2018 DSIP Guidance Response Section 4.6 (Energy Efficiency), particularly Subparts 2-5 in “Additional Detail” for more details.

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

NYSEG and RG&E expect to continue to collaborate with the Joint Utilities to share best practices and lessons learned from within and beyond New York. AVANGRID has affiliates within the United States and in Europe that will also share best practices and lessons learned. Our subject matter experts attend conferences and read the industry press to keep abreast of developments within their respective areas of responsibility.

As noted above, the Joint Utilities have collaborated with stakeholders on a number of Integrated Planning issues through Load and DER Forecasting and Hosting Capacity engagement groups. Many of our stakeholders bring experiences from other jurisdictions to these discussions. We expect this sharing of intelligence to continue as we work with stakeholders to address DER forecasting and hosting capacity forecasting issues.

4.2 Advanced Forecasting

Introduction/Context and Background

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

We have been working with the Joint Utilities since the 2016 Supplemental DSIP filing to develop forecasting methodologies that can more precisely reflect the impacts of distributed energy resources (DER) on system needs. These discussions have been informed by stakeholder consultations.[5] We have also been working together to improve coordination with the New York Independent System Operator (NYISO) to reflect DER impacts in long-term forecasts.[6] The Joint Utilities have focused on developing granular forecasts, employing a hybrid of top-down and bottom-up methodologies. Forecast accuracy will improve by considering all available data, queued projects, and relevant macroeconomic trends.

In advance of the availability of Advanced Metering Infrastructure (AMI) data, we have developed a forecast of load by distribution substation using class load shapes and available Supervisory Control and Data Acquisition (SCADA) data in order to respond to stakeholder input and comply with Commission guidance.[7]

Implementation Plan, Schedule, and Investments

To describe the details of the current and future implementations, the utility should use system diagrams, process flow diagrams, tables, and narrative text as needed for clarity and thoroughness. When describing the progression from the current implementation to the future implementation, the utility should use narrative text, Gantt charts, and calendars which present and explain the planned sequence and timing of the notable development activities, dependencies, and milestones.

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5 The Joint Utilities hosted two stakeholder engagement sessions on March 27, 2017 and July 14, 2017 that focused on DER and load forecasting. These efforts are responsive to DER and load forecasting guidance provided in the Commission's March 9, 2017 Order in Case No. 16-M-0411 – In the Matter of Distributed System Implementation Plans, in particular, p. 8.

6 See discussion in the Joint Utilities Supplemental DSIP Filing, pp. 36-37.

7 Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, ("REV Proceeding"), Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016) ("DSIP Order"), Attachment 1, p. 19.

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

Our Advanced Forecasting process reflects the current state of data inputs. For example, as AMI data becomes available, we will be able to develop load shapes by substation and circuit that are based on actual hourly customer meter data. We will also be able to develop DER forecasts by leveraging more granular data on the location, type, and performance attributes of installed DER.

Our existing forecasting process has been applied to generate a five-year 8,760 forecast by substation, and we are completing efforts to produce a forecast by circuit. These forecasts are used to perform system planning analyses and interconnection studies. Estimates of load and DER are an input to our estimates of hosting capacity by circuit that are made available to third parties on our hosting capacity portal.[8] Our load forecasts also contribute to the insights that are made available to Non-Wires Alternatives (NWA) bidders. These forecasting results benefit DER developers and customers.

We have continued to make progress since our 2016 DSIP filing to include DER that have already been connected to our system (primarily solar installations) in our DER Attribute Database. We expect to complete this effort in 2019.

Finally, we are conducting two innovation tests in our Energy Smart Community (ESC) to improve our advanced forecasting capabilities. First, we have applied Integral Analytics LoadSEER software to our 15 ESC circuits to determine how DER will affect the load shape on each circuit, capturing the interrelated effects of DER. Second, we are testing Clean Power Research's WattPlan Grid in the ESC to help predict customer DER adoption.

Our 2018 DER and Load Forecasting process, including data inputs, calculations and results is presented in Figure 4.2-1.

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[8] Link to Hosting Capacity Portal.

FIGURE 4.2-1: DER AND LOAD FORECASTING PROCESS – 2018

Data Inputs [*and Sources*]

- Customer count and monthly billed MWh by service class [*Customer Service*]
- Load shapes and distribution loss factors by service class
- DG: by substation (and circuit if identified), nameplate rating, in-service date [*Interconnections*]
- Mapping SCADA reads by substation (or circuit if available) [*Integrated Planning*]

Forecast Assumptions

- Annual load growth rates
- Annual DER growth rates

Computations

DER and Load Forecasting Steps

1) Map customer counts and calculate use-per-customer by service class to substations and circuits
2) Reconcile bottoms-up load shapes to substation and circuit SCADA reads to develop base year load shapes by service class
3) Apply annual load growth rates, weighted by service class composition, and adjust to reflect annual DER growth rates by circuit

Results [*and Uses*]

- DER Forecast by distribution substation [*System Planning and Interconnection Studies, Hosting Capacity, NWAs]*
- 5-Year, 8760 Load Forecast by distribution substation [*System Planning and Interconnection Studies, Hosting Capacity, NWAs]*

Note:

- NYSEG has 410 substations and 1,597 circuits
- RG&E has 145 substations and 798 circuits

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

The Advanced Forecasting implementation plan is designed to support stakeholders' needs over the next five years and beyond by steadily improving the quality of data and assumptions that will be relied upon to produce load and DER forecasts. If approved, we will implement AMI over a four-year period. Although the precise implementation schedule remains under development, we anticipate improving the forecast of load and DER for circuits each year as actual AMI meter reads become available across our service territory and AMI data can be reflected in our forecast methodologies and resulting forecasts. Our multi-year Grid Automation project will provide information regarding power flows from network devices installed along circuits that may also inform load and DER forecasts as forecast methodologies are refined and estimates reflect experience informed by actual data. We expect to improve the quality of our DER forecasts as we gather more data and insights about DER that is connected to our system, including insights regarding economics and other factors that drive customer adoption.

Our five-year roadmap for Advanced Forecasting is presented in Figure 4.2-2.

FIGURE 4.2-2: ADVANCED FORECASTING ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)
Forecast Load at a Granular (Circuit and Time Period) Level	Estimated 8,760 Forecasts by Substation Integral Analytics LoadSEER software applied to 15 ESC circuits.	Apply Available NYSEG/RG&E Load Shapes by Customer Class Estimate 8,760 Load and DER Forecasts by Substation and Circuit Automate Data Flows to Increase Advanced Forecasting Efficiency	Reflect AMI and Grid Automation Data in Load Forecast Models Implement LoadSEER to scale, if economic, where interval data is available
Forecast DER Supply by Resource Type, Location and Time Period	Progress Including Connected DER in Databases	Reflect all Connected DER in Databases Develop DER Forecast Methodology, Incorporating Customer Adoption Predictive Models Test DER Adoption Forecasting Tool in the ESC	Reflect installed DER Location and Operations Data in DER Forecast Models
Incorporate Scenario and Probabilistic Techniques into Load and DER Forecasting	Foundational System Investments to Improve Data Granularity and Quality	Research and Test Probabilistic Methodologies	Incorporate Scenarios and Probabilistic Planning Methodologies

The ability to produce probabilistic forecasts will improve the robustness of the analyses and insights that are supported by the forecasts, including analyses that deliver benefits to customers, other stakeholders, and the grid. These analyses include:

- Identifying areas on the grid that require long-term capital investments or NWA to enhance or maintain our ability to provide reliable distribution service;
- Estimating hosting capacity by substation and circuit;
- Performing special studies to determine whether larger DER can be interconnected; and
- Providing the NYISO with more accurate and granular forecasts to support planning of

the State's bulk transmission system to reflect DER.

Our Technology Platform supports the requirements identified by the Advanced Forecasting business area by collecting granular data and performing analytics with our Enterprise Analytics platform:

- Granular historical load information for each element of the network (substation, circuit, premise);
- Existing and forecasted DER asset information;
- Installed DER characteristics (*i.e.*, DER type, performance, locational and temporal information); and
- Disaggregation of metering data into load and DER data.

As discussed in Chapter VIII of our 2018 DSIP Report, the technologies that support these requirements include several "Foundational Investments" including AMI, Telecommunications / IT, Grid Automation, Grid Model Enhancement Project (GMEP), DER Measurement, Monitor, and Control (MM&C), Enterprise Analytics, and Advanced Forecasting Tools. Our DER Management System (DERMS) technology and information that we acquire during the interconnection process will also contribute to improvements in Advanced Forecasting.

While all of these projects are in various stages of planning and/or development, the timing of AMI implementation is the determining factor in our ability to improve the quality of our forecasts throughout the five-year DSIP forecast period. AMI is also critical to generating data required to develop probabilistic forecasting methodologies. In fact, during this five-year DSIP period, the degree to which we are able to base DER and load forecasts on measured data could be used to assess the variance in our forecasts and be reflected in our probabilistic forecast methodology.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified two risks that relate to performance of the Advanced Forecasting function, and have taken measures to mitigate both risks, as shown in Figure 4.2-3.

FIGURE 4.2-3: ADVANCED FORECASTING RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality data that is relied upon by the DSP to perform Advanced Forecasting	• NYSEG and RG&E have proposed to implement AMI to collect actual granular usage data throughout its service territory to develop more accurate load shapes. Thus, timely implementation of AMI contributes to mitigation. • Build redundancy into AMI telecommunications infrastructure. • Completing the DER database to track the location and operating attributes of all DER. • Grid Automation will enable SCADA to have greater visibility into power flows and performance along the network that will improve advanced forecasting. • NYSEG and RG&E are designing the Grid Model Enhancement Project Phase 1 to incorporate governance and data processes and flows.
2. **Forecast Methodology:** Forecasting DER is relatively new responsibility and will require modeling of customer and third-party decisions.	• Collaborating with other New York utilities and monitoring advances in DER forecasting in other jurisdictions • We are testing Clean Power Research' WattPlan in the ESC to help predict customer propensity to adopt DER.

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities have solicited and received stakeholder feedback on several forecasting topics, including the role of 8,760 forecasts, incorporation of external inputs to utility forecasts, such as public policy and developer forecasts, and the future evolution of forecasting to incorporate more probabilistic methods and scenario analyses. The Joint Utilities have extended their outreach to utilities across the country and in the European Union to exchange best practices in DER and load forecasting, identifying processes worth investigating, as discussed further in Subpart 15 below.

We also addressed Advanced Forecasting in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

Additional Detail

Utility planners and operators, DER developers and operators, and other stakeholders all require load and supply forecasts which are timely, accurate, and detailed enough to support both short-term and long-term planning. Such forecasts are an important factor in predicting the hosting capacity available at existing and potential DER locations and are necessary for efficient development and use of grid resources. As the variety of methods for using DERs to address electric system needs expands, utilities must perform advanced forecasting analyses which integrate an increasing number and variety of DERs into their load and supply forecasts.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities which enable advanced electric system forecasting and provide the most current forecast results:

Our Advanced Forecasting function will improve over the next five years as AMI and other technologies begin providing accurate granular data that is the key factor in developing load and DER forecasts at the circuit level, including our ability to implement probabilistic methodologies. We, along with utilities in New York, expect to improve the quality of DER forecasts as data becomes available and as we learn more about customer behavior in response to the availability of new information and insights, new energy-related products and services, and DER options.

1) *Identify where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download up-to-date load and supply forecasts.*

We are developing a single, one-stop DER Developer portal that will address all interactions with DER developers with various information, data, and insights, subject to access rights that will be developed by working with Staff, DER developers and other stakeholders.[9] Certain information may be considered commercially sensitive and DER developers will want to restrict access to their own data if it can be used for competitive purposes. We will also provide the ability to download in Excel format for DER developers that want to manipulate available load and DER supply forecasts to perform analyses.

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9 Refer to Appendix B of our 2018 DSIP Report.

2) *Identify and characterize each load and supply forecasting requirement identified from stakeholder inputs.*

As noted above, the Joint Utilities have solicited and received stakeholder feedback on several forecasting topics, including the role of 8,760 forecasts, incorporation of external inputs to utility forecasts, such as public policy and developer forecasts, and the future evolution of forecasting to incorporate more probabilistic methods and scenario analyses. Based on these discussions, we believe that delivering 8,760 load and supply forecasts by distribution substation and by circuit in the future, with further disaggregation by type of DER to the extent possible will meet DER developer needs.

We propose to provide forecasts of load and DER for 36 distinct load shapes: 12 months times 3 day-types (weekday, weekend, and holiday). We believe that this will be easier to manage and provide DER developers and operators with the information that meets their requirements.

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

We are currently providing granular load forecasts, net of the contribution of DER, based on the 2018 DER and load forecasting methodology described above. The existing methodology contributes to the quality of system planning analyses, interconnection studies, hosting capacity estimates, and the information provided to NWA bidders. The DER and load forecasts, when considered along with these analyses, achieve the primary objectives of informing developer investment decisions and providing insights as to where those investments are likely to contribute to customer and grid value. The NYISO will also benefit from more accurate and granular forecasts to support planning of the State's bulk transmission system to reflect DER.

The next steps are to: (1) improve the quality of input data used to develop the load forecasts by leveraging AMI and SCADA information as it becomes available throughout our service areas, (2) improve the quality of DER location and performance attribute information that feeds the forecast, and (3) develop valid forecasts by type of DER with spatial and temporal granularity. We expect to make significant progress in all three areas during the five-year DSIP period.

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

We are currently completing 8,760 load forecasts by substation, and will evolve to forecasting by circuit. The quality of these forecasts will improve over the five-year DSIP period as AMI data becomes available. We are not yet able to produce a valid forecast of DER supply either in aggregate (*i.e.*, the sum of all DER), or by type of DER.

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

Efforts to improve the granularity and quality of DER and load forecasts continue. Because forecasting is dependent on the quality of data in the models, we expect to incorporate additional data sources into the forecast models, such as system monitoring information, meteorological data, and customer demographics.

The greatest need for improvement is in the ability to produce separate forecasts for different types of DER including photovoltaics, energy storage, electric vehicles, and energy efficiency. These forecasts will improve as our database of connected DER improves, as we collect more AMI data that will support advanced enterprise analytics, as we learn about customer adoption drivers from our Clean Power Research WattPlan Grid innovation project in the ESC, and as the industry gains experience in producing DER forecasts by type of DER.

We currently forecast energy efficiency that is attributable to our own programs, although we do not disaggregate these forecasts by location or time period. We will assess whether it is possible to track the location of customers participating in our energy efficiency programs and to develop models that help predict the temporal effectiveness of certain energy efficiency measures, particularly if they are influenced by outside light and temperature conditions.

The LoadSEER tool implemented in the ESC provides the potential ability to estimate the impact of alternative DER forecasts on changes in load and power on the distribution system.

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

The capabilities required to implement probabilistic planning should correspond to and evolve with sources of forecasting uncertainty. There are many sources of uncertainty, but data availability and experience will reduce uncertainties. Some uncertainty will always exist regarding impacts on load or DER-specific forecasts. These are candidates for scenario analyses. The LoadSEER tool being tested in the Energy Smart Community is designed to support scenario-based forecasting, reflecting alternative forecasts of DER, and based on technology advances which consider variables such as DER adoption, weather conditions, and economic conditions. We need to complete our planned improvements to data granularity and quality before applying the LoadSEER tool to perform scenario-based forecasting.

Probabilistic forecasting of load and DER is a relatively recent focus in the industry. We will continue to collaborate with the Joint Utilities and monitor advances beyond New York to identify appropriate probabilistic planning methods. These methods will necessarily evolve as our forecasting methods progress to take advantage of higher quality and more disaggregated input data. We have not identified specific probabilistic forecasting methods at this time.

As AMI data becomes available over the implementation period, we expect forecast variances attributable to the lack of AMI metered load data will decline, and continue to diminish as metered load data becomes available to all customers for forecast analytics. We also expect that forecast variances will decline as data regarding DER performance in our service areas is more readily available.

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

The Companies are focused in the near term on continuing to build foundational processes that will be able to support large numbers and different types of DER. We are incorporating energy efficiency, energy storage, and electric vehicles into all of our Integrated Planning processes and investing in technology that will track the type, location and other attributes of DER. Integrated Planning's primary analytical engine is the Power Flow Model, a tool that relies on an up-to-date mathematical representation of the physical and electrical attributes of distribution infrastructure that comprise the network, system flow data from our SCADA system and AMI, a forecast of loads by circuit, and the location and operational attributes of connected and forecasted DER. Our trial of Clean Power Research's WattPlan Grid will reveal the benefits of granular, spatial adoption forecasting towards improving load and DER forecasts for all types of DER. The entire foundation is built to anticipate and reflect the inter-related effects of various DER throughout the year and by substation and circuit.

In addition. we are applying Integral Analytics LoadSEER Software to our 15 ESC circuits to determine how DER will affect the load shape on each circuit, capturing the interrelated effects of DER. The LoadSEER tool is a spatial load forecasting tool that is used by distribution system planners to predict how much power must be delivered, where on the grid the load will occur and when it must be supplied. The tool enhances the quality of system data to support integrated system planning with DER. Our system planners can use the tool to analyze probabilistic scenarios such as changes in solar penetration, electric vehicle adoption and circuit-by-circuit analysis to determine which drivers are responsible for load growth.

As mentioned in Subpart 2 above, we propose to provide forecasts of load and DER for 36 distinct load shapes: 12 months times three day-types (weekday, weekend, and holiday). As indicated in Subpart 5 above, we will produce separate forecasts for different types of DER including photovoltaics, energy storage, electric vehicles, and energy efficiency. We currently have forecasted DER shapes for photovoltaics.

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

These forecasts are necessary to identify areas on the grid that require long-term capital investments or NWAs to provide reliable distribution service, perform NWA solicitations, and perform special studies to determine whether larger DER can be interconnected. Please see our response to Subpart 3 above.

9) *Describe the utility's specific objectives, means, and methods for acquiring and managing the data needed for its advanced forecasting methodologies.*

We currently rely on a top-down, bottom-up forecasting methodology that reconciles available aggregated actual flow data with estimated load curves that reflect the customer mix by circuit. The underlying customer load curves are generic load curves for the northeastern United States. Figure 4.2-4 identifies the data that we currently utilize until AMI and more detailed SCADA data become available.

In the future, advanced forecasting will be based on load curves that reflect actual customer usage on each circuit, as well as actual DER data by circuit, gradually replacing forecast calculations that rely on estimated load profile data. This will enable development of more reliable 8,760-hour annual forecasts of DER and load at the substation and circuit level. These 8,760-hour annual forecasts, in turn, will support Integrated Planning (traditional distribution system analyses, hosting capacity, and beneficial locations) and Grid Operations (outage scheduling and contingency analysis), including the quality of load shapes that are shared with DER providers.

As discussed in 2018 DSIP Guidance Response Section 4.1 (Integrated Planning), our primary focus has been to continue to build a strong foundation in order to be able to integrate large quantities of DER into our Integrated Planning and Grid Operations functions. It will not be possible to achieve a long-term vision of optimizing DER and traditional utility assets to provide benefits to our customers and the grid unless we build a foundation that can manage DER and operational data. We are taking steps to ensure the quality of data that is relied upon for all of our IP functions, including Advanced Forecasting. These include:

- Designing the GMEP Phase 1 to incorporate governance and data processes and flows;
- Enterprise Data Platform deliverables are clearly specified, including data architecture, dictionary, flow diagrams, etc.; and
- Performing a data governance/data quality pilot roadmap for DER integration.

Among these activities, we are developing a Cognizant Technology Solutions database tool that will manage the transfer of data into CYME. We will also implement additional CYME and the ADMS modules to analyze power flows and calculate solar PV hosting capacity.

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

The 2018 load and DER forecast methodology is described above. Looking ahead, we are developing the following Advanced Forecasting capabilities in order to produce the more granular load and supply forecast that will be required as we integrate greater quantities of DER. Figure 4.2-4 identifies, the positive outcomes that we expect from each capability.

FIGURE 4.2-4: ADVANCED FORECASTING CAPABILITIES AND OUTCOMES

Capability	Outcome	Value to Customers	Value to Grid	DER Optimization
Advanced Forecasting				
Forecast load by circuit and time period	Granular Forecasts	✔	✔	✔
Forecast DER supply by resource type, location and time period	More Accurate Forecasts	✔	✔	✔
Perform scenario analyses that evaluate alternative load and DER forecast assumptions	More Robust Forecasts	✔	✔	✔
Incorporate probabilistic techniques into load and DER forecasts	Robust Consideration of Uncertainties	✔	✔	✔

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

If we define "accuracy" as the expected variance around a particular forecast, the accuracy of our existing forecasts decreases as they become more granular. Thus, our NYSEG and RG&E service area load forecasts are the most accurate, with diminished accuracy as we produce forecasts with greater spatial definition (*i.e.,* by substation and then by circuit). The forecasts become less accurate as we add time granularity because we are relying on generic load curves. Finally, the DER supply forecast is the least accurate aspect of our forecast as we need to gain more experience and develop new methodologies to develop these forecasts.

These forecasts will improve as we collect AMI and more detailed SCADA data, as well as improve our DER database. Because forecasting is dependent on the quality of data in the models, the Joint Utilities are incorporating additional sources of data into their forecast models such as system monitoring information, meteorological data, and customer demographics. The improvements to granular DER forecasts will translate into more reliable load forecasts. As a consequence, the impact of DER growth on system planning will be clearer and more actionable.

12) Describe the substation-level load forecasts provided to support analyses by DER developers and operators and explain why the forecasts are sufficient for supporting those analyses.

We will continue to improve the quality of hosting capacity estimates and develop hosting capacity forecasts in future development stages. DER developers have not yet communicated other “use cases” they intend to perform based on substation-level load forecasts that are provided by the Joint Utilities.

13) Provide sensitivity analyses which explain how the accuracy of substation-level forecasts is affected by distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency measures.

The LoadSEER tool has the potential to perform these sensitivity analyses, as described in the response to Subpart 6 above. We are planning the system to meet both load and DER on each circuit.

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

We are performing an analysis of the adoption of DER by applying the WattPlan Grid software tool. While we are certainly willing and interested to receive forecast input data from DER developers, we do not want to depend on this source of information. By way of analogy, the interconnection queue is indicative of DER that might be connected in the future, but a simple aggregation of queue requests is not particularly reliable. On the other hand, having sample data on the anticipated performance of connected DER from developers would help us refine our estimates of forecast DER supply.

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

The Joint Utilities reached out to utilities across the country and in the European Union to exchange best practices in DER and load forecasting, including methodologies, inputs, geospatial and temporal granularity, and the role of forecasts in Integrated Planning. These discussions allowed the Joint Utilities to benchmark their forecasting practices with utilities dealing with similar or higher DER penetrations and to identify forecasting processes worth investigating within each respective company.

16) Describe new methodologies to improve overall accuracy of forecasts for demand and energy reductions that derive from EE programs and increased penetration of DER. In particular, discuss how the increased potential for inaccurate load and energy forecasts associated with out-of-model EE and DER adjustments will be minimized or eliminated.

As noted in response to Subpart 5, we currently forecast energy efficiency attributable to our own programs, although we do not disaggregate these forecasts by location or time period. We will assess whether it is possible to track the location of customers participating in our energy efficiency programs and to develop models that help predict the temporal effectiveness of certain energy efficiency measures, particularly if they are influenced by outside light and temperature conditions. As we obtain more accurate load data, we will analyze the change in net load for customers that have installed a particular energy efficiency DER to improve our forecast models and avoid double counting of energy efficiency.

4.3 Grid Operations

Introduction/Context and Background

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

We have made significant progress since the 2016 Initial DSIP toward development of Distribution Grid Operations functions needed to operate as the DSP, working closely with the Joint Utilities. Grid Operations consists of four functions:

1) **Measure, Monitor, and Control** (MM&C): performance of all grid assets — including distributed energy resources (DER) — to provide real-time visibility of grid status and to include all these resources in grid optimization;
2) **Grid Optimization:** application of advanced energy management systems to optimize the grid in real-time with high DER penetration rates;
3) **DER Management:** management all types of intermittent and limited energy resources holistically to disaggregate dispatch directives to each DER and aggregator within a target area (*e.g.*, transmission node, station, bus, feeder, zone of protection, stage of regulation, etc.) subject to resource limitations and program constraints; and
4) **New York Independent System Operator (NYISO) Coordination:** development of standards and protocols to safely integrate DER into both utility and NYISO programs.

We have made significant progress in each of these areas. These advances include efforts to improve the grid's resiliency through automation measures and increased real-time visibility of network and DER assets.

Our guiding principles for building Grid Operations' capabilities are:

- Develop an integrated solution, without isolated computer systems, and leveraging existing corporate systems;
- Incorporate DER in every Grid Operations function and supporting technology/system;
- Build capabilities that leverage a common, up-to-date model of the grid and DER;
- Integrate data integrity and management capabilities into all functions; and
- Apply an open standards approach to retain flexibility for the inevitable evolution of capabilities.

We have been conducting a series of demonstration and innovation projects using the Energy Smart Community (ESC) as a platform to test new technologies before deploying them throughout our New York service areas. These technologies include:

- Advanced Metering Infrastructure (AMI): testing the implementation of AMI and related data management challenges with the installation of approximately 12,300 electric and 7,600 gas smart meters through Energy Smart Community. AMI data is being relied upon for grid optimization and identify the best times to deploy DER and grid assets.
- Grid Automation: providing real-time monitoring and control and testing the ability to respond to grid events.
- Advanced Distribution Management System (ADMS): testing the use of this integrated suite of technologies to contribute to optimization of grid assets and DER. ADMS is being integrated with our recently upgraded Outage Management System, enabling us to identify outages leveraging data from the AMI meters.

We have also been developing capabilities to support advanced monitoring and control of DER.

Implementation Plan, Schedule, and Investments

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

We have made substantial progress in each of the four Grid Operations functions. As described below, we have developed foundational technologies, processes, and standards to integrate the complete range of DER types into Grid Operations. These efforts are creating more dynamic grid capabilities, providing greater visibility of the grid and grid assets, and creating a more resilient network. These are significant efforts that will be completed over the next several years.

The efforts to date have resulted in a number of achievements and new capabilities:

1) <u>MM&C</u>: Our efforts since filing the initial DSIP have concentrated on expanding Grid Automation and advancing MM&C capabilities, revising the MM&C requirements to include considerations of emerging technologies, such as energy storage, and identifying lower-cost Monitoring and Control (M&C) solutions. The Companies, along with the other Joint Utilities, have developed statewide standards for advanced MM&C capabilities, an effort that is continuing. In order to accommodate the penetration of DER established in statewide goals, we must have more granular DER M&C. As a result of these efforts, the Companies have more advanced MM&C technological capabilities, including a complete distribution automation plan and ADMS that are being tested in the ESC. We agreed, along with the other Joint Utilities, to require M&C for all DER larger than 500 kilowatts (kW). In addition, the Companies have contracted with a DER for the Flexible Interconnection Capacity Solution (FICS) innovation project, and will be implementing enhanced DER monitoring and control for Active Network Management (ANM).
2) <u>Grid Optimization</u>: We have executed a number of initiatives to optimize the grid. We

have installed ADMS components, developed the initial ADMS, upgraded our Outage Management System OMS with distribution Supervisory Control and Data Acquisition (SCADA) and geographic maps, installed AMI in the Energy Smart Community environment, and incorporated reverse power flow alternative settings. The Companies have also applied the smart meter requirements to include service voltage scanning for Volt/VAR Optimization (VVO).

3) DER Management: The Companies will integrate a Distributed Energy Resource Management System (DERMS) with the ADMS that will:

- provide granular dispatch directives by grid location directly to DER and to multiple aggregators;
- handle the details of DER and grid requirements;
- optimize the utilization of DER within constrained locations while minimizing cost and maximizing value and power quality subject to program limitations; and
- translate dispatch directives to aggregator and to individual DER.

As a New York State distribution-level retail market is designed, a DER Market Management System (DER MMS) will be implemented to manage market clearing, transactions, settlement, and metering & verification. The DER MMS will be integrated with the DERMS and ADMS, and will coordinate with the NYISO and aggregators.

4) ISO-DSP Coordination: We have been working with the Joint Utilities together with the NYISO to enable increased DER, including new protocols, standards, and procedures. The Companies, along with the other Joint Utilities, have begun development of an ISO market design, reviewed the ISO Meter Data Study, addressed issues of dual participation and compensation, developed a transmission node identification methodology, and evaluated the current ISO/DSP protocols for aggregator dispatch coordination.

Our current implementation plan supports stakeholder current and future needs through implementing Grid Operations capabilities in a phased approach, incorporating small-scale deployment and enabling us to apply lessons learned before system-wide implementation. This also allows us to be flexible in both addressing stakeholder needs that arise along the way and in adopting new and low-cost technologies. For example, we plan to test low-cost methods to monitor, coordinate, and control DER to achieve grid optimization.

The ADMS is the backbone of advanced Grid Operations which will provide DER visibility into the grid and will identify problem areas on the grid. The ADMS creates the platform we will use to optimize the grid. It will allow an increasing number of DER developers, aggregators, and customers to participate as both supply and demand resources as the ADMS will provide locational awareness and visibility of DER in order to respond to location-specific system needs.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Our short-term (2019-2020) initiatives focus on developing and testing foundational technologies and associated capabilities to operate as the DSP, while longer-term (2021-2023) initiatives enable additional DSP capabilities. Real-time data acquisition enables advanced Grid Operations functions, particularly AMI data on customer usage patterns. Our current AMI proposal in NYPSC Case No. 17-E-0058 and 17-G-0059 have a five-year system-wide rollout. As such, both short-term and long-term developments and specific timing are dependent upon the system-wide AMI deployment schedule.

A. Capabilities and Roadmaps

Progress over the next five years will focus on developing capabilities in each of the four Grid Operations functions, as discussed over the next several pages.

1) Measurement, Monitoring, & Control:

   We are building three MM&C capabilities:

   a. *Measure dynamic grid, load, and DER status and performance, including at the grid edge (i.e., points of service) and behind-the-meter resources*: Short-term efforts will focus on developing system-wide monitor and control standards, working together with the Joint Utilities, to provide more granular visibility and monitoring of DER assets. Beginning in 2021, we will apply MM&C standards to all DER types. We will also connect a range of DER to advanced MM&C mechanisms to provide more management and optimization capabilities.

   b. *Monitor grid and DER performance, and the status of distribution assets*: Over the short term, we will determine MM&C implications for reverse power flow, as an increasing number of DER will act as either supply or demand resources. We will also continue to implement Grid Automation, and explore additional technologies that can provide enhanced monitoring and control of DER. We will align MM&C capabilities into the ADMS system, as well as other advanced functions, such as VVO and the DERMS. We will also apply advanced MM&C capabilities to DER that have a potential impact on system reliability and power quality, and integrate these with future market services.

   c. *Control distribution assets and manage DER performance to meet system operational needs*: Over the short term, we will test the integration of smart inverters with monitoring and control activities to optimize power quality.

Our Measurement, Monitoring, & Control function roadmap is presented in the Figure 4.3-1.

FIGURE 4.3-1: MEASUREMENT, MONITORING & CONTROL FUNCTION ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)	Technologies	Innovation Projects
Measure, Monitor, Control	Continuing Grid Automation Complete Automation within the ESC AMI Implemented within the ESC Subscribed First Customer to FICS (ANM) Completed Factory Acceptance Tests (FAT) and Site Acceptance Tests (SAT) for FICS Incorporate DER MM&C on 500 kW and Larger Units	Continue Grid Automation Expand AMI System-Wide Commission First FICS Installation Prove Functionality of Smart Meter-Smart Inverter Interface Develop Economic Solution for Enhanced DER M&C Implement and Operate Energy Storage Projects	Continue Grid Automation Complete System-Wide AMI Implementation Implement Smart Meter-Smart Inverter Interface Field Demonstration Implement ANM as a Business-as-Usual Process Lower DER Size Thresholds for M&C Implement Enhanced DER M&C for All FTM DER	Telecommunications/IT AMI Grid Automation ANM DER MM&C	Enhanced DER M&C Smart Meter-Smart Inverter Interface FICS Energy Storage Projects

2) <u>Grid Optimization</u>:

We are building four Grid Optimization capabilities:

a. *Implement an Advanced Distribution Management System to optimize the grid, including DER, to maximize value to the grid and customers while maintaining reliability and power quality.* The ADMS will provide capabilities, such as a Distribution State Estimator (DSE), Distribution Power Flow (DPF), Optimal Power Flow (OPF), volt-VAR optimization (VVO), and Fault Location, Isolation, and Service Restoration (FLISR) to optimize the grid and improve grid efficiency. In the short term, we will complete the ADMS implementation within the Energy Smart Community. Longer term, the Companies will roll out ADMS system-wide. Optimizing grid power flows, including DER, will accommodate greater penetration of DER.

b. *Integrate the OMS and AMI with the ADMS to better respond to grid and DER outages, resolve issues, and minimize system impacts.* This capability involves increasing outage detection speeds at which the operator is notified of outages, identifies outage scope, and dispatches resources to restore service more quickly and accurately following service disruptions. Short-term initiatives include the integration of the Energy Smart Community AMI data into the OMS. The Energy Smart Community ADMS power flow, feeder optimization, and FLISR capabilities will be enhanced with the integration of this additional information. Longer term, integration with the system-wide AMI and system-wide ADMS will make these enhanced capabilities available system-wide.

c. *Actively manage grid and DER resources to optimize the grid in real time.* Over the short term, we will utilize active management of DER to operate the grid within system limits, such as power quality, voltage, and thermal limitations. We will manage the grid under reverse power flow conditions to accommodate DER operating as both a supply and demand resource, utilizing ADMS power flows. Longer term, we will incorporate ANM as a business-as-usual interconnection alternative. Actively managing DER and grid resources together will accommodate greater penetration of DER.

d. *Stage the implementation of Voltage-VAR Optimization*. Initially, this will involve the activation of the VVO application of the ADMS, leveraging the automation of line regulators and capacitors. The second stage involves the integration of AMI smart meters as end-of-line voltage sensors for closed-loop VVO control. This enhancement will increase the effectiveness of the VVO by utilizing actual grid measurements. The final stage will incorporate DER and smart inverters as dynamic voltage and var resources to further flatten the voltage profile and balance feeder vars (reactive flow). This maximizes the effectiveness of VVO and increases the value of participating DER.

Our Grid Optimization Function roadmap is presented in the Figure 4.3-2.

FIGURE 4.3-2: GRID OPTIMIZATION FUNCTION ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)	Technologies	Innovation Projects
Optimize Feeders Using Distribution Power Flow Tools (DSE, DPF, OPF)	ESC Feeder Phasing Survey ESC ADMS FAT July 2018 ESC ADMS SAT September 2018	Complete ESC ADMS Implement DSE, DPF, OPF Applications	System-Wide ADMS	ADMS	ESC ADMS
Minimize Outage Impacts	Completed System-Wide OMS with Full Distribution SCADA and Geographic Maps Implemented ESC AMI Scoped AMI-ADMS Interface	Implement FLISR in the ESC Integrate AMI and ADMS Integrate OMS and ADMS	System-Wide ADMS System-Wide AMI	ADMS AMI OMS	ESC ADMS ESC AMI
Actively Manage Network (ANM), Including DER	Subscribed First Customer for FICS Completed FICS FAT Completed FICS SAT Submitted ANM Concept Paper for DOE FOA-1840 Grant with EPRI and SGS	Implement FICS Subscribe Additional ANM Customers	Include ANM Alternatives a Business-as-Usual Interconnection analyses	ADMS ANM	ESC ADMS FICS
Maximize Feeder Efficiency Through VVO	Specified Smart Meter Requirements Included the Capability to Scan Service Voltage for VVO CMP Voltage Optimization Project	Implement Model-Based VVO using ESC ADMS	Implement System-Wide ADMS Incorporate AMI for Closed-Loop VVO Incorporate DER into VVO	ADMS AMI Enhanced DER M&C Smart Meter-Smart Inverter Interface	Maine VO Pilot ESC ADMS ESC AMI Enhanced DER M&C Smart Meter-Smart Inverter Interface

3) DER Management:

We are building four DER management capabilities through the implementation of a

DERMS:

a. *Aggregate, disaggregate, and federate all types of DER both directly and through multiple third-party aggregators.*[10] The DERMS will combine direct-controlled DER and DER from multiple third-party aggregators into a resource pool. All DER, including distributed generation (DG), energy storage, and demand response (DR) will be managed holistically, but will be able to be dispatched by grid location (*e.g.*, transmission node, substation, bus, distribution circuit, etc.) to meet system needs or constraints. A system-wide DERMS is anticipated after implementation of the ADMS.

b. *Simplify the handling of DER for grid operators.* When grid operators need to address constraints on a feeder, a substation, or a transmission tie point, etc., the DERMS will present the resources available at the requested grid location(s). The operator can then develop an overall response strategy to address the system needs or constraints. In addition, ANM would also be utilized, though on a much smaller scale than DERMS, to automatically manage circuit constraints and limitations. We have contracted a DER for the FICS innovation project and will implement enhanced DER monitoring and control for ANM.

c. *Given a dispatch strategy, optimize the use of available resources within resource limitations and program constraints.* The DERMS will validate and verify the dispatch strategy can be achieved with available resources or return the closest achievable results. In this way, the operator is not manually compiling a solution with multiple types of DER, each with multiple constraints. The strategy can them be selected or modified before executing.

d. *Once a strategy is executed, disaggregate and translate it into dispatch directives for each participating DER and third-party aggregator.* In addition to issuing dispatch instructions directly to DER, the DERMS will break down and transmit dispatch directives to each aggregator for each type of DER. It will also maintain a record of DER/Aggregator dispatch for measurement and verification (M&V) and settlement purposes.

Figure 4.3-3 presents our DER Management Function roadmap.

10 Federate refers to the combining of resource pools from multiple aggregators, plus direct controlled DER, and managing the entire pool of resources to obtain an objective.

FIGURE 4.3-3: DER MANAGEMENT FUNCTION ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)	Technologies	Innovation Projects
Aggregate All Types of DER (Both Directly and Through Multiple Aggregators)		Energy Storage Projects	Install DERMS	DERMS	Energy Storage Projects FICS
Simplify the Handling of DER Settings and Services	Contracted DER Site for FICS Executed Contract with Battery Storage Aggregator	Deploy and Operate FICS Deploy and Operate Energy Storage Projects	Install DERMS	DERMS	Energy Storage Projects FICS
Optimize Dispatch Directives Utilizing All Available Resources			Install DERMS	DERMS	
Disaggregate and Translate Dispatch Directives to Each Resource and Third-Party Aggregator.	Developed DER Group Management Schema	Test Group Management Functionality in FICS and Energy Storage Projects	Establish Process to Maintain Resource Data Synchronization with the NYISO and Third-Party Aggregators	DERMS	FICS Energy Storage Projects

4) ISO-DSP Coordination:

We are building four capabilities to achieve ISO-DSP coordination objectives:

a. *Enable coordinated long-term planning that considers high DER penetrations*: NYSEG and RG&E, along with the other Joint Utilities, will coordinate with NYISO to develop market rules and protocols to facilitate better coordination between NYISO and DSPs. We will also develop ISO-DSP network management rules. Longer term, the parties will further refine market rules and protocols.

b. *Provide feedback to support NYISO day-ahead planning to adhere to system reliability constraints*: The Joint Utilities' ISO-DSP working group will develop meter data requirements over the short term. Over the long term, ISO-DSP working group will improve communications protocols and control. In addition, the working group will evaluate the need for refinements to the *DSP Communications and Coordination Manual* to reflect the evolution of operational coordination requirements. The Joint Utilities plan to leverage the results of the NYISO DER pilot program and the Joint Utilities' demonstration projects to inform future refinements, expanding the *DSP-Aggregator Agreement for NYISO Pilot Program* into a more comprehensive agreement that will be applicable when NYISO activates its DER participation model. We plan to leverage the lessons learned from all the Joint Utilities' demonstration projects in future updates. The Joint Utilities will also coordinate with NYISO on additional meter data rules, dual participation, short-term forecasting, and transmission node mapping. The ADMS under development will support transmission nodal management and the planned DERMS will support DER dispatch by transmission node.

c. *Facilitate DER access to DSP and NYISO revenue streams and resolve dual participation conflicts*: DER will be able to participate in both distribution-level DSP markets and NYISO wholesale-level markets. These dual participation capabilities require additional coordination between the ISO and DSP, including additional market rules, protocols, and a compensation framework. We will continue to develop these standards with NYISO, along with meter data requirements. The planned DER MMS will support dual participation once transactive distribution-level markets are designed and market rules are developed.

d. *Interface with Aggregators to coordinate dispatchable DER participation in NYISO markets*: We will work with the Joint Utilities to continue efforts to develop a standard interface to improve operational coordination and address market rules, procedures, and protocols and incorporate them into planning and operations, enhancing rules as necessary to reflect the changing nature of DER activities on the grid. The planned DERMS will support multiple aggregator interfaces, as well as direct management of all types of DER.

Our ISO-DSP Coordination Function roadmap is presented in the Figure 4.3-4.

FIGURE 4.3-4: ISO-DSP COORDINATION FUNCTION ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)	Technologies	Innovation Projects
Coordinate Planning	Began Development of ISO Market Design	Develop Market Rules, Procedures, and Protocols Develop DSP-ISO Network Management Define Transmission Tie Points and Coordination Process	Improve Coordination Protocols and Controls Further Develop Market Rules, Procedures, and Protocols	DERMS ADMS	
Support Reliability	Issued ISO Meter Data Study	Develop Meter Data Requirements	Improve Communications Protocols and Control Refine *DSP Communications and Coordination* Manual Expand *DSP-Aggregator Agreement for NYISO Pilot Program* Coordinate with the NYISO on Meter Data Rules, Dual Participation, Short-Term Forecasting, and Transmission Node Pricing Development	AMI	
Facilitate Dual Participation	Addressed Dual Participation Issues and Compensation Framework	Finalize Dual Participation and Compensation Framework		DER MMS	
Coordinate Aggregator Dispatch	Evaluate Current ISO/DSP Protocols	Develop Standard Interface to Improve Operational Coordination	Enhance Operational Coordination, Communication, and Control	DERMS	

B. Technology Investments

Grid Operations requires new technology investments to accommodate high DER penetrations, and to monitor and operate the distribution system on a real-time basis to maintain power system stability, power quality, resiliency, and reliability of service. These technology investments will be deployed in a layered process.

> Foundational technologies, including AMI and Grid Automation, will support grid reliability and operational efficiency. We are also developing a Grid Model Enhancement Project to support real-time optimization capabilities, including DER, and an Enterprise Analytics Platform for processing granular, time-differentiated data in support of our core Grid Operations, Integrated Planning, and Market Services functions. These technologies will support future capabilities as the DSP evolves.
>
> DSP-Enabling technologies, including ADMS, DERMS, and ANM, will support DER integration and optimization.
>
> Market Services technologies, including DER MMS, will support our products and services marketplace and the future evolution of markets.

We will test new or immature technologies through innovation projects, leveraging the Energy Smart Community when efficient, before rolling out programs on a system-wide basis. We will install the ADMS to incorporate real-time distribution power flow and related capabilities, which will be complete in 2019. Longer term, we will roll out the ADMS system-wide (expected in 2021). In addition, we will develop more granular DER M&C to allow for greater optimization and higher DER penetration through two short-term M&C innovation initiatives: the Enhanced DER M&C project and the smart meter-smart inverter (SMSI) interface proof-of-concept project will allow the integration of smart inverters into an envisioned distribution ancillary services market. For VVO, we are commissioning closed-loop voltage optimization (VO) in 2018 on two feeders at our affiliate Central Maine Power (CMP). This project will be a stepping stone for future New York-based VO projects. In addition, we will implement model-based VVO in the Energy Smart Community utilizing the ADMS by 2019. We are also developing four energy storage projects including a behind-the-meter energy storage demonstration project that we expect to provide insights into small-scale DER management and interfacing with a DER aggregator.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

We have identified several potential risks and mitigation efforts related to Grid Operations developments, which are included in Figure 4.3-5. We are reflecting these risk mitigation strategies in the design and development of our Technology Platform, as described in Chapter VII of our 2018 DSIP Report.

FIGURE 4.3-5: GRID OPERATIONS RISKS AND MITIGATION MEASURES

Risk	Mitigation Measures
1. **Technology Obsolescence:** Grid Operations' efforts are particularly dependent upon a range of technologies deployed.	• Adherence to open standards and interoperability where possible (*e.g.*, foundational investments, including automation and AMI, both incorporate these mitigation strategies). • Ensure 'evergreen' platform components where subsequent releases will include new functions and capabilities.
2. **Technology Deployment:** The integrated set of distribution system and information technologies need to be correctly specified and then implemented according to plan, recognizing that regulatory actions (or inaction) will need to be managed. In particular, most technologies rely on implementation of AMI and automation, which are foundational technologies. Any delay in AMI and automation may mean a delay in enabling capabilities.	• Compile technology needs by business area and identify interdependencies among needs and technologies within DSP and with other corporate platforms and solutions • Master schedule and establish accountability • Establish a DSIP project for DSP Architecture and Integration • Leverage global platform architecture and expertise, where applicable
3. **Data and Data Security:** DSP performance will depend on the quality and security of data that is relied upon by the DSP, third parties, and customers to make decisions.	• Grid Model Enhancement Project (GMEP) Phase 1 to incorporate governance and data processes and flows • Clear specification of Enterprise Data Platform deliverables: data architecture, dictionary, flow diagrams, etc. • Data governance/data quality pilot roadmap for DER integration • Redundancy built into AMI telecommunications infrastructure • Maintenance of grid models to ensure data accuracy • Provide flexibility in implementation to apply lessons learned and changing assumptions
4. **Operating as the DSP:** AVANGRID accountability and ability to collaborate with internal and external stakeholders will lead to success as the DSP and in integrating DER. Learn from the Energy Smart Community and innovation projects.	• DSP implementation governance with identified project leads to oversee and coordinate the DSIP project portfolio • Internal communications of DSP goals and activities to employees • Apply change management practices and stakeholder management plans to projects of substantial process/operational impact (*e.g.*, AMI, OMS, ADMS, etc.) • Capture lessons learned and develop scalability plans to apply at scale for all innovation and pilot projects • Develop metrics that reflect stakeholder expectations

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design; how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses.

NYSEG and RG&E have hosted and participated in stakeholder engagement through various Joint Utilities' working groups and interactions with NYISO. We are involved with several Joint Utilities' working groups, including two focused on Grid Operations activities: Monitoring and Control Working Group and ISO/DSP Coordination Working Group. The Monitoring and Control Working Group has focused on developing low-cost M&C solutions that satisfy system safety and reliability requirements while being sensitive to the cost burdens.

The ISO/DSP Coordination Working Group focuses on developing procedures and protocols to allow for better coordination between NYISO and the DSPs. In addition, the Joint Utilities and NYISO established a working group at the start of 2017 to define coordination protocols that will promote DER integration and support market services. The Joint Utilities hosted a stakeholder engagement session in October 2017 to communicate the progress made on these topics and gather input on how to advance them further. We are currently evaluating the impact of existing ISO-DSP protocols, have begun to consider the integration of ISO market design concepts into our planning and operations, and have reviewed the ISO meter study data to reflect specifications into our AMI configuration. In addition, the Joint Utilities coordinate with the Federal Energy Regulatory Commission (FERC), providing input and feedback to FERC in developing standards and operating policies. We plan to abide by industry protocols as they are established and modified over time.

We also addressed Grid Operations and our Technology Platform in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

Additional Detail

The utility must enable a much more dynamic, data-driven, multi-party mode of grid operations where DERs effectively generate customer value by increasing efficiency, stability, and reliability in both the distribution system and the bulk electric system. To achieve this outcome, the utility must develop and/or substantially modify a wide range of components encompassing operating policies and processes, advanced information systems, extensive data communications infrastructure, widely distributed sensors and control devices, and grid components such as switches, power flow controllers, and solid-state transformers.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities needed to transform grid operations in both the distribution system and the bulk electric system:

General Grid Ops

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

Our primary responsibility is to maintain distribution system safety and reliability. The Joint Utilities have coordinated with DER aggregators and the NYISO to define operational coordination requirements, including specific roles and responsibilities for each party, to ensure that we can continue to preserve safety and reliability for a system characterized by increasing numbers of DER. As part of our various utility programs (*e.g.*, demand response) and procurements (*i.e.*, NWA), NYSEG and RG&E require DER aggregators and other third-party market participants to execute agreements that define our respective roles and responsibilities. For example, we require contracts with DER aggregators, which typically specify the amount of advanced notification we will provide the DER aggregator prior to an event, and we also define all reporting and settlement requirements for the DER aggregator.

In addition to our role as the distribution system platform provider (DSPP), the major parties involved in performing Grid Operations and integrating DER are our energy control centers (ECCs), the NYISO, aggregators, and DER customers.

Energy Control Center (ECC): Our ECC serves as the distribution grid operator. The ECC is responsible for the operation of the utility grid by monitoring and responding to changing network conditions, utilizing grid-side, supply-side, and demand-side resources. The ECC will require new tools and more granular grid visibility to dispatch DER. The ADMS will act as the "core" advanced technology that integrates multiple systems to automate grid functions including outage restoration and grid optimization. The ADMS provides ECC operators with tools to verify the state and security of the distribution grid, allowing them to incorporate DER into short-term forecasting and other operations. The ADMS will also support additional layered capabilities, such as the DER Management System, which ECC operators will use to manage the entire fleet of connected DER (including distributed generation, energy storage, and demand response). This facilitates the management, optimization, and dispatch of DER to secure the grid. The ECC will rely on these technologies to improve network performance through automation and efficiency gains. In the longer term, ECCs will incorporate the use of a Microgrid Management System (MGMS) and the DER Market Management System to support future markets with development of these systems occurring after the market design is defined.

NYISO: The NYISO operates the wholesale market and performs planning and operation of the bulk power system. Increasing DER penetration will require greater coordination and communication between the DSP and the NYISO. The DSP will work with the NYISO in establishing an interface definition between the two entities for effective distribution network management, including data requirements, communication and coordination, activation of DER, and mechanisms for DER aggregation. Our DER Attribute Database will compile attributes of DER necessary for dispatching and interfacing with NYISO, as well as forecasting and outage scheduling. Our ECC and planning engineers will work with the NYISO for day-ahead, short-term, and long-term planning that affects the transmission grid and for resolving unplanned events.

Aggregators: An aggregator bundles individual DER from multiple customers, which can then be managed collectively to provide energy, capacity, or other services. Third-party aggregators will need to coordinate with our ECC and our energy supply function to manage these resources, which can be used for many functions including solutions that reduce energy usage during periods of peak demand.

DER Owners and Operators: DER owners and operators will increasingly be able to provide benefits to the grid, and will become key players as the distribution network gains more granular monitoring and control and the ability to integrate these assets. To facilitate this integration, our DERMS analyzes available DER and dispatches it as needed. DERMS will also have the flexibility and scalability to interact with multiple aggregators and customers for DER-sourced voltage and VAR support.

The Joint Utilities have developed a *Draft DSP Communications and Coordination Manual* to define the roles and responsibilities among the utility, the NYISO, DER aggregators, and individual DER to enable DER wholesale market participation while preserving system safety and reliability.[11] For example, as part of the NYISO's bidding and scheduling process, the DSP will analyze the dispatch feasibility of individual DER and DER aggregations (as provided by the DER aggregator) to ensure wholesale market participation does not jeopardize distribution system safety or reliability. The Joint Utilities have also developed a *Draft DSP-Aggregator Agreement for NYISO Pilot Program* to further define the roles and responsibilities between the DSP and DER aggregators.[12]

Deployment of technology platforms, including the ADMS and the DERMS, will provide the DSPs with the ability to analyze and manage DER assets. The deployment of these technologies will be implemented in phases. While technically possible, it will be a challenge to retrofit to obtain monitoring and control capabilities for all DER, particularly if the coming market design does not provide the appropriate incentives to retrofit. Ideally, the upcoming Market Design and Implementation Plan will provide incentives for DER to provide distribution grid services. Enhanced DER M&C will enable this participation.

The DSPs can also use these technology platforms to coordinate with the NYISO and third-party stakeholders to manage local DER in order to benefit the local distribution system and provide a pathway for these local assets to participate in the NYISO wholesale markets.

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11 Draft DSP Communication and Coordination Manual available here.

12 Pilot program agreement available here.

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

We have decided to integrate Energy Management System (EMS) and Data Management System (DMS) housed within a single Physical Security Perimeter (PSP) and Electronic Security Perimeter (ESP) to facilitate system integration and to minimize support requirements, as well as to maximize both cyber security and physical security of these systems. We are implementing a single ECC model to facilitate transmission and distribution (T&D) coordination. We also chose our GIS to be the source of the grid model for both DSP Integrated Planning and Grid Operations to maintain synchronization of the model between planning and operations and provide a single accurate data source of record for all business functions. The role of the distribution operator is evolving at NYSEG and RG&E and we are updating switching authority and operating procedures to advance the appropriate roles and responsibilities in a safe manner.

3) Describe how roles and responsibilities have been/will be developed, documented, and managed for each party involved in the planning and execution of grid operations.

We expect to continue to develop and refine the roles and responsibilities for parties that contribute to Grid Operations by documenting lessons learned through technology project implementation in the Energy Smart Community and by continuing to collaborate with these parties and interested stakeholders. For example, the deployment of the ADMS and DERMS platform within the ESC will allow our ECC to monitor and control DER on a more granular level.

We will continue to work with the Joint Utilities and the NYISO to define and refine all roles and responsibilities, proactively implement standards and protocols, and streamline processes (*e.g.*, vendor prequalification) to ensure continued safe and reliable operations as DER comprise an increasing share of generation. While the high-level roles and responsibilities will generally be consistent across our programs and procurements, the unique characteristics of each utility may result in differences (*e.g.*, pre-defined time periods in which the DER portfolio is required to be available for performance). In addition, as the DSP, we expect to provide the distribution-level functions that the NYISO performs at the transmission level. A significant DSP function that needs to be developed will include dispatch of individual DER. Relevant parties, including the DSP, the NYISO, DER operators, and aggregators will require synchronized resource data and multiple real-time communication flows in order to collectively ensure a reliable and secure grid.

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

a. organizations;

We believe that a common set of protocols is required in order to implement the advanced capabilities to perform as the DSP. We have been coordinating with a number of organizations (*e.g.*, NYISO, FERC, aggregators) to develop and refine Grid Operations processes and standards to support DER deployment. Successful DSP implementation will hinge upon coordinating with the parties listed in Subpart 1, as well as the FERC to provide input and feedback on developing operating standards.

We described our participation in Joint Utilities working groups in addressing Stakeholder Interface above.

b.operating policies and processes;

As discussed above, we continue to develop and refine operating policies through coordination with parties that contribute to Grid Operations, and apply processes and standards through testing of new technologies in a series of innovation projects. We are developing policies and processes through coordination with the Joint Utilities and NYISO, as well as our own utility-specific requirements.

Joint Utilities' Policies and Processes

The Joint Utilities have developed a set of monitoring and control standards as outlined in the Supplemental Distributed System Implementation Plan (Supplemental DSIP) to utilize existing systems and efficiently integrate new technologies into network.[13] Specific Joint Utilities' policies and processes under development include:

- Polling frequency and communication protocols to gain real-time visibility of the grid;
- Enhanced DER M&C to improve situational awareness and grid visibility, and better manage abnormal system conditions; and
- Curtailment and notification of DER connection/disconnection.

We are also implementing circuit parameters, DER performance forecasting, advance function support, and worker safety improvements. In addition, since filing the Supplemental DSIP, the Joint Utilities have developed several technical documents to streamline interconnection processes while clarifying and formalizing aspects of the interconnection process, including:[14]

- Interim requirements on anti-islanding;
- Monitoring and control requirements;
- Recommended changes to EPRI's proposed modifications to the SIR screens to improve effectiveness and support future automation;
- Documentation of voltage and voltage flicker requirements in support of the SIR revisions; and
- Proposed energy storage application requirements and Standardized Interconnection Requirements (SIR) updates.

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13 Supplemental DSIP pp. 77-81.

14 These discussions were organized by the Interconnection Technical Working Group (ITWG).

Appendix A: 2018 DSIP Guidance Requirements

NYISO Policies and Processes

Coordination between the NYISO and the DSPs is also needed to manage increasing levels of participation in wholesale markets and distribution-level services. Operational coordination is required to enable increased market participation and access to market value through contracts and tariffs that is an objective of DSP 1.0 as presented in Chapter III of our 2018 DSIP Report. The NYISO prepared a DER Roadmap to provide DER with the ability to participate in the wholesale markets.[15] The NYISO's DER Roadmap outlines the progress the NYISO anticipates making in the next three to five years to integrate dispatchable DER *(i.e.*, controllable resources) into the wholesale energy, ancillary service, and capacity markets. The NYISO DER Roadmap identifies the types of enhancements that will be needed to effectively integrate DER, including "enhancements to wholesale market design, system planning, and grid operations to better align resource investments and performance with system needs and conditions."[16]

NYSEG and RG&E Policies and Processes

We continue efforts to update our connected DER database and improve the quality and granularity of load data that utilized to perform interconnection studies, where such studies are required. In the interim, we have delivered a Phase I Interconnection portal. See 2018 DSIP Guidance Response Sections 4.10 (DER Interconnections) for more details on interconnection policies and 4.2 (Advanced Forecasting) for additional details on our approach to DER forecasting.

Other efforts include:

- <u>Advanced Function Support</u>: As advanced functions, as well as the standards and procedures governing such functionality, are still in development, including the UL 1741 standard governing smart inverters. We continue to develop and assess appropriate standards and procedures for advanced functions.
- <u>Worker Safety</u>: Standards governing worker safety and grid energization are under review as DER continue to be added to the grid. Our approach to these standards focuses on situational awareness of DER operations in order to gain grid visibility and ensure worker safety. DER providers and the Joint Utilities will continue to develop standards as DER continue to proliferate on the grid.
- <u>Monitoring and Control</u>: We continue to develop more granular data to monitor and control DER, in particular the size threshold of units to be monitored. Lowering the size thresholds of units monitored creates a more agile grid that is better able to detect and respond to issues. The system-wide M&C requirements are included below. Monitor and control requirements have become more granular to integrate more DER into Grid

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15 New York Independent System Operator, *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets*, January 2017.

16 *Id.*, p. 5.

Operations.[17]

FIGURE 4.3-6: STATEWIDE M&C REQUIREMENTS

M&C Element	< 50 kW	50 kW - 500 kW*	500+ kW*
Monitoring	Monitoring *may* be required	Monitoring *may* be required	Monitoring *shall* be required
Control (PCC Recloser)			PCC Recloser *shall* be required
Control (RTU)		Basic control *may* be required	

* Individual or aggregated units

In addition, NYSEG and RG&E follow IEEE[18] standards and protocols on DER dispatching and integration, including IEEE-2030.5[19], IEEE-2030.7[20], and IEEE-1547.1[21]. We will adopt additional protocols as appropriate.

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

The Companies are developing several Grid Operations technologies to support situational awareness, optimize resources, develop more granular dispatch and control of resources, and provide data for system modeling. We will deploy these technologies in a staged manner, as explained in "Future Implementation and Planning" above. See Chapter VIII of our 2018 DSIP Report for a description of key technologies.

d.data communications infrastructure;

A telecommunications network is required to support both AMI and Grid Automation. Both projects require the telecommunications network to process data and interact with field devices.

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17 The Supplemental DSIP proposed standard monitor and control (M&C) requirements for DER at least 1 megawatt (MW). However, as asserted by the Joint Utilities, MM&C may be required for smaller units to mitigate system impacts and prevent future events that could jeopardize safety and reliability. As a result, the Supplemental DSIP stated that requirements will continue to incorporate other DER and lower size thresholds as markets and technologies evolve. Resulting from the Joint Utilities' M&C Working Group sessions since January 2017, interim threshold requirements were set at 300 kW in July 2017, which Staff amended in November 2017 to 500 kW, though utilities maintain the discretion to alter thresholds based on site-specific conditions.

18 Institute of Electrical and Electronics Engineers (IEEE) is a professional association that provides electrical standards that are applied to a number of industries.

19 IEEE 2030.5 is a standard for communications between smart grids and consumers, giving consumers a range of methods to manage energy use and generation. Information exchanged via the standard includes demand response, pricing, and energy usage, enabling integration of smart devices, such as thermostats, meters, electric vehicles, smart inverters, and appliances.

20 Governs microgrid controllers.

21 IEEE-1547.1 governs smart inverter communications.

The network will include diverse communications solutions (*e.g.*, radio frequency, cellular phone, microwave frequency, fiber optics, leased circuits) and will allow remote access and control of devices on the grid. The network will also transmit data on the performance of installed DER and support our DR programs.

Finally, the telecommunications network will allow us to communicate with Remote Terminal Units and equipment at substations, providing better visibility into substation operations, and provide real-time situational awareness that will reduce outages and improve response time.

We plan to build and/or lease the telecommunications infrastructure. This involves the strategic addition of fiber optic, microwave links, and digital radio capability, depending on security and cost effectiveness of each application. Additionally, the Companies will erect towers to support radio frequency communication with the ECC from remote locations.

In anticipation of AMI, we are prepared to engineer, procure, and construct a telecommunications network across the territories to support automation and AMI efforts. As a common network is deployed, additional nodes and services can be added with minimal incremental cost. We plan to work with telecommunications providers to determine the most cost-effective approach to achieve our objectives. These communication links are vital to realizing the benefits of automating our substations and distribution system.

e. grid sensors and control devices;

Grid automation will support installation of grid sensors and control devices to support a range of functions, including VVO, feeder optimization, and FLISR. Grid Automation equipment is comprised of load-tap-changers (LTCs), breakers, reclosers, regulators, capacitor banks, switches, and supporting telecommunications networks that allow us to manage and optimize power flows on circuits in response to changing system conditions and events. In the long term, we anticipate having all distribution control devices automated. We will continue to automate reclosers, tie switches, and sectionalizing switches to better optimize feeder configuration and outage management (through FLISR), while automation of LTCs, capacitors, regulators, and end-of-line AMI will support VVO. Similarly, VVO capabilities will then utilize DER controls to allow for retail services.

In order to begin improving system reliability, resiliency, and efficiency of the distribution grid during the system-wide rollout, we are executing a three-stage Grid Automation program. We have been implementing the first two phases of Grid Automation before continuing onto the third phase. Level I automation includes all substations and three-phase reclosers. The automation of substation and three-phase reclosers will provide remote visibility of these critical devices to SCADA and the OMS. In addition to providing critical system metering, this initiative will allow the ECC to view alarms and unplanned events 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 metering from these devices will also contribute to the convergence and accuracy of solutions in the Distribution State Estimator (DSE).

f. grid infrastructure components such as switches, power flow controllers, and solid-state transformers;

Level II Distribution Automation includes line regulators, line capacitors, and circuit tie switches and sectionalizing switches to enable VVO, optimal circuit switching, and FLISR applications. Level III automation includes single-phase reclosers to further increase situational awareness and granularity of control. Automation is nearly complete in the Energy Smart Community project, including gang-operated switches for circuit optimization and FLISR. Through VVO, the voltage regulators and capacitors will be automated, adjusting settings on both types of devices based on real-time information collected from the field. The automation of capacitors will allow the ADMS to reduce losses through power factor improvement by reacting to the real-time VAR flows, and by remotely adjusting capacitor bank settings, eliminating the need to send crews to configure capacitor bank setting annually or seasonally. The automation of voltage regulators and capacitors will allow operators to exercise automatic Volt-VAR control based on real-time voltage and VAR readings along the circuits. Continuous VVO achieves energy conservation by improving voltage profiles over a wide 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 AMI smart meters will yield an even higher level of optimization without the need to install additional sensors on our distribution lines. The automation of reclosers and 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 automation of regulators and capacitor banks on the distribution system. This data and the ability to remotely control voltage at these sites provide the ability to maintain voltage more precisely over time, ensuring better operation of customer electric equipment. This additional SCADA visibility, alarm notifications, and remote-control capabilities to Distribution Operators will result in reduced customer outage minutes and fewer field crew truck rolls.

g.cyber security measures for protecting grid operations from cybersecurity threats; and,

Our Operational Smart Grids (OSG) organization, which covers the Energy Management System, OMS, ADMS, DERMS, and infrastructure, has developed procedures that support the protection of grid operations. While all North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards support this objective, the primary standards include: CIP-002 (Cyber System Categorization), CIP-005 (Electronic Security Perimeters) CIP-007 (Cyber Security Management), CIP-008 (Incident Response), CIP-009 (Disaster Recovery) and CIP-010

(Configuration Management & Vulnerability Assessment).[22] When implemented system-wide, the integrated ADMS will also adhere to these standards. The AVANGRID compliance program and its adherence to NERC standards is subject to periodic review and auditing that determines the effectiveness of implemented security measures.

h.cyber recovery measures for restoring grid cyber operations following cyber disruptions.

AVANGRID has processes, procedures, and controls that address physical and electronic access to critical financial and operational systems. The Systems, Applications, and Products team develops Information Technology cyber security systems, including Grid Operations security systems. These systems fall under the Sarbanes-Oxley Act (SOX) requirements and are audited/tested annually by both internal and external auditors to assure effectiveness of these controls.[23] These tests address the physical controls for managing and reviewing physical access to the data center, which incorporate the system and disaster recovery plan. The tests align with our corporate Business Continuity plans, and include strict access provisioning and de-provisioning processes that apply the principle of least privilege. Privileged and standard user access reviews are conducted biannually. In addition, backup and recovery controls are in place and tested regularly as part of the audit processes. Our energy control center is equipped with redundant control systems and has backup control centers in cases in which the primary ECC becomes uninhabitable. The ECC is also equipped with back-to-back firewalls between corporate and outside systems.

For the Energy Management System, AVANGRID adheres to NERC standards, including CIP, Transmission Operations (TOP), Communications (COM), Emergency Preparedness & Operations (EOP), Modeling, Data and Analysis (MOD), Personnel Performance, Training and Qualifications (PRC), and others. OSG focuses much of its compliance energies on adherence to CIP Standards 002 through 011. These standards encompass cyber asset management, access management, cyber security, incident response, and disaster recovery and information protection. The Energy Management System/OMS has a back-up control center, a redundant control system, a program Development System (PDS), and a Quality Assurance System (QAS) to ensure program changes and new code are tested and stable before updating the production systems. In addition, NERC TOP standards require regular evacuation drills and tests of system failover.

VVO

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

a. identify where automated VVO is currently deployed in the utility's system;

We are implementing a voltage optimization (VO) pilot project in Maine through our affiliate,

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22 NERC CIP includes a set of standards and requirements to secure assets needed for safe operation of North America's bulk electric system. CIP standards overview available here.

23 Sarbanes-Oxley Act 101.

Central Maine Power. After implementing the ADMS in the Energy Smart Community, we intend to deploy model-based VVO on the 15 ESC feeders, incorporating lessons learned from the CMP VO pilot.

The CMP VO project consists of voltage regulator automation on two adjacent feeders and the implementation of a voltage optimization algorithm. The project includes 98 AMI voltage sensors on five feeders, including two test circuits. These sensors are used to monitor end-of-line voltage for these five circuits, both before and after voltage optimization. We will be using AMI for the measurement and verification on the project.

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

As noted above, we are currently implementing a VO project, and thus, do not yet have results to share on actual energy changes. The Conservation Voltage Reduction (CVR) factor below describes how we will measure the impacts, which vary by location, given the high dependency on load mix, making the energy changes difficult to predict. We will measure the changes on a quarterly basis. After the CMP project runs for a year, the project will then calculate the energy loss and demand reductions. For VVO projects in New York, we expect to evaluate and provide energy loss and demand reduction results a year after launching the project.

VVO is an operational strategy designed to reduce the energy used by customer appliances and equipment, as well as utility system losses, by optimizing distribution feeder voltages[24] for all load conditions. The degree to which reducing the feeder voltage reduces a customer's energy consumption depends on the "CVR factor," which depends on the types of loads that are connected to the feeder.[25] The equation for the CVR factor (CVR_f) is shown in Equation 1. A CVR_f of 1 indicates that a 1% reduction in voltage corresponds to a 1% reduction in energy consumption.

[24] The definition of Conservation Voltage Reduction used here is adapted from the U.S. Department of Energy's 2012 report titled "Application of Automated Controls for Voltage and Reactive Power Management – Initial Results" available at http://energy.gov/sites/prod/files/Voltage%26ReactivePower_Dec2012Final.pdf.

[25] The amount of the load reduction and resulting savings to the customer from CVR will vary depending on the type of appliances used by the customer. See EPRI, Green Circuit: Distribution Efficiency Case Studies (2011) available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001023518.

Equation 1: CVR Factor

$$\mathrm{CVR}f = \frac{\Delta \mathrm{E}(\%)}{\Delta \mathrm{V}(\%)}$$

$$\Delta E = \frac{E^{usage}_{after} - E^{usage}_{before}}{E^{usage}_{before}}\ ^{26} \qquad \Delta V = \frac{V_{after} - V_{before}}{V_{before}}\ ^{27}$$

Studies conducted by utilities in different parts of the country have shown that CVR factors between about 0.7 and 1.0 are common. While utilities have long understood and used VVO for certain purposes, including generation capacity deficiency emergencies, transmission line capacity relief and peak load reduction, the improved visibility and control provided by new technologies is prompting utilities to examine it for additional energy and peak savings opportunities. The objective of constant VVO is to achieve optimal voltage, while the objective of the load relief CVR is to achieve minimal voltage.

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

See response in Subpart 5b above. Once the effectiveness of VVO is measured (*i.e.*, the CVR_f is determined based on the effectiveness of the pilot through determining the actual energy savings achievable for what cost), a business case will be developed, including recommendations for expansion and modifications to the plan.

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

See response in Subpart 5b above. Application of our Benefit-Cost Analysis (BCA) Handbook will provide an assessment of the value of VVO to our grid.[28]

e. provide the utility's plan and schedule for expanding its automated VVO capabilities;

See response in Subpart 5b above. After a successful VVO rollout in CMP and the Energy Smart Community, VVO projects will then expand outward with ADMS, AMI, and the continual expansion of Grid Automation, which is necessary to enable VVO capabilities throughout our service areas.

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[26] Percent Change in energy consumption after voltage optimization is implemented on the feeder

[27] Percent Change in voltage on the feeder after voltage optimization is implemented

[28] Refer to Appendix B of our 2018 DSIP Report for link.

f. describe the utility's planned approach for securely utilizing DERs for VVO functions; and,

We anticipate securely utilizing DER for VVO functions through our staged implementation plan, which includes DER to flatten voltage profiles and balance VAR loads. Stage 3 will require two-way communications to send control mode, set-point, and curtailment commands to DER. This allows both community-sized and net-metered DER to participate in ancillary (VVO) services and reliability (flexibility) programs for increased value stacking. The project involves two M&C projects: the Enhanced DER M&C project and the Smart Meter – Smart Inverter proof-of-concept project.

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

As mentioned above, we do not yet have data to estimate the energy loss and demand reductions associated with VVO. We anticipate having results from the CMP project in 2019. Thereafter, we will measure New York-based results from the ADMS starting in 2019. VVO on a system-wide basis first requires foundational elements, including AMI, automation, and enabling technologies, such as ADMS.

Advanced Capabilities

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

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

We are continuing long-term efforts for full distribution automation. Figure 4.3-7 shows our current automation capabilities.

FIGURE 4.3-7: CURRENT AUTOMATION CAPABILITIES

Station	Total Units	Non-Automated Units[29]
Substations	689	267
Three-Phase Reclosers	802	386
Regulators	984	984
Capacitors	3,440	3,440
Line Switches	12,780	12,718
Single-Phase Reclosers	72	72

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

The tables below highlight our plans for automating additional substations and distribution

[29] Non-automated refers to the number of assets that do not have full remote monitoring and control capabilities.

system equipment over the next several years.

FIGURE 4.3-8: SUBSTATION AUTOMATION PROGRAM

Station	2018	2019	2020	2021	2022+[30]	Total
Primary Stations[31]	181	181	182	184	374	1,102
Secondary Stations[32]	261	281	301	321	702	1,866
Total	442	462	483	505	1,076	2,968

FIGURE 4.3-9: GRID AUTOMATION PROGRAM

Item	2018	2019	2020	2021	2022+[33]	Total
Single-Phase Reclosers	0	0	0	11	55	66
Regulators	0	193	386	579	1,696	2,854
Capacitors	0	64	128	192	563	947
Three-Phase Reclosers / Switches	769	1,185	1,601	2,017	4,868	10,440
Total	769	1,442	2,115	2,799	7,182	14,307

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

Our Grid Automation plan is discussed in Chapter VIII of our 2018 DSIP Report.

Our plans and goals for advanced Grid Operations' capabilities have not changed since the 2016 filing. The Companies have continued to progress in automating the grid. Automation of voltage regulators and capacitors will allow the ADMS to perform VVO, adjusting settings on both types of devices based on real-time information collected from the field. This automation of capacitors also eliminates the need to send crews to configure capacity bank settings annually or seasonally. The automation of LTCs and voltage regulators will allow the ADMS to perform VVO based on real-time voltage readings along the circuits. VVO 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 AMI smart meters, as discussed in the report, will yield an even higher level of optimization. The automation of breakers, reclosers, tie switches and sectionalizing switches, will allow the ADMS to perform optimal feeder reconfiguration and FLISR, increasing efficiency, reliability, and resiliency.

30 Through 2023.

31 Primary stations refer to those 46 kilovolts (kV) and above.

32 Secondary stations refer to those considered below 46 kV.

33 Through 2023.

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

The Companies are focused on implementing both general monitoring and control of the grid and DER-specific M&C. As markets for DER participation continue to develop, DER management and dispatchability will increase DER value. The ability to integrate DER into grid optimization schemes provides the opportunity for these customers to participate in the ancillary services markets, providing additional value. In addition, M&C initiatives will assist in establishing an appropriate level of visibility, ensuring ongoing system safety and reliability as DER become increasingly integrated and impactful to the grid. The advanced automation enabled with DER M&C allows grid operators to better anticipate grid issues. In the end, effective M&C improves system efficiency, enhances grid resiliency, and improves customer satisfaction. In addition, increasing automation capabilities will provide more timely response to outages, more efficient Grid Operations through remote troubleshooting and analysis, reduced energy losses, and enhanced visibility, control, and optimization of DER on the grid.

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

The ADMS is comprised of a suite of applications required to operate a highly dynamic grid. ADMS will optimize the grid, including DER, to maximize value to the grid and customers while maintaining reliability and power quality. The ADMS will provide capabilities, such as a DSE, DPF, OPF, VVO, and FLISR to optimize the grid and improve grid efficiency. In the short term, the Companies will complete the ADMS implementation within the Energy Smart Community. Longer term, the Companies will roll out ADMS system-wide. Optimizing the grid power flows, including DER, will accommodate greater penetration of DER.

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

See Chapter VIII of our 2018 DSIP Report, as well as responses to Subparts 6c, 6e, and Future Implementation and Planning above.

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

After the ADMS implementation, we plan to implement DERMS, MGMS, and DER MMS. See Chapter VIII of our 2018 DSIP Report of the report for a discussion of applicable technologies and approaches.

4.4 Energy Storage Integration

Introduction/Context and Background

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

The need to reflect grid-sited energy storage in Integrated Planning was acknowledged in NYSEG and RG&E's 2016 DSIP filing,[34] with integration of energy storage into advanced forecasting[35] and other Integrated Planning processes identified as a 2019-2021 roadmap action. We also noted the potential for energy storage as a grid operations asset, capable of supporting load and maintaining optimal voltage when needed.[36] Incorporation of energy storage in non-wires alternatives (NWA) procurements was identified as a "2022+" roadmap action.[37] Finally, our 2016 DSIP filing identified energy storage as a potential opportunity area for new demonstration projects. We have spent the last year developing four innovation projects to test use cases that will inform the use of energy storage as an effective solution to traditional infrastructure challenges.

Energy storage has received considerably more attention in the electric industry and in New York since 2016. Most recently, on June 21, 2018, New York State Energy Research Development Authority (NYSERDA) released the New York State Energy Storage Roadmap that includes policy, regulatory, and programmatic actions designed to accelerate the development of energy storage in New York by accelerating the learning curve and helping to drive down development costs.[38] These actions are designed to place New York on a path to achieve the previously announced 2030 Energy Storage goal.[39] Our 2018 DSIP is responsive to New York's storage goals and addresses the role that we can serve to support the deployment of energy storage in our service areas. Our objective is to proactively support the identification and development of energy storage projects that benefit our customers and the grid, and provide a return on investment to DER developers.

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34 See pp. 3, 9, and 15.

35 Id., p. 42.

36 Id., p. 25, 104.

37 Id., p. 57.

38 For more information, refer to the NYSERDA website.

39 The NYSERDA analysis examines several alternative energy storage business cases and contemplates that several programmatic policy, regulatory and actions are being considered to address economic challenges faced by energy storage as an emerging technology.

Implementation Schedule and Investments Plan

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

The actions taken to build the Integrated Planning, Grid Operations, Market Services, and Information Sharing functions are designed to address DER developers and other stakeholders' current and future needs. Each of the Integrated Planning sub-functions (*e.g.*, Advanced Forecasting, Hosting Capacity, and NWAs) are being designed to integrate all distributed energy resources (DER), including energy storage and demand response. Our technology and systems investments will help to identify potential locations for energy storage and improve the quality of our analyses as advanced metering infrastructure (AMI) data becomes available.

Focusing more specifically on energy storage, NWAs require support from several functions to produce an outcome that benefits the grid and customers. After circulating the request for proposal (RFP) to a large number of potential bidders, we provide bidders with system data and aggregated customer data that they will need to prepare an informed bid. The system data is generated by localized Integrated Planning modeling. Our NWA solicitations have provided valuable learning as approximately 90% of the respondents have incorporated battery storage as part of their proposed solution. The review and evaluation of these proposals by a cross-functional team has provided valuable experience regarding the potential value of storage as a resource and how it can benefit the grid and our customers.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Our strategy and implementation plan for integrating energy storage is based on our four-step integration and deployment process for emerging technologies:

1) **Learn:** Energy Storage is a relatively new technology that is the subject of R&D efforts that consider the technology, performance under alternative use cases, and alternative business models. AVANGRID is an active participant in this learning stage, through developing our own innovation projects and from similar efforts throughout the world.
2) **Build:** We are planning and pursuing certain foundational grid modernization and DSP investments, preparing to support energy storage and other DER. These foundational

investments will support the range of use cases that are being considered by the industry.

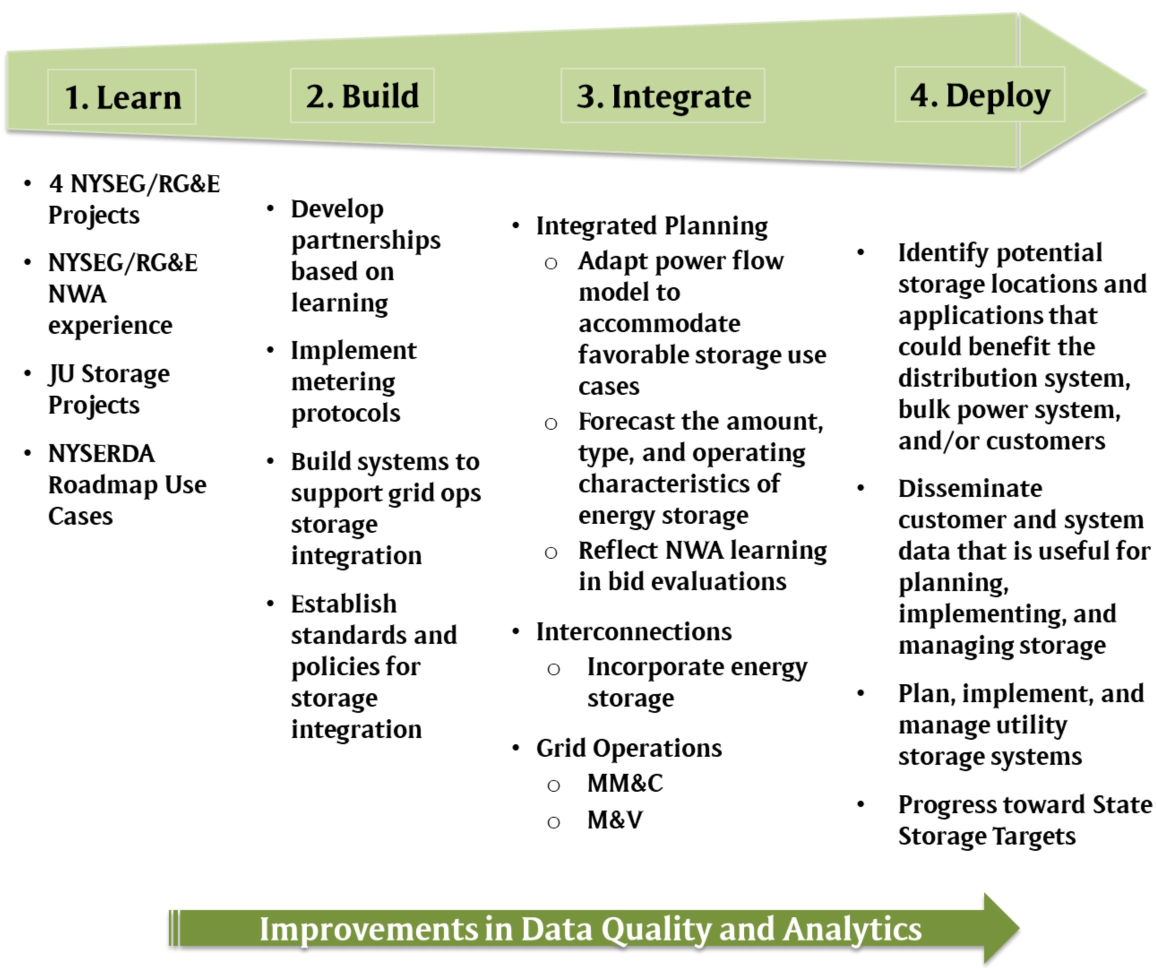
3) **Integrate into Planning, Grid Operations, Interconnections, and Information Sharing:** As use cases are validated, they will be considered to be solutions within our existing functions and we will identify opportunities and locations that are well-suited to replicate the use case, for both utility-owned and third-party projects.

4) **Deploy:** As use cases are validated, we will identify opportunities and locations that are well suited for utility and third-party energy storage projects.

We expect this four-stage process to continue over the next five years, even as we begin deploying energy storage throughout the NYSEG and RG&E service areas. We also expect that the economics of energy storage will improve over the next five years and beyond from RD&D efforts and experience gained from project deployment and initial operations. Stronger storage economics will improve the results of Benefit/Cost Analyses for utility-owned projects and returns on investment will improve for third party energy storage developers.

Figure 4.4-1 presents our four-step integration and deployment strategy for energy storage.

FIGURE 4.4-1: ENERGY STORAGE INTEGRATION AND DEPLOYMENT STRATEGY



Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E will gather accurate information from storage projects on the attributes of the proposed installation, including business cases. The Integrated Planning function will model the applications and determine whether they would be included in the portfolio of DER that provides significant benefits to the grid and our customers. If a storage project passes this test, it will be approved for interconnection. NYSEG and RG&E, along with other utilities within New York and beyond, are performing innovation projects to identify use cases that are economic.

As with any new technology, we anticipate start-up challenges for all participants, including NYSEG and RG&E. This is part of the innovation process that tests the performance of battery designs and business models. Our innovation projects serve as our mitigation response to the risks imposed by implementing a relatively new technology and new business models. The four-stage process mitigates the potential economic consequences of overinvesting in energy storage in the first few years.

Certain risks to realization of New York's energy storage goals are largely beyond the control of NYSEG and RG&E. The first risk is decisions by storage developers not to proceed with an approved project. The remaining risks are market-related and result from proposed projects not being economical. This may occur due to inadequate battery storage technology that either limits the performance relative to use case needs or because storage costs are uneconomic. Grid-sited storage, in particular, is generally thought to require longer discharge periods that could increase costs or result in a shorter life span. Second, the Companies acknowledge that NYISO market rules, rate structures and designs may not align with the energy storage value proposition. NYSEG and RG&E can propose rate designs that support energy storage, however, market rule and rate design changes can be a complex, lengthy process.

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

DER developer needs are identified, discussed, and validated through the Joint Utilities' stakeholder engagement process. Several topics that relate to energy storage have been addressed in these meetings, including the impact of energy storage on integrated planning activities (*e.g.,* advanced forecasting and hosting capacity) and the interconnection process. Engagement with storage developers and other stakeholders is also occurring as part of

NYSERDA's Energy Storage Roadmap effort. NYSERDA kicked off this effort with a stakeholder meeting and webinar on February 1, 2018. The roadmap includes recommended actions that will accelerate the deployment of energy storage projects in New York State.

While these processes have been informative, working with energy storage developers and other stakeholders to develop our four storage innovation projects has substantially improved our understanding of the varying approaches that storage developers are taking to potential opportunities. We are learning about their technologies, financial objectives and requirements, business models, how developers plan to execute the project, and long-term strategies. Having an opportunity to discuss an actual project and consider project economics and how we can jointly serve customers, address our needs, and provide value to developers enhances the quality of the dialogue and ability to learn from each other.

We also addressed Energy Storage in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions. This presentation included a review of our four storage innovation projects.

Additional Detail

Significant energy storage integration will be needed within the five-year planning horizon of the DSIP Update filing. Areas of particular interest related to energy storage include:

- *existing energy storage resources in the distribution system;*
- *the utility's planned energy storage projects;*
- *a five-year energy storage deployment forecast;*
- *potential energy storage locations and applications that could benefit customers and/or the electric system;*
- *resources and functions needed for integrating energy storage; and,*
- *the utility's alignment with New York State's energy storage goals and initiatives.*

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following details for the areas of interest listed above:

As mentioned above, NYSERDA issued an Energy Storage Roadmap in June 2018 to inform a plan for the Commission to establish a 2030 Energy Storage goal and set of actions. The NYSERDA analysis examined several alternative energy storage use cases. Several policy, regulatory, and programmatic actions are under consideration to address the economic challenges faced by energy storage. In addition, the Commission has modified the Standardized

Interconnection Requirements (SIR) to make it easier for storage projects of up to 5MW to be connected to the grid.[40]

NYSEG and RG&E's responses to the specific requirements are based on the existing regulatory framework, including rate design. As described in the response to Subpart 10 below, the Joint Utilities are considering approximately twenty storage innovation projects in an effort to identify the most promising use cases for energy storage.

1) *Provide the locations, types, capacities (power and energy), configurations (i.e. standalone or co-located with load and/or generation), and functions of existing energy storage resources in the distribution system.*

NYSEG and RG&E do not currently have utility-owned energy storage projects connected to the distribution system.

2) *Describe the utility's current efforts to plan, implement, and operate beneficial energy storage applications. Information provided should include:*
   a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range energy storage plans;*
   b. *the original project schedule;*
   c. *the current project status;*
   d. *lessons learned to-date;*
   e. *project adjustments and improvement opportunities identified to-date; and,*
   f. *next steps with clear timelines and deliverables.*

As shown in in Figure 4.4-2, NYSEG and RG&E are developing four energy storage innovation projects. Two of the innovation projects are associated with the Energy Smart Community in NYSEG's service territory:

(1) Aggregated Behind-the-Meter Battery Storage: aggregation of small (approximately 50 kW), medium (approximately 150 kW), and large (approximately 250 kW) battery storage DER with a combined capacity of 1 MW and a storage energy capability of 4 MWh (referred to in the storage industry segment as a 1 MW/4 MWh facility) located on up to eight commercial and industrial customer sites. The primary goal of the project is to reduce customer demand, smooth customer load shapes, and bid a portion of the total capacity into the NYISO capacity market. A secondary business case is to reduce circuit and system peak demand, while gathering data on the impact of alternative rate designs on the value of behind-the-meter battery storage to our customers. This project tests the potential for aggregation to provide a dual purpose; to provide grid support and generate a revenue stream that would not be available to an individual customer.

[40] Order in Case No. 18-E-0018, issued April 19, 2018.

(2) Distribution Circuit Deployed Battery Storage: examines the potential to integrate, operate, and optimize the value from a 500 kW/2 MWh battery storage system that is located at the end of a distribution circuit. The primary goal is to reduce circuit daily and monthly peak demand, while maintaining circuit loading consistent with the circuit's hypothetical capacity rating. Secondary business cases test voltage regulation capabilities, the potential to increase hosting capacity along the circuit, and the ability to participate in NYISO demand response programs.

The other two projects are located in our RG&E service territory:

(3) Integrated EV and Battery Storage: This project is comprised of five plug-in electric vehicles powered by a portfolio consisting of two DC Fast Chargers (approximately 50 kW each), five "Level 2" chargers (7.2 kW each), and a 150 kW/600 kWh stationary battery. We are interested to learn how the stationary battery can be integrated with EV chargers to reduce circuit and building peak demand, increase building load factor, and improve the economics of EV adoption.

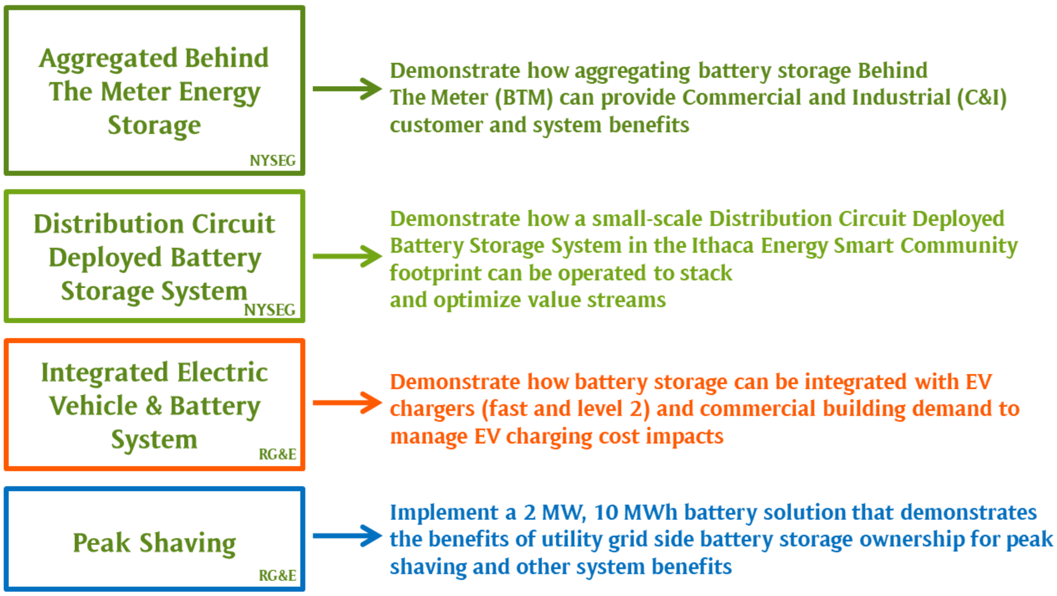
(4) Peak Shaving Substation Storage: This project locates a 2 MW/10 MWh battery storage system adjacent to Station 127, a Farmington New York substation. We are interested to learn how to effectively integrate, operate and optimize the value of a grid-side battery storage system to reduce the station's peak demand while maintaining substation loading with its thermal rating. We also plan to test the ability of the battery storage system to reduce the number of power quality issues experienced in this area of our system. A secondary objective is to increase substation loading efficiency, reduce O&M expenses, and maintain a level power factor.

The first and third projects are filed as REV Demonstration projects, as defined by the Commission.[41] All four projects are currently in the implementation phase with commercial operation targeted for year-end 2018 As shown in Figure 4.4-2.

[41] Pursuant to New York State Public Service Commission's Order Adopting Regulatory Policy Framework and Implementation Plan, issued and effective February 26, 2015.

FIGURE 4.4-2: BATTERY STORAGE INNOVATION PROJECTS

- Four proposed battery storage projects, two at NYSEG, two at RG&E
- Mandated as part of NY REV proceeding
- Projects are being fast tracked for completion by December 2018



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

It is not possible to develop a viable five-year forecast of energy storage projects (e.g. locations, types, capacities, configurations, etc.) at this time since we are in the initial learning stage of the energy storage development effort. This learning process will be informed by our own innovation projects, the NYSERDA Storage Roadmap effort, and other innovation projects within and beyond New York. It is our expectation that we will emerge from this stage with an understanding of the use cases that contain the most benefit and promise. After the initial learning stage, we anticipate being able to assess the economic potential for energy storage for each business case based on the Benefit Cost Analysis (BCA). As with economic efficiency studies, we plan to develop a five-year forecast of the energy storage based on the economic potential. The quality of the energy storage forecast should improve as experience is gained. The forecast will also change in response to technology advances, changes in legislation, future incentives, regulations, market rules, and other related policies that impact project economics.

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

a. its location;

b. the energy storage capacity (power and energy) provided;

c. the function(s) performed;

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

e. the nature and economic value of each benefit derived from the energy storage resource.

It is AVANGRID's objective to proactively support the identification and development of energy storage projects that benefit our customers, the grid, and provide a return on investment to DER developers. To the extent that grid benefits are realized, these will accrue to our entire customer base through increased efficiencies, increased reliability/resiliency, and/or lower costs. We are interested in business cases that provide direct or indirect value to as many customers as possible. This includes projects that are able to take advantage of the fact that average cost declines as battery size increases.

The Joint Utilities are developing innovation projects that benefit one or more of three value targets: utility customers, the distribution system, or the bulk power system. The NYSERDA Storage Roadmap adds to our insights regarding the use cases that are potentially economic and any policy or regulatory levers that are recommended. We will include this information for all projects located on our distribution system in our 2020 DSIP filing. When we are able to respond to Subpart 3 regarding a forecast of energy storage projects on our distribution system, we will provide our expectation with respect to Subparts 4b-4e that is aligned with this initial forecast.

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

a. Explain how each of those resources and functions supports the utility's needs.

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

We are currently in the learning stage with respect to energy storage, with four innovation projects under development. The resources and functions required to plan, implement, monitor and manage storage are involved in these innovation projects and will also contribute to future development phases, including deployment of energy storage resources throughout our system. The four innovation projects are providing lessons learned to help each function improve their respective processes. As show in Figure 4.4-3, storage projects touch many business areas.

FIGURE 4.4-3: FUNCTIONS AND RESPONSIBILITIES CONTRIBUTING TO ENERGY STORAGE PROJECTS

Function	Responsibilities
Smart Grids Innovation	Collaboration on Innovation efforts
Integrated Planning	Integration with the grid; assessment of stacked benefits; NWA procurement activities
Project Management	Oversight and management is designated for each project
Distribution Design/Planning	Power flow modeling to determine how the project impacts the local distribution configuration and to support interconnection
Transmission Planning	Assessment of potential impacts on the transmission network
Customer Interface	Relationship with storage developers and end-use customers
Metering	Design and implement metering scheme
Safety	Ensure that the implementation meets safety requirements
Market Operations	Plan to realize value in NYISO markets
IT/OT and other Communications	Integration with NYSEG/RG&E grid operations systems
Distribution Operations	Substation and line management
Engineering	Substation engineering, Protection scheme, and integration with the Energy Control System
Technical Services	Quality Management, Environmental, and Cost Control support

6) *Describe the means and methods for determining the real-time status, behavior, and effect of energy storage resources in the distribution system. Information produced by those means and methods should include:*

a. *the amount of energy currently stored (state of charge);*

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

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

d. *the net effect (amount and duration of supply or demand) on the distribution system of each charge/discharge event (considering any co-located load and/or generation); and,*

e. *the capacity of the distribution system to deliver or receive power at a given location and time.*

The energy storage projects discussed in Subpart 2 will inform these means and methods, which are currently unavailable, given the nascent stage of energy storage deployments in our service territory to date.

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

a. the amount of energy stored (state of charge);

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

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

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

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

Establishing a forecast methodology is one of four capabilities we are building to support energy storage integration:

a) Identify potential energy storage locations and applications that could benefit the distribution system, bulk power system, and/or customers;

b) Plan, implement, and monitor performance attributes, and manage utility storage systems;

c) Forecast the amount, type, and operating characteristics of energy storage, including inputs that inform the DER forecast being prepared by the Advanced Forecasting function; and

d) Disseminate customer and system data that is useful for planning, implementing, and managing storage.

These capabilities combine to support realization of New York's energy storage goals, while providing value to customers, the grid, and DER developers. The quality of our energy storage forecast will improve as we gain experience and are able to benefit from lessons learned by other utilities regarding the performance attributes that we will monitor. It will be important to also reflect improvements in battery technologies and execution efficiencies that we expect to achieve with experience.

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

We anticipate DER developers will identify customers or available land plots for storage projects and developers will seek customer authorization for data from identified customers. The Companies would provide e identical usage data to all DER developers and energy service companies evaluating offerings to a customer or group of customers. Storage project developers will have access to all system information made available to DER developers. This would include system information made available to potential respondents to NWA RFPs if storage is a bid component. Please see the responses to 2018 DSIP Guidance Response Sections 4.7

(Distribution System Data) and 4.8 (Customer Data) for information on how these data are shared with developers.

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

NYSEG and RG&E are committed to developing all storage projects on the network that are economic as determined by a BCA (for utility projects) and enabling third-party storage projects. We anticipate storage projects developed on our network will be informed by utility innovation projects and NYSERDA's analysis of use cases. Similarly, we expect that third-party developers will benefit from similar research within and beyond New York. We plan to pursue New York State's objective based on the existing policies and regulations in place from time to time, including rate designs. Our Integrated Planning, Interconnections, and Grid Operations capability building efforts are designed to support this approach.

In short, we want economic projects to be built that reflect lessons learned in actual project development and operations. This is necessary to ensure that the portfolio of energy storage assets remains economical and delivers the desired benefits to customers, the grid, and DER developers.

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

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

4.5 Electric Vehicle Integration

Introduction/Context and Background

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

The 2016 DSIP filing did not address Electric Vehicle (EV) Integration. Our 2018 DSIP objectives are to identify, prioritize, and execute actions in the near- to mid-term future in order to unlock the potential of transportation electrification.

NYSEG and RG&E have been working collaboratively with the Joint Utilities to prepare an EV Readiness Framework.[42] With the benefit of this exercise, we have been developing our own EV roadmap. These efforts are responsive to New York's establishment of a target of approximately 800,000 zero emissions vehicles by 2025, a June 1, 2018 commitment to contribute $250 million to build out EV charging infrastructure on New York's interstate highways, and other public-private sector initiatives to accelerate the adoption of electric vehicles in the State.[43] Transportation is the single largest contributor to greenhouse gases in New York and the realization of New York's EV goals would contribute significantly to achievement of the targeted reduction in greenhouse gas emissions of 40 percent by 2030 and 80 percent by 2050.[44]

The EV Readiness Framework lays out the path to guide our respective utility efforts to become "EV ready" by identifying existing hurdles to widespread deployment of EV charging infrastructure (and vehicles, where appropriate) and discussing solutions. It reflects input from stakeholders through a number of dedicated stakeholder engagement sessions.

The Joint Utilities' EV Readiness Framework set out to identify, prioritize, and execute actions in the near- to mid-term in order to unlock the potential of transportation electrification. The near-term priorities identified in the EV Readiness Framework include:

- Planning of EV charging infrastructure;
- Forecasting EV growth to assess and mitigate potential system impacts;
- Streamlining deployment of New York's charging infrastructure by addressing local building codes and ordinances and other challenges to siting charging infrastructure;
- Advancing rate design considerations that will improve the customer experience while minimizing impacts to utility system operation; and

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42 Joint Utilities of New York EV Readiness Framework, Final Draft, March 2018.

43 New York's participation in the 2014 Multi-State ZEV Task Force establishes a target for New York of 850,000 ZEV by 2025.

44 Established by the 2015 New York State Energy Plan.

- Conducting education and outreach efforts that improve customer awareness about the benefits of EVs.

Implementation Plan, Schedule, and Investments

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

Development of an AVANGRID EV Roadmap

NYSEG and RG&E have used the EV Readiness Framework as a starting point to develop our own AVANGRID EV Roadmap. Our roadmap addresses EV market development, EVSE integration, and EVSE deployment. Our goal is to create an environment that facilitates and supports the adoption of electric transportation within our service territories. We are building four capabilities to support a robust electric vehicle market:

(1) Forecast EV growth and assess network impacts and needs;

(2) Integrate EV load while minimizing impact on peak demand;

(3) Support EV market growth with sufficient charging infrastructure; and

(4) Positively influence customer perception of EVs.

By developing these capabilities, NYSEG and RG&E will support realization of New York's zero emission vehicle goals, while providing value to customers, the grid, and supporting the EV and EVSE markets. We are pursuing eleven initiatives to build these capabilities. These initiatives are identified in our DSIP Report and in the Progress and Future Implementation Planning section below where they are linked with one of the four capabilities we are building.

Addressing Stakeholder Needs

We are addressing the needs of our many stakeholders that have an interest in the deployment of EVs by working with them as we develop our EV initiatives. These stakeholder groups and their respective needs include:

- <u>Customers</u>: Anticipating EV growth, ensuring sufficient system readiness, and encouraging off-peak charging will ensure continued safe and reliable service for all customers while increasing system efficiency that can help reduce prices for all of our customers.

- <u>EV Drivers</u>: Supporting robust public charging infrastructure will help give drivers the confidence they need to transition from internal combustion engine vehicles to electric vehicles.

- <u>EVSE Companies</u>: Support for the EVSE market will help to overcome the "chicken and egg" issue where drivers require charging infrastructure to feel comfortable purchasing an EV and EVSE companies need customers to support a sustainable business model.

- State Policymakers: The New York 2025 Zero Emission Vehicle (ZEV) mandate requires approximately 800,000 ZEVs by 2025. It is expected that a large number of these vehicles will be battery electric vehicles (BEVs) and plug in hybrid vehicles (PHEVs). Our efforts to communicate the benefits of EVs to customers and to support market growth with sufficient charging infrastructure will help New York to achieve its ZEV goals. We are also focusing on EVs as an opportunity to increase system efficiency and support New York's overall REV goals.
- Environmental Groups: Electrification of transportation provides a significant opportunity to reduce emissions in New York State.

Progress on EV Initiatives

We have made substantial progress on building three of our four EV capabilities:

EV Capability (2) Integrate EV load while minimizing impact on peak demand:

- *EV Rate*: We have developed and filed an EV time-of-use rate that will be available to all EV owners and lessees. This rate was filed with the PSC in Q2 2018 and if approved, may be available to customers starting as early as Q4 2018.
- *Smart Home Rate Pilot*: Our Smart Home Rate Pilot will assess how to optimize vehicle charging based on price signaling. The implementation plan will be filed in Q3 2018 and addresses our implementation through 2019.
- *Integrated EV Charging and Battery Storage*: This innovation project will inform future deployment of batteries to meet EV charging load needs. The project, filed in Q2 2018 and anticipated to become operational in Q4 2018, utilizes a 150 KW/ 600 kWh stationary battery to meet the load needs of DC fast charging (DCFC) and Level 2 charging.[45]

EV Capability (3) Support sufficient charging infrastructure:

- *DC Fast Charger Pilot*: We have begun implementing the Direct Current Fast Charging Pilot to evaluate scalable business models for DC fast charging. Stakeholder engagement on the pilot began in Q1 2018, and we plan to engage potential site hosts in Q3 2018. We expect the pilot to become operational in late 2018 or early 2019.

EV Capability (4) Positively influence customer perception of EVs:

[45] There are 3 standard levels of EV charging. All electric cars can charge on levels 1 (charge time: 8-15 hours) and 2 (charge time: 3-8 hours). Only certain types of EVs can charge on level 3 (charge time: 20 minutes-1 hour).

- *EV Events*: We are conducting Employee EV Ride and Drive events to promote EV adoption. The events provide our employees with information and hands-on experience with EVs who, in turn, become EV ambassadors for friends, family, and the general public.
- *EVSE Market Offering*: Level 2 EVSE are now available for purchase on RG&E's Your Energy Savings Store website and NYSEG's Smart Solutions website.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Our implementation plan and roadmap includes actions that contribute to building each of our four EV capabilities:

EV Capability (1) Forecast EV growth and assess network impacts and needs:

- *EV Forecasting Pilot*: We will begin a forecasting pilot project in Q4 2018 to develop granular EV adoption forecasts at the circuit level based on a propensity-to adopt-methodology. The project will run through 2019, after which the Companies will assess the results to determine the benefit and apply lessons learned to evaluate the applicability for full-scale deployment.
- *System Impact Assessment*: We will begin a System Impact Assessment pilot project in Q4 2018 that will use the results of the forecasting pilot to evaluate expected system impacts under multiple EV forecasting scenarios. This project will also help assess the costs and benefits of EVs at various levels of adoption.

EV Capability (2) Integrate EV load while minimizing impact on peak demand:

- *Residential EV Demand Response*: Our Residential EV Demand Response pilot project will assess the value of EV customer participation in our DR program. The pilot is expected to be implemented beginning in 2019. We will then assess the results to determine the benefits of a full-scale rollout.

EV Capability (3) Support EV market growth with sufficient charging infrastructure:

- *DC Fast Charger Pilot and DCFC Network Program*: The DCFC Network Program will support development of a public DCFC network. The design will be based on lessons learned and results from the 2018 pilot and based on input from stakeholders, DPS Staff, and the Commission.[46] The program will likely run between 2020 and 2023.

- *Destination Chargers*: This program will support development of public Level 2 charging infrastructure. The program will reflect input from stakeholders, DPS Staff, and the Commission and is also being addressed in Case # 18-E-0138. We estimate that this program will operate between 2020 and 2023.

EV Capability (4) Positively influence customer perception of EVs:

- *EV Customer Communications & Content*: This initiative will provide focused tools and content to promote the benefits of EVs to customers. The effort will include website content, targeted customer communications, and public events and run from 2018 through 2023.

Our Roadmap for EVs, which reflects each of these initiatives, is presented in Figure 4.5-1.

FIGURE 4.5-1: EV ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)
Forecast EV Growth and Network Impacts		EV Forecasting Pilot System Impact Assessment Pilot	
Integrate EV Load while Minimizing impact on Peak Demand	EV Rate	Smart Home Rate Pilot Integrated EV Charging & Battery Storage Residential EV DR Pilot	
Support EV Charging Infrastructure	DC Fast Charging Pilot Stakeholder Engagement	DC Fast Charging Pilot	Build Out DCFC Network Destination Chargers
Influence Customer Perceptions of EVs	Employee EV Ride & Drive Events EVSE Market Offering	EV Customer Communications & Content	EV Customer Communications & Content

46 Case # 18-E-0138 – Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure, available here.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified four potential risks related to our EV integration and deployment efforts, and have taken mitigation efforts for each risk, as shown in Figure 4.5-2.

FIGURE 4.5-2: EV INTEGRATION RISKS AND MITIGATION

Risks	Mitigation Measures
1. **Regulatory:** EV deployment is highly dependent upon regulatory approval	• NYSEG and RG&E work closely with DPS Staff and other stakeholders to identify and incorporate regulatory concerns as our initiatives are being developed
2. **Cost Recovery:** Timely cost recovery is necessary to maintain financial strength	• EV initiatives are included in the 5-year Capital Plan • Existing AVANGRID/NYSEG and RG&E financial controls will be maintained
3. **Timing:** New York's EV market is in the initial stage of development	• NYSEG and RG&E will continue to monitor EV markets and develop local forecasting capabilities to identify EV market opportunities
4. **Technology:** EVSE technologies are continuing to develop and the pace of change is increasing	• The Companies take a phased investment approach and require standardization and interoperability for integration of new technologies and systems

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design; how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses.

The Joint Utilities' EV Readiness Framework is the product of stakeholder engagement, including two EVSE stakeholder sessions hosted by the Joint Utilities in 2017 and 2018.[47] The Joint Utilities have actively engaged with EVSE companies and EV market providers throughout the Joint Utilities' EV Readiness Framework development process. This includes an EVSE stakeholder engagement session to develop a set of guiding principles for advanced EV

[47] Meeting materials can be found on the Joint Utilities website here.

adoption.[48] We leveraged NYSERDA's REV Connect initiative to gather input from EVSE companies and to establish a partnership to collaboratively design a scalable investment strategy for DC fast charging. As we continue to develop our EV plans and projects, we will seek stakeholder input whenever practical to ensure we are developing initiatives that align with customer and stakeholder needs.

We also addressed our approach to Electric Vehicles in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions. This presentation included a review of our portfolio of EV innovation projects.

Additional Detail

Utility resources and capabilities which support electric vehicle (EV) integration at all levels in the distribution system will likely be needed within the five-year planning horizon of the DSIP Update filing. This is being driven by rapid progress toward lower vehicle costs, longer range per charge, and faster charging rates which are nearing the point of "gas parity" when significant EV adoption is generally predicted to begin. Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to electric vehicle integration:

1) *Using a common framework (organization, format, semantics, definitions, etc.) developed jointly with the other utilities, identify and characterize the existing and anticipated EV charging scenarios in the utility's service territory. Each scenario identified should be characterized by:*

The Companies' current EV forecasts are based on New York's 2025 Zero Emission Vehicle (ZEV) goals. Initial assessments of the required amount of charging infrastructure to meet these ZEV goals are based on the ratios identified in National Renewable Energy Laboratory's (NREL) National Plug-in Electric Vehicle Infrastructure Analysis.[49] For example, the central scenario in this analysis identified that towns and small cities with a population between 2,500 and 50,000 will require a ratio of 2.2 DC fast charge plugs for every 1,000 plug-in electric vehicles and 54 non-residential level 2 plugs for every 1,000 plug-in electric vehicles. Additionally, we are using the recently published "Electric Vehicle Infrastructure Projection Tool" published by NREL for further analysis. However, even *this* detailed analysis does not address many of the

[48] Summary presentation material for the stakeholder meeting on September 28, 2017 can be found on the Joint Utilities website here.

[49] National Plug-In Electric Vehicle Infrastructure Analysis, US Department of Energy, Office of Energy Efficiency and Renewable Energy, September 2017.

characteristics requested in the subparts to this question. While the Companies continue to develop the AVANGRID EV roadmap, much of the detailed planning and analysis remains to be developed. Many of the characteristics requested below require a myriad of assumptions regarding aspects of the vehicle market that are not yet well understood—including travel patterns, the anticipated vehicle architecture of the market moving forward (*e.g.*, plug-in hybrid vs battery electric), and the expected or preferred technology for charging vehicles in specific locations.

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

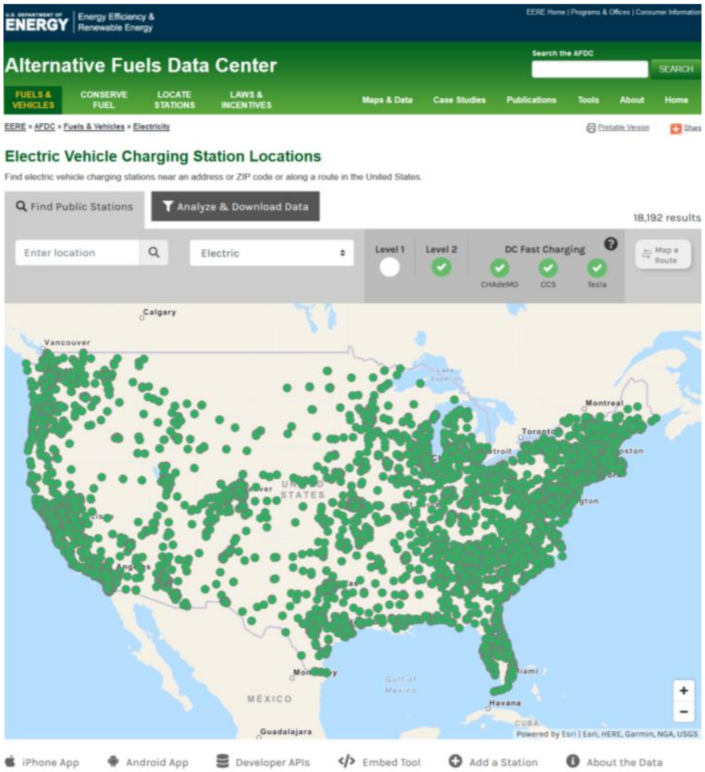
Consistent with NREL's analysis, we estimate that at least 88% of charging will be done at home.

b. the number and spatial distribution of existing instances of the scenario;

Insight into existing charging infrastructure utilizes the US Department of Energy (DOE) Alternative Fuels Data Center, which includes spatial data on L1, L2, and DC fast charging stations throughout the United States.[50] A presentation of this data is presented in Figure 4.5-3below.

[50] DOE Alternative Fuels Data Center available here.

FIGURE 4.5-3: DOE ALTERNATIVES FUEL DATA CENTER



Source: DOE

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

Forecast scenarios will be derived from the NYS ZEV Goals, as well ratios of EV ratios of total vehicles developed by the National Renewable Energy Library (NREL).[51]

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

We do not have the data or insights at this time to respond to this subpart.

e. the number of vehicles charged at a typical location, by vehicle type;

We do not have the data or insights at this time to respond to this subpart.

[51] NREL. "New Release: NREL Evaluates National Charging Infrastructure Needs for Growing Fleet of Plug-In Vehicles." October 4, 2017. Available here.

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

We do not have the data or insights at this time to respond to this subpart.

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

We do not have the data or insights at this time to respond to this subpart.

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

We are not aware of any storage installations accompanying EV charging within NYSEG or RG&E service territories. RG&E is testing EV charging supported by storage in our Integrated EV and Battery Storage demonstration project. This project is comprised of five plug-in electric passenger vehicles powered by a portfolio consisting of two DC Fast Chargers (approximately 50 kW each), five Level 2 chargers (7.2 kW each), and a 150 kW/600 kWh stationary battery and management system. We are testing how the stationary battery can be integrated with EV chargers to reduce circuit and building peak demand, increase building load factor, and improve the economics of EV adoption.

i. an hourly profile of a typical location's aggregated charging load over a one year period;

There are very few separately metered EV chargers in NYSEG or RG&E's service territory today.

j. the type and size of the existing utility service at a typical location;

There are very few separately metered EV chargers in NYSEG or RG&E's service territory today.

k. the type and size of utility service needed to support the EV charging use case;

We do not have the data or insights at this time to respond to this subpart.

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

We prioritize support for DC fast charging infrastructure within our service territories for a number of reasons:

- Although we expect that the majority of EV owners will charge at home, NYSEG and RG&E service territories include large suburban and rural areas, which will require DCFC for long-distance travel;
- DCFC is a high-power load and in many instances will require distribution system investments; and
- Due to cost and expected utilization, currently there is no viable business model for DCFC. The DCFC market will require investments from multiple stakeholders, including utilities and New York State.

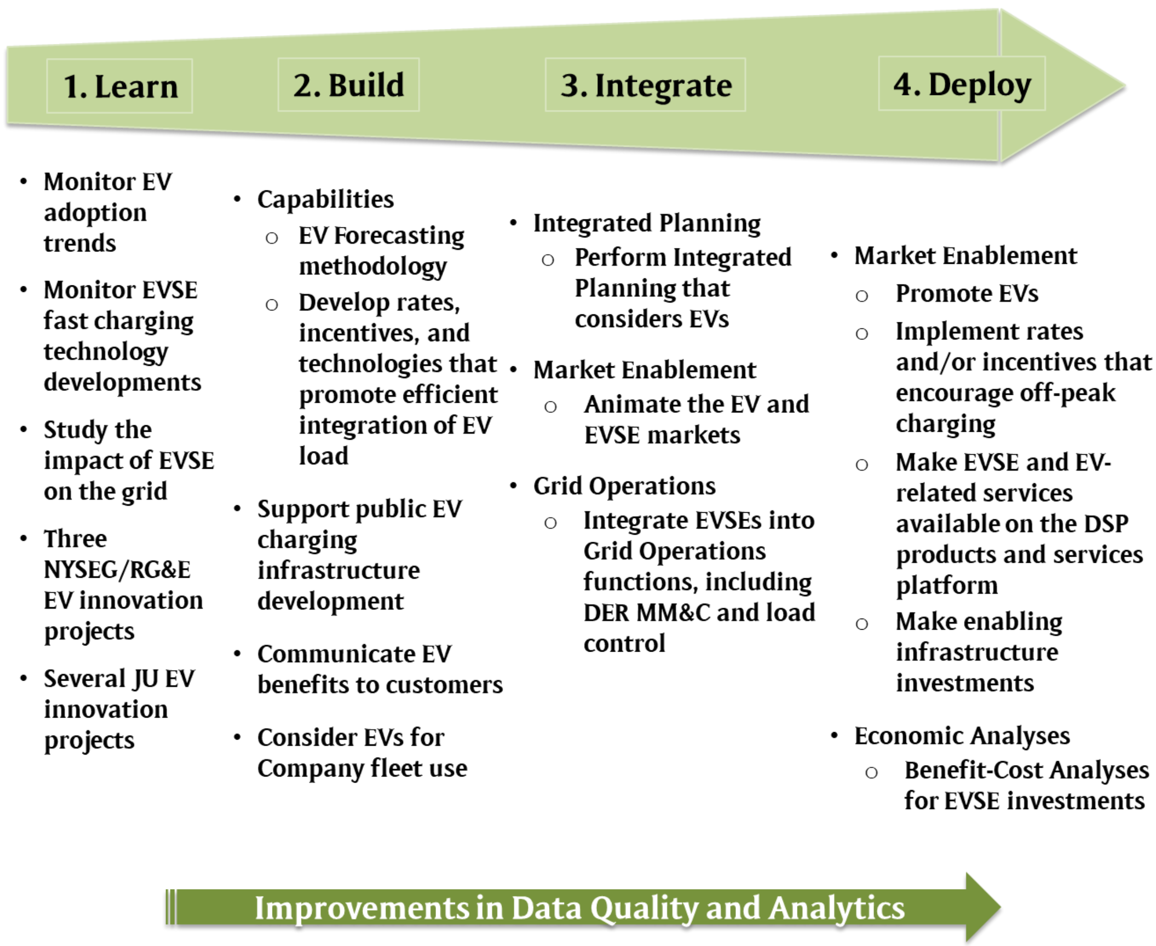
We will support destination Level 2 charging to ensure appropriate levels of charging infrastructure at multi-family dwellings, workplaces, hotels, resorts, restaurants, and other relevant facilities.

3) Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing EV charging at multiple levels in the distribution system.

a. Explain how each of those resources and functions supports the utility's needs.

As the Joint Utilities developed the EV Readiness Framework, it became apparent that utilities are in the early stages of planning, implementing, monitoring, and managing EV charging as it relates to the distribution system. The modest adoption of EVs to date has not warranted dedicated resources and functions. NYSEG, RG&E and the other Joint Utilities have managed EV charging through existing processes. We will provide more detail on the resources and functions required for planning, implementing, monitoring, and managing EV charging in the next DSIP filing and will reflect insights gained from our four EV innovation projects: Integrated EV & Battery Storage project, DC Fast Charger project, Smart Home Rate Project, and the EV Demand Response project, as well as our the EV Rate initiative. We have developed an EV integration and deployment strategy that involves each of our core DSP functions. Our EV integration and deployment strategy is presented in Figure 4.5-4.

FIGURE 4.5-4: EV INTEGRATION AND DEPLOYMENT STRATEGY



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

The Companies' integration and deployment strategy addresses stakeholder objectives to integrate and deploy EVs, with supporting infrastructure investments. We will continue to solicit the input of stakeholders in our service territory and with the Joint Utilities.

4) Identify the types of customer and system data that are necessary for planning, implementing, and managing EV charging infrastructure and services and describe how the utility provides those data to interested third parties.

The Companies continue to assess the customer and system data necessary for planning and managing EV charging programs. As the Companies establish a more definitive approach to the EV rollout, we plan to identify data needs and share them with third parties, consistent with our approach to sharing system data with DER developers.

5) By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with New York State policy, including its *established goals for EV adoption.*

Our goal is to build the capabilities to enable a robust EV market in our service territories. As identified in the Implementation Schedule above, these capabilities include:

- Forecast and assess network impacts / needs;
- Integrate EV load while minimizing impact on peak demand;
- Support EV market growth with sufficient charging infrastructure; and
- Communicate the benefits of EVs to customers.

These capabilities will help increase consumer adoption of EVs, ensure drivers have ample options to charge their vehicles, and increase system efficiency. A robust EV market will directly support several of New York's REV goals including:

- Make energy affordable through increasing system efficiency;
- Cut greenhouse gas emissions by 80% by 2050 through supporting adoption of EVs;
- Empower New Yorkers to make informed energy choices through increasing awareness of the benefits of EVs; and
- Support cleaner transportation through supporting public charging infrastructure.

6) Describe the utility's current efforts to plan, implement, and manage EV-related projects. Information provided should include:

a. a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range EV integration plans;

Our EV Roadmap will continue to evolve and become more detailed. We recognize that electrifying the transportation sector is major contributor for the de-carbonization of New York's economy. In addition to the environmental benefits, increased use of EVs can improve asset utilization by increasing non-peak electricity use which has the potential to reduce electricity rates for all ratepayers. Current and future initiatives, as well as scheduling, are discussed in the Implementation Plan above.

b. the original project schedule;

Our high-level roadmap is presented above as part of the Future Implementation and Planning section of this response.

c. the current project status;

The current project status is discussed in the Future Implementation Planning section of this response.

d. lessons learned to-date;

The Companies have not yet derived any lessons learned from our EV innovation projects, which are in the early stages of development. The Companies will assess lessons learned and incorporate them into system-wide rollouts.

e. project adjustments and improvement opportunities identified to-date;

Our EV innovation projects are in the early stages of development; adjustments and improvement opportunities have not yet been identified.

f. next steps with clear timelines and deliverables;

We are currently focused on innovation projects and will continue with the rollouts, as well as assessing lessons learned throughout the process.

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

The Joint Utilities' Electric Vehicle Working Group provides a platform for collaboration and coordination on EV-related issues among the Joint Utilities. Most recently, the working group developed the EV Readiness Framework, which documented a consistent approach to EV integration agreed to by the individual utilities, considering input from other key stakeholders. The document also highlights a summary of utility EV demonstration and pilot projects. EV innovation projects will likely form the basis of planning related to transportation electrification moving forward. The Joint Utilities anticipate that the EV Working Group will continue to serve as a productive platform to collaborate and coordinate as it relates to EV-related projects.

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

The Companies continue to coordinate with these entities through efforts organized and managed by the Joint Utilities.

4.6 Energy Efficiency Integration and Innovation

Introduction/Context and Background

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

As discussed in our 2017 Energy Efficiency Transition Implementation Plans (ETIP), we have continued our well-performing energy efficiency programs while aligning our Integrated Planning process and energy efficiency activities with initiatives to implement the Governor's Reforming the Energy Vision (REV) strategy and New York's Clean Energy Standard (CES).[52] As described further below, we have integrated energy efficiency into our Non-Wires Alternative (NWA) planning and procurement processes. We view energy efficiency as a grid resource that saves our customers money while producing a public benefit.

Learning through innovation projects is a key part of our strategy in order to stretch our energy efficiency spending as far as possible. We have designed, implemented, and learned from an integrated set of innovation projects that provide insights on how our customers prefer to engage with energy efficiency and demand response activities. These are discussed below in response to Subpart 7. We remain committed to creating markets that enable energy efficiency by promoting customer choice, attracting investment, and reducing costs.

Implementation Plan, Schedule, and Investments

To describe the details of the current and future implementations, the utility should use system diagrams, process flow diagrams, tables, and narrative text as needed for clarity and thoroughness. When describing the progression from the current implementation to the future implementation, the utility should use narrative text, Gantt charts, and calendars which present and explain the planned sequence and timing of the notable development activities, dependencies, and milestones.

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

Our existing energy efficiency portfolio includes:

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52 NYSERDA website link: New York Clean Energy Standard

- Residential Electric and Natural Gas Programs;
- Residential Natural Gas Rebate Program;
- Multi-Family Electric and Gas Programs;
- Non-Residential Electric and Gas Programs;
- Commercial and Industrial Rebate Program;
- Small Business Direct Install Program; and
- Large Customer Self-Direct Program.

In addition to offering a suite of energy efficiency programs approved and listed in the 2017 ETIP filing, we offer a menu of incentives to attract customers to participate in the programs. These incentives include equipment replacement and rebates for residential and business customers that install more efficient equipment and related energy management controls. We are looking to push rebates upstream to distributors of energy efficient heating, ventilation, and air conditioning (HVAC) equipment and will expand this strategy to other types of efficient equipment. Customers receive the benefit of the rebate, without having to take any action as the distributor is reimbursed by NYSEG or RG&E.

These programs produce energy savings and carbon reductions throughout the year, including hours when local distribution facilities experience peak demand. In addition to reducing participating customers' energy bills, they produce carbon reduction and other environmental benefits for every kilowatt-hour (kWh) saved.

With the issuance of the Department of Public Service Staff Whitepaper, Guidance for 2018 DSIP Updates ("Staff 2018 Guidance") and New York State Energy Research Development Authority's (NYSERDA) April 2018 white paper, "Energy Efficiency New York" ("EE New York"), we are focused on learning on how to position energy efficiency to contribute to savings for our customers, to increase the efficiency and reliability of our grid, and to realize New York's clean energy policy goals. As observed in the EE New York white paper, energy efficiency has the potential to deliver one-third of New York's greenhouse gas emissions reduction goal. Energy efficiency, including finding ways to engage our customers through innovative offerings, engagement strategies, and delivery models is a foundational component of our global aspiration to deliver clean energy.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Appendix A: 2018 DSIP Guidance Requirements

We are committed to connecting our customers with the insights and options to invest in energy efficiency that reduce their costs, contribute to lower carbon emissions, and provide value to the grid by helping avoid or defer infrastructure investments. Energy efficiency may be self-directed based on customer education or insights provided by NYSEG or RG&E, delivered by one of our utility programs, or provided by NYSERDA or another third party.

At this time, we anticipate that our portfolio of strategies and tactics will evolve over the five-year DSIP period and include the following:

1) Options and insights made available to customers through one of our on-line marketplaces;
2) Conservation and load management, including passive and active demand response programs, that become a utility contribution to an NWA opportunity;
3) Targeted energy efficiency to a location that we anticipate will be experiencing constraints within a few years, but may not end up being a good NWA opportunity;
4) Energy efficiency programs that are offered to all of our customers that have a positive benefit cost analysis (BCA);
5) Energy efficiency programs that are made available to low- or moderate-income (LMI) customers separately or in coordination with NYSERDA or another public agency;
6) Targeted energy efficiency to particular customers based on data and data analytics that suggests that they are likely candidates for significant and cost-beneficial investments in energy efficiency;
7) Targeted insights, communicated to particular customers based on data and data analytics that prepare them to make self-directed decisions that reduce their energy usage;
8) Rebates provided "upstream" to vendors that sell energy efficiency appliances, supported by customer education; and
9) Connecting customers to third-party finance options.

We have already gained experience in the first few options within NYSEG and RG&E service territories, as well as through our other utility affiliates. This portfolio of options will be improved through innovation projects, and is clearly consistent with New York's vision for energy efficiency and AVANGRID's vision to deliver clean energy and value to customers. While the Commission will retain oversight over our energy efficiency portfolio, we believe we already have the necessary authority to take these actions. In addition, while some incremental investments will be required around data analytics, these initiatives will leverage the advanced metering infrastructure (AMI) and other foundational investments we already have planned. Thus, the most significant investment will be leveraging the data that will be made available through AMI to improve the customer engagement and quality of insights to customers, or enabling our customers to use our insights and platforms to self-direct their own solutions. AMI metering data will provide more granularity around the impacts of energy efficiency on usage, providing additional rigor to the measurement and verification of energy savings. Over time, this will allow us to design and implement better programs, with appropriate financial discipline, and enhance public support for energy efficiency programs.

The most successful of these options may become transformative, achieving success similar to industry LED lighting programs. This would allow us to continue to explore, learn, and invest in new energy efficiency opportunities.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified two risks related to performance of our Energy Efficiency efforts, and have taken measures to mitigate each risk, as shown in Figure 4.6-1.

FIGURE 4.6-1: ENERGY EFFICIENCY RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Delivering Customer Value:** Customer value will also be driven by the products and services offered by third parties using the NYSEG/RG&E platform.	• Apply lessons learned from Energy Smart Community and innovation projects to adjust and implement to scale • Confirm value propositions with focus groups • Communicate value and promote customer adoption of products and services • Advocate Reforming the Energy Vision policies that align with customer value
2. **Execution:** Ability to collaborate with internal and external stakeholders to integrate energy efficiency.	• We must learn from the Energy Smart Community and innovation projects. • Integrate energy efficiency into Integrated Planning and NWA processes • Capture lessons learned and develop plans to apply at scale for all demonstration and innovation projects

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design; how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Companies, along with the other Joint Utilities, were active participants in the Clean Energy Advisory Council (CEAC) process that included approximately 60 parties (122 meeting participants) and produced 14 reports, including, most notably for the future path of energy efficiency, the "Energy Efficiency Procurement and Markets Report," issued on May 19, 2017. A second major stakeholder effort began in June 2018 as part of Case 18-M-0084, regarding New York's Comprehensive Energy Efficiency Initiative.

We engage directly with energy efficiency and demand response providers as part of our NWA procurement efforts. We engage with these stakeholders and directly with our customers as part the Energy Smart Community project and other innovation initiatives. Stakeholder engagement is embedded in our design and implementation efforts to obtain lessons learned in our various innovation efforts.

We also addressed our approach to Energy Efficiency in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

Additional Detail

Energy Efficiency integration with a focus on innovative market enabling tools and approaches is an essential utility function that needs to be thoroughly addressed within the five-year planning horizon of the DSIP Update filing. The utilities should provide the information specified below to show how their joint and individual efforts are fully integrating current and expanded energy efficiency efforts into their system planning and forecasting functions. The utilities should also describe how new tools and approaches are being used to support the growth of a more dynamic market of service providers that deliver energy efficiency at a reduced cost by leveraging private capital and financing to deliver greater customer value while optimizing the grid value of these services. Throughout this time period each utility will evolve their current ETIPs into a System Energy Efficiency Plans (SEEPs) describing the entirety of the utility's expanded reliance on and use of cost effective energy efficiency to support their distribution system and customer needs. ETIPs / SEEPs will continue to be filed separately in accordance with Staff issued ETIP / SEEP Content Guidance but the DSIP must incorporate and plan for the integration and reliance on these expanded energy efficiency resources and should include a link to the most recent ETIP/SEEP filing.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to energy efficiency:

Our most recent ETIP filing, submitted on June 1, 2017, can be downloaded from the Commission's website.[53] Our future System Energy Efficiency Plans (SEEPs) will support the vision for potential future energy efficiency services which are flexible and support REV principles. Most notably those promoting system reliability and resiliency, market animation, leveraging ratepayer contributions, and the reduction of carbon emissions.[54]

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

NYSEG and RG&E consider energy efficiency as the first option when meeting customer demand. Energy efficiency actions that reduce demand during peak periods are more likely to lead to long-term savings from capital investments or NWA contracts that are driven by peak demand.

It is our practice to look for energy efficiency opportunities in areas that are potential NWA candidates. Thus, we have targeted a few large customers located behind Station 51, a currently planned NWA, in an effort to identify energy efficiency and other demand-side actions that would reduce the peak demand that would otherwise need to be met by the NWA. It is important to develop and target energy efficiency options to areas of the system expected to need investments to meet capacity needs as these will result in the greatest cost savings, an outcome that we expect to see in project-specific BCAs.

The sustained impact of past energy efficiency programs is reflected in the load forecasts, a practice utilities have applied for years. However, we anticipate we can improve our ability to reflect locational energy efficiency in our databases and forecasts once we have AMI and other foundational investments in place, starting with our Energy Smart Community project. We further anticipate that applying new data analytics to customer usage data from AMI and other data from our own databases and public demographic information will allow us to target communications to customers offering insights regarding energy efficiency opportunities and actions they should consider.

2) *The locations and amounts of current energy and peak load reductions attributable to energy efficiency and how the utility determines these.*

NYSEG and RG&E estimate the location and amounts of anticipated energy and peak load reductions when they are associated with an NWA. These are based on customer-specific assessments and we rely on them when defining the NWA requirements.

We do not currently have an automated way to track the location of savings from energy efficiency programs, other than for identified NWA opportunities that have been assessed for

53 Available here.

54 Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, April 25, 2014, "Order Instituting Proceeding", ("REV Order"), page 2.

this purpose. However, as noted in the response to Subpart 1, we expect to be able to target energy efficiency activities to locations of future need, including locations that may not be candidates for an NWA. This could involve targeted solicitation of customers within those areas identified by analyzing AMI and other customer information, offering incentives to engage in energy efficiency measures that contribute to alleviating a local constraint. These incentives may include incentives to turn thermostat settings higher by a few degrees during peak periods or pay-for-performance compensation models. The Connecticut affiliate, United Illuminating Company, has been exploring similar strategies and has two DER innovation projects in development.

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

Our ETIP filings present estimated energy savings for the non-residential, residential, and multi-family sectors for the current year as well as three forecasted years. These estimates are based on spending levels on energy efficiency programs targeted by sector and an estimate of the effectiveness of each program in realizing energy savings. Savings estimates are informed by our Evaluation, Measurement, and Verification (EM&V) activities, as described in our ETIP filings. NYSEG and RG&E have established five objectives to guide EM&V activities:

1) Verification of program and portfolio record keeping;
2) Verification of measure installations and savings reporting;
3) Determination of savings persistence of individual measures, including lifetime savings;
4) Measurement of demand reduction coincident with the circuit/substation, utility system, and New York Independent System Operator (NYISO) demand peaks; and
5) Ex-post benefit/cost testing of programs and portfolios.

With respect to the item 4, we anticipate that impact evaluations would include site and measure-specific interval metering to develop peak period coincidence factors. The availability of AMI throughout our service territories will support efforts to estimate peak load reductions. In the interim, we will rely on the installation of on-site metering of a statistically significant sample of measures and projects.

We are also testing geo-targeting concepts, varying incentive levels, and building stock analyses in an effort to predict energy efficiency impacts in targeted geographic areas.

4) *How the utility assesses energy efficiency as a potential solution for addressing needs in the electric system and reducing costs.*

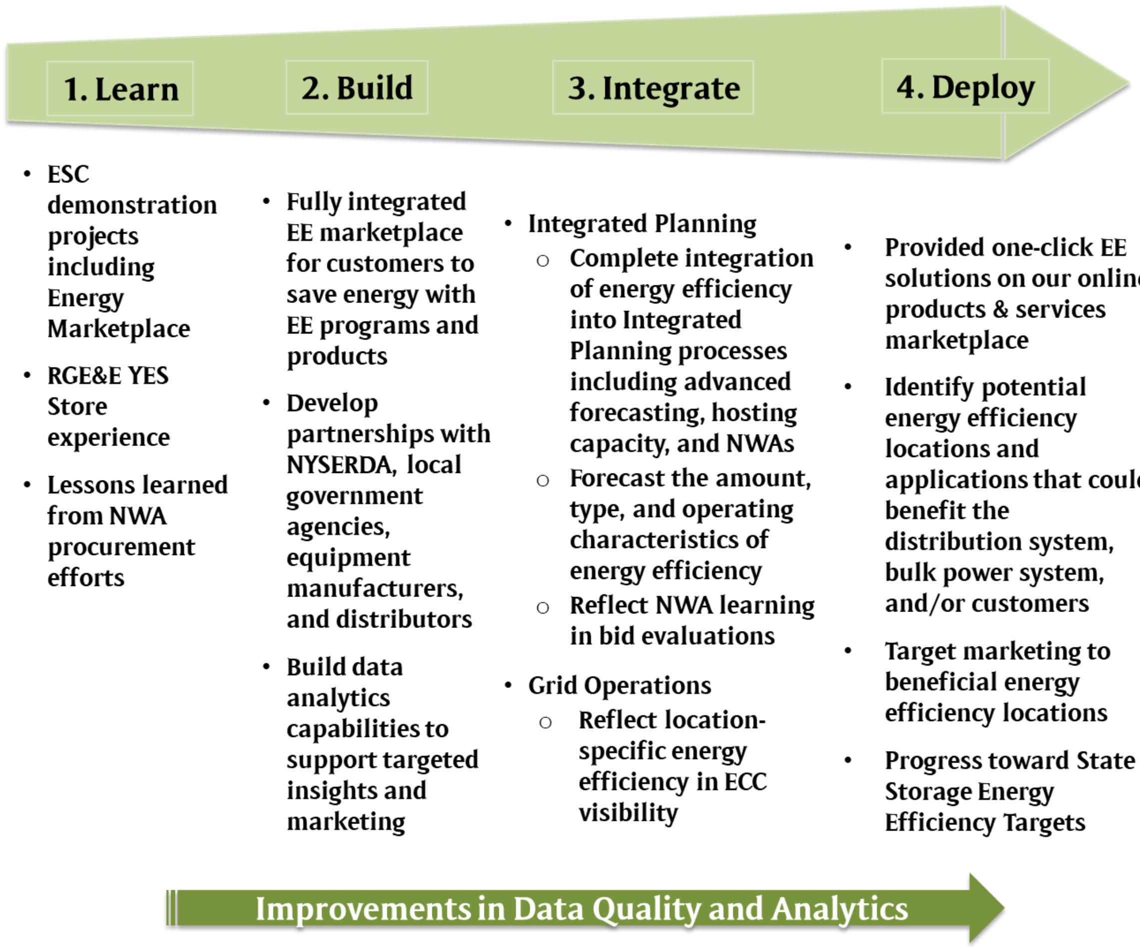
NYSEG and RG&E are already incorporating energy efficiency within our NWA projects, and expect to continue to improve as we gain more experience with NWA solicitation and contracting efforts. While energy efficiency has long been recognized as contributing to customer and environmental goals, this third benefit solidifies its position as a core utility function. As we move from learning to deployment, energy efficiency will increasingly be treated as a system resource by us, accounted for in traditional cost recovery or rate-based approaches and integrated into DSIPs, which document a utility's integrated approach to planning, investment and operations. Ideally, the regulatory framework will align our shareholders' interests with those of our customers and public benefits and help us to contribute to EE New York's relatively aggressive 3% efficiency savings target.

In addition, we have three innovation efforts that target energy efficiency specifically. First, we have installed approximately 12,300 electric meters and 7,600 gas meters in our Energy Smart Community AMI project. Participants will be able to access their personal energy data and receive usage alerts, along with tools and tips to help better manage their energy usage. This is being accompanied by outreach that seeks to gather insights on how we might be able to identify incentives to provide market-based energy efficiency programs.

Second, RG&E's Energy Marketplace includes an on-line portal demonstration project (the Your Energy Savings, "YES" Store) that offers point-of-sale on products such as LED lighting, advanced power strips, and Wi-Fi enabled thermostats that help customers reduce their energy usage and contribution to system peak demand. This products and services marketplace also offers non-incentivized water saving devices and connected home technologies in which customers can connect to their home monitoring systems, smoke alarms, and even control their lighting through use of a smart phone. The RG&E YES Store is also being leveraged as a distribution channel to cross-promote the Smart Savings Rewards Direct Load Control Demand Response program. Each eligible thermostat product page contains links to the demand response program and email marketing campaigns that have been developed to target previous YES Store smart thermostat purchasers, further integrating energy reduction and demand response.

We are integrating energy efficiency into our Integrated Planning function by employing the DER integration and deployment strategy as shown in Figure 4.6-2.

FIGURE 4.6-2: ENERGY EFFICIENCY INTEGRATION AND DEPLOYMENT STRATEGY



Our innovation efforts are described more fully in the response to Subpart 7 below.

5) How the utility collects, manages, and disseminates customer and system data (including energy efficiency project and load profile data) that is useful for planning, implementing, and managing energy efficiency solutions and achieving energy efficiency potential.

We are focused on applying data analytics to AMI and other customer-specific data in order to inform these customers of the energy savings accessible through energy efficiency and the variety of actions that they should consider taking advantage of NYSERDA and our programs. Our customers can self-direct from among these energy efficiency solutions and from products and services offered by competitive suppliers that will help them reduce their energy usage.

Our overall approach to sharing system data and customer data is discussed in 2018 DSIP Guidance Response Sections 4.7 (Distribution System Data) and 4.8 (Customer Data) and in Chapter VII of our 2018 DSIP Report.

6) How the utility's accomplishments and plans are aligned with New York State climate *and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with a new 2025 energy efficiency target called for in Governor Cuomo's 2018 State of the State Address.*

AVANGRID, including NYSEG and RG&E, is aligned with the energy efficiency goals that have been set forth by Governor Cuomo and his administration including the concepts laid out in NYSERDA's April 2018 white paper, "Energy Efficiency New York" ("EE New York"). We look forward to engaging with NYSERDA, DPS Staff, and other stakeholders in Case 18-M-0084, regarding New York's Comprehensive Energy Efficiency Initiative. New York's greenhouse gas emissions reduction goal is consistent with our corporate goals and we are on a global path to deliver clean energy to our customers. Energy efficiency and other ways to engage our customers through innovative offerings, engagement strategies, and delivery models, is a foundational component of our corporate strategy.

7) *A description of lessons learned to date from energy efficiency components of REV Demonstration Projects with specific plans for scaled expansion of successful business model demonstrations. In addition, provide a description of each hypothesis being tested as part of energy efficiency components of ongoing Demonstration Projects and the anticipated schedule for assessment.*

In April 2018, we launched the Smart Partner Program as part of our Energy Smart Community demonstration project. This is a partnership with Cornell's Cooperative Extension that provides energy efficiency outreach and education for low- and moderate-income (LMI) customers within Ithaca and Tompkins County. The program leverages Cornell's Cooperative Extension *Get Your Greenback* program and introduces our market Energy Manager and Smart Solutions platform tools to serve more than 400 LMI customers in the Energy Smart Community.

The design of the Smart Solutions platform reflects lessons learned in our 2015 Community Energy Coordination demonstration project that tested approaches to reducing customer barriers to the adoption of DER, including energy efficiency, in NYSEG's service territory.

Our RG&E YES Store is an e-commerce site launched in Q3 2016 and developed to test energy-related online transactions, customer satisfaction, and the delivery of more comprehensive energy solutions for customers. Each phase of the launch was executed with email marketing campaigns designed to motivate customers to act toward purchasing energy efficiency products. This products and services marketplace continues to expand product offerings and coordinated offerings with new programs such as demand response and energy efficiency.

The Energy Smart Community project has incorporated Energy Manager to offer more informed customer options based on granular AMI usage information. The NYSEG Smart Solutions and Energy Manager platforms have been deployed to provide a seamless experience for obtaining AMI interval data, energy efficiency tips and self-audits, access energy-related service and products providers, instant rebates and enrollment demand response and pilot rate programs. The platform was designed to ensure that customers receive relevant offers and customized solutions that meet their needs and reinforce NYSEG's role as the trusted energy advisor while providing opportunities for market participants. Our Energy Smart Community products and services marketplace also supports bundled offerings such as direct enrollment in the demand response program with a thermostat purchase. Offerings will continue to evolve, and customers will be able to connect to the marketplace through the Energy Manager tool and be able share their energy usage with participating service providers.

8) Explain how the utilities are coordinating on energy efficiency to ensure diversity of both the models demonstrated and the technologies/methods employed in those applications.

The Joint Utilities have actively coordinated their energy efficiency program design and implementation since the May 2007 order instituting an Energy Efficiency Portfolio Standard, which continues through formal and informal teams addressing all aspects of the Reforming the Energy Vision and Clean Energy Fund Proceedings. As mentioned above, we actively participate, along with the other Joint Utilities, in the Clean Energy Advisory Council process.[55] This coordination continues today including in the evolution of the utility energy efficiency programs from the ETIP framework to the recently instituted SEEP framework, according to which, over the next five-year DSIP planning period, each utility will integrate energy efficiency planning into their forecasted system plans and evolve their ETIP into a SEEP that describes the entirety of the utility's expanded reliance on and use of cost effective energy efficiency to support their distribution system and customer needs.[56]

As part of the continuing coordination efforts, the Joint Utilities participate in a working group in which we share information regarding development and testing of new energy efficiency programs and strategies. These coordination efforts address topics such as distribution channel marketing, home energy reporting, online energy marketplaces, and smart home rates. This coordination will inform current and future energy efficiency efforts, and help the utilities design a diverse portfolio of projects targeting a broad range of customers. The Joint Utilities remain committed to continuing this coordination to further support the diversity of energy efficiency programs across the state, and to achieve the energy efficiency targets prescribed by the State Energy Plan.

9) Describe how the utility is coordinating and partnering with NYSERDA's related ongoing statewide efforts to facilitate energy efficiency market development and growth.

We are currently collaborating with NYSERDA on their Agriculture Energy Audit Program, Commercial Implementation Assistance Program, Industrial and Process Efficiency Program, Multifamily Performance Program, and Empower Program. We are interested in continuing to coordinate with NYSERDA to develop complementary program offerings, while streamlining enrollment and referral processes to facilitate customer participation to benefit from both sets of energy efficiency programs. We are particularly interested in NYSERDA's Pay for Performance

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55 16-01005, In the Matter of the CEAC's Clean Energy Implementation & Coordination Working Group January 31, 2017), pp. 2-6.

56 CASE 15-M-0252 - In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets And Targets For 2019 – 2020, (March 18, 2018), p. 29.

pilots and look forward to collaborating on those initiatives.

4.7 Distribution System Data

Introduction/Context and Background

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

Over the past two years, we have worked with the Joint Utilities and stakeholders to refine distribution system data-sharing procedures, standards, and protocols.[57] Distributed energy resource (DER) developers/operators are now able to securely access our system data through web-based tools.

System data is collected at various levels of granularity, including the circuit, substation, and system level. System operators, planners, and designers rely on system data to generate useful information for planning and grid operations. Sharing system data provides insight into areas on our system where a DER developer is likely to be able to interconnect at a lower cost. System data also helps a DER provider tailor a response to a non-wires alternative (NWA) Request for Proposals (RFP).

Since the 2016 DSIP, we have been focused on taking inventory and providing extensive system data through a variety of methods. The Companies, in coordination with the Joint Utilities, developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals. The system data website includes utility-specific links to an expanded range of useful information, including:

- DSIPs;
- Capital investment plans;
- Planned resiliency and reliability projects;
- Reliability statistics;
- Hosting capacity;
- Beneficial locations;
- Load forecasts;
- Historical load data;
- NWA opportunities;
- Locational System Relief Value (LSRV) locations;
- Queued and installed distributed generation (DG); and
- Standard interconnection requirements (SIR) pre-application information.

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[57] Refer to our 2018 DSIP Report Appendix B for link to Joint Utilities' system data portal for more information on system data tools.

Implementation Plan, Schedule, and Investments

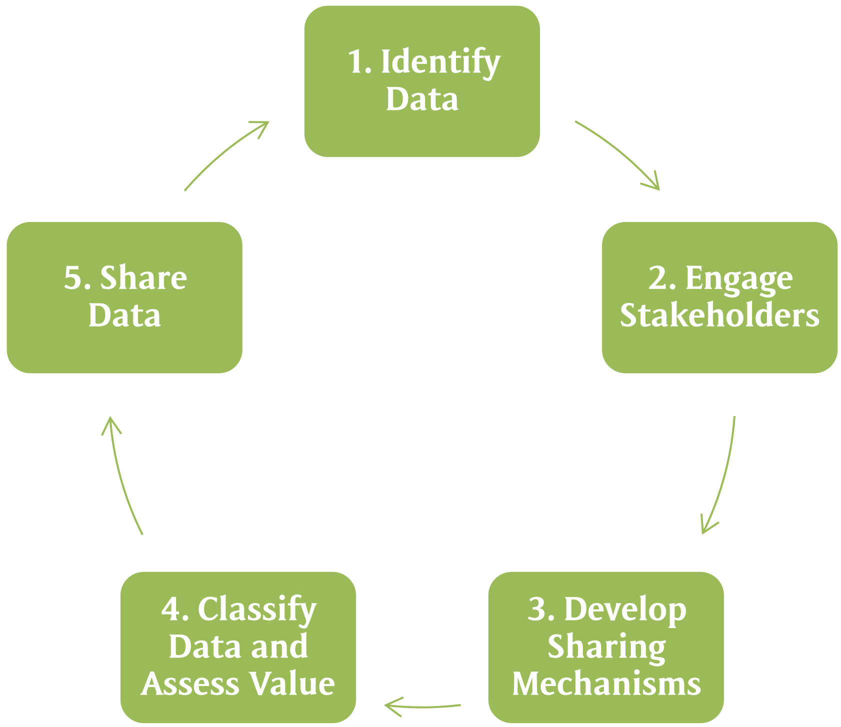
Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

As presented in Figure 4.7-1, we have a five-step approach to implementing distribution system data-sharing capabilities, which is an iterative approach as we make progress:

1. Share data: We have shared significant customer and system information through a variety of channels. As noted above, the Joint Utilities have developed a website, which includes an inventory of available data including links to 2016 DSIPs, capital investment plans, planned resiliency/reliability projects, and load forecast information, as examples. NYSEG and RG&E have also launched portals to provide system information to DER providers including interconnection, NWA, and system data portals, as well as hosting capacity maps.
2. Identify data: System data is data that originates or pertains to the electrical grid. It includes grid information at a location, such as real and reactive power consumption, estimated hosting capacity, power quality, and reliability. Since the 2016 DSIP, we have been focused on inventorying and providing extensive system data through a variety of methods. We leveraged advanced metering infrastructure (AMI) data that is available in our Energy Smart Community project to inform hosting capacity and system planning.
3. Engage stakeholders: The Joint Utilities have made significant efforts to work with stakeholders to identify system data that is most valuable. The Joint Utilities hosted a number of stakeholder discussions in order to identify and prioritize additional third-party and customer data needs, while clarifying what data is currently being used and how.
4. Assess sharing mechanisms: We developed a number of data portals and continue to refine/expand system data based on stakeholder needs.
5. Classify data and value: As we develop sharing mechanisms, we continue to classify the data and assess the value to third parties.

FIGURE 4.7-1: INFORMATION SHARING APPROACH



Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Future efforts will focus on refining sharing mechanisms and proactively anticipating and/or responding to third-party provider system data needs. An increase in the frequency and usefulness of system information will contribute to an optimized and integrated platform as DER penetration rates increase. We will continually identify new data and assess what information can and should be shared based on the value to customers and the market. We will also continue to focus on updates to its data portals, as well as refining and/or expanding system data use cases to better meet stakeholder needs. For examples, we are investing in technology and systems to acquire 8,760-hour annual load data at substations, along circuits, and at customer premises to improve the accuracy of its hosting capacity.

Figure 4.7-2 presents our high-level distribution system data roadmap.

FIGURE 4.7-2: DISTRIBUTION SYSTEM DATA ROADMAP

Process Step	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term (2021-2023)
Share Data	Published Available System Data on Portal Provided Circuit-Level Hosting Capacity Data and Maps	Continuous Sharing of Developments within Each Utility's System Data Portals. Develop Broader Set of Specifications for Joint Utilities' Portals.	Development of an Advanced NWA Data Portal
Identify Data	Assessed ESC AMI Data to Inform Hosting Capacity and System Planning	Adapt Portals and System Data Needs Based on SIR Update	Assess Full Volume 8,760 AMI Data to System Data Requirements
Engage Stakeholders	Engaged Stakeholders through Joint Utilities' Process to Develop Data Uses Cases	Engage with Stakeholders and Joint Utilities to Assess Need to Broaden the Types of Data Elements to be Developed Participate in a Forum for Data-Sharing Reciprocity	Annual Needs Assessment to Seek Stakeholder Feedback on Data Portals.
Assess Sharing Mechanisms	Tested New Hosting Capacity Capabilities within ESC	Conduct a Benchmarking Study of How Out-of-State Utilities Classify Basic vs. Value-Added Data	Develop Stage-4 Hosting Capacity Portal
Classify Data and Values	Developed Comprehensive List of System Data	Complete Mapping of All Available Data and Queries Necessary to Provide System Data; Mapping Includes Security and Privacy Requirements	Ongoing Assessment of System Data, Focused on Increased Granularity from AMI and Automation

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

Distribution system data-sharing capabilities must balance safeguarding system data with providing third parties with system data needed for operations. Distributed system platform (DSP) performance will depend on the security of data, among our Technology Platform systems and with customers, including DER developers and operators. We will continue to refine data governance procedures to safeguard data and build redundancies into the network.

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design; how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses.

The Joint Utilities have made significant progress working with stakeholders to identify system data that is most valuable, hosting a number of stakeholder discussions in order to identify and prioritize additional stakeholder data needs. During those sessions, the Joint Utilities worked with stakeholders to clarify what data is being used, how it is being used, and the additional data sets that would be of value to third parties and customers. Through discussions with stakeholders, the Joint Utilities have been able to better understand the specificity and rationale of information requested by developers and subsequently have made progress in providing additional information that is of value to developers. The Joint Utilities' System Data Working Group will continue focusing on updates to and consistency of individual utility data portals, as well as refining and/or expanding system data use cases to better meet stakeholder needs. The Joint Utilities will continue engaging stakeholders on business use case discussions, which will continue to provide a forum for further dialogue around potential value-added information by improving access to more refined "information sets" developed through analysis/analytic applications.

We also addressed sharing of system data in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

Additional Detail

The DSIP Update should describe the utility resources and capabilities which will enable timely and effective system data sharing. Based on data requirements derived from extensive stakeholder inputs, the utilities should collect, manage, and share a wide variety of detailed distribution system data. The shared data must enable DER developers/operators and other third parties to timely and effectively perform the analyses (engineering, operations, and business) needed to support well informed decisions. That enablement is materially affected by the types of data shared, the spatial and temporal *granularity of the data, the accuracy of the data, the age of the data, data formats, and the methods used for sharing the data.*

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to Distribution System Data:

1) Identify and characterize each system data requirement derived from stakeholder input.

System data can be collected at various granularities including the circuit, substation, and system level. System operators, planners, and designers rely on system data to generate useful information for planning and grid operations. Sharing system data provides insight into areas a DER developer might interconnect with the system at a lower cost. It also helps a DER provider tailor a response to an NWA RFP. System data requirements derived from stakeholder input include:[58]

- DSIPs: Joint Utilities' initial DSIPs, Joint Utilities' Supplemental Distributed System Implementation Plan ("Supplemental DSIP"), and associated appendices provide DER developers/operators information related to future plans to build the DSP.
- Capital investment plans: Provide DER developers/operators with information on key locations for investments and constrained regions.
- Planned resiliency and reliability projects: Project lists include location, size, and reasoning for investments.
- Reliability statistics: Help identify constrained areas.
- Hosting capacity: Feeder-level hosting capacity for analyzed feeder.
- Beneficial locations: Identified high-priority locations where DER could provide distribution system relief.
- Load forecasts: We are developing more granular load forecasts to integrate DER.
- Historical load data: Provides DER developers/operators with information on usage patterns.
- NWA opportunities: As reported on the NWA portal, provides NWA project summaries and status.
- Locational System Relief Value (LSRV) locations: LSRV locations allow DER developers to relieve grid congestion in those areas for credit.
- Queued and installed Distributed Generation (DG): Provides DER developers with information on generation in the interconnection requests queue or already installed.

58 Refer to our 2018 DSIP Report Appendix B for link to Joint Utilities' system data portal for more information on system data tools.

- Standard Interconnection Requirements (SIR) pre-application information: Validates queue information, informs the timing of applications, and informs the future status of feeder/substation conditions related to potential versus actual DER connected and associated costs.

2) Describe in detail the resources and methods used for sharing each type of distribution system data with DER developers/operators and other third parties.

Since the 2016 DSIP, we updated or launched a number of system data sharing portals to support system sharing. Additional detail is presented in Figure 4.7-3.

FIGURE 4.7-3: SYSTEM DATA SHARING PORTAL

Data Element	Information Provided via Portals
Hosting Capacity	Feeder level hosting capacity for analyzed feeders[59]
Interconnection Portal	Interconnection application and status[60]
System Data Portal	Links to key system data information including portal links, filings and system reporting[61]
NWA Portal	NWA project summaries and status [62]

In addition, the Joint Utilities' DSIPs are available on the Joint Utilities website and 5-year capital investment plans are filed with the Commission annually and are publicly available. Beneficial locations for DER are identified in the NYSEG and RG&E Five-Year Capital Investment Plan, filed at the end of March each year. They are identified by the projects listed as candidates for an NWA. NWA opportunities are available through NWA portal. The queued and installed DG information are available through the SIR Inventory Information. The SIR pre-application information is available through the online application. In addition, resiliency/reliability projects are available through the 2016 Annual Reliability Report, and reliability statistics are available through the 2016 Electric Reliability Report. Load forecasts are available through email requests.[63]

We will continue to focus on updates to the data portals, as well as refining and/or expanding system data use cases to better meet stakeholder needs. For examples, we are investing in technology and systems to acquire 8,760-hour annual load data at substations, along circuits, and at customer premises to improve the accuracy of its hosting capacity. We will also need to update our hosting capacity and interconnection portals and system data to incorporate the new requirements from the SIR Update that is anticipated in Q1 2019.

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59 Portal

60 NYSEG, RG&E

61 Joint Utilities

62 NYSEG, RG&E

63 Email requests made to NYRegAdmin@avangrid.com

3) Describe where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download each type of shared distribution system data.

As noted above, information such as hosting capacity, interconnections, NWAs, and selected system data are available on various portals.

In addition, certain types of data we expect to provide to developers is presented in Figure 4.7-4below. Some of these data are not available currently, but will become available as our Technology Platform is developed. Increased granularity of system data, particularly with respect to geospatial and time dimensions, will contribute to more efficient DER offerings, solutions and investments.

FIGURE 4.7-4: 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[64]
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

64 We are developing a process to securely provide these data to DER providers.

4) Describe how and when each type of data provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

Since filing our 2016 DSIP, we have focused on taking inventory and providing extensive system data through a variety of methods. In June 2017, the Joint Utilities provided a central data portal on the Joint Utilities' website with links to utility-specific web portals. As we continue to integrate more DER into operations and refine the portals, as well as incorporate feedback from DER providers, the data provided to DER developers/operators will improve. This Joint Utilities web portal, in addition to posting the links on utility-specific web portals, has increased access to and increased the availability of system information. Stakeholders now have improved awareness of the data currently available through utility-specific web portals. We will continue update our data portals, and refine and/or expand system data through use cases to better meet stakeholder needs.

5) Identify and characterize the use cases which involve third party access to sensitive distribution system data and describe how the third party's needs are addressed in each case.

As discussed in the Stakeholder Interface response, the Joint Utilities hosted a number of stakeholder discussions in order to identify and prioritize additional stakeholder data needs. During those sessions, the Joint Utilities worked with stakeholders to clarify what data is being used, how it is being used and the additional data sets would be of value to third parties and customers. As part of the process, the Joint Utilities and stakeholders collaboratively developed multiple use case scenarios. The use cases help the participants better understand how data is used and what data is necessary to meet stakeholder needs. Through targeted use case discussions, interested stakeholders worked together with the Joint Utilities to develop five initial business use cases. Figure 4.7-5 presents an example of one such use case, where developers identified "need to have" and "nice to have" types of information.

FIGURE 4.7-5: SYSTEM DATA USE CASE EXAMPLE

Stakeholder Use Case #1 (UC-1): Interconnection Cost Estimates – Pre-Coordinated Electric System Interconnection Review (CESIR)	
Description	A developer will want to review utility-provided information to make an informed and reasonably accurate assessment of what interconnection costs and timeline outcome might be and whether or not it would be cost-effective to go forward with the project.
Information Requested	**Why the Information is Requested**
"Need to Have"	
Min/Max/Avg Load Data at Feeder and Substation Levels	• Can provide insight into thermal limitations, voltage fluctuation constraints (*i.e.*, higher fault duty =more stable) • Informs analysis of possible modifications due to exceeding substation backfeeding thresholds • Provides generation/load ratio calculations as they relate to Sandia screening
DER Already Connected	• Related to load data above, critical component to calculating potential DER capacity on feeder/substation • Can inform of possible existence of substation level upgrades that may have already been completed at existing level of penetration
Pre-Application Report Information (provided with Preliminary CESIR)	• Information/feeder conditions may have changed since date of pre-application report and date of application submission • Developer may not have completed pre-application report request for reasons related to expedition of application process
SIR Inventory Information (to include application status of interconnections in the inventory)	• Validates queue information provided in other data sources • Informs timing of application submission, CESIR commencement • Informs future state of feeder/substation conditions related to potential vs. actual DER connected, which in turn informs cost/impact estimation
Circuits identified by ID # on mapping tools	• Allows user to cross reference data from all different sources with mapping tools
"Nice To have"	
Conductor Size	• Can be used to evaluate potential thermal capacity of feeder and estimate re-conductoring costs, if necessary
Utility Fault Current Contribution and Impedance at PCC	• Can be used to evaluate necessity of system upgrades • With some utilities requiring specific grounding transformer sizing to meet effective grounding requirements, this information is critical to performing those calculations

In response to positive feedback received during the stakeholder meetings, the Joint Utilities are engaging interested developers in further discussions to collaborate on additional business use cases.[65]

Through discussions with stakeholders, Joint Utilities have been able to better understand the specificity and rationale of the information requested by developers and subsequently have made progress in providing additional information that is of greater value to developers. The use case discussions also provide an avenue to explore why certain information may have a low probability of being shared. However, this information is embedded in utility planning models, it is not readily available for public presentment.

The Joint Utilities System Data Working Group will continue to engage stakeholders on the business use cases for system data, identify additional datasets to share, and respond to stakeholder requests to improve ease of access to system data.

6) Identify each type of distribution system data which is/will be provided to third parties and whether the utility plans to propose a fee.

As we continue to develop information-sharing capabilities and markets, we will identify whether information provided to third parties is free of charge or is provided for a fee. Reforming the Energy Vision (REV) policy distinguishes between “basic” and “value-added” customer and system data. Basic data is data compiled by the DSP that is either essential to support the fundamental customer/provider relationship (*e.g.*, billing data) or data that supports broad system-wide capabilities and services (*e.g.,* hosting capacity). Value-added data includes customized requests by market participants that helps them pursue market opportunities. The DSP can charge a fee for these services to contribute to the costs of providing value-added data and avoid imposing a cost burden on non-participants.[66] The Joint Utilities have been ordered to develop terms and conditions for providing whole building data.[67] The Joint Utilities are working on a standardized Data Security Agreement that would apply to customer data that is provided to third parties.

The Joint Utilities have not yet established a fixed definition for the fee structures for data requests, but any such effort would be related to whether the data is readily available and the level of effort needed to package and deliver the data. Information that is not readily available and requires additional utility effort to make it available and usable would be considered data provided at a fee.

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65 An expanded selection of business use cases can be found on the website.

66 Order Establishing Community Choice Data Access Fees, December 17, 2017, p. 19.

67 Case 14-M-0101 et al. “Joint Utility Aggregated Whole Building Data Terms and Conditions.” Filed June 19, 2018.

7) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are highly consistent with the means and methods at the other utilities.

The Joint Utilities' 2016 stakeholder engagement sessions identified information to be shared with third parties. In response to stakeholder feedback, the Joint Utilities have developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals with available system data, including DSIPs, capital investment plans, reliability information, hosting capacity, beneficial locations/NWA opportunities, load forecasts and historical load, LSRV, queued/installed DG, and SIR pre-application information.

This new Joint Utilities web portal, in addition to hosting the links to the enhanced utility-specific web portals, has increased access to and improved the usability of useful stakeholder-requested information. This data provides greater transparency into locations on the distribution system where DER integration may have higher-value relative to other locations, greater insight into areas with potentially lower interconnection costs, and greater visibility into system characteristics and needs, which fosters market development. The Joint Utilities have advanced their efforts to release additional data in more accessible formats and stakeholders now have a better understanding of the data currently available through utility-specific web portals.

Through the business use case work, and in response to stakeholder comments, the Joint Utilities are evolving the system data effort to focus more on user experience, data presentment, and potentially more analytic information presentment. The discussions around business use cases have identified the volume of requested information that is already publicly available, but previously may not have been easily accessible and as a result the Joint Utilities have enhanced the accessibility and similarity of the information provided, with the understanding that granularity may vary across utilities.

8) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

We are still developing distribution system information-sharing capabilities, which is an iterative process that progresses based on stakeholder engagement/feedback from DER developers/operators. While we will continue to work with the Joint Utilities on developing data-sharing capabilities, we expect to develop unique data-sharing capabilities based on specific needs of DER developers/operators and system requirements.

4.8 Customer Data

Introduction/Context and Background

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

During the last two years, the Companies have been working with the Joint Utilities to evolve customer data sharing procedures, standards, and protocols. The protection of customer information, including energy usage data and personal information, is an integral part of our responsibilities and commitment to customers. These efforts have established a foundation to provide more information with customers and developers.

We have increased data access by expanding the use of the electronic data exchange (EDI) to new parties, including the New York State Energy Research and Development Authority (NYSERDA), community distributed generation (CDG) hosts, and community choice aggregation (CCA) providers.[68] EDI is an exchange of transactions in a standardized format and is used to communicate a variety of pre-set information including usage and billing information, payment, eligibility, and other information.

We have also launched Smart Solutions, which leverages customer data and market providers to provide customers with products and services that may be of value to them. Smart Solutions provides a products and services marketplace that introduces our customers to solution providers for services such as energy audits or solar proposals. It also sells products, such as smart thermostats, that can support our demand response and energy efficiency programs. NYSEG also launched Energy Manager and Green Button Download My Data in the Energy Smart Community to provide customers with more granular advanced metering infrastructure (AMI) information.

Implementation Plan, Schedule, and Investments

To describe the details of the current and future implementations, the utility should use system diagrams, process flow diagrams, tables, and narrative text as needed for clarity and thoroughness. When describing the progression from the current implementation to the future implementation, the utility should use narrative text, Gantt charts, and calendars which present and explain the planned sequence and timing of the notable development activities, dependencies, and milestones.

[68] New York State Energy Research and Development Authority (NYSERDA) is developing a "Utility Energy Registry" (UER) to provide aggregated load data and promote and facilitate community-based energy planning.

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

Customers have access to their billing and usage information, as well as account detail information (*i.e.,* billing address and account information), via the account manager tool on the NYSEG and RG&E websites.

Customer data is shared with third-party providers in a variety of ways. Authorized energy service companies (ESCOs), distributed energy resource (DER) providers, and other market participants have access to approved customer data via a secure website.[69] Customers enable the sharing of their data by sharing their Point of Delivery ID (POD ID) to an authorized third party. This ensures that providers have access to the information only after receiving authorization from the customers and subject to Commission and our requirements that preserve the security of customer data.[70] Customer data is also shared with ESCOs and other parties via EDI. With the implementation of AMI in the Energy Smart Community, more granular customer usage data is available to customers and third parties, with customer authorization.

Through the Joint Utilities' Customer Data Working Group and stakeholder input, we have developed privacy standards and identified data sets for NYSERDA's Utility Energy Registry (UER) initiative that will share aggregated community level-load data with DER developers. This data is particularly valuable to enable efficient development of CCA and CDG projects. Through the working group and stakeholder input process, we have also developed privacy standards and data sets for Whole Building Energy Usage Aggregations and aggregations of data related to CCAs. The coordination with the Joint Utilities will continue in order to explore ways to improve access to data while continuing to strengthen privacy and cybersecurity protections to protect the security of customer data and the distribution system.

Our Energy Smart Community (ESC) project includes several projects that support future development of information sharing. With approximately 12,300 electric and 7,600 gas AMI meters installed in the Energy Smart Community, we have a strong foundation to assess how more granular data (*e.g.*, residential customer hourly usage information) will be analyzed and shared with customers and third parties, including solar providers, county energy planners, and academics. The ESC enables us to:

- Develop and engage customers on sharing more granular usage information and providing a means to share this information with third parties;
- Develop new online markets to bring together market providers enabled by more

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69 NYSEG secure website and RG&E secure website.

70 For all CCA requests, NYSEG and RG&E require all parties participating in the formation and operation of a CCA to complete the Vendor Risk Assessment (VRA) and execute the Data Security Agreement (DSA). Once an ESCO is selected and has completed the VRA and DSA and is under contract with the CCA, the approved ESCOs may receive customer-specific information.

detailed customer information;

- Leverage granular information to test new rates and customer offerings; and
- Develop new sharing mechanisms such as the Energy Manager portal. Energy Manager will house Green Button Download My Data and Green Button Connect, which will allow customers to share their energy data.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Future efforts to share customer data are guided by use cases that have been developed through a collaboration of the Joint Utilities and DER developers. Selected Customer Data Use Cases are presented in Figure 4.8-1.

FIGURE 4.8-1: CUSTOMER DATA USE CASES

Example Use Cases	Desired Data	Value
ESCOs want aggregated customer data to support prospecting for Community Choice Aggregation (CCA) commodity supply opportunities	• Aggregated usage and installed capacity (ICAP) data at a zip code level or other geo-targeting method • Rate class segmentation • 24 monthly usage with kWh, KW and ICAP tag values	Understand the available opportunity within a community to participate in CCA
Demand Response Program Participation: Aggregated customer data can be used for locating potential participants to enroll in demand response programs	Aggregated customer usage by geography	Future customer acquisition could target areas that will include an NWA
ESCOs want aggregated customer data to assist in making pricing proposals for CCAs	• 24 monthly usage with kWh • Capacity measure • Customer count • Distribution for meter read cycles	Information is critical for accurate pricing
NYSERDA's Utility Energy Registry wants aggregated customer data for energy analyses	Aggregated usage and demand data by municipality.	Energy use profiling and energy intensity analyses by community and region.

We will continue to refine sharing mechanisms and respond to third-party provider customer data needs. We will also continually identify new data and assess what information can and should be shared based on the value to customers and the market. We also plan to update our data portals and refine and expand customer data business cases to meet stakeholder needs. Our five-year DSIP Customer Data Roadmap is presented in Figure 4.8-1.

FIGURE 4.8-2: CUSTOMER DATA ROADMAP

<table>
<tr><th>Capability</th><th>Achievements
(2016-2018)</th><th>Short-Term Initiatives
(2019-2020)</th><th>Long-Term Initiatives
(2021-2023)</th></tr>
<tr><td rowspan="2">Provide Usage Data to Customers and Third Parties</td><td rowspan="2">Initiated Collection and Sharing of AMI Data for ESC (Green Button Download My Data)
Identified Data for UER and Whole Building
Provided “Basic Customer Data” Queries for Third Parties</td><td>Provide Green Button Connect Functionality in the ESC</td><td>Evolve Customer Data Availability based on Customer, Market, and Regulatory Requirements</td></tr>
<tr><td colspan="2">Communicate Available AMI Data through Green Button Download My Data and Connect
Collaborate with Stakeholders to Design and Implement Best Practices that Balance Data Availability, Security/Privacy, and Costs to Provide</td></tr>
<tr><td>Provide Energy Management Insights to Customers</td><td>Collaborated with Stakeholders to Develop Use Cases and Identify Customer and Third-Party Data Needs</td><td>Develop Data Analytical Skillsets
Develop Customer Analytics to Support Customer-Specific Insights</td><td>Increase Sophistication of Customer Insights
Aggregations beyond geospatial classifications.</td></tr>
<tr><td>Enable Expanded Data Sharing Options</td><td>Shared Data via EDI or Secure Web Sites
Expanded the use of EDI to NYSERDA, CDG Hosts and CCAs</td><td>Install Restful API Protocols (Green Button Connect) in ESC
Connect Insights to Platform Solutions</td><td>Enable Customer Data Sharing via Green Button Connect System Wide
Provide Map of Available AMI Data
Expand Self-Service Options for Customer-Specific and Aggregated Data</td></tr>
<tr><td>Refine Data Standards and Protocols and Share Insights with Third Parties</td><td>Aggregated Customer Data Privacy Standards, UER, and Whole Building
Joint Utilities’ Customer Privacy Approach</td><td>Evolve Customer Data Sharing Procedures, Standards, and Protocols
Apply Data Analytics to Provide Insights for Third Parties</td><td>Improve Access to Data while Strengthening Privacy and Cyber Security Protections
Develop Derivative Data to Support Value-Added Market Analyses and Engagement</td></tr>
</table>

As shown in our roadmap, we are making several investments to support customer data sharing capabilities, including in AMI deployment through the Energy Smart Community project, as well as a number of portals to connect customers with additional products and services and with third-party providers.[71] Green Button Connect will allow ESC customers to share more granular AMI-based information with authorized third parties.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified three risks that relate to performance of the customer data sharing function, and have taken measures to mitigate each risk, as shown in Figure 4.8-3.

FIGURE 4.8-3: CUSTOMER DATA RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data Security:** NYSEG and RG&E or a third-party experience one or more data security breaches that impact customers.	• We maintain cyber security policies. • Systems that compile and communicate customer data to customers and third parties (with authorization) are designed to comply with existing NERC/CIP security standards. • Third parties are required to enter into a Data Security Agreement and maintain an Implementation and Data Protection Plan that is approved by the Commission.
2. **Cost Recovery:** NYSEG and RG&E will need to recover costs of providing customer data to third parties	• We are allowed to recover costs through a tariff for providing data to third parties, if incremental costs are required to provide the data.
3. **Customer Acceptance:** Customers must trust that the distributed system platform (DSP) will protect their personally identifiable information (PII) if they are to engage fully with Reforming the Energy Vision (REV) opportunities	• We are testing the customer experience through the Energy Smart Community, including transactions that involve the sharing of customer data with third parties.

71 Refer to Appendix B of our 2018 DSIP Report for links to our portals.

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities have proactively engaged with stakeholders through the Joint Utilities' Customer Data Working Group to share proposals for aggregated customer data privacy standards and progress in improving the type of data and the processes for accessing customer specific data with proper customer authorization. The Joint Utilities held meetings with DER developers to better understand their data needs, share current practices, and inform their future data sharing plans. We expect to continue to engage with stakeholders through the Joint Utilities as we strive to achieve a balance among the value to DER providers in certain data, privacy and security concerns, and the cost to provide the data.

We also shared our plan to build Customer Data capabilities in our June 20, 2018 meeting with a broad group of our key stakeholders.

Additional Detail

The DSIP Update should describe the utility resources and capabilities which provide or employ data describing customer energy consumption and production. Detailed time-series interval data describing customer energy consumption and production is beneficial to the utilities, DER developers, customers, and other stakeholders. The data enable both short-term and long-term analyses and decisions affecting many investments and behaviors which can materially improve customer value by reducing costs and/or improving service. The data's value is directly proportional to its usefulness which is affected by its accuracy, granularity, age, content, format, and accessibility. While efficient and timely access to the data is vital for each legitimate use, the data must be strongly protected from loss, theft, or corruption.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to Customer Data:

We have been exploring ways to provide customer data to customers, market providers and DER developers to support the development of new products and services for customers. Providing customers with more granular and timely usage and cost data empowers customers to make better energy choices. Access to customer-specific or aggregated data can help DER developers tailor their products and services to better serve customers.

We have established a foundation to provide more information with customers and developers today than ever before. In coordination with the Joint Utilities, we are actively exploring different ways to improve access to data while continuing to strengthen privacy and cybersecurity protections to protect the security of customer data and the distribution system..72 During the last two years, we, working with the Joint Utilities, have continued to evolve customer data sharing procedures, standards, and protocols. The protection of customer information, including energy usage data and personal information, is an integral part of our responsibilities and commitment to their customers.

1) Date Types, Description and Management Processes

a. Describe the type(s) of customer load and supply data acquired by the utility.

We collect several types of data from customers including energy usage data. We assign an installed capacity (ICAP) tag for every customer based on a formula established by the New York Independent System Operator (NYISO).

We capture and acquire customer load (use) and supply (injection from DER) data that flows through customer meters. These include commercial interval, AMI, and/or register-read meters. We have only recently installed AMI meters in our Energy Smart Community. There are differences in the type and granularity of the customer load and supply data acquired across the Joint Utilities based on customer types, existing metering, and the extent AMI has been adopted by the utility. In some cases – generally commercial, industrial customers, and some residential and commercial customers – usage data will be acquired in time-of-use blocks. Certain additional data, such as demand (in kilowatts, kW) and reactive power (VAR) data, will also be acquired if required for billing under the applicable tariff. AMI data, when implemented, will capture more granular (interval) usage data and we will update our data sharing mechanisms and standards.

Certain large commercial and industrial (C&I) customers are required to participate in our Mandatory Hourly Pricing (MHP) tariffs. We install a meter that reads electric usage information on an hourly basis to serve these customers and other customers that voluntarily elect to receive service under this tariff.

In circumstances where supply is not separately metered, we collect the "net metered" data only and do not have separate visibility into load and supply data. There are relatively few customers that have separately metered on-site generation.

b. Describe the accuracy, granularity, latency, content, and format for each type of data

[72] Case 14-M-0101 *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Staff Proposal Distributed System Implementation Plan Guidance (issued October 15, 2015), p. 21.

acquired.

NYSEG and RG&E meters are subject to Public Service Commission (PSC) rules and inspected to ensure they remain accurate. We collect meter reads on an hourly basis from large C&I customers that receive service under a time-of-use tariff. We collect meter reads on either a monthly or bi-monthly basis from certain customers, with this latter set of customers receiving an estimated bill during months when their meter is not read. AMI will eliminate the need to rely on estimated bills, and the concerns expressed by customers regarding bills that are often associated with estimated bills. Meter reads are raw data that must be converted into usage by calculating the change in a meter read as compared to the prior meter read value.

c. Describe in detail the utility's means and methods for creating, collecting, managing, and securing each type of data.

We adhere to the AVANGRID *Cybersecurity Controls Framework* and the AVANGRID *Cybersecurity Policy.* The Cybersecurity Controls Framework and Policy, along with associated rules and corporate procedures support a governance program for the protection of both customer and system information and data. The governance program and associated controls are based on industry best practices, and reflect legal and regulatory obligations. The AVANGRID Third-Party Risk Management Program requires that information/data is classified based on criticality and requires that all third parties validate that they have the protections in place to secure that information/data. This program incorporates collaboration among NYSEG and RG&E cybersecurity, legal services, business areas and procurement, ensuring that the risk management process applies to all third parties who have contractual relationships with the Companies. We have a standardized procedure for identifying, assessing, and mitigating security risks that can be introduced at the vendor level. In addition, all contractual relationships with third parties must include a Security Requirements section that documents a comprehensive Cyber Security Plan (CSP) describing the cyber security controls and requirements implemented to safeguard information/data against cyber threats. The plan must include controls that reflect our commitment to the protection of customer and system information/data from disclosure or harm.

2) Data Uses, Access and Security

a. Describe the means and methods that customers and their properly designated agents can use to acquire their load and supply data directly from their utility meters without going through the utility, should they want to.

We currently acquire the vast majority of meter data by employing meter readers. We collect reads through a dial-in process for approximately 2,000 customers that are served under our MHP tariff. Customers are currently able to view billing and usage information, as well as account detail information (*i.e.*, billing address and account information), via the account manager tool on the NYSEG and RG&E websites. Customers continue to have access to their data through our customer portal, which is likely to be much easier and more reliable than reading their meter and tracking their own usage.

We have a proposal to implement AMI, which will modernize the collection of customer meter information. We expect that this access should be easier and more reliable with AMI paired with our Energy Manager portal or Green Button Connect as customers will be able to exercise a "self-service" option to either download their own usage information or authorize to have information shared on a secure basis with a third party. When implemented, our AMI meters will be able to provide near real-time usage data to third-party Home Area Network devices (displays and other devices with storage) so data can be shared.

b. Identify and characterize the categories of legitimate users beyond customers and their properly designated agents who will be provided access to each type of data.

NYSEG and RG&E will make it easy for customers to share their information with third parties that have been authorized to use our portals. Authorization requires execution of a Data Security Agreement that provides assurance to us and our customers that customer data, including personally identifiable information, will be secure. However, customers are the ultimate authority in determining which users of their data are "legitimate", much as they do when buying any product or service today. Our responsibility begins and ends with the authorized transfer of customer data using our portals. Green Button Connect provides similar assurance of data security and privacy to customers.

The Commission has exercised certain oversight of third parties through the Uniform Business Practices (UBP) rules. These rules, which are modified from time to time to keep up with industry changes, provide consumer protections, streamlined business transactions, and communications protocols between ESCOs and utilities. Our overall goal is to ensure that customer transactions remain simple and secure.

c. For each type of data, describe how its respective users will productively apply the data and explain why the data provided will be sufficient to fully support each type of application.

The Joint Utilities have been proactively engaging with stakeholders to discuss proposals for providing aggregated customer data consistent with customer privacy standards and progress in improving the type of data and the process for accessing customer specific data with proper customer authorization. There are a number of stakeholders who can benefit from aggregated data. Communities and municipalities use aggregated data to understand the community's overall energy usage which in turn can help identify ways to lower energy costs and provide community-based energy options such as CDG or CCAs. ESCOs use aggregated data to identify communities that could benefit from new energy options.

We meet with DER developers to understand their specific customer usage data needs, share current practices, and inform their future data sharing plans. For example, we meet with DER developers when we are developing an innovation project that is intended to create value for the customers, the developer, and us. Through targeted conversations, utilities not only understand the underlying basis for developer requests, but stakeholders gain better insight into the current availability of the information and how to access it. At the same time, we do not want to limit the potential legal and authorized uses of data in order to preserve the innovation that we expect to be unleashed by the REV business model. As the DSP, we view our responsibility for sharing data as a unique opportunity to compile and/or analyze this information.. For example, we plan to provide aggregated data to help third parties respond to the needs of groups of customers or whole communities.

Through collaboration with Staff and stakeholders, the Joint Utilities are finalizing development of sharing aggregated data for whole buildings and sharing data with municipalities through NYSERDA's Utility Energy Registry. These new offerings will allow building owners to better manage and benchmark their building energy usage and allow communities to make informed decisions on Community based Distributed Generation Projects, Energy Choice Aggregation programs and Energy Efficiency initiatives. In addition, the Joint Utilities have been working together on proposed statewide privacy standards for aggregated and whole-building customer data sharing.

Established standards will offer stakeholders more access to data in a consistent approach, while still protecting customers' privacy rights. The Joint Utilities proposed a "15/15" privacy standard for aggregated customer data.[73] The aggregated customer data would be used to support community planning and CCA development. The 15/15 standard states that aggregation of customer usage information must include a minimum of 15 customer accounts and no one customer can represent more the 15% of the total usage. The standard was to ensure that no customer usage information could be uniquely identified. The Commission adopted the proposed privacy standard[74] but acknowledged that the 15/15 standard is conservative and directed the Joint Utilities to track all aggregated data requests.[75]

The Joint Utilities were also required to propose a building energy management and benchmarking data standard for the Commission's consideration.[76] The Joint Utilities performed a benchmarking study on aggregated customer data privacy standards in use or considered by other utilities across the United States, and proposed using a "4/50" privacy standard for whole-building aggregated customer data to be provided to building owners or their authorized agents.[77,78] The benchmarking effort also provided guidance on terms and conditions and local ordinance exceptions. The Joint Utilities invited comments from stakeholders on the proposed privacy standard at a Stakeholder engagement session on May 22, 2017. The input received during the session was taken into consideration to develop the final proposed privacy standard and related terms and conditions.

Figure 4.8-4 presents the whole building privacy standards benchmark. The table represents a summary of benchmarking of other utilities that the Joint Utilities commissioned regarding the

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73 Supplemental DSIP, pp. 11, 122, 144.

74 DSIP Order, pp. 25-28.

75 DSIP Order, *supra* note 2 pp. 26-27

76 DSIP Order, *supra* note 2 p. 28

77 Under a "4/50" standard, aggregated customer usage data is considered sufficiently anonymous to share publicly if (1) the aggregated group contains at least 4 individual accounts, and (2) no single account represents more than 50% of the total load.

78 Building owners that must comply with existing laws and ordinances, such as Local Law 84 in New York City, are exempt from the privacy standard

minimum number of meters or meters and volume that would be required before the utility would distribute aggregate whole building usage information to a building owner or its' agent.

FIGURE 4.8-4: WHOLE BUILDING PRIVACY STANDARDS BENCHMARK

Aggregation Threshold		Most Common
Definition	Value	
Minimum Number of Meters	5	6 of 11 study utilities (55%)
	2	4 of 11 study utilities (35%)
	4	1 of 11 study utilities (9%)
Minimum Number of Meters and Volume	4/50	4 of 5 study utilities (80%)
	4/80	1 of 5 study utilities (20%)

Recently, on June 19, 2018, the Joint Utilities filed proposed terms and conditions for building owners or their agents to obtain aggregated whole building data.[79]

d. *For each type of data, describe in detail the utility's policies, means, and methods for securely providing legitimate users with efficient, timely, and useful access to the data. Include information which thoroughly describes and explains the utility's approach to providing customer data to third parties who would use the data to identify and design service opportunities which benefit the utility and/or its customers.*

Customer data is shared with market providers in a variety of ways. Authorized ESCOs, DER providers and other market participants have access to approved customer data via secure NYSEG and RG&E websites.[80] Customers enable the sharing of their data by providing their Point of Delivery ID with an authorized third party. This ensures that providers have access to the information only after receiving authorization from the customers except where required or permitted by Commission order.[81] Customer data is also shared with ESCOs and other parties via EDI. EDI is the exchange of transactions in a standardized format and is used to communicate a variety of pre-set information including usage and billing information, payment, eligibility, and other information. Providers can only receive customer data via EDI when customers have authorized the sharing of information by providing third parties with a POD ID. We have expanded the use of EDI to new parties including NYSERDA, CDG hosts and CCA providers to

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79 Case 14-M-0101 and Case 16-M-0411, Joint Utility Aggregated Whole Building Data Terms and Conditions. June 19, 2018.

80 NYSEG secure website and RG&E secure website.

81 For example, NYSEG and RG&E are permitted by Commission order (ORDER AUTHORIZING FRAMEWORK FOR COMMUNITY CHOICE AGGREGATION OPT-OUT PROGRAM Issued and Effective April 21, 2016, CASE 14-M-0224 – Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs) require all parties participating in the formation and operation of a CCA to implement an approved Data Protection Plan and execute the Data Security Agreement (DSA) with the Utility. Once the CCA is approved and an Energy Services Company (ESCO) is selected as part of the CCA, the approved ESCOs may receive customer-specific information.

increase data access.

We anticipate that the types of data to be communicated to customers and third parties will evolve over time to include on-site generation (if metered by the utility), peak load data, and information on appliances and other home devices that helps third parties tailor services to our customers. NYSEG and RG&E will make all customer usage data that is collected by the utility available to customers and authorized third parties.

We have made progress in the development of means and methods for securely providing legitimate users with efficient, timely, and useful access to Customer Data through the Green Button Connect platform. The objective of the Green Button Connect portal is to:

- Provide utility customer data to third parties with easy and secure access to energy usage information in a consumer-friendly and computer-friendly format;
- Allow utility customer to automate the secure transfer of their own energy usage data to authorized third parties, based on affirmative (opt-in) customer consent and control; and
- Allow third party vendors to access interval data for electricity and gas usage.

In order for third parties to be listed in the portal, third parties are approved by us, and customers authorize the utility to share data with their selected third parties.

This approval process will include:

- A standardized procedure for identifying, assessing, and mitigating security risks that can be introduced by the third party;
- An assessment for cyber and information security controls, based on the NYSEG & RG&E cyber security controls framework, including operational, technical and administrative controls;
- Third party execution of a data security rider/data services agreement, which includes the right to audit any third-party processing, handling, transmitting, etc., of non-public information; and
- Third party will also need to agreement with standard terms and conditions that address liability after the data is made available to the third party and ensures data is secured and encrypted before and during transmission to the third party.

Data security is also enhanced by the following actions:

- Data requests and responses are made using the secure HTTPS protocol and authenticated via a two-way certificate exchange (OAuth 2.0 authorization);
- NYSEG and RG&E maintain unexpired, unrevoked RSA cryptosystem certificates with a public key length of at least 2048 bits, per the energy service provider interface (ESPI) standard;
- Customers share only data they want to share; and
- Customers are able to limit the time authorized third parties have access to their data.

e. Describe how the utilities are jointly developing and implementing uniform policies, protocols, and resources for controlling third party access to customer data.

The Joint Utilities are relying on the use case discussions with DER developers to define processes to implement uniform policies and approaches in response to the Commission and stakeholder requests. Since the Initial DSIP, the Joint Utilities have collaborated in the Customer Data and Retail Access Working Groups to advance several customer data efforts, including:

- Submitting two joint filings on customer privacy standards and approaches;
- Requiring a Vendor Risk Assessment and execution of a Data Security Agreement;
- Defining data sets and costs in support of CCA efforts through development and filing of CCA tariffs;
- Working with DPS Staff and NYSERDA on UER and appropriate privacy standards;
- Developing DER UBP;
- Evaluating potential opportunities for aggregated data automation and developing whole-building owner aggregated data access and privacy standards; and
- Engaging with stakeholders to solicit feedback and inform future customer data needs and means of accessing that information.

As described above, there are a number of channels that share customer data with customers and authorized third parties. These include utility bills, Green Button Connect (GBC), Electronic Data Interchange Utility Energy Registry Secure File Transfer Protocol (SFTP), File Transfer Protocol with Pretty Good Privacy (PGP) Encryption, online third-party data platforms, and the data identified in UBP for DER. Each data sharing platform may be designed with a different user audience in mind, have unique access requirements, and be used to convey different kinds of information.

f. Describe in detail the utility's policies, means, and methods for rigorously anticipating data risks and preventing loss, theft, or corruption of customer data.

The Companies, in alignment with the Joint Utilities, require Vendor Risk Assessments and execution of Data Security Agreements with third parties that receive customer data. We also ensure that all aggregated data is anonymized to prevent identification of customer-specific data.

We ensure that our own data systems comply with our cyber security policies to protect the privacy and security of customer and system data. Our IT team monitors developments that relate to potential cyber-attacks from outside agents and takes actions when appropriate to protect sensitive customer and system data.

g. Identify each type of customer data which is/will be provided to third parties at no cost to the recipient, and the extent to which the practice comports with DPS policies in place at the time, as appropriate.

REV policy distinguishes between "basic" and "value-added" customer and system data. Basic data is data that is compiled by the DSP is either essential to support the fundamental customer/provider relationship (*e.g.*, billing data) or provide broad system-wide benefits (*e.g.*, hosting capacity). Basic data is provided at no cost to the recipient.

The Commission addressed the provision of aggregated and customer-specific data to ESCOs as part of its Community Choice Aggregation order.[82] In that order, the Commission established protocols for utilities to provide three types of data:

1) Aggregated customer and consumption (usage) data to support procurement efforts;
2) Customer contact information to send opt-out letters; and
3) Detailed customer information for the purposes of enrolling and serving each customer.

h. Identify each type of customer data which the utility proposes to provide to third parties for a fee, and the extent to which the practice comports with DPS policies in place at the time, as appropriate. For each data type identified, describe the proposed fee structure and explain the utility's rationale for charging a fee to the recipient.

Value-added data includes customized requests by market participants that helps them pursue market opportunities. The DSP can charge a fee for these services to contribute to the costs of providing value-added data and avoid imposing a cost burden on non-participants.[83] Value-added data will provide more detailed needs, including customized requests and market participant requests to pursue market opportunities. Fees may be permitted to promote fair contribution to system costs by beneficiaries and to avoid undue burden on non-participants. We provide basic data as defined by the Order and data we aggregate for the UER, Whole Building Data and substantially similar data set requests that meet the applicable privacy thresholds, which will not incur a fee. Any other data requests will be considered as value-added and we will assess a fee based on our costs for time and material for compiling, formatting and securely transmitting the data.

i. Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are highly consistent with the means and methods at the other utilities, and the extent to which these practices comport with DPS policies in place at the time, as appropriate.

The Joint Utilities are working together to develop a statewide standard in phases, with the understanding that utilities will have different starting points. Utilities implementing full AMI solutions plan to provide basic customer usage data to customers via online platforms and to customer-authorized third parties using the GBC standard or a comparable specification. Utilities not implementing full AMI solutions expect to provide basic customer usage data to

82 Order Authorizing Framework for Community Choice Aggregation Opt-Out Program, April 21, 2016, pp. 42-46.

83 Order Establishing Community Choice Data Access Fees, December 17, 2017, p. 19.

end-users via Green Button Download My Data or an alternative specification. The Joint Utilities will continue to leverage existing data transfer protocols and platforms including EDI, SFTP, and online customer engagement platforms.

j. Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

NYSEG and RGE plan to continue to work with the Joint Utilities through the Customer Data Working Group to develop of new means and methods for sharing customer data with third parties that are aligned with the solutions of other utilities who have or are in the process of implementing customer data sharing solutions.

3) Green Button Connect Capabilities

a. Describe where and how DER developers, customers, and other stakeholders can readily access up-to-date information about the areas where customer consumption data provided via Green Button Connect (GBC) is available or planned.

Within the coming months, we will be installing and testing Green Button Connect capabilities in the Energy Smart Community using AMI data. Green Button Connect and other protocols provide a more current data exchange standard that utilizes new capabilities such as cloud sharing and web services to scale to support large information sharing transactions that are expected in the future. Energy Smart Community customers will be able to view and share their detailed customer information. Through customer research in the Energy Smart Community, we will assess the best approaches to provide these capabilities and the ways customers can use the applications. We will leverage this learning to support rolling out Green Button Connect to all of its customers when we deploy AMI system-wide.

b. Describe how the utility is making customers and third parties aware of its GBC resources and capabilities.

Green Button Connect is currently being tested in the Energy Smart Community. We will reflect any lessons learned before implementing Green Button Connect at scale and will communicate its availability and value when it is implemented.

c. Describe the utility's policies, means, and methods for measuring and evaluating customer and third-party utilization of its GBC capabilities.

We will evaluate the customer and third-party experience with Green Button Connect in the Energy Smart Community, and will reflect lessons learned before implementing Green Button Connect at scale.

4.9 Cyber Security

Introduction/Context and Background

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

NYSEG and RG&E have worked with the Joint Utilities over the past two years developing and implementing cyber security procedures, standards, and protocols designed to securely allow third parties access to system data. We approach DSP-associated cyber security from three fronts:

1. Energy Control Systems: The NYSEG AND RG&E Operational Smart Grids (OSG) team manages the energy control systems and associated cyber security for advanced grid operations deployment, including the Energy Management System (EMS), the Outage Management System (OMS), the Advanced Distribution Management System (ADMS), the Distributed Energy Resource Management System (DERMS), and associated infrastructure. We comply with North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) standards and guidelines and current cyber security industry best practices.[84] We also follow a third-party risk management process, ensuring compliance to CIP standards and industry best practice.

2. Billing Systems: The Systems, Applications, and Products (SAP) team develops IT cyber security systems for our Customer Information Systems, particularly billing processes. The advanced functionality we are developing requires new billing systems, necessitating us to move from a Customer Care System to a Customer Relationship Management & Billing (CRM&B) system. CRM&B will involve more customer engagement through more comprehensive billing options and outage management improvements. In addition, the SAP system must comply with Sarbanes-Oxley (SOX) requirements.[85] SOX ensures the validity of financial records and protection against disclosure of confidential information. To remain SOX compliant, NYSEG and RG&E have effective security controls in place to ensure the confidentiality, integrity, and availability of their financial data.

3. Advanced Metering Infrastructure (AMI) Systems: AMI cyber security measures are designed to secure communications between AMI devices and customers, including via Wi-Fi enabled devices, over power lines, and through customer-sited universal communications devices. Cyber security controls continue to evolve with advances in services and technology.

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[84] NERC CIP includes a set of 14 standards and requirements to secure assets needed for safe operation of North America's bulk electric system.

[85] The Sarbanes-Oxley Act of 2002 aimed to provide more transparency in accounting practices of public companies to protect shareholders and the public.

In addition, we have implemented a formal cyber security Program and a Controls Framework based on industry standards of best practice, to protect the Confidentiality, Integrity, Availability and Reliability of our cyber infrastructure and its associated cyber assets. The cyber security program is risk-based and continues to evolve in concert with advances in technology, threat detection methodologies, and changing risk landscapes.

Implementation Plan, Schedule, and Investments

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

We support ongoing efforts to increase the amount of customer and system data available to customers and third parties. Today, there is significantly more information shared through new mechanisms with clearer and more standardized security and privacy standards. In our role as the distributed system platform (DSP), we will have increasing interdependences with third parties. These parties, including non-wires alternative (NWA) providers, are foundational to ensuring reliability on the grid. Thus, our third-party Cyber Security Risk Management process is an important element of our DSP risk management framework. This process applies to all third parties who have contractual relationships with us, including NWA providers that participate in our distributed energy resource (DER) procurement efforts. The process is initiated through the procurement process and includes a review of the third party's cyber security profile, legal and regulatory compliance requirements, and rules and guidelines for consistency with our Risk Management Framework.

We have developed new sharing mechanisms, applying risk management practices from current cyber security and privacy programs to incorporate into new technologies. We are active participants in the Joint Utilities' Cyber Security Working Group to develop a common approach to managing cyber security and privacy risks.

Third parties are increasingly able to access system and customer data as DER penetration rates increase. We have adopted all NERC CIP standards to energy control systems as new technologies have been rolled out. We have deployed AMI through the Energy Smart Community project, and will continue to refine AMI systems through that project before rolling out the program system-wide. The AMI cyber security elements include:

- Cyber security procedures for the head-end system to securely manage data collection and monitor/control of the telecommunications system;
- Cyber security procedures to support the Meter Data Management System (MDMS), which stores and processes the AMI data; and
- Cyber security standards to support CRM&B system upgrades to facilitate individualized customer support securely.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

We will continue to consider new data to be shared and the terms under which data can be provided, collaborating with the Joint Utilities. We will continue to collaborate with the Joint Utilities' ongoing development of common cyber security controls and privacy standards, protocols, and processes to support DER markets. An important element of supporting DER and other market participants is to ensure that third parties understand and comply with privacy and security obligations. We will educate and communicate with third parties on the security requirements and processes. We will continue to monitor industry standards of best practice, refining and evolving controls as applicable.

Our Cyber Security roadmap is presented in Figure 4.9-1.

FIGURE 4.9-1: CYBER SECURITY ROADMAP

<table>
<tr><th>Capability</th><th>Achievements (2016-2018)</th><th>Short-Term Initiatives (2019-2020)</th><th>Long-Term Initiatives (2021-2023)</th></tr>
<tr><td>Secure System Data Provided to Third Parties
Protect and Secure Customer Data</td><td>Developed and Implemented Cyber Security Procedures, Standards, and Protocols
Applied Cyber Security Risk Management Process
Developed Data Security Agreement and Vendor Risk Agreement
Adhered to AVANGRID Third-Party Risk Management Program</td><td>Collaborate with Joint Utilities on Cyber Security Controls and Privacy Standards
Apply Data Security Agreements and Perform Vendor Risk Assessments
Require Third-Party Adherence to Industry Best Practices (including NERC CIP, NIST, ISO)</td><td rowspan="3">Monitor Industry Standards of Best Practice and Refine Controls</td></tr>
<tr><td>Protect Internal Systems (Energy Control, Billing, and AMI)</td><td>Maintained Disaster Recovery, Business Continuity, and Incident Response Plans
Applied NERC CIP Standards to Energy Control Systems
Established Annual Disaster Recovery Test</td><td>Apply Industry Standards of Best Practice to AMI (including NIST, ISO, and COBIT)
Include Cyber Security Plan Requirements in Vendor RFIs and RFPs
Build Redundancy into AMI Telecommunications Infrastructure
Incorporate Governance into GMEP Design</td></tr>
<tr><td>Protect Cyber Infrastructure</td><td colspan="2">Maintain and Apply AVANGRID Cyber Security Controls Framework and AVANGRID Cybersecurity Policy</td></tr>
</table>

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

Our cyber security program and processes are our risk mitigation functions in response to threats to the security and privacy of customer and system data, and to the functions performed by our Energy Control Systems, Billing Systems, and AMI Systems, as discussed in the Introduction to this Requirements section. Our policies and procedures for protecting system and customer data are presented in Requirements sections 4.7 and 4.8, respectively. Our policies and procedures for addressing the security of our own systems are addressed in the Current Progress response above and in Subparts 1-5 below. Other risks include timely implementation, such as the inability of a third party to meet security controls requirements, which we mitigate through vetting during the procurement process.

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design; how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses.

The Joint Utilities' Cyber Security Working Group was established to develop a common approach to managing cyber security and privacy risks, including interactions with third parties. These efforts have contributed to the development of standard Data Security Agreements and Vendor Risk Assessments.

Additional Detail

Utility cyber resources contain confidential customer and system data and perform functions which are essential to safe and reliable grid operations; consequently, the security, resilience, and recoverability of those resources is of paramount importance. Utilities must ensure that data is not lost, stolen, or corrupted and that cyber resources are not disabled, damaged, or destroyed by malicious acts, errors, accidents, or disasters.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to Cyber Security:

1) *Describe in detail the utility policies, procedures, and assets that address the security, resilience, and recoverability of data stored and processes running in interacting systems and devices which are owned and operated by third-parties (NYISO, DER operators, customers, and neighboring utilities). Details provided should include:*

a. *the required third-party implementation of applicable technology standards;*

<u>Energy Control Systems (ECS)</u>: The AVANGRID Operational OSG ECS follow NERC critical infrastructure protection rules and guidelines and current cyber security practices. Third-party systems must also comply with these CIP standards. CIP standards 002 through 009 provide a cyber security framework for critical cyber assets on the distribution grid. The following CIP standards are particularly relevant for DSIP-related technology deployments and associated

security measures:

- CIP-002 (Cyber System Categorization): addresses cyber assets/systems review and approval.
- CIP-004 (Personnel & Training): addresses security awareness, cyber security training/access, and criminal background checks.
- CIP-005 (Electronic Security Perimeters): addresses perimeter and remote access.
- CIP-007 (Cyber Security Management): addresses malicious code issues, security monitoring/control, and ports and services.
- CIP-010 (Configuration Management & Vulnerability Assessment): addresses vulnerability assessments and configuration monitoring.
- OSG procedures for CIP-011 (Information Protection): addresses cyber security information.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: Cyber security controls are based on industry standards of best practice, including, but not limited to; National Institute of Standards and Technology (NIST), International Organization for Standardization, Control Objectives for Information and Related Technologies (COBIT), etc.

b. the required third-party implementation of applicable procedural controls;

Energy Control Systems (ECS): OSG third-party vendors and contractors are required to adhere to all applicable industry standard best practice, including, but not limited to NIST, International Organization for Standardization, and NERC-CIP as applicable.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. We do not require third-party implementation of cyber security standards.

AMI Systems: Cyber security third party risk management process is aligned with Joint Utilities process and procedures.

c. the means and methods for verifying, documenting, and reporting third-party compliance with utility policies and procedures;

Energy Control Systems (ECS): As mentioned above, OSG third-party vendors and contractors are required to adhere to all applicable NERC procedures. The NYSEG and RG&E compliance program, and its adherence to NERC standards, is subject to periodic review and auditing (and monetary fines, if noncompliant) that determines the effectiveness of implemented security measures.

Billing Systems: Billing systems are managed by NYSEG AND RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: The third-party risk management process includes the addition of a data security rider/data services agreement, which includes the right to audit any third-party processing, handling, transmitting, etc., of non-public information.

d. the means and methods for identifying, characterizing, monitoring, reporting, and mitigating applicable risks;

Energy Control Systems (ECS): The NERC CIP standards address applicable risks. As mentioned above, the NYSEG and RG&E compliance program, and its adherence to NERC standards, is subject to periodic review and auditing that determines the effectiveness of implemented security measures.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: Our third-party risk management process includes a standardized procedure for identifying, assessing, and mitigating security risks that can be introduced at the vendor level.

Several of our business areas engage with third parties to initiate the process during Request for Information or Request for Proposal. Our process is multi-departmental with areas of responsibility identified for the engaging business, procurement, security and legal services.

Our RFPs must include a Security Requirements section. Our RFPs specifically request that the bidder develop and propose a comprehensive AMI-specific Cyber Security Plan that describes and documents their plans to address physical and cyber risks.

e. the means and methods for testing, documenting, and reporting the effectiveness of implemented security measures;

Energy Control Systems (ECS): The NERC CIP standards address the security measures required. As mentioned above, the NYSEG and RG&E compliance program, and its adherence to NERC standards, is subject to periodic review and auditing that determines the effectiveness of implemented security measures.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: Effectiveness testing is an auditing function.

f. the means and methods for detecting, isolating, eliminating, documenting, and reporting security incidents; and,

Energy Control Systems: OSG procedures for CIP-008 (Incident Response) addresses Incident Recovery plan specifications, plan implementation and testing, and plan review, update and communication. OSG adheres to the NYSEG and RG&E Corporate Unified Incident Response Plan, a comprehensive approach to incident management.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: The Cyber Security program includes a documented, implemented and tested Unified Incident Response Plan, as well as on-going collaboration with cyber security authorities and working groups.

g. the means and methods for managing utility and third-party changes affecting security measures for third-party interactions.

Energy Control Systems (ECS): The NYSEG and RG&E compliance program, and its adherence to NERC standards, is subject to periodic review and auditing that examines and qualifies the means and methods of change management and cyber security management.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: The cyber security program includes on-going collaboration with cyber security authorities and working groups providing vital information for the development and implementation of protections that are in alignment with best practices. Cyber Security actively participates in:

- *The Electricity Information Sharing and Analysis Center (E-ISAC)*: The E-ISAC's mission is to be the trusted source for electricity subsector security information through gathering and analysing security information, coordinating incident management, and communicating mitigation strategies with stakeholders within the electricity subsector, across interdependent sectors, and with government partners.
- *Edison Electric Institute (EEI)*: The EEI represents all United States investor-owned electric companies. EEI provides public policy leadership, strategic business intelligence, essential conferences and forums.
- *Electricity Subsector Coordinating Council (ESCC)*: The ESCC serves as the principal liaison between the federal government and the electric power sector, with the mission of coordinating efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure.
- *Electric Power Research Institute (EPRI)*: EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public.
- *The Industrial Control Systems Cyber Emergency Response Team (ICS-CERT)*: The ICS-CERT works to reduce risks within and across all critical infrastructure sectors by partnering with law enforcement agencies and the intelligence community and coordinating efforts among federal, state, local, and tribal governments and control systems owners, operators, and vendors. Additionally, ICS-CERT collaborates with international and private sector Computer Emergency Response Teams (CERTs) to share control systems-related security incidents and mitigation measures. The ICS CERT provides a current information resource to help industries understand and prepare for ongoing and emerging control systems cyber security issues, vulnerabilities, and mitigation strategies to include Control Systems Vulnerabilities and Attack Paths.
- *INFRAGARD*: INFRAGARD is a partnership between the Federal Bureau of Investigation

and the private sector. It is an association of persons who represent businesses, academic institutions, state and local law enforcement agencies, and other participants dedicated to sharing information and intelligence to prevent hostile acts against the United States.

- *United States Computer Emergency Readiness Team (US-CERT)*: The US-CERT leads efforts to improve the nation's cyber security posture, coordinate cyber information sharing, and proactively manage cyber risks to the nation while protecting the constitutional rights of Americans.

Cyber security also follows business implemented change control processes.

2) *Describe in detail the security, resilience, and recoverability measures applied to each utility cyber resource which:*

a. contains customer data;

Energy Control Systems (ECS): With regard to data security measures, once the data from Point of Connection (POC) reclosers for DER leaves the device, it is treated like any other data point in the SCADA / Energy Management System (EMS) system. This includes compliance with all applicable CIP standards and other basic security measures. As for data quality, all analog readings have the option to include "reasonability" alarm limits. These are not implemented for POC reclosers at the present time. The historian database is located in redundant servers located in different computer rooms. All servers have an automatic process of data synchronization. We conduct annual a Disaster Recovery Test and periodic emergency fire drills. The backup control center in Kirkwood is a "hot standby" and is available to users within 30 minutes.

Billing Systems: NYSEG and RG&E have processes and procedures to support controls that address physical and electronic access to critical financial and operational systems. The SAP system falls under Sarbanes-Oxley requirements and is audited and tested annually by both internal and external auditors to assure effectiveness of these controls. These tests address the physical controls for managing and reviewing physical access to the data center, which incorporates the system and disaster recovery plan. , The tests align with our corporate Business Continuity plans, and include strict access provisioning and de-provisioning processes that apply the principle of least privilege. Privileged and standard user access reviews are conducted biannually. In addition, backup and recovery controls are in place and tested regularly as part of the audit processes. AMI Systems: Resilience and recovery controls are identified in our Disaster Recovery, Business Continuity, and Incident Response Plans.

b. contains utility system data; and/or,

Energy Control Systems: CIP-008 (Incident Response) and CIP-009 (Disaster Recovery) clarify these procedures. As mentioned, for incident response, OSG adheres to the Unified Incident Response Plan, a comprehensive approach to incident management. OSG has developed detailed procedures that address the testing and recovery of systems for NYSEG and RG&E. In addition, the Energy Control Center (ECC) has developed operational recovery procedures that involve coordination with OSG.

Billing Systems: Utility system data recovery measures fall under the purview of the Sarbanes-Oxley requirements mentioned above.

AMI Systems: Resilience and recovery controls are identified in our Disaster Recovery, Business Continuity,, and Incident Response Plans.

c. performs one or more functions supporting safe and reliable grid operations.

Energy Control Systems (ECS): CIP-008 (Incident Response) and CIP-009 (Disaster Recovery) clarify these procedures, as well as the ECC operational recovery procedures.

Billing Systems: This is not applicable for billing systems, which are not associated with performing grid operations functions.

AMI Systems: Resilience and recovery controls are identified in our Disaster Recovery, Business Continuity, and Incident Response Plans.

3) For each significant utility cyber process supporting safe and reliable grid operations:

a. Provide and explain the resilience policy which establishes the utility's criteria for the extent of resource loss, damage, or destruction that can be absorbed before the process is disrupted;

Energy Control Systems (ECS): As mentioned, OSG procedures for CIP-008 address Incident Response plan specifications, plan implementation and testing, and plan review, update and communication. In addition, OSG procedures for CIP-009 address Disaster Recovery plan specifications, plan implementation and testing, and plan review, update and communication. OSG also adheres to the Unified Incident Response Plan for incident management and for disaster recovery, OSG developed detailed procedures that address the testing and recovery of systems for NYSEG and RG&E. In addition, the ECC has developed operational recovery procedures that involve coordination with OSG.

Billing Systems: NYSEG and RG&E IT follows a documented Criticality Model that establishes criteria for assessing the criticality of a business process or IT Service. This model is then used for Disaster Recovery Tiering purposes.

AMI Systems: Our Business Continuity Plan and Incident Response Plan establish scenarios requiring activation of the plan.

b. Provide and explain the recovery time objective which establishes the utility's criteria for the maximum acceptable amount of time needed to restore the process to its normal state;

Energy Control Systems: These objectives are set out in the OSG procedures listed in Subpart 3a.

Billing Systems: NYSEG and RG&E's IT function utilizes a standard Business Impact Analysis form for capturing the business area's justification for a system to be considered for IT DR Tiering. This form captures their requested Recovery Point Objective and Recovery Time Objective.

AMI Systems: Recovery time objectives are defined based on criticality and documented in the Unified Incident Response Plan.

c. *Provide and explain the plan for timely recovery of the process following a disruption; and,*

Energy Control Systems: These objectives are set out in the OSG procedures listed above in 3a.

Billing Systems: Tier 1 applications are recovered by following the steps in the detailed NYSEG and RG&E IT Business Continuity plan.

AMI Systems: Plans for recovery are defined and documented in the Unified Incident Response Plan, Disaster Recovery Plan, and Business Continuity Plan.

d. *Describe each process, resource, and standard used to develop, implement, test, document, and maintain the plan for timely process data recovery.*

Energy Control Systems: These objectives are set out in the OSG procedures listed in Subpart 3a.

Billing Systems: NYSEG and RG&E's Business Impact Analysis form applies to these procedures. They are completed by a business area with guidance from an IT Application Business Relationship Manager. These forms and the Tier 1 list is reviewed and updated annually. All approved Tier 1 applications are tested annually and individual recovery plans are updated annually as needed.

AMI Systems: These processes, resources, and standards are defined and documented in the Unified Incident Response Plan, Disaster Recovery Plan, and Business Continuity Plan.

4) *Identify and characterize the types of cyber protection needed for strongly securing the utility's advanced metering resources and capabilities. Describe in detail the means and methods employed to provide the required protection.*

There are multiple layers of encryption implemented to protect meter data. The network and application security layers support and provide confidentiality through encryption and authentication, data integrity and non-repudiation through unique key implementation, and intrusion detection.

All communications and messages from the meter to the Head End System are secured through end-to-end encryption by the implementation of 128-bit AES encryption at the application layer.

128-bit AES encryption is implemented at multiple layers; from meter to the field area routers and the first wall of the demilitarized zone and from the field area routers to the head end routers/second router of the demilitarized zone. The network layer security employs Active Directory, Certification Authority Server, RADIUS Server (using Microsoft NPS), and Head End Router (Cisco ISR 4331) to provide tunnels to the routers. The security manager application secures the signing of messages from the head-end system to the endpoints.

5) *Identify and characterize the requirements for timely restoring advanced metering resources and capabilities following a cyber disruption. Describe in detail the means and methods employed to provide the required recovery capabilities.*

Restoration requirements are based on recovery capabilities as defined in our Unified Incident Response and Disaster Recovery Plans.

4.10 DER Interconnection

Introduction/Context and Background

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

Interconnection is the connection of DER to the Companies' distribution system in a safe, efficient, and reliable manner, thus contributing these same attributes to the grid.

Since filing the Joint Utilities' Supplemental Distributed System Implementation Plan (Supplemental DSIP), the Joint Utilities have developed several technical documents addressing interconnection priorities while clarifying and formalizing aspects of the interconnection process, including:[86]

- Interim requirements on anti-islanding;
- Monitoring and control requirements;
- Recommended changes to Electric Power Research Institute's (EPRI) proposed modifications to the Standardized Interconnection Requirements (SIR) screens to improve effectiveness and support future automation;
- Documentation of specific to voltage issues and voltage flicker in support of the SIR revisions; and
- Proposed energy storage application requirements and SIR updates.

We have made substantial improvements in the Interconnection process, reducing the size of the queue, and reducing wait times through improvements to the portal, automation, and applying more personnel and technology resources to the interconnection process.

Implementation Plan, Schedule, and Investments

To describe the details of the current and future implementations, the utility should use system diagrams, process flow diagrams, tables, and narrative text as needed for clarity and thoroughness. When describing the progression from the current implementation to the future implementation, the utility should use narrative text, Gantt charts, and calendars which present and explain the planned sequence and timing of the notable development activities, dependencies, and milestones.

[86] These discussions were organized by the Interconnection Technical Working Group (ITWG).

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

NYSEG and RG&E have developed and implemented Phase 1 of an online Interconnection portal as recommended by a September, 2016 EPRI report entitled, Interconnection Online Application Portal Functional Requirements ("IOAP Report"). The Phase 1 goal was to automate the application management portion of the process, including application submittal, validation, tracking, and approval and facilitate receipt of complete applications and the efficient exchange of information to process applications through a well-designed portal.[87]

These process improvements occur within the context of the SIR, which was established in 1999 and provides a framework for processing applications to interconnect distributed generation facilities to New York's investor-owned utilities' electric distribution systems.[88]

The IOAP Report specified a three-phase roadmap for achieving increased automation of the DER interconnection process:[89]

- Phase 1: Automate Application Management
- Phase 2: Automate SIR Technical Screening
- Phase 3: Full Automation of all Processes

We have completed Phase 1 and our interconnection portal enables the following outcomes that benefit DER developers:[90]

- **Application Validation and Approval** – Provides us with the ability to validate the application fields for basic characteristics and the ability to approve applications that are less than 50 kW based on a well-defined set of parameters;
- **Application Tracking** – Allows developers and our interconnections team to view the status of their application;
- **User Restrictions** – For privacy and security, allows different users to have different access based on "need to know" and their roles;
- **Cost Estimates, Status of Payments and Pay Online:** Enables applicants' visibility into cost and payment status, and enables on-line payments;
- **Viewing Hosting Capacity Maps:** Enables the public to view maps of the system where

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87 Available here:

88 New York State Standardized Interconnection Requirements, July 13, 2018 Available here.

89 *Id.*, pp. 13-17.

90 Our Interconnection Portal can be found at: http://nyseg.com/SuppliersAndPartners/distributedgeneration/distributedgenerationonlineportalapplication.html

it may be better or worse to install DER, from a cost perspective; and

- **Reporting Capability and Options**: Enables us to run reports on applications and to export results for sharing with government entities such as NYSERDA and Staff of the New York Department of Public Service ("Staff").

Phase 2 focuses on the automation of the SIR technical screens for projects above 50 kW, including but not limited to review of the point of common coupling, certification status of specified equipment, and compatibility of the line configuration with the interconnection type. Phase 3 strives for automation of all interconnection processes.

In December 2017, Staff released proposed changes to the SIR based on written feedback received from the Joint Utilities and DER developer community. The proposed changes fall into three main categories:

(1) Incorporating energy storage into the SIR;

(2) Updating preliminary and supplemental screens; and

(3) Minor editorial revisions.

A final order was issued on April 19, 2018.[91]

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

The number of interconnection requests continues to grow, and we must keep pace by continuing to improve the interconnection process through streamlining and automation. It is likely that certain larger projects will continue to require special studies and it is important to continue to perform these studies efficiently, even as we take steps to automate the interconnection process so that it can apply to as many large projects as possible. We are currently focused on improving the quality and granularity of load and other data that supports

91 April 19, 2018 order available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={83E4738F-38C2-4995-9EC8-D5ABEF5B20CD}. Press release available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D522F1F3-B26E-42FB-B46C-291988FDC4C8}.

interconnection, automation of a greater proportion of the interconnection process, with the objective of continued improvements in the wait time experienced by applicants. The Companies are also continuing efforts to update their database of connected DER and increasing the efficiency of CYME analyses.

The Roadmap for DER Interconnections is presented in Figure 4.10-1.

FIGURE 4.10-1: DER INTERCONNECTIONS ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)
Process Interconnection Applications	Dramatically Reduced Queue Times as Requests Grew Completed Phase I Interconnection Portal	Phase 2 Interconnection Portal Automate Data Flows to GIS, Systems, Applications, and Products (SAP), and CYME Reduce Reliance on Manual Processes	Increase Automation of Interconnections for Large DER (Phase 3)
Track Interconnection Applications to Achieve SIR Timelines	Developed Interconnection Database		
Negotiate Flexible Interconnection Service (FICS) Agreements	Developed FICS Process Subscribed first customer to FICS (ANM) Completed Factory Acceptance Tests (FAT) and Site Acceptance Tests (SAT) for FICS	Commission First FICS installation	Identify Projects Applicable to Active Network Management Alternatives

We have begun on the Phase 2 requirements (Automate SIR Technical Screening), requiring integration of multiple internal systems, such as billing, customer information systems, work management systems, and load flow software programs, to allow for the push and pull of data in common formats between back office systems. It also requires the ability to calculate SIR screens A to F (identified in the response to Subpart 2h as presented in Appendix G of the SIR, as revised on April 19, 2018, based on utility data and recognize the outputs as pass or fail. Phase 2 is to be completed by mid-2019. Finally, with respect to Phase 3, as noted in the EPRI report, it is not clear that fully automated functionality of all processes is feasible. As feasibility is further determined completion of this effort will be planned for the 2021-2023 timeframe.

We are currently conducting an innovation demonstration project to test the ability to work with developers to come to agreement under a flexible interconnect protocol, Flexible Interconnection Capacity Solution (FICS) whereby during constrained periods caused by the DER when voltage or thermal limits may be reached, the DER developer agrees to allow the utility to curtail the electricity generation export below maximum capacity. In exchange for allowing the DER to be constrained, the developer is able to reduce or avoid incremental network reinforcement costs that they may have incurred under the traditional interconnection process. FICS uses Smarter Grid Solutions' Active Network Management (ANM) technology to allow communication and control of the project DER.

We were also partners in a NYSERDA PON3397 project to integrate PowerClerk (Interconnection Administration), CYME (Interconnection Analysis), and Connect+ (ANM solution) as a proof-of-concept to support Phase 2 and Phase 3 SIR requirements. We have learned that additional automation of the interconnection process is possible with technology integration and automatic pre-CESIR (coordinated electric system interconnection review) screenings. We also learned that these processes will need to be updated as the SIR changes and the screenings are updated. We plan to leverage these lessons learned as we build our foundational technologies in the near term, and our enabling technologies in the longer term.

Our future efforts include enhancements to the interconnection process to accommodate emerging technologies, including energy storage. Given the growing interest in energy storage, the Joint Utilities are working to remove barriers to energy storage interconnections by developing a standardized technical screening process for energy storage interconnection applications. This process would standardize the materials required at the time of the application and formalize the review process to help streamline storage applications. The Joint Utilities are also discussing whether it is appropriate to restructure the timing and cost structure of the SIR review for energy storage in light of the heightened complexity of storage relative to solar photovoltaic (PV) facilities. We are particularly concerned with the incremental time and resources required to properly evaluate the protection and controls necessary to ensure a safe and reliable interconnection under various operating conditions. The Joint Utilities are currently working to resolve these issues to ensure that energy storage applications are given the appropriate level of review without the process becoming too costly or burdensome to the developer.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified two risks that relate to performance of the interconnection process, and have taken measures to mitigate each risk, as shown in Figure 4.10-2.

FIGURE 4.10-2: DER INTERCONNECTION RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality data that is relied upon by the DSP to perform special interconnection studies	• NYSEG and RG&E are designing the Grid Model Enhancement Project (GMEP) Phase 1 to incorporate governance and data processes and flows • Enterprise Data Platform deliverables are clearly specified including data architecture, dictionary, flow diagrams, etc. • Performing a data governance/data quality pilot roadmap for DER integration • Bring the DER database up-to-date
2. **Large Volume of Interconnection Requests:** the DSP must meet the SIR requirements	• Efforts to automate data flows and other aspects of the interconnection process to the extent possible • Daily "green/yellow/red" reports on interconnection status to internal functions that contribute to interconnections and a company officer.

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The interconnections process has been the subject of extensive stakeholder collaboration, organized by the Joint Utilities. Prior to filing the Supplemental DSIP in November 2016, we began participating in the Interconnection Technical Working Group and Interconnection Policy Working Group (IPWG) to coordinate with the Joint Utilities, DPS Staff and stakeholders on interconnection issues. We have actively participated in the interconnection working groups to identify and vet changes to the SIR and develop technical guidance and continued individual efforts to improve the interconnection process, thus successfully completing IOAP Phase 1 and Phase 2 requirements.

The ITWG promotes consistent standards across the utilities to address technical concerns affecting the distributed generation (DG) community that relate to interconnection procedures. The IPWG explores non-technical issues related to the processes and policies relevant to the interconnection in New York. As of spring 2016, the ITWG was in the early stages of identifying agenda items and challenges for the group to focus on, with significant progress yet to be made.

The initial agenda items identified for discussion included: anti-islanding protection; remote monitoring and control; technical screening process; and substation backfeeding / 3VO.[92] The IPWG was formed in the summer of 2016 and initially focused on queue management, group studies, return on investment studies, and cost sharing issues. The process for developing and implementing a roadmap for the IOAP was only beginning to be defined in the Supplemental DSIP.[93]

We continue to participate in the ITWG and IPWG and coordinate with the Joint Utilities on interconnection issues. In particular, we will continue actively supporting the Joint Utilities' goals of reducing barriers to entry of all DER types, and working collaboratively with Staff and stakeholders to provide greater predictability of interconnection costs to the customer.

We also addressed DER Interconnections in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their subparts.

Additional Detail

The utility resources and capabilities which enable DER interconnections to the distribution system are a critical early objective. Many of the details which identify and characterize those resources and capabilities are being worked out by the Interconnection Technology Working Group (ITWG) and the Interconnection Policy Working Group (IPWG) which are stakeholder collaboratives led jointly by Staff and NYSERDA. The goal of both working groups is to establish the requirements for standard resources, processes, specifications, and policies which foster efficient, timely, safe, and reliable DER interconnections.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to DER interconnections:

1) *A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.*

The NYSEG Distributed Generation website can be accessed here.

The RG&E instructions on use of the NYSEG/RG&E online application portal are available here.

2) *Where, how, and when the utility will implement and maintain a resource where DER developers and other stakeholders with appropriate access controls can readily access,*

92 Zero sequence overvoltage protection

93 Supplemental DSIP, p. 63

navigate, view, sort, filter, and download up-to-date information about all DER interconnections in the utility's system. The resource should provide the following information for each DER interconnection:

The NYSEG interconnection queue is available online here.

The RG&E interconnection queue is available online here.

a. DER type, size, and location;

The DER type is typically revealed in the project name. The size and location of each project are identified.

b. DER developer;
c. DER owner operator;
d. DER operator

The developer is identified. The owner operator or operator are not currently identified.

e. the connected substation, circuit, phase, and tap;

The substation and circuit are identified. The phase and tap are not included in the reported information, although it would be possible to identify the phase based on the circuit location. We can also add a Geographic Information System (GIS) ID to be responsive to the request for "tap" identification, if the developers have a desire for this information that justifies the expense we would incur to provide it.

f. the DER's remote monitoring, measurement, and control capabilities;

This information is not currently publicly available. Installations greater than 1 MW have a point-of-connection recloser. Installations greater than 500 kW are subject to monitoring and control. Control is generally an on/off feature; we are generally not able to dispatch the resource.

g. the DER's primary and secondary (where applicable) purpose(s); and,

This information is not currently publicly available. Some installations may have smart inverters that are available for voltage control.

h. the DER's current interconnection status (operational, construction in-progress, construction scheduled, or interconnection requested) and its actual/planned in-service date.

The interconnection queue includes the following information related to interconnection status:

- Application Received
- Application Accepted
- Date Completed Preliminary Screening

The preliminary screens requiring automation in Phase 2, referred to as screens A through F, are as follows:

- Screen A: Is the PCC on a Networked Secondary System?
- Screen B: Is Certified Equipment Used?
- Screen C: Is the Electric Power System (EPS) Rating Exceeded?
- Screen D: Is the Line Configuration Compatible with the Interconnection Type?
- Screen E: Simplified Penetration Test
- Screen F: Simplified Voltage Fluctuation Test

- Date Coordinated Electric System Interconnection Review (CESIR) Funding Received
- CESIR Completion Date
- CESIR Final Technical Review Completion Date

Technical Screens G through I are as follows:

- Screen G: Supplemental Penetration Test
- Screen H: Power Quality Tests
- Screen I: Safety and Reliability Tests

- Date Initial Construction Funding Received/Contract Sent
- Date Full Construction Funding Received
- Comments on Project Status

3) The utility's means and methods for tracking and managing its DER interconnection application process to ensure achievement of the performance timelines established in New York State's Standardized Interconnection Requirements.

The Companies prepare a daily "green/yellow/red" report that is circulated to all internal functions that serve a role in the interconnection process. The Vice President responsible for compliance with the SIR receives the daily report. The daily report tracks SIR reporting requirement periods, as well as the internal steps that are necessary to meet the interim SIR deadlines, *e.g.*, reviews by our planning and engineering departments.

4) Where, how, and when the utility will provide a resource to applicants and other appropriate stakeholders for accessing up-to-date information concerning application status and process workflows.

DER developers have access to this information for their own projects. It is likely that developers consider this information to be commercially sensitive. If they are willing to authorize us to release it, we will want to evaluate the value of this information to other stakeholders as compared to the expense of providing it.

5) The utility's processes, resources, and standards for constructing approved DER interconnections.

After a project is received from the Interconnections Group, the Field Planning Group will design the recommended upgrades from Distribution Planning and any other line upgrades needed using Company-approved construction standards. The work flow follows task-based routing. Once the design is complete it is handed off to line department to construct in field. Handoff points are tracked using tasks on the notifications.

The following two documents have been filed with the New York State Public Service Commission:

- 07-M-0906, Generation Interconnection Operating Standards and Procedures; and
- 07-M-0906 Generator Energy Deliverability Study Process and Scope.

The Companies' standards for the interconnection of distributed generation are contained in Bulletin 86-01,Requirements for the Interconnection of Generation, Transmission and End-User Facilities. Our specifications and requirements are supplemented by the following documents:

- NYSEG's Specifications for Customer Electric Service 2.4 kV to 34.5 kV (SP-1099);
- NYSEG's Requirements for the Installation of Electric Services & Metering; and
- RG&E''s Requirements for Installation of Electric Services & Meters.

6) The utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels.

Our process for tracking and managing construction to interconnect approved DER begins when the developer has provided 100% of the estimated system upgrade costs. There are several steps to the process:

- The assigned Manager Programs/Projects sends an email to the appropriate division and corporate personnel which contains details of the project including completed studies, scope and estimate of cost of required system upgrades that have been prefunded by the developer, and applicable project drawings.
- The project email is followed up with a kick-off meeting (teleconference) among those included on the project email. Project details and targeted in-service dates are discussed.
- The assigned field planner arranges a site visit with the developer and then completes detailed engineering for the interconnection of the generation including creation of work orders for materials, project drawings, etc. and forwards to our Real Estate team.
- After all real estate issues are resolved the project work orders are released and requirements sent material procurement.
- After materials received the job is forwarded to the construction scheduler for scheduling of construction leading to construction until energization is achieved.

Throughout this process the Manager Programs/Projects remains in communication with the developer and division personnel

7) Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information concerning construction status and workflows for approved interconnections.

With the exception of construction status, which is reported to developers via email and teleconferences, application workflows are typically reported via our online interconnection portal.. Only DER developers have access to workflow information for their own projects. It is likely that developers consider this information to be commercially sensitive. If they are willing to authorize us to release it, we will want to evaluate the value of this information to other stakeholders as compared to the expense of providing it.

4.11 Advanced Metering Infrastructure

Introduction/Context and Background

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

Advanced metering infrastructure (AMI) is an integrated set of technologies that collect interval energy usage data through smart meters, validate and store the data in a database, and provide customers access to their own meter data through a web portal. The data from our AMI system can provide us with real-time power consumption data and allow customers to make informed choices about energy usage based on the price at the time of use (TOU).

AMI is a foundational system for the Distributed System Platform (DSP). Our AMI project will include installation of intelligent or smart meters, including new electric and gas meters and new gas modules to be retrofitted on existing gas meters, a supporting telecommunications network and IT infrastructure comprised of diverse communications solutions (*e.g.*, radio frequency and cell, fiber), and software applications to process data and interact with field devices. In addition, the telecommunications network will provide a channel for Grid Automation.

Since the initial DSIP filing in 2016, two initiatives have improved our understanding of AMI capabilities, and the policies, processes, resources, and standards that need to be put in place to successfully deploy the technology. First, we have issued a request for proposal (RFP) to acquire AMI technology. We have carefully reviewed vendor responses, and that review process contributed to refinements to our AMI system design that we proposed in our initial 2016 filing.[94] Second, we have deployed AMI technology in the Energy Smart Community, and have experienced first-hand the capabilities of today's state-of-the-art AMI systems. These two initiatives provide additional enhancements and capabilities beyond our filed 2016 AMI plans:

> **Storm resiliency:** Today's AMI systems can be "hardened" to support communications through multi-day power outage situations, through the use of larger battery backup packs or solar power backup at key network locations. As a consequence, our current AMI specifications specify multi-day battery backup for 25% of all network communication nodes. This multi-day backup will allow communications with smart meters when they experience power restoration, even if power has been off for more than 24 hours. Receiving these power restoration messages will improve the efficiency of the overall storm restoration process during multi-day outages.
>
> **Interoperability:** The AMI industry continues to move toward true equipment interoperability between vendors, in order that smart meter and network

[94] Case No. 15-E-0283, *et. al.*

communication interfaces manufactured by one vendor can be used in AMI systems featuring equipment from another vendor. This interoperability means that the acquisition of equipment post-deployment will take place in a more competitive environment, which should lead to lower post-deployment equipment costs. Thus, we have required interoperability capability from each of the vendors they are considering as suppliers for full AMI deployment, to ensure that post-deployment equipment replacement and system expansion can be completed as efficiently as possible.

Network Throughput: In 2016, the specifications for granularity and delivery frequency were hourly consumption data delivered four times per day. Today's AMI systems have more network capacity, and as a consequence, we anticipate deploying a system that can deliver consumption data every 15 minutes back to our operations center. The higher capacity networks will support more finely tuned time-sensitive rates and will provide customers more real-time data to help them manage electric bills.

Edge Information Processing: The most recent generation of AMI smart meters can process meter information collected in real time, sending the results of the information processing back to the operations center. In addition, the meters can integrate directly collected meter data with meter data from nearby meters to understand area situations and react accordingly. For example, meters can interpret their own power off messages with messages from nearby meters to communicate outage scope more effectively. In addition, the meters can identify which circuit power phase they are connected to and transmit this information back to the operations center to support more accurate load balancing. As a final example, the meters can assess nearby power loads, as well as the direct power load on the meter, and can take remote action to manage circuit overload situations and avoid transformer overloads. The emergence of edge computing will create future AMI benefits for customers. By way of analogy, in 2016, the smart meters had the computing power of a smart phone, but today's smart meters have the computing power of a laptop.

Implementation Plan, Schedule, and Investments

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

We have made significant progress in the deployment of AMI in the Energy Smart Community. NYSEG has installed approximately 12,300 electric meters and 7,600 gas smart meters. AMI's telecommunication system is also deployed across all 15 circuits in the Energy Smart Community. Our AMI system will be integrated into a number of systems, including the Outage Management System (OMS) and Energy Manager, our products and services marketplace. The information from the system is currently used for billing and as the basis for customer engagement, including segmentation, energy usage information, and new rate design options.

AMI data will support Stage 2 (closed-loop) VVO, which will more efficiently manage voltage levels to reduce energy loss on the system. We will continue to integrate AMI data into additional systems and initiatives, including time-varying rates, Smart Home vehicle charging pilots, and updated Hosting Capacity and Interconnection portals.

There are significant technical and non-technical lessons learned from the Energy Smart Community AMI project that will be leveraged for full-scale AMI deployment. Prior to our deployment in the Energy Smart Community, NYSEG, in cooperation with Cornell Cooperative Extension of Tompkins County, hosted community meetings to educate residents on our innovation project and the benefits of AMI. We have learned that participation in public events and presence at gathering places such as farmer's markets, festivals, and educational events proved to be very effective in building awareness and grassroots support. Feedback from these events and other public presentations helped to refine NYSEG's messaging, as we learned that a simple, and straightforward, non-technical communications style was most effective.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Our system-wide AMI system will enable:

- a new customer information data stream consisting of granular consumption data that will support time-varying pricing and other innovative rates that have the potential to reduce energy costs for customers;
- a web portal that communicates energy usage to help customers make better decisions about their DER investments and energy purchase options;[95]
- a new enterprise analytics system to use energy consumption and grid performance data to plan and operate the distribution grid more efficiently;
- real-time outage and power restoration notifications that yield a more reliable and resilient distribution grid; and

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95 Energy usage data available to customers through NYSEG's ESC Energy Manager and RG&E's Energy Marketplace. See Appendix B of our 2018 DSIP Report for more details on our tools available for DER developers and customers.

- operational efficiencies by enabling Grid Automation functions (such as Volt-VAR Optimization).

AVANGRID is prepared to install AMI meters and the communication network over a four-year period beginning in 2019. We have deployed approximately 12,300 electric and 7,600 gas AMI meters in our Energy Smart Community. This experience has informed the development of our system-wide deployment plan. AMI will benefit customers by providing large volumes of granular usage and event information to optimize customer value through demand response and energy efficiency programs, as well as time-varying pricing (TVP) and future innovative rate structures.

Customer information will be integrated into customer facing applications enabling customers to better manage their electricity and gas usage and energy bills and improve our system operators' situational awareness. Additional benefits include decreased estimated readings, incremental energy savings by utilizing energy management made possible with AMI; integration of AMI with the Companies' Outage Management System to reduce outage duration and customer outage costs; and the potential creation of innovative energy- and cost-saving programs by customer sharing of granular usage information with third parties, with permission. Investment in AMI is aligned with AVANGRID's commitments to carbon reduction, clean energy, energy efficiency, and technology innovation.

At a high level, our AMI project has several key workstreams, as shown in Figure 4.11-1. Assuming we start deploying meters in March 2019, we anticipate completing installation by the end of 2022.

FIGURE 4.11-1: AMI WORKSTREAM PROJECT SCHEDULE

Project Element	17-1	17-2	17-3	17-4	18-1	18-2	18-3	18-4	19-1	19-2	19-3	19-4	20-1	20-2	20-3	20-4	21-1	21-2	21-3	21-4	22-1	22-2	22-3	22-4
Support Regulatory Process																								
Establish Project Governance and Management Team																								
Procure Outside Services and Equipment																								
Deploy AMI IT																								
Deploy CRM																								
Manage Process Change																								
Manage Employee Training and Transition																								
Engage Customers																								
Deploy Communications Network																								
Deploy Customer Meters																								

We will not begin deploying AMI on a system-wide basis until after we receive regulatory approval. For planning purposes, we are projecting this effort to culminate in an agreement by the end of the third quarter of 2018.

We have a Management Team and Governance plan in place. The management team is proceeding with internal resource planning, scheduling and overall deployment planning. Co-directors of the project have been identified, and the members of the team working for the directors are in place.

One of the largest efforts of the Management Team is to develop a schedule of RFPs that will be used to acquire needed products and services to complete the deployment. Figure 4.11-2 lists AMI RFPs that are in the procurement process workstream to ensure that our AMI deployment can begin as soon as regulatory approval is achieved.

FIGURE 4.11-2: AMI RFPS

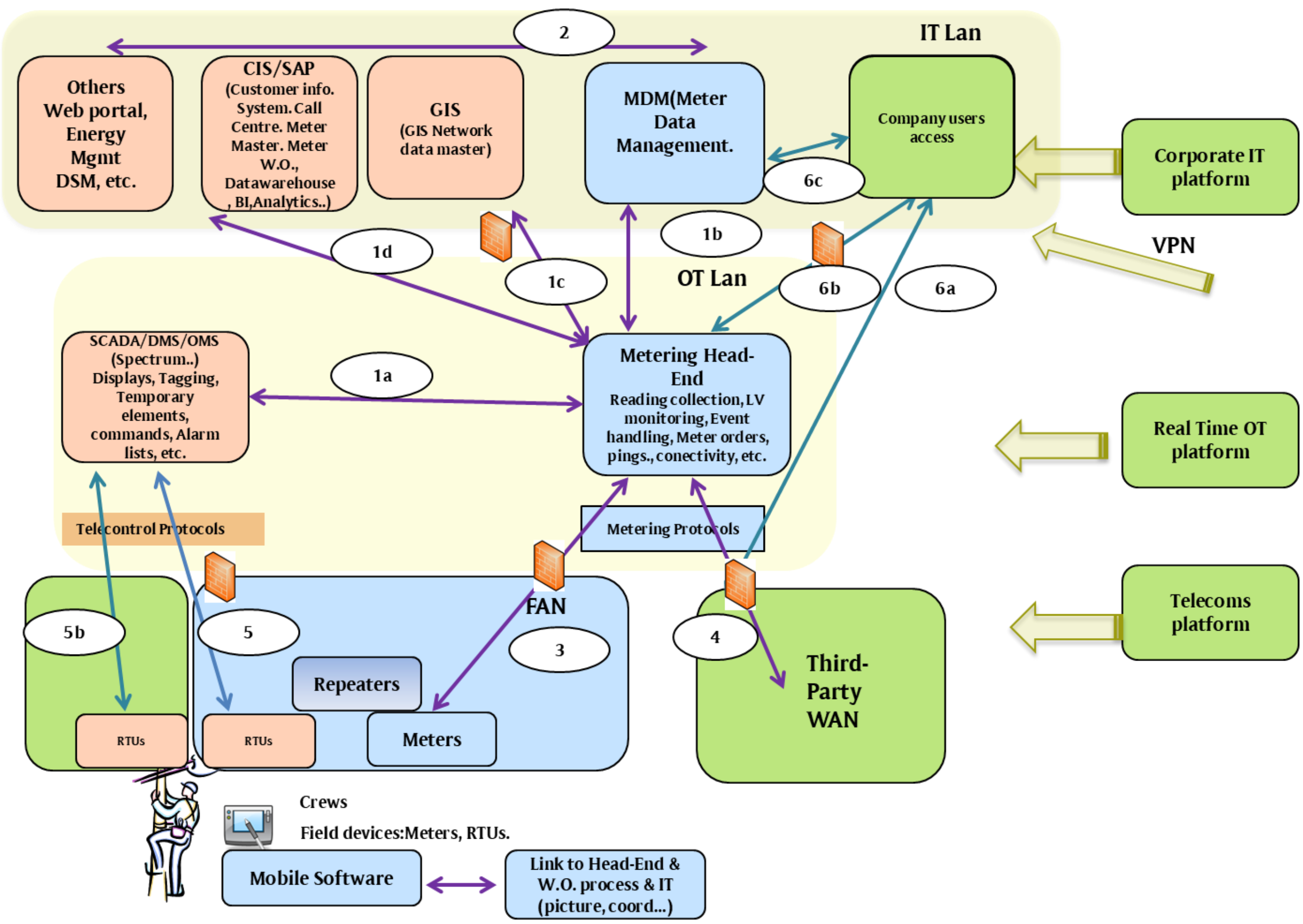
RFP	No.	Description
AMI Solution	1	This is a comprehensive RFP that covers all needed electric and gas meters, electric and gas communications modules, communications network, head end software, meter installation, and meter data management (MDM) data management software. This RFP provides the core infrastructure needed to measure, collect, and manage both customer consumption data and also meter monitoring data to support enhanced grid operations.
System Integrator	2	This RFP provides human resource support for the project management office (PMO), and also resources for managing and handling data exceptions that arise during AMI deployment. In addition to staffing part of the PMO, the successful vendor will also have access to a "bench" of other human resources that might be needed during the course of the deployment
IT Integration	3	This RFP provides the programming and testing expertise needed to integrate our AMI and MDM software to each other, and to the customer information system and the Spectrum Platform including OMS. Integration will be required with Systems, Applications, and Products (SAP); Click, Customer Relationship Management and Billing (CRM&B), Customer Care System, and other systems.
Web Portal	4	This RFP solicits software to present AMI data in a digestible form to the customer. The software will be a web-based tool that can also be used by Customer Service Representatives to help answer customer questions.
Network Canopy	5	This RFP solicits hardware and installation services to expand the New York WiMAX network to connect to our AMI network and provide information backhaul services for AMI.
AMI Network Solution	6	This RFP solicits services for installing our AMI communications network devices to distribution poles and towers across the service area.
Meter Seals/ Adaptors	7	This RFP solicits meter seals for all the electric meters and A-based adapters for approximately 2.5% of the electric meter sockets. *(meters must be onsite prior to deployment)*
Meter Panel Repairs	8	This RFP solicits electrician services to complete minor repairs on customer meter panels to facilitate our AMI meter deployment. In fact, customers are responsible for these repairs, but when NYSEG and RG&E assume the cost of repair they avoid schedule delays, which leads to better installation efficiency.
Customer/ Community Outreach	9	This RFP solicits services to develop and manage a process to communicate to customers in every important population center in the service territory. The services would also include assistance with the development of promotional materials and public service ads for AMI.
CRM Integration	10	This will involve multiple RFPs and IT services to integrate an upgrade to the customer information system with associated systems in New York. The new customer information system will more effectively support the time variable rates that help create value with our AMI technology.
Network Trouble-shooting	11	This RFP solicits both analytical and field services to refine and improve the performance of the installed AMI communications network. The services would include network performance analysis and then field trips to reposition, service, or upgrade the communications network with additional equipment.

AMI IT work includes putting IT hardware infrastructure in place, installing AMI head end software, MDM software, and web portal software, and completing the integrations necessary so that the hardware and software directs information flows when and where they are needed.

Figure 4.11-3 presents an overview of the necessary AMI IT Systems Architecture. In addition to AMI IT implementation and integration, our overall AMI deployment involves deployment of an upgraded CRM&B to support time variable rates. This system upgrades a major undertaking and is scheduled for 2019 and 2020 in the overall project plan.

We anticipate a major effort to implement process changes to take advantage of the new AMI capabilities. This effort would cover 2019 through mid-2021 period. We have developed an employee retraining and transition plan for workers in 220 positions displaced following our AMI deployment. This program will begin late in 2019 and continue through the end of the project in 2022. We have developed an extensive customer engagement program which is currently planned to begin in the fourth quarter of 2018 and continue throughout the rest of the project. Our AMI wireless communications network will be deployed over a 2.5-year period beginning in the second quarter of 2019. Finally, the 1.9 million AMI meters will be deployed over a 3.5-year period beginning in the second quarter of 2019.

FIGURE 4.11-3: AMI SYSTEMS ARCHITECTURE OVERVIEW



Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks that relate to the deployment of AMI, and have taken measures to mitigate each risk, as shown in Figure 4.11-4.

FIGURE 4.11-4: AMI RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Deployment and Performance:** Deployment risk related to schedule and cost overruns; performance risk related to technology performing per expectations	• Energy Smart Community deployment has provided experience in process change planning, customer communications, new rate implementation, and benefit realization. These lessons learned are incorporated in our AMI project planning • Performance risk is minimal as many AMI deployments have occurred throughout the country
2. **Customer Acceptance:** Uncertainty regarding AMI benefits and concerns about health, safety, privacy and other perceived threats	• We have developed a comprehensive customer engagement plan to communicate the benefits of AMI and a realistic, informed assessment of perceived threats
3. **Regulatory Approval Delay:** AMI plan assumes approval in Q4 2018; delay will increase costs and reduce benefits	• We are releasing support services and equipment RFPs in 2018 in advance of receiving regulatory approval, and request locked-in pricing for a year • We have established an AMI Project Management Office, appointed an Advisory Committee, established the project schedule, and developed a project governance plan.

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design; how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses.

The AMI technology we anticipate deploying system-wide starting in 2019 has capabilities that will support DER developer needs, as well as the needs of customers and other stakeholders. AMI smart meters have dual usage registers to measure both power delivered to the customer and power delivered to the grid. Consequently, the meters will collect measurements that will support individual DER developer needs, and also in aggregate supply information on overall distribution circuit hosting capacity and energy requirements. This information will support identification of optimal locations for community-level DER projects.

AMI will provide the detailed information on distribution circuit load and voltage that is needed to plan optimal locations for DER siting decision. This data will support accurate forecasts of load by substation and circuit that supports the Advance Forecasting function. These forecasts will be more detailed and granular with respect to time of day and location on distribution circuit than our current forecasts.

More granular AMI data will improve estimates of hosting capacity by circuit, which can provide a preliminary indication of the lowest-cost locations for connecting to the grid. Hosting capacity is estimated as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line voltage and/or secondary network system. Estimating hosting capacity is a data-driven exercise and depends critically on the availability and quality of granular data. The resulting hosting capacity heat maps are critical to identify optimum locations for DER.

Improved Integrated Planning capabilities and communication of desired locations for DER will support our efforts to identify non-wires alternatives (NWAs) for addressing energy needs at particular locations without adding significant amounts of new distribution capacity.

AMI meters enable the verification of installed DER performance during curtailment situations. Granular AMI data can accurately measure the curtailment and aggregating the curtailment actions can help us assess the success of the overall curtailment effort and take actions to expand or contract the efforts. System operators require real-time visibility and the ability to respond to DER operations and understand their impact on distribution facility power flows. Operators must be able to ramp controllable DER down or up (*e.g.*, energy storage, demand response or dispatchable distributed generation) in order to address a system constraint, to maintain power flow limits, or to maintain voltage levels.

AMI meters will collect granular interval consumption data that will support the development of time-varying rates. Granular consumption data from AMI meters can also support a bill alerts program to help customers understand their power usage during the billing month, so that they could adjust their consumption if needed to stay within target energy budgets.

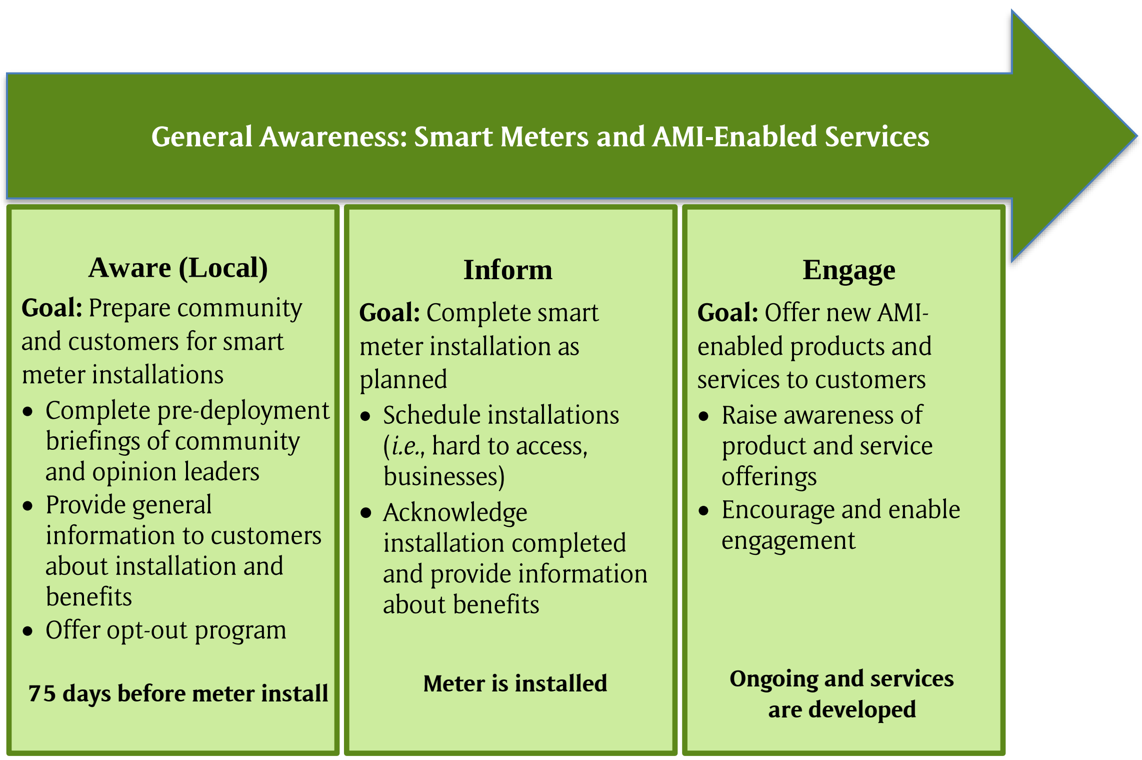
AMI meters will support a number of cost-reduction process changes inside the company that will result in higher customer benefits, such as reduced outage time, lower cost of collecting customer billing information, lower cost of service connections and disconnections, and lower customer service costs in the call center and billing departments.

To ensure that the DER developers and other stakeholders understand how to take advantage of the new AMI-provided capabilities, we have developed a detailed customer outreach and engagement plan. This plan provides a roadmap to build and operate a customer communications program and identifies metrics so that the plan can be continuously improved over time. The plan is central to the overall deployment of AMI, which is not only a physical meter replacement program but also a communications program to ensure our AMI asset is effectively utilized.

As shown in Figure 4.11-5, our customer engagement plan consists of three phases designed to help customers become:

1. **Aware**: A series of communication campaigns designed to educate customers about smart meter benefits and the general scope and timing of the deployment;
2. **Informed**: A series of communication campaigns designed to prepare customers for deployment, reiterate meter benefits, and provide information on available program opportunities for each customer; and
3. **Engaged**: Ongoing communications, starting from the day of meter installation, to provide individual customers with the knowledge and insights to participate in smart meter opportunities.

FIGURE 4.11-5: CUSTOMER ENGAGEMENT PLAN



Each phase includes campaigns with defined targets, messages, audiences and communication channels. Metrics are being developed to track participation and behavioral changes. We will develop and adjust communication messages as necessary and select communication channels throughout the duration of the plan.

Additional Detail

Advanced Metering Infrastructure (AMI) provides grid-edge measurement, data acquisition, and control capabilities which are either essential or beneficial to a number of important functions in modern distribution system. Granular time-series data from smart meters and other intelligent devices at customers' premises enable advanced analyses, innovative rate designs, and customer engagement strategies which benefit both the customers and the grid. Voltage sensing and measurement functions support increased system efficiency and enable improved outage detection and restoration processes. Capabilities supporting DER measurement, monitoring, and control are essential for DER integration.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to AMI:

1) *Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.*

In the 2016 DSIP Plan, we assumed that AMI deployment starts in 2018 and ends in 2022. The original deployment plan is included in Figure 4.11-6. The Energy Smart Community project will serve as a testbed for the DSP and as the first phase in the full deployment of AMI. We provided the following figure to depict the installment progress in NYSEG and RG&E.[96]

FIGURE 4.11-6: NYSEG AND RG&E ADVANCED METERING DEPLOYMENT PLANS

Advanced Meter Deployment (% Total)	2018	2019	2020	2021
NYSEG	20%	40%	30%	10%
RG&E	0%	30%	40%	30%

As shown in Figure 4.11-7, our current AMI deployment plan retains a completion date of 2022, with initial deployment delayed to 2019.

FIGURE 4.11-7: NYSEG AND RG&E CURRENT ADVANCED METERING DEPLOYMENT PLANS

Advanced Meter Deployment (% of Total)	2018	2019	2020	2021	2022
NYSEG	0%	15%	30%	32%	23%
RG&E	0%	5%	30%	37%	28%
Total	0%	11%	30%	34%	25%

NYSEG has deployed approximately 12,300 electric and 7,600 gas smart meters in an area of

96 2016 DSIP, p. 120.

approximately 50 square miles centered in Ithaca, New York. This deployment of Energy Smart Community meters is performing well, and demonstrating many of the features of AMI smart meters. NYSEG has pursued the acquisition of interoperable AMI technology, so that the Energy Smart Community meters may be incorporated into the full deployment plan, irrespective of who the final prime AMI technology vendor turns out to be.

2) *Describe in detail where and how the utility's AMI provides capabilities which:*

a. *help the utility integrate DERs into its system and operations;*

AMI meters provide two measurement channels to record power inflows and power outflows separately at each DER site. In addition, AMI meters provide voltage measurements at each DER site. These AMI meter capabilities with respect with data enhancement will help with load planning, distribution circuit management, determine hosting capacity and assign locational value.

b. *help DER developers plan and implement DERs;*

Since AMI meters provide interval consumption data and frequent measurements of voltage, NYSEG and RG&E distribution planners will be able to review distribution circuit loads and identify the hosting capacity of each circuit. Communicating this hosting capacity to DER providers will help direct incremental DER resources to the circuits that can best link those DER resources to the other customers on the distribution grid.

c. *help DER operators plan and manage operation of their DERs;*

AMI meters will permit us to develop accurate and detailed load curves for each circuit segment. In addition, the granular consumption data from AMI meters will support the development of time variable rates. All of this information will help the DER operators understand the value of kilowatt-hours produced at a particular time, so that the return of power back into the grid can be optimized. Moreover, AMI data will provide verification of DER performance and support transactional markets.

d. *enable or enhance the utility's ability to implement and manage automated Volt-VAR Optimization (VVO);*

AMI meters provide comprehensive voltage monitoring for all customers, so that CVR/voltage-VAR optimization (VVO) functions can make voltage adjustments without risk of compromising service to any individual customer. Separate voltage sensors at key points along the circuit could provide data to support CVR/VVO operations, but the more detailed AMI voltage data will support the fine tuning of the operation plan to optimize savings. AMI technology software and firmware is now designed to integrate with CVR/VVO systems to optimize the transfer of information between the smart meters and the CVR/VVO controller. This integration is expected to increase the incremental improvement of CVR/VVO generated by use of Smart Meter data.

e. improve the utility's ability to prevent, detect, and resolve electric service interruptions;

AMI meters issue power-off and power-on messages in real time, and these messages support earlier outage identification, more accurate outage scoping, and faster, more efficient service restoration after faults are resolved. In addition, AMI meters can be "pinged" when individual customers report outages, so that situations where the power outage problem is on the customer's side of the meter and not the utility's side can be readily identified and "false alarm" truck rolls can be avoided.

f. improve the utility's ability to implement rate programs which facilitate and promote customer engagement, DER development, and EV adoption;

AMI meters can supply very granular interval consumption data which supports the creation of time-of-use rates. Rates can be set higher for times when power is more expensive to supply, and lower for times when power is less expensive to supply. These price signals can help customers find the most efficient times to use power, and the most profitable times to return power to the grid. Consequently, customers can take an active role in managing their power production and consumption, and overall costs of using power consequently decline. Our AMI web portal that communicates usage patterns can help customers understand the opportunities available or with managing their bills.

3) Describe in detail how the AMI enables secure communication with and among devices at customers' premises to support customer engagement, energy efficiency, and innovative rates.

Our AMI system will provide meters with three alternative ways to communicate with other devices in the customers' premises.

First, the meter contains a standard wireless protocol radio that can communicate to WI-FI enabled devices.

Second, the meter can communicate with devices at the customer premise over the premise power lines. The power line communications feature facilitates communications in premises where the meter and the target premise device are not located near to each other, in situations where a WI-FI signal might not be able to reach from the meter to the device in the customer premise.

Third, AMI meters can connect to a universal communications device inside the premise, which could relay communications via Zigbee, Z -Wave, or other short range wireless protocol.

The customer premise devices linked to the meter by one of the three methods described above can be information displays, programmable thermostats, or appliance control devices that can be used to engage customers and manage energy efficiency strategies.

4) Describe where and how DER developers, customers, and other stakeholders can access up-to-date information about the locations and capabilities of existing and planned smart meters.

Upon receiving regulatory approval to install AMI, we will add a link to the NYSEG and RG&E

website home pages that will include maps of the deployment activity, answers to frequently-asked questions, and how to exploit the benefits enabled by smart meters. The Energy Smart Community website provides an example of the support provided on the web portal.[97]

[97] Portal available here.

4.12 Hosting Capacity

Introduction/Context and Background

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

Since filing the Initial DSIP and the Supplemental DSIP, we released and updated our Stage 1 red zone indicator maps, reflecting collaboration among the Joint Utilities.[98] We estimate each circuit's hosting capacity by evaluating potential power system criteria violations as a result of interconnecting large solar photovoltaic (PV) systems to three-phase distribution lines.[99] This methodology was selected to deliver value in a timely manner to active DER developers. This approach increases visibility into hosting capacity for larger-scale solar PV systems that often target rural areas served by upstate utilities where land is available, but where hosting capacity can vary substantially from site to site.

We met the Commission's targets for posting its Stage 2 hosting capacity estimates for all radial distribution circuits by October 2017, providing feeder-level hosting capacity for all relevant circuits.[100] These estimates were prepared using the Electric Power Research Institute (EPRI) DRIVE™ tool and CYME.[101] Based on engagement with, and feedback from, stakeholders, the Joint Utilities committed to adding pop-up tables to their maps in a "Stage 2.1" that provided additional system data, including minimum and maximum total feeder hosting capacity, peak load, voltage and the status of voltage protection upgrades, and installed and queued distributed generation (DG) values. The Companies began providing these Stage 2.1 hosting capacity tables in mid-April 2018. The Joint Utilities are also committed to updating queued DG on a monthly frequency.[102] The installed and queued DG is of particular interest to distributed energy resource (DER) providers as the Stage 2 analyses did not include existing DER. We have taken steps to execute the CYME model in batch form to decrease the time required to perform a hosting capacity update, preparing us to meet stakeholder requests for more frequent updates in

98 Hosting capacity map are made available to DER developers on our Hosting Capacity Portal.

99 Solar with an AC nameplate rating starting at and gradually increasing from 300 kW.

100 Stage 2 was implemented in compliance with the Commission's March 9, 2017 Order in No. 16-M-0411 (p.14) requiring Stage 2 hosting capacity analysis for all radial distribution circuits at and above 12 kV to be completed by October 1, 2017.

101 The EPRI DRIVE tool was developed to estimate hosting capacity. The DRIVE tool was chosen to support further alignment and a common approach across the Joint Utilities, as it leverages existing circuit models in a utility's native distribution planning software to carry out a streamlined analysis of hosting capacity. The Joint Utilities remain engaged in EPRI's DRIVE User's Group and continue to raise areas within the DRIVE tool that require future enhancements to meet both utility and stakeholder interests. CYME refers to a power flow modeling tool that we use to perform Integrated Planning analyses, including hosting capacity.

102 Our IT function is working on this update.

hosting capacity. The Companies expect to publish an annual update to the Stage 2 feeder-level hosting capacity by October 1, 2018.

Implementation Plan, Schedule, and Investments

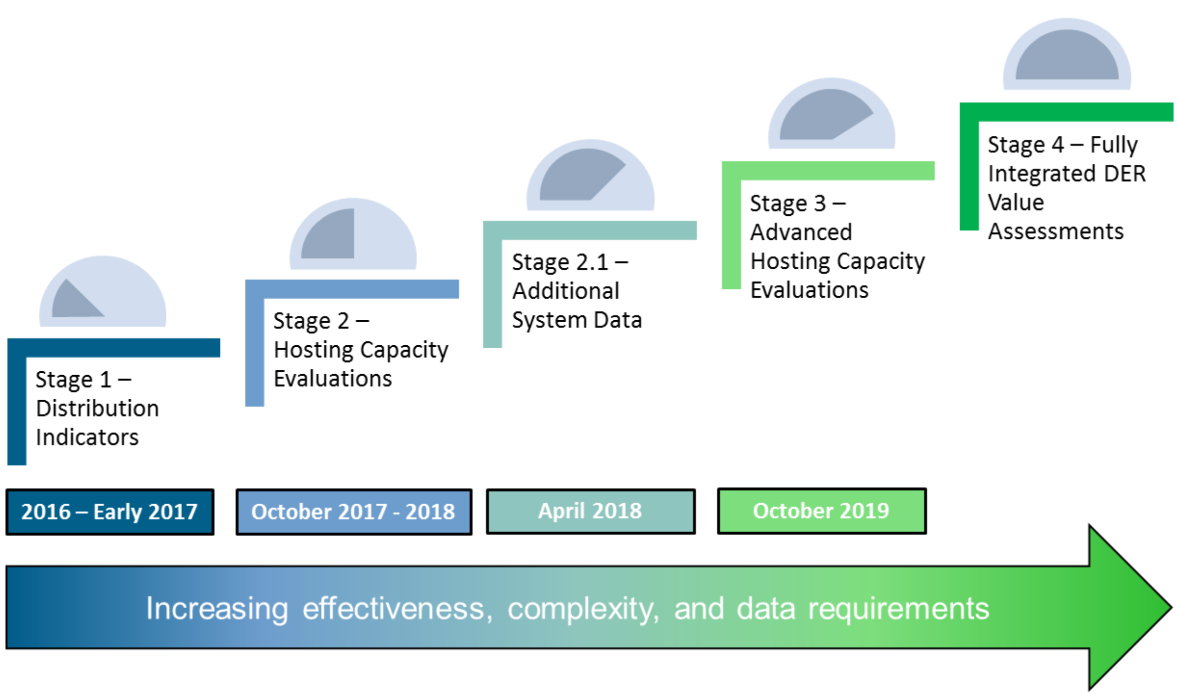
To describe the details of the current and future implementations, the utility should use system diagrams, process flow diagrams, tables, and narrative text as needed for clarity and thoroughness. When describing the progression from the current implementation to the future implementation, the utility should use narrative text, Gantt charts, and calendars which present and explain the planned sequence and timing of the notable development activities, dependencies, and milestones.

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

The Joint Utilities have engaged in extensive stakeholder consultations to develop an agreed upon schedule for improving hosting capacity. The current Joint Utilities' hosting capacity roadmap is presented below.

FIGURE 4.12-1: JOINT UTILITIES' HOSTING CAPACITY ROADMAP



As noted above, we have completed Stage 2.1 on schedule. Hosting capacity is of particular interest to stakeholders as it allows prospective interconnection customers to make more informed business decisions prior to committing resources to an interconnection application.

NYSEG and RG&E will publish an update to Stage 2 hosting capacity in October 2018.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

As shown in Figure 4.12-2, our hosting capacity roadmap focuses on building three fundamental capabilities.

FIGURE 4.12-2: HOSTING CAPACITY ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)
Calculate Hosting Capacity Along Circuits	Add Pop-Up Information Tables to Hosting Capacity Maps Execute CYME Model in Batch Form	Stage 3 Hosting Capacity (Nodal Analyses) Reflect all Existing DER in CYME Analyses Automate Data Flows and Calculations	Stage 4 Hosting Capacity
Forecast Hosting Capacity for 3-5 Years		Process Steps to Determine with Stakeholder Input	
Communicate Hosting Capacity to DER Developers	Post Hosting Capacity on a Website Portal	Expand Pop-Up Information Tables on Hosting Capacity Maps Update Hosting Capacity with Greater Frequency	Communicate Hosting Capacity Forecast and Stage 4 Evaluations

The Joint Utilities have engaged stakeholders to develop Stage 3 objectives, and have subsequently collaborated to discuss how to address the requirement in the Department of Public Service Staff Whitepaper, Guidance for 2018 DSIP Updates ("Staff 2018 Guidance") to produce forecasts of hosting capacity. Based on stakeholder input, the Joint Utilities have agreed to first develop a more granular hosting capacity analysis that would enable developers to identify more specific locations along a circuit with higher levels of hosting capacity and potentially lower interconnection costs. The Joint Utilities have also agreed to update hosting capacity on a more frequent basis and to incorporate existing DER in the analysis.[103] Our approach to adding these new capabilities may be influenced by a scheduled Version 2.0 update to EPRI's DRIVE hosting capacity tool.[104] EPRI is targeting October 2018 for this update but additional effort is required to integrate DRIVE with our hosting capacity tool and process.

The Joint Utilities, including NYSEG and RG&E, are turning their attention to Stage 3, which will initially focus on three enhancements to the hosting capacity analysis:

- Incorporating existing DER into the analysis, with smaller PV and storage reflected in circuit load curves;
- Estimating hosting capacity at points along our circuits ("nodal Hosting Capacity Analysis"); and
- Improve the hosting capacity refresh rate with a goal of updating hosting capacity on a more frequent basis, posting results on the portal;

More frequent updates align with treatment of hosting capacity as a system resource, but will require further automation of our hosting capacity process to achieve a refresh rate that is more frequent than annual updates. These Stage 3 enhancements are scheduled to be in place by October 1, 2019. We will incorporate Stage 3 enhancements in the hosting capacity portal as they are completed, with the hosting capacity results reported based on large PV facilities. In order for us to meet the Stage 3 requirements, we will need to complete our DER attribute database, update our CYME base cases to reflect DER, and run the EPRI DRIVE program, estimating hosting capacity on a nodal basis.

Stage 3.x will consider how combined heat and power facilities (CHP), energy storage, electric vehicles, and other DER might be reflected in hosting capacity analyses, as well as consideration of upstream substation/bank level constraints. The hosting capacity pop-up information will be expanded to provide information on how much distributed generation has been added since the last refresh.

The Joint Utilities have begun to discuss how to develop forecasts of hosting capacity for a 3 to 5-year period and will engage with stakeholders before deciding upon an approach and committing to a date for initial delivery of hosting capacity forecasts. We anticipate discussing how to address the forecast of inputs necessary to forecasting hosting capacity including the

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103 The impacts of all existing DER are reflected in the underlying circuit load curves and load allocations of the analysis in Stage 2. This enhancement incorporates existing DER into the circuit models used for the hosting capacity analysis with a priority on large PV, which remains the DER technology with the most significant impacts on hosting capacity.

104 We anticipate that the Version 2 of DRIVE will include new metrics on substation/bank impacts including backfeed and "3VO" protection.

location, timing and configuration of prospective DER additions, projected changes to customer loads, and future investments in the grid through traditional infrastructure or Non-Wires Alternatives (NWAs). We also anticipate discussions regarding energy storage use cases and the appropriate methodology to provide an estimate of hosting capacity that informs potential energy storage investments

The Staff 2018 Guidance raises the prospect of actions that could be taken by utilities to increase hosting capacity. The Companies believe that the most efficient way to accomplish this goal is to integrate our Measurement, Monitoring and Control (MM&C) function into grid optimization. We are also evaluating changes to our distribution planning criteria that drive our asset management activities to require consideration of whether there are relatively low-cost additions to asset management projects that would increase hosting capacity in an area where it appears to be needed. For example, when we are installing reconductors as part of a project, we could install a larger size than would otherwise be required. We may also be able to identify circuits through our hosting capacity pop-up windows that are scheduled for asset management projects within a few years as a means to provide a forecast of potential increases in hosting capacity on a circuit. Finally, we can employ Active Network Management (ANM), a control system for managing DER within system limits in real-time. ANM allows increased DER hosting capacity by incorporating various smart grid components (such as regulators, capacitors, sensors, and switches) and managing the DER watts, VARs, and/or voltage within system limits.

The ability to provide increasingly granular estimates of hosting capacity depends on our foundational investments in Advanced Metering Infrastructure (AMI), Grid Automation, and development of our DER attribute database. These investments provide the granular data necessary to input into our CYME power modeling tool. We will rely on the Data Gateway tool to transfer Supervisory Control and Data Acquisition (SCADA) data into CYME in the future. As part of our Energy Smart Community innovation platform, we are working on enhancements to this process that are necessary to support more frequent updates of hosting capacity.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified three risks that relate to the Hosting Capacity function, and have taken measures to mitigate each risk, as shown in Figure 4.12-3.

FIGURE 4.12-3: HOSTING CAPACITY RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality data that is relied upon by the DSP to perform Hosting Capacity Analyses	• NYSEG and RG&E have proposed to implement AMI to collect more granular usage data throughout its service territory. • Build redundancy into AMI telecommunications infrastructure • Completing the DER database to track the location and operating attributes of all DER • Enhance Data Gateway capability to transfer SCADA data to CYME • NYSEG and RG&E are designing the Grid Model Enhancement Project ("GMEP") Phase 1 to incorporate governance and data processes and flows. • Performing a data governance/data quality pilot roadmap for DER integration
2. **Uneconomic Increases in Hosting Capacity**	• Developing appropriate distribution planning criteria that will result in efficient increases in hosting capacity where needed • Changes to asset management processes to integrate new criteria
3. **Hosting Capacity Forecast Methodology:** Forecasting Hosting Capacity is a new responsibility	• Evaluating LoadSEER technology in the Energy Smart Community • Collaboration with other New York utilities and EPRI • Engagement with stakeholders to confirm use cases

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

Hosting capacity information is of particular interest to stakeholders as it allows prospective interconnection customers to make more informed business decisions prior to committing resources to an interconnection application. The Joint Utilities have engaged in stakeholder consultations in designing the approach to hosting capacity. Following the release of the Stage 2 hosting capacity maps, the Joint Utilities hosted a stakeholder engagement session on November 2, 2017, to provide stakeholders the opportunity to provide input on future enhancements as well as on the development of Stage 3. To encourage a direct line of communication with stakeholders on the Stage 2 displays and functionality, the Joint Utilities provided a live demonstration of the displays, which was also later posted on the Joint Utilities' hosting capacity webpage along with the other meeting materials. The additional capabilities delivered as Stage 2.1 were responsive to requests made by DER developers in these meetings.

Stakeholders also provided valuable input on the areas where they want to see the most improvement in Stage 3. After actively engaging with stakeholders on enhancements that will provide them the greatest value in the next iteration, the Joint Utilities agreed to focus on the following as the foremost consideration in developing Stage 3. These are identified above in the Future Implementation and Planning Section.

As a result of active stakeholder engagement and dialogue, we believe that DER developers appreciate the need to balance the value of increasing the granularity of the analysis against the additional computational time and its subsequent impact on refresh frequency.

We also presented our Hosting Capacity roadmap in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

Additional Detail

Providing an electric distribution system with the capacity to host large scale DER integration is a key part of New York's energy vision. To achieve that outcome, the utilities must perform several functions to ensure that large amounts of DER can access and utilize hosting capacity in ways that are affordable, effective, efficient, and timely. The utilities have made significant early progress in producing and sharing information about the hosting capacity of their current systems. DER developers and other stakeholders value the new information as a significant improvement to the information which was previously available to them; however, more is needed in three areas.

First, as DER developers and other stakeholders access and use the utilities' hosting capacity information, it is becoming increasingly evident that assessments of currently available hosting capacity do not adequately inform DER development processes and decisions. DER developers and the utilities would both be better informed by hosting capacity forecasts which look ahead three to five years. Once available, such forecasts would become the preferred resource for planning DER development.

Second, as grid operations evolve to accommodate and optimize significant DER development, some of those operations will come to rely on the availability of hosting capacity as a managed system resource. Such operations will continually require very current information about available hosting capacity throughout the distribution system.

This means that the utilities should be prepared to timely increase the rate at which they produce and share their information about currently available hosting capacity.

And third, the availability of ample hosting capacity at a given location on the grid does not necessarily mean that other factors (i.e. space, accessibility, safety, zoning, customer interest, etc.) will also favor deploying a DER at that location. At the same time, there are many locations where circumstances strongly favor DER development; however, the amount of hosting capacity available at those locations is inadequate. This could mean that utilities will need to take measures to increase hosting capacity at attractive DER development sites in order to support the State's goals for integrating renewable energy resources. Considering these points, the utilities should be prepared to timely increase hosting capacity in their distribution systems.

The DSIP Update should provide detailed information related to assessing current hosting capacity, forecasting hosting capacity, and increasing hosting capacity to show that the utility is timely developing – either individually or jointly with one or more of the other utilities – the necessary information resources and capabilities associated with hosting capacity.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to hosting capacity:

1) *The utility's current efforts to plan, implement, and manage projects related to hosting capacity. Information provided should include:*
    a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range hosting capacity plans;*
    b. *the original project schedule;*
    c. *the current project status;*
    d. *lessons learned to-date;*
    e. *project adjustments and improvement opportunities identified to-date; and,*
    f. *next steps with clear timelines and deliverables*

Our prior efforts to plan, implement, and manage hosting capacity projects are driven by the target deadlines that the Joint Utilities have agreed to. We have met the Stage 2 deadline and provided hosting capacity analysis for distribution circuits of 12 kV or greater by October 2017. In fact, we were able to provide hosting capacity analysis for all of our distribution circuits, including those below 12 kV. We have developed the capabilities necessary to provide Stage 2.1 functionality by April 2018. Our hosting capacity estimates rely on the EPRI DRIVE program with data fed into CYME.

Our current efforts are focused in two areas: (1) foundational investments that will provide more granular data that is required to perform hosting capacity along a circuit, and (2) capability building to support agreed upon or anticipated changes in hosting capacity requirements.

With respect to the first area of focus, we have installed approximately 12,300 electric and 7,600 gas smart meters and are testing AMI in the Energy Smart Community and are beginning to collect data that will inform hosting capacity analyses by providing an accurate representation of peak load and the load curve on each of 15 ESC circuits. We plan to begin rolling out AMI throughout our service area over a four-year period, if authorized by the Commission. We have also installed Grid Automation functionality in the Energy Smart Community and are collecting SCADA data that provides much greater visibility into performance along the 15 ESC circuits. We are making several other investments that will improve the quality of usage and performance data that we rely on for a variety of analytics, including the calculation of hosting capacity. These investments include the GMEP and DER attribute database that combine to provide us with an accurate depiction of our distribution system that is necessary to evaluate hosting capacity.

With respect to the second area of focus, we are building three capabilities:

1. Estimate hosting capacity along circuits;
2. Forecast hosting capacity for 3 to 5 years; and
3. Communicate hosting capacity to DER developers.

We are already communicating hosting capacity to DER developers but will continue to look to improve in this area.

The ability to provide nodal hosting capacity analyses also depends on the ability to use AMI and other data. We are installing the most recent version of CYME and have established the ability to execute CYME in batch form. We are developing Data Gateway to import operational data into CYME, and should complete this undertaking by 2020. We are also addressing the question of whether it is possible to increase hosting capacity where it may be needed by reconsidering our distribution planning criteria that drive asset management decisions.

With respect to the more recently established objectives of forecasting hosting capacity and developing hosting capacity evaluations that pertain to energy storage, we anticipate working with the Joint Utilities and DER developers to define energy storage use cases as a first step, and then develop a methodology that addresses these requirements. Our innovation projects may inform these use cases, if results are available.

In terms of lessons learned, the current process remains time-consuming and requires approximately three months to perform a complete update of hosting capacity on NYSEG's 1,597 and RG&E's 798 circuits. We have taken action to speed up the refresh process by executing CYME in batch form. Further automation of the hosting capacity process is necessary, and this objective will be reflected as we build new processes to incorporate AMI and actual system data.

2) Where and how DER developers/operators and other third parties can readily access the utility's hosting capacity information.

NYSEG, RG&E and other New York utilities communicate hosting capacity by posting maps to a website as a first stop for DER developers considering development in a particular neighborhood or area. Maximum feeder hosting capacity is reported for 3-phase overhead and underground conductors using a color-coded legend that reports capacity in ranges from 0 to 0.29 MW to >5MW. DER developers and other interested stakeholders are able to access NYSEG and RG&E hosting capacity maps via publicly available portals here. Appendix B of our 2018 DSIP Report presents links to all of our developer tools.

The analyses presented in these displays provide the circuit level hosting capacity for the distribution circuits evaluated. Hosting Capacity is an estimate of the amount of DER that may be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades. At present, this analysis is conducted under current configurations, without installed DER, and prior to infrastructure upgrades such as installing a recloser or remote terminal unit at the Point of Common Coupling, replacing a voltage regulating device or controller to allow for reverse flow, substation-related upgrades including "3V0" protection, or other protection-related upgrades. The analyses represent the overall feeder level hosting capacity only, and do not account for all factors that could impact interconnection costs (including substation constraints). Issues related to circuit protection require further analysis to make a definitive determination of hosting capacity. Additional displays with tabulated data have been included in the form of data pop-up displays to indicate that the hosting capacity may be lower at any given location. As a rule of thumb, the minimum hosting capacity value is indicative of the available hosting capacity across the length of the circuit and most often defined by the hosting capacity value located at the most downstream node from the substation. The maximum hosting capacity value is indicative of the available hosting capacity at a specific location, most often located at the node closest to the substation.

The Companies are developing a single portal that addresses all DER developer needs. The hosting capacity maps present circuit level analysis for large scale solar PV. There is recent interest, as noted in the Staff 2018 Guidance to examine the impact of other technologies including energy storage.

3) How and when the existing hosting capacity assessment information provided to DER developers/operators and other third parties will increase and improve as work progresses.

Our hosting capacity assessment will improve as the actions described in response to Subpart 1 are implemented:

- They will improve over the next 18 months as we develop the ability to estimate hosting capacity along our circuits;
- They will improve over the next five years as AMI, Grid Automation and other foundational investments produce actual usage and system performance data that is reflected in hosting capacity updates;
- They will improve by 2020 as we complete our Data Gateway project;
- They will improve over the next five years as we complete our GMEP project and update our network configuration to reflect infrastructure development and NWAs on a more timely basis;

- They will improve over the next two years as we automate the hosting capacity evaluation processes and can provide more frequent refreshes;
- They will improve over the next two years as we develop the DER database and begin to reflect connected DER in the hosting capacity refreshes; and
- They will improve during the latter half of the DSIP period as we implement forecasted hosting capacity based on stakeholder input and collaboration with the Joint Utilities.

4) The means and methods used for determining the hosting capacity currently available at each location in the distribution system.

Hosting capacity is estimated as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line voltage and/or secondary network system.[105] Estimating hosting capacity is a data-driven exercise and depends critically on the availability and quality of granular data. We estimate each circuit's hosting capacity by evaluating potential power system criteria violations as a result of interconnecting large solar PV systems to three-phase distribution lines.[106] CYME software reflects DER performance in load flow analyses that are relied upon by EPRI's DRIVE tool to estimate hosting capacity.

5) The means and methods used for forecasting the future hosting capacity available at each location in the distribution system.

The Joint Utilities have begun to discuss how to develop forecasts of hosting capacity and will engage with stakeholders before developing an approach and committing to a date for this aspect of the requirements. We anticipate discussing how to address the forecast of inputs necessary to forecasting hosting capacity including the location, timing and configuration of prospective DER additions, projected changes to customer loads, and future investments in the grid through traditional infrastructure or NWAs. This will be reflected in a future hosting capacity stage, after completion of Stage 3.0 that will include nodal hosting capacity analyses.

6) How and when the future hosting capacity forecast information provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

We will begin sharing forecasted hosting capacity information via our DER developer portal as soon as we have valid forecasts that can be shared. Our efforts to work with stakeholders and other utilities are intended to accelerate this outcome and improve the quality of information that will be communicated.

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105 Electric Power Research Institute ("EPRI"), *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, Report Number 3002008848 ("EPRI Roadmap"), June 2016, p. 2. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848.

106 Solar with an AC nameplate rating starting at and gradually increasing from 300 kW.

7) The utility's specific objectives and methods to:

a. identify and characterize the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development; and,

We will identify circuits and locations along circuits where limited hosting capacity is a barrier through our Integrated Planning process, planning specific asset management activities, and assessment of requests to interconnect new DER projects. While many factors contribute to an evaluation of hosting capacity, physical infrastructure is the most important factor. These results will be reflected on the hosting capacity maps.

The identification of beneficial locations, which considers more than hosting capacity, is also responsive to this objective.

b. timely increase hosting capacity to enable productive DER development at those locations.

We believe that changes to distribution planning criteria that increase hosting capacity by reflecting the benefits of increasing hosting capacity when designing asset management solutions is the most economical solution to increase hosting capacity. We do not believe that a "build it and they will come" strategy will be efficient or economic and is more likely to impose extra costs on our customers.

An alternative and preferred approach is to incorporate more granular DER MM&C into grid optimization schemes to enable more connections to a circuit. The Companies are current conducting a MM&C Enhancement proof-of-concept project by substituting more flexible MM&C capabilities for point-of-connection reclosers that effectively operate as an on/off switch when engaged. Finally, as noted above, we can employ Active Network Management, a control system for managing DER within system limits in real-time. ANM allows increased DER hosting capacity by incorporating various smart grid components (such as regulators, capacitors, sensors, and switches) and managing the DER watts, VARs, and/or voltage within system limits.

4.13 Beneficial Locations for DER and Non-Wires Alternatives

Introduction/Context and Background

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

Beneficial locations are high-priority locations where there is a potential for localized DER deployment to address projected system needs, such as load relief or reliability, and defer or avoid traditional utility infrastructure investments, or where there is a prospective infrastructure need but where a solution has not yet been identified. We identify beneficial locations through areas served by the projects listed in the five-year capital forecast issued by Investment Planning.

Non-Wires Alternatives (NWAs) are a subset of beneficial locations that meet an established set of "Suitability Criteria". Suitability Criteria serve as an efficient initial screening role in identifying NWA opportunities. They also ensure that utilities' capital planning process is transparent and that a common framework is applied by New York's utilities in order to "provide greater clarity, certainty, and long-term visibility to the market and to promote an efficient allocation of time and resources for both developers and utilities".[107] As explained further in the Joint Utilities' Supplemental Distributed System Implementation Plan ("Supplemental DSIP"), Suitability Criteria are intended to promote the following goals:

(1) identifying the projects that are best suited for competitive procurement of an NWA;

(2) giving developers the greatest opportunity to compete; and

(3) providing the greatest opportunities for success of the process.[108]

The Joint Utilities worked with stakeholders to develop an initial set of suitability criteria, grouped within three broad categories: project type, timing, and cost.[109] Distinct project types that reflect the purpose of the capital project (*e.g.*, load relief or reliability) are assessed with respect to their suitability to be addressed as well by an NWA as a traditional distribution system planning solution. Timing is important because NWA projects have their own timelines because of the need to conduct RFPs that may be more complex than competitive bidding for traditional construction projects and the subsequent time required to execute an NWA contract and develop the solution.

As part of its Supplemental DSIP filing discussion of NWA, the Joint Utilities indicated that they intended to assess the appropriate Suitability Criteria on an annual basis. In 2017, the Joint Utilities have focused on the NWA identification and evaluation process in order to improve

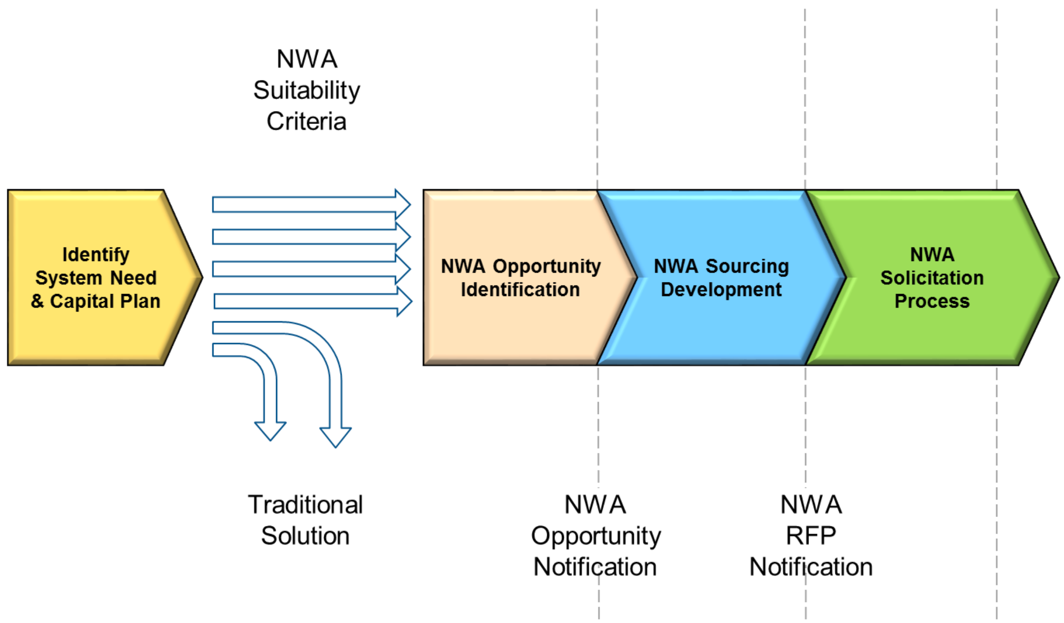
107 Supplemental DSIP, p. 41.

108 Supplemental DSIP, p. 41

109 Supplemental DSIP, pp. 43-46.

transparency and support developers' business planning, making two filings in 2017 related to NWA suitability criteria and NWA sourcing processes, respectively. The first filing, submitted March 1, 2017, proposed utility-specific guidance for three criteria that were identified in the Supplemental DSIP NWA Suitability Criteria framework: project type, timeline, and cost.[110] To provide potential NWA suppliers with greater insight into the planning and sourcing processes, the Joint Utilities submitted a second filing on May 8, 2017, which addressed the Commission's directive to describe "how the Suitability Criteria will be incorporated into utility planning procedures, and how and when the Suitability Criteria will be applied to projects in their current capital plans."[111] This second filing presented details pertaining to the end-to-end process for identifying and sourcing NWA, including the capital planning process, opportunity identification, and sourcing and solicitation processes. The Joint Utilities' Planning processes and sourcing overview is represented schematically in Figure 4.13-1.[112]

FIGURE 4.13-1: JOINT UTILITIES' PLANNING PROCESSES AND SOURCING OVERVIEW



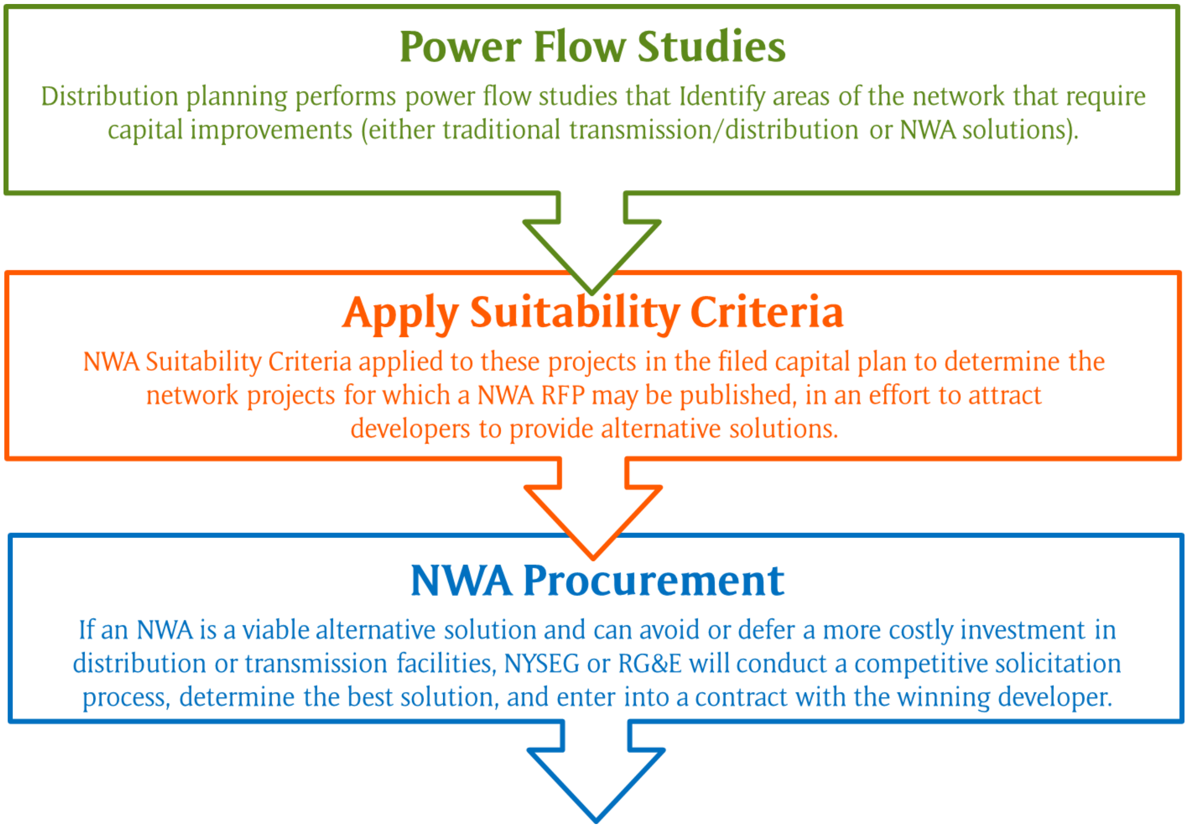
Our current process for identifying and procuring NWAs is presented in Figure 4.13-2.

110 DSIP Proceeding, Joint Utilities Utility-Specific Implementation Matrices for Non-Wires Alternatives Suitability Criteria (filed March 1, 2017) ("March 1 Filing").

111 DSIP Proceeding, DSIP Order, p. 32.

112 DSIP Proceeding, Joint Utilities Supplemental Information on The Non-Wires Alternatives Identification and Sourcing Process and Notification Practices (filed May 8, 2017) ("May 8 Filing"). Joint Utilities filing.

FIGURE 4.13-2: NWA IDENTIFICATION AND DEVELOPMENT



The Companies have focused considerable attention since the 2016 DSIP on developing our NWA capabilities. As a result, we have made substantial progress in building its NWA function and in identifying potential candidates for NWA, with many lessons learned along the way.

Implementation Plan, Schedule, and Investments

To describe the details of the current and future implementations, the utility should use system diagrams, process flow diagrams, tables, and narrative text as needed for clarity and thoroughness. When describing the progression from the current implementation to the future implementation, the utility should use narrative text, Gantt charts, and calendars which present and explain the planned sequence and timing of the notable development activities, dependencies, and milestones.

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

The NWA function is relatively new to the Companies and the electric industry. Not surprisingly, we have learned a great deal over the past two years, making several enhancements and improvements to NWA processes. As a result, we are capable of applying the suitability criteria each year, subject to an internal NWA governance process. The NWA process is integrated into the annual capital planning and budgeting processes. We are able to identify both transmission and distribution NWA. The NWA function is now coordinating with related functions throughout the Companies, including Transmission and Distribution ("T&D") Planning, Interconnection, Regulatory, Legal, Cyber Security, Projects (formerly, Electric Capital Delivery), Operations, the ECC, and our regional division organizations. We are also coordinating with external stakeholders including DER Developers (NWA Suppliers), our engineering contractors, and Commission Staff.

Most importantly, we have gained significant experience identifying NWAs as well as designing and executing the RFP process.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

Future implementation and planning in this topical area focuses primarily on the identification of beneficial locations and the implementation of compensation mechanisms. AMI and our other foundational investments will provide granular locational data and more rigorous load flow analyses that are required to be able to identify beneficial locations and then act upon them through Value of DER (VDER) compensation, targeted energy efficiency incentives, locational demand response compensation, or some other means.

The Roadmap for Beneficial Locations and identification of NWAs is presented in Figure 4.13-3.

FIGURE 4.13-3: BENEFICIAL LOCATIONS FOR DER AND NWA ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)
Identify & Screen NWA Locations	Applied Suitability Criteria, Identifying 15 Potential NWA in 2017; 32 in 2018[113]	Refine Criteria as Appropriate Further Integrate NWA and Capital Planning Processes Integrate EE/DR in NWA Opportunities	
Identify High-Priority Beneficial Locations	Identified Beneficial Locations based on Existing Data	Develop Processes to Identify Beneficial Locations as AMI and other Granular System Data Becomes Available	Apply Process to Regions as AMI and System Data Become Available
Estimate the Locational Value of DER to the Grid	Participate with Joint Utilities in VDER Policy Proceedings	Apply Approved VDER Methodology	Apply and Update Approved VDER Methodology to Locations as AMI and System Data Become Available
Compensate DER for Locational Grid Value	Participate with Joint Utilities in VDER Policy Proceedings	Establish Tariff or Other Compensation Vehicle	Align DSP and NYISO Compensation Mechanisms

We will continue efforts to integrate energy efficiency, demand response and other DER into the NWA planning process. We will also continue to make enhancements to front-end NWA processes. However, the most important efforts will focus on efforts to execute competitive RFPs and negotiate contracts, discussed in 2018 DSIP Guidance Response Section 4.14 (Procuring Non-Wires Alternatives).

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

[113] The 32 locations are identified in the NYSEG and RG&E Five-Year Capital Investment Plan 2018-2022, March 29, 2018.

NYSEG and RG&E have identified three risks that relate to the identification of beneficial locations and NWAs, and have taken measures to mitigate each risk, as shown in Figure 4.13-4.

FIGURE 4.13-4: BENEFICIAL LOCATIONS RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality data that is relied upon by the DSP to identify beneficial locations and potential NWAs	• NYSEG and RG&E are designing the Grid Model Enhancement Project ("GMEP") Phase 1 to incorporate governance and data processes and flows • Enterprise Data Platform deliverables are clearly specified including data architecture, dictionary, flow diagrams, etc. • Performing a data governance/data quality pilot roadmap for DER integration
2. **Technology Deployment:** The integrated set of distribution system and information technologies need to be correctly specified and then implemented according to plan	• Develop master schedule and establish accountability • Build redundancy into AMI telecommunications infrastructure
3. **Customer Value:** DSP must be efficient and enable reliable, resilient, safe distribution service	• We advocate for REV policies that align with customer value • We are developing third-party NWA contract provisions that ensure reliable service

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities established a DER Sourcing & NWA Suitability Criteria Working Group to engage stakeholders on issues pertaining to beneficial locations and NWAs. This working group met on April 20, 2017 and November 9, 2017. We also addressed NWA procurement in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

We also presented our Beneficial Locations and NWA roadmap in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

Additional Detail

To help promote productive DER development, it is essential that the utility identify, characterize, and publicly present the locations in its service area where DERs and/or energy efficiency might provide significant benefits to the distribution system and/or to the bulk electric system. Based on its criteria for evaluating opportunities for non-wires alternatives (NWA), the utility then selects some of those locations for NWA procurements and/or energy efficiency measures that will benefit the distribution system.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities supporting identification and presentment of beneficial locations for DERs and NWAs:

The Companies are committed to providing system information to DER developers that helps them locate DER where it provides benefits to our customers and the grid, as well as promising business opportunities for DER developers.

1) The resources provided to developers and other stakeholders for:

a. accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and,

Our methodology to identify beneficial locations is under consideration and will reflect policy determinations related to Value of DER (VDER) and Location System Relief Value (LSRV) as we seek to identify high value" distribution areas suitable for LSRV denomination that reflect NYSEG and RG&E's electric costs of service (MCOS) studies. We will subsequently review the design of the portal for sharing beneficial location information with third parties and reflect these proposed sorting and filtering requirements.

b. efficiently sorting and filtering locations by the type(s) of capability needed, the timing and amount of each needed capability, the type(s) and value of desired benefit, the serving substation, the circuit, and the geographic area.

The development and identification of "DER Beneficial" locations for NYSEG and RG&E will be combined with the development and identification of "high value" distribution areas suitable for Location System Relief Value (LSRV) denomination under NYSEG and RG&E's electric costs of service (MCOS) studies. In the MCOS studies, the Companies identify load pockets or constrained areas with capital expansion projects. High value (DER Beneficial) areas will include major station investments or network line upgrades needed to meet load growth during the upcoming planning period. The projects may include those selected as Non-Wires Alternatives (NWA) but additional high value projects may also need to be considered. Once LSRV projects are selected, the Companies will identify all circuits that are connected to the identified LSRV investment. Interconnection of DER that reduce peak loading on those circuits can potentially reduce investment at the substation or upstream feeder. The approach to select DER Beneficial locations will be independent of hosting capacity limits; hosting capacity limits will be separately established for the specific circuit/feeder to reflect whether the feeder or transformer can reliably accommodate the DER without material system upgrades. Analysis of hosting capacity considers, among other things, voltage/power quality constraints, thermal constraints, protection limits, safety, and reliability. The goal is to signal these high value (DER Beneficial) locations to the DER Developers to meet incremental demand in those circuits (or equivalently, the avoided costs of reducing demand by interconnecting DER.) The Companies will provide public information regarding LRSV for all locations to encourage optimal DER deployment via access to the web-based portal. The utilities will provide a web-based application that will identify the high value areas.

The website application will be part of the Interconnection On-line Application Portal (IOAP) anticipated by the Commission. The specific high value areas will be updated every three years, or more frequently if the utility MCOS are updated more frequently. Whenever a high value area experiences a cumulative DER addition in sufficient capacity so that the established DER cap for the area is achieved, the LSRV value in that area will be re-set to zero and the area will not be considered a high value area until the next investment cycle is due. We will address sorting and filtering of beneficial locations when we update the portal to reflect these enhancements.

2) The means and methods for identifying and evaluating locations in the distribution system where:

a. a NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations; and/or,

The Companies have begun integrating energy efficiency into our NWA planning and procurement processes. It is our practice to look for energy efficiency opportunities that in areas that are potential NWA candidates. Thus, we have targeted a few large customers located behind Station 51, a currently planned NWA, in an effort to identify energy efficiency and other demand-side actions that would reduce the peak demand that would otherwise need to be met by the NWA. It is important to develop and target energy efficiency options to areas of the system that are expected to need investments to meet capacity needs as these will result in the greatest cost savings, an outcome that we expect to see in project-specific Benefit Cost Analyses (BCAs).

NYSEG and RG&E estimate the location and amounts of anticipated energy and peak load reductions when they are associated with an NWA. These are based on customer-specific assessments and we rely on them when defining the NWA requirements.

b. one or more DERs and/or energy efficiency measures could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk electric system reliability, efficiency, and/or operations.

As NYSGE and RG&E are not currently able to estimate the location of savings from energy efficiency programs, other than for identified NWA opportunities that have been assessed for this purpose. However, we expect to be able to target energy efficiency activities to locations of future need, including locations that may not be candidates for an NWA. This involves identification of "beneficial locations" for specified types of energy efficiency, targeted solicitation of customers within those areas based on Advanced Metering Infrastructure (AMI) and other customer information and data analytics, and incentives that are offered to candidate customers to engage in energy efficiency measures that contribute to alleviating a local constraint. These incentives could take the form of incentives to turn down air conditioning a few degrees during peak periods or pay-for-performance compensation models. Our Connecticut affiliate, United Illuminating Company, has been exploring similar strategies and have two location-focused DER innovation projects that are in development.

3) Locations where energy exported to the system, or load reduction, would be eligible for:

a. compensation under the utility VDER Value Stack tariff;

Please refer to the response to Subpart 2b. We anticipate that a VDER tariff will provide a price signal and serve as an efficient mechanism to communicate the value of load reduction or DER supply to DER providers.

b. utility dynamic load management programs, including the Commercial System Relief Program, Distribution Load Relief Program, and Direct Load Control Program;

Please refer to the response to Subpart 2b. We intend to use data analytics to identify areas that could be served by an existing or potential NYSEG/RG&E program and then market directly to customers in these locations.

c. and/or, increased value-based customer incentives for energy efficiency measures with load profiles that align with the system needs through utility energy efficiency programs or New York State Energy Research and Development Authority's (NYSERDA) Clean Energy Fund (CEF) programs, while ensuring utility-NYSERDA coordination.

Please refer to the response to Subpart 2b.

4.14 Procuring Non-Wires Alternatives

Introduction/Context and Background

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

Fifteen potential NWA passed the Suitability Criteria in 2017. We have issued four Requests for Proposals (RFPs); three for NYSEG; one for RG&E to date. We are currently in contract discussions with a DER developer for the NYSEG Java NWA pilot project. If negotiations are successful, this project will be in service in 2019.

Most of our lessons learned are focused on the front-end processes: identifying NWA, applying the suitability criteria, developing RFPs, identifying approximately 300 potential bidders, conducting outreach to encourage participation in RFPs, and applying the BCA Handbook to bids. Fortunately, many of the potential bidders are large firms with relevant experience. We will continue to work with potential bidders to improve participation in NWA RFPs.[114] Additionally, we are able to supplement our NWA requests by incorporating energy efficiency and demand response programs as part of NWA projects to create a portfolio approach to each NWA opportunity.[115]

Implementation Plan, Schedule, and Investments

To describe the details of the current and future implementations, the utility should use system diagrams, process flow diagrams, tables, and narrative text as needed for clarity and thoroughness. When describing the progression from the current implementation to the future implementation, the utility should use narrative text, Gantt charts, and calendars which present and explain the planned sequence and timing of the notable development activities, dependencies, and milestones.

Current Progress

Describe the current implementation as of July 31, 2018; describe how the current implementation supports stakeholders' current and future needs.

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[114] As an example, bidders have requested more information to help them determine if gas supply deliverability in the particular NWA area will support gas-fired DER.

[115] For example, we have targeted a few large customers located behind Station 51, a currently planned NWA, in an effort to identify energy efficiency and other demand-side actions that would reduce the peak demand that would otherwise need to be met by the NWA.

NWA opportunities are posted on the Joint Utilities' website, with links to individual NWA opportunities. This increases transparency and efficiency for developers in NWA solicitations.

NYSEG and RG&E are able to execute RFPs and attract sufficient interest to produce a fair and competitive outcome. We are able to reflect energy efficiency in the NWA procurement process and evaluate energy storage that is included in the majority of NWA RFP responses. We have gained experience applying the Benefit Cost Analysis (BCA) Handbook as part of the evaluation process and identified potential streamlining opportunities.

We are negotiating our first two NWAs and will reflect lessons learned when these are completed. We anticipate issuing as many as four additional NWAs in 2018.

Future Implementation and Planning

Describe the future implementation that will be deployed by July 31, 2023; Describe how the future implementation will support stakeholders' needs in 2023 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation. Include investment areas as necessary at a high-level; do not include actual dollar amounts.

We have more to learn to improve the contract negotiation process, particularly in the area of specifying appropriate performance criteria and financial penalties for non-compliance. We are striving to find the proper balance between the need to ensure reliability of service to our distribution customers that will be served by an NWA, and concerns regarding the potential impact on project cost and profitability of performance requirements that could be viewed as being overly stringent.

The Roadmap for Procurement of NWAs is presented in Figure 4.14-1.

FIGURE 4.14-1: NWA PROCUREMENT ROADMAP

Capability	Achievements (2016-2018)	Short-Term Initiatives (2019-2020)	Long-Term Initiatives (2021-2023)
Execute Competitive RFPs & Contracts	Established NWA Governance Issued four RFPs Applied BCA Handbook	Improve Quality of Information to Inform and De-Risk RFP Responses	
		Evaluate Storage Options & Streamline BCA Reflect Contracting Lessons Learned	Progress Toward Standard Terms and Conditions
Administer NWA Contracts		Improve Quality of Information for M&V Hand-Off Administration to Construction (Interconnection) and the Control (Energy Control Center) Functions	Refine M&V and Monitoring and Control “Back-End” Processes
Scale NWA Function		Build Processes and Add Resources to Support Scale	Scale NWA Function

Our efforts to collect accurate load data throughout the electric system will provide potential NWA bidders with better information that, in turn, reduce any uncertainty regarding a performance premium that might otherwise be reflected in their proposal. Projects that contemplate islanding will continue to require particular attention, especially since we retain the responsibility for reliable and quality service when the project is operating in islanding mode.

Longer-term initiatives focus on improving the quality of data that can be made available to potential bidders and refining contract administration processes including measurement and verification (M&V) of NWA performance.

Risks and Mitigation

Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified three risks that relate to performance of the NWA Procurement function, and have taken measures to mitigate each risk, as shown in Figure 4.14-2.

FIGURE 4.14-2: PROCURING NWAS RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality of data that is relied upon by the DSP to perform validate the performance of NWAs	• NYSEG and RG&E are designing the Grid Model Enhancement Project ("GMEP") Phase 1 to incorporate governance and data processes and flows • Enterprise Data Platform deliverables are clearly specified including data architecture, dictionary, flow diagrams, etc. • Performing a data governance/data quality pilot roadmap for DER integration
2. **Cost Recovery:** Timely cost recovery is necessary to maintain financial strength	• Integrated Planning cycle is connected to the 5-year Capital Plan • Existing AVANGRID/NYSEG and RG&E financial controls will be maintained
3. **Customer Value:** DSP must be efficient and enable reliable, resilient, safe distribution service	• We advocate for REV policies that align with customer value • We are negotiating third-party NWA performance contracts that ensure reliable service

Stakeholder Interface

Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities established a DER Sourcing & NWA Suitability Criteria Working Group to engaging stakeholders on issues pertaining to beneficial locations and NWAs. This working group met on April 20, 2017 and November 9, 2017.

We also presented our NWA roadmap in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

Additional Detail

DER development and use in the electric distribution system is stimulated when the utilities investigate and implement non-wires alternatives (NWAs) to traditional system upgrades. Through this process, the utilities, DER developers, and other stakeholders are learning how to cost effectively use DERs to reduce electric delivery costs while maintaining system reliability and safety.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities supporting utility procurement of DERs as alternatives to traditional distribution system upgrades:

The Companies have implemented an efficient NWA RFP process and are currently focused on accelerating the contracting process and building capabilities to administer contracts that are executed. We also addressed NWA procurement in our June 20, 2018 meeting with a broad group of our key stakeholders to provide an overview of our 2018 DSIP, request their feedback, and respond to their questions.

1) *How the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions which can be implemented in time to serve the system need.*

The Companies have not experienced any issues with respect to the ability to issue an RFP, evaluate the bids, and identify the winning bidder. The process of negotiating a contract with a winning bidder is taking longer time than anticipated, perhaps because it is a novel form of contract in the industry and both buyer and seller lack sufficient experience. We believe that the existing three-year lead time relative to the time of need that is defined in the suitability criteria is sufficient time to execute a contract.

2) *The NWA procurement means and methods; including:*

a. *how the utility and DER developers time and expense associated with each procurement transaction are minimized;*

The interests of the Companies, our customers, and NWA bidders are clearly aligned, and all stakeholders are interested in minimizing the time and expense associated with the NWA procurement process. We debrief after each RFP process with internal and external stakeholders to identify potential efficiencies. An NWA is a reliability support agreement and is proving to be a challenging contract to negotiate.

b. the use of standardized contracts and procurement methods across the utilities.

To enhance the DER integration process, the Joint Utilities continue to share lessons learned from developing and implementing specific NWA RFPs (including supporting data) and resultant contract terms and conditions. It is not yet clear whether it will be possible to arrive at a set of standard terms and conditions. On the one hand, standard terms and conditions could streamline negotiations and the time required to arrive at a final contract. This is certainly achievable when the product or service being transacted is a well-defined commodity or service. However, at this point in time NWAs seem to share more differences than similarities and it would not be appropriate to preclude the potential for parties to negotiate a contract that produces net benefits for customers. We are currently negotiating two agreements with two different suppliers that have significantly different project attributes. For example, one project has a backup supply component; the other does not. These contracts will require tailored provisions to address the unique aspect of each project.

However, it may be possible to derive a standard table of contents for NWA contracts, with a definition of the purpose of each term and the standards that would be applied by the Commission in agreeing to the contract as a whole. This may eventually lead to some significant subset of terms being standardized with a few terms that address the fundamental economic and risk issues subject to tailoring to meet any unique circumstances. For example, a successful NWA contract will clearly state assumptions, incentives, and expectations for the intended use of the resource by the utility, constraints a resource may have to generate additional revenue streams through participating in other markets (*e.g.* wholesale), operational and commercial requirements including expected performance and corresponding payment terms. In terms of payment guidelines, the utility must clearly outline payment duration and schedule, and include language that holds DER vendors accountable for commercial payment and ensures bids include the cost of any security instruments required. Through the information sharing across the utilities, the Joint Utilities have agreed that contracts should also include clear and consistent use of key terms and descriptions regarding the NWA DER vendor's market participation, regardless of payment cadence. Draft NWA contracts are intended to be released with the RFPs and may be included publicly on the issuing utility's website in the future.

The Joint Utilities are working through initial NWA solicitations and contract negotiations. At this time, the Joint Utilities agree that developing and using a standardized contract is premature as solicitation and contracting lessons are still being learned, but will continue to share best practices for issuing contracts and implementing procurement methods.

3) *Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities. For each opportunity, the resource should describe the location, type, size, and timing of the system need to be addressed by the project.*

The Companies publicize our NWAs to attract the attention of any and all potential bidders. We also maintain a lengthy list of potential bidders that receive direct communication that a new opportunity will be subject to a competitive solicitation. The current list of NWA opportunities describe the location, project name/descriptor, and timing of the system need to be addressed by the project is available on our websites.[116,117] These are included in Appendix B to our 2018 DSIP Report.

4) How the utility considers all aspects of operational criteria and public policy goals when selecting which DERs to procure as part of a NWA solution.

The evaluation criteria may be unique to each NWA and are therefore specified in each NWA's RFP documents. The bid evaluation team applies the criteria, including a BCA test when scoring each bid. The operational criteria are considered before the BCA Handbook is applied. If an attribute is in the BCA Handbook, we consider it to be a public policy goal. All evaluations are documented to provide an audit trail. The bid evaluation team has the flexibility, and should have the flexibility, to apply judgment when determining which bid maximizes the risk-adjusted value to the grid and our customers, but must explain all decisions.

5) Where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:

a. describe the location, type, size, and timing of the system need addressed by the project;

b. describe the location, type, size, and provider of the selected alternative solution;

c. provide the amount of traditional solution cost which was/will be avoided;

d. explain how the selected alternative solution enables the savings; and,

e. describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s).

This question calls for disclosure of commercially sensitive information. Publication of such information could result in harm to the Companies, our customers, and the contracting NWA party. For this reason, we restrict public information to a description of the project which generally includes the NWA technology, location and term of the deferral. Subject to these qualifications, we are increasing the information that is made publicly available on the website.

116 NYSEG

117 RG&E

5 Other DSIP-Related Information

5.1 DSIP Governance

The DSIP Update should clearly and fully describe how the utility's DSIP activities and resources are organized and managed. The information provided should:

1) Describe the DSIP's scope, objectives, and participant roles and responsibilities. A participant could be a utility employee, a third party supporting the utility's implementation, or a party representing one or more stakeholder entities.

Our 2018 DSIP filing addresses all of the requirements established in the Staff Guidance, as well as other topics that are integral to our performance as the DSP, including Market Services and our Technology Platform. A team of approximately 100 NYSEG, RG&E, and AVANGRID employees contributed to the development of the 2018 DSIP, working over an 8-month period. Many of these employees are subject matter experts have responsibilities that involve DSP activities including Integrated Planning, Grid Operations, Market Services and Information Sharing. In this respect, their DSIP responsibilities are integrated with their daily work responsibilities in managing and executing DSP functions.

We rely on technology and service vendors to support our DSP functions when it is necessary and efficient to do so.

We have collaborated with stakeholders in the course of preparing the 2018 DSIP, working with the Joint Utilities and separately as NYSEG and RG&E. We work with these stakeholders in performing our DSP role.

2) Describe the nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSIP work. Also describe and explain how the work processes are expected to evolve over the next five years. Workflow diagrams that show significant internal and external dependencies will be especially useful.

AVANGRID has implemented an AVANGRID Utility of the Future governance structure that has responsibility over all REV-related activities including the DSIP. The Utility of the Future governance structure is led by an executive sponsor and a Utility of the Future Steering Committee. Reporting the executive sponsor are three teams – a Policy team, a Platform team, and an Implementation team. The responsibilities of these teams are:

- The Policy team addresses the regulatory, legal, and conceptual issues associated with REV topics as they are being developed in proceedings. This group also is responsible for outreach to stakeholders.
- The Platform team is responsible for ensuring that the DSP is designed properly and

flexible enough to be able to incorporate new products and services into the existing distribution system to optimize operations, be resilient, and continue to provide safe and reliable customer service at its core.

- The Implementation team, as the name implies, develops the implementation plans for each project and takes the projects from the design phase to fully operational. Specific implementation initiatives are presented in roadmaps in our 2018 DSIP Report and in this Appendix A, including timing. The Technology Platform, in particular, reflects consideration of interdependencies among technologies and systems, and the dependencies on the availability of AMI data as one primary example.

Each team has an identified leader that is accountable for executing their respective responsibilities. All three teams work cooperatively together and, at points, necessarily overlap to ensure that transitions from concept to design to implementation are done seamlessly. This structure will serve to oversee and manage the complete, efficient, and expedient design and implementation of our collection of DSIP projects.

3) Identify and describe in detail the tools (i.e. project management, collaboration, and content management software) and information resources currently employed internally by the utility and/or presented for stakeholder use. Also describe and explain how the tools and information resources are managed and how they are expected to evolve over the next five years.

As described in Subpart 2 above, the Utility of the Future team is responsible for taking REV (and thus DSIP) ideas from concept to design to implementation. The Program Management department at NYSEG/RG&E is the project management office that coordinates the functions and ensures collaboration between the groups. It is important to note that the Utility of the Future team is not a stand-alone group set apart from our regular operations. The team members and supporting cast remain in their respective operational organizations (*e.g.*, Planning, Smart Grids, Customer Service). The projects and products that are currently being implemented, and planned to be implemented, are part of the day-to-day responsibilities at NYSEG and RG&E, with support from many resources throughout the AVANGRID networks organization. We feel strongly that business participation is key to a successful transformation. Our approach ensures that, because all employees are engaged in the REV process, there is no need to "make it fit" after the fact. Employee engagement and buy-in are accomplished up front, which makes implementation smooth and part of the daily operations.

As REV evolves and the DSIP implements new projects and products, we will continue to follow our established system to ensure consistency in how we evaluate and implement projects.

4) Describe the Joint Utilities of New York Website contents and functions which support aspects of the utility's implementation program. Provide specific examples to explain how those contents and functions help both the utility and its stakeholders.

The Joint Utilities of New York website is a central location for stakeholders to refer to in order to track ongoing collaborative efforts among the utilities and our many DSIP stakeholder organizations. Stakeholder collaboration is essential to the design and implementation of several DSP functions. In addition to a formal Advisory Group, we have held formal stakeholder discussions in at least nine areas (Customer Data, DER Sourcing and NWA Suitability, EVSE, System Data, Monitoring & Control, NYISO/DSP, Hosting Capacity, Load/DER Forecasting, and Interconnection). We expect that these groups will continue to evolve with new groups being formed and others completing their work.

5) *Describe and explain the planned sequence and timing of key DSIP management activities and milestones. Using calendars, Gantt charts, and narrative text, provide information addressing management functions, collaborative processes (stakeholder engagement and Joint Utilities coordination, for example), and development and maintenance of program tools and information resources.*

Our Utility of the Future Program Management Group will be tracking project activities, dependencies, and milestones working together with the three teams identified in response to Subpart 2. The plans are identified on the Roadmaps presented in our 2018 DSIP.

6) *Describe and explain the planned sequence and timing of the notable activities, dependencies, milestones, and outcomes affecting implementation. Using calendars, Gantt charts, and narrative text, provide information addressing all significant utility processes, resources, and capabilities. Explain how each notable outcome enables one or more significant DSP applications.*

Our Utility of the Future Program Management Group will be tracking project activities, dependencies, and milestones working together with the three teams identified in response to Subpart 2. The plans are identified on the Roadmaps presented in our 2018 DSIP.

Glossary of Terms

Advanced Distribution Management System (ADMS): Refers to the platform to optimize the grid and integrates a number of utility systems to allow for a range of advanced functions, including automated outage restoration, power flow optimization, and conservation voltage reduction.

Advanced Metering Infrastructure (AMI): A metering system for measuring individual household electricity consumption at intervals of an hour or less and communicating that information at frequent intervals to the distribution utility.

Active Network Management (ANM): Refers to a control system for managing DER within system limits in real-time. ANM allows increased DER hosting capacity by incorporating various smart grid components (such as regulators, capacitors, sensors, and switches) and managing the DER watts, VARs, and/or voltage within system limits.

Aggregator: Refers to a marketer, broker, or public agency that combines the loads of multiple end-use customers to negotiate the purchase of electricity, the transmission of electricity, and other related services for these customers.

Ancillary Service: Services, such as spinning reserves, non-spinning reserves, and regulation, that support the transmission of energy from generating resources to loads while maintaining reliable operation of the network.

Battery Storage: Refers to the use of a cell or connected group of cells to convert chemical energy into electrical energy by reversible chemical reactions and that may be recharged by passing a current through it in the direction opposite to that of its discharge.

Behind-the-Meter: Relating to technology or efforts on the end-use customer side of the electric system.

Beneficial Location: Circuits or locations on the grid where DER could help address constraints and potentially defer grid investments.

Benefit Cost Analysis: a method of evaluating all potential costs and benefits or revenues resulting from the completion of a project.

Breakers: Automatically operated devices that protect a circuit from damage due to excess current from an overload or short circuit.

Business Case: A justification for a proposed project or undertaking on the basis of its expected commercial benefit.

Capacitor Banks: A collection of capacitors that can be switched in and out of the circuit. Capacitors are a transmission device designed to inject power into the network.

Circuit: A conductor or a system of conductors through which electric current flows.

Combined Heat and Power (CHP): A system producing both heat and electricity from a single source, often using the “waste” energy from electricity generation to produce heat.

Appendix A: 2018 DSIP Guidance Requirements

Community Choice Aggregation (CCA): A form of group purchasing that allows local governments or other entities to pool their demand and procure energy on behalf of their customers, while using transmission and distribution service from the utility.

Community Distributed Generation (CDG): Programs that allow customers to subscribe to large-scale solar facilities, allowing customers to support locally produced electricity generation through monthly bill credits.

Critical Infrastructure Protection (CIP): The North American Electric Reliability Corporation critical infrastructure protection (NERC CIP) plan is a set of requirements designed to secure the assets required for operating North America's bulk electric system.

Customer Information: Data pertaining to customer energy usage and account information.

Customer Relationship Management and Billing System (CRM&B): The Companies are planning a billing system upgrade using CRM&B, which will provide individualized customer experience to improve the Companies' customer engagement.

CVR Factor: The term used to refer to the ratio between voltage reduction and energy load consumption for a particular part of a distribution system (load, feeder, substation, or utility). Factors vary widely from substation to substation, feeder to feeder, and especially load to load.

Cyber Security: The process of protecting data and information systems from unauthorized access, use, disclosure, disruption, modification, or destruction.

CYME: Refers to a distribution software suite of applications to analyze power flows.

Data Analytics Platform: Refers to the platform on which Grid Operations and other business areas will compile and analyze data to optimize systems.

Data Privacy: Refers to requirements of utilities to ensure that customer usage, billing, and other information is not released either through data breaches or interactions with third parties. Utilities ensure customer data privacy through a combination of measures, including removing personally identifiable information and/or providing third parties with aggregated data to ensure customer privacy.

DC Fast Charging: stands for Direct Current Fast Charging; these can charge electric vehicles must faster than Level 1 and Level 2 charging stations. There are 3 standard levels of EV charging. All electric cars can charge on levels 1 (charge time: 8-15 hours) and 2 (charge time: 3-8 hours). Only certain types of EVs can charge on level 3 (charge time: 20 minutes-1 hour).

Demand Response (DR): Refers to utility programs that send price signals to customers to lower energy consumption, particularly during times of peak energy consumption, such as hot summer days.

Demand Side Management (DSM): The planning, executing and monitoring of utility activities designed to help customers use electricity more efficiently.

DER Developer: A person or entity that develops, owns, or controls the means of DER generation and looks for ways to combine technologies to improve performance and efficiency of DER.

DER Management System (DERMS): Software to improve an operator's real-time visibility into the status of distributed energy resources and allows distribution utilities to have more granular control and flexibility to manage grid assets.

DER Market Management System (DER MMS): Refers to the system that will help manage settlement and market transactions as a full distribution-level transactive market is developed and in place. As

DER products and services mature, a DER MMS will be required to manage the market and track transactions, perform market clearing, support Measurement and Verification, and settle transactions.

DER Sourcing: DER sourcing allows DER to provide services as an alternative to distribution capital or operational costs.

Dispatchable: A generator or load that is capable of responding to real-time control.

Distributed Energy Resources (DER): DER includes end-use energy efficiency, demand response, distributed storage, and distributed generation. DER will principally be located on customer premises, but may also be located on distribution system facilities.

Distributed Generation (DG): Electrical generation and storage performed by a variety of small, grid-connected devices.

Distributed System Implementation Plan (DSIP): A vision for the electric industry and the expected changes over the next five years, along with progress made and plans to invest in enabling technologies.

Distributed System Platform (DSP): A flexible platform for new energy products and services that incorporates DER into distribution system planning and operations in order to improve overall system efficiency and to better serve customer needs.

Distribution: The delivery of energy to retail customers. This includes the system of equipment connecting between transmission and end customers.

Distribution System: the portion of the electric system that is composed of medium voltage (69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system.

Distribution System Performance: Refers to power quality and the response and/or control of grid assets to meet operational needs.

Distribution System Status: Refers to the status of real-time system conditions, including power quality, outage information, and equipment condition (such as alarms for equipment problems).

Earnings Adjustment Mechanism (EAM): Incremental performance incentives that utilities, as a DSP, can earn in return for achieving REV objectives. Source: REV Connect.

Edge Computing: A mesh network of micro data centers that process or store critical data locally and push all received data to a central data center or cloud storage repository.

Electronic Data Interchange (EDI): EDI is the electronic exchange of business information in a standardized format between business entities.

Energy Control Center (ECC): ECCs function as a DSP and distribution grid operator. They work to optimize the grid based on changing network conditions, and maximize the utilization of grid-side, supply-side, and demand-side resources.

Energy Efficiency (EE): Refers to the goal to reduce the amount of energy generated for a given purpose.

Energy Storage: A device that is able to store energy and release the energy on demand.

Electric Vehicle Supply Equipment (EVSE): Equipment that supplies electric energy to recharge electric vehicles (EVs).

Appendix A: 2018 DSIP Guidance Requirements

Electric Grid: A system of synchronized power providers and consumers connected by transmission and distribution lines and operated by one or more control centers.

EV Readiness Framework: A framework developed by the Joint Utilities to address priorities regarding infrastructure planning, education and outreach, forecasting EV growth, and demonstration and pilot programs related to EV adoption.

Fault: On a transmission or distribution line, an abnormal flow of electric current, *e.g.*, an open circuit (an interruption in the flow) or a short circuit (a flow that bypasses the normal load).

Fault Location, Isolation, and Service Restoration (FLISR): A system that will use automated devices to reconfigure the grid and restore power to the maximum number of customers following a system disruption.

Feeder: Primary distribution lines leaving distribution substations.

Federal Energy Regulatory Commission (FERC): The Federal Energy Regulatory Commission, or FERC, is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects.

Green Button Connect: Capability which allows utility customers to automate the secure transfer their own energy usage data to authorized third parties, based on affirmative (opt-in) customer consent and control.

Greenhouse Gas (GHG): A greenhouse gas is any gaseous compound in the atmosphere that is capable of absorbing infrared radiation, thereby trapping and holding heat in the atmosphere. The most significant greenhouse gases are water vapor (H_2O), carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

Grid Automation: Refers to the Companies' vision to automate all distribution control devices, including breakers, reclosers, regulators, capacity banks, switches, and supporting telecommunications networks, to allow the Companies to measure and control power flows on circuits.

Grid Model Enhancement Project (GMEP): Refers to the complete distribution model including network load and DER characteristics. The information in the GMEP will feed the Distribution Planning Tools to support effective planning (including NWA analysis), to calculate hosting capacity, and to analyze interconnection requests, and will also feed the ADMS as the basis for power flow calculations for optimization and congestion management.

Grid Modernization: Refers to foundational technologies and investments to improve the reliability, resiliency, and automation of the transmission and distribution system, thus contributing to a more efficient and modern grid. There are three foundational grid modernization investments: AMI, Grid Automation, and Telecommunications/IT. These technologies and investments provide the raw, granular, time-differentiated data required by DSP enabling technologies, and also support energy storage and other DER.

Grid Operations: The core function that monitors and operates the distribution grid to provide safe, reliable, and resilient distribution service.

Home Energy Management: Systems that integrate "smart" appliances, HVAC, and other systems to optimize energy use based on granular data.

Appendix A: 2018 DSIP Guidance Requirements

Hosting Capacity: The amount of DER that can be accommodated without adversely impacting power quality or reliability without the need for grid upgrades paid for by DER developers.[118]

Intermittent Resource: An electric generating resource that is not continuously available. Examples include residential rooftop solar that provide output during the day.

Innovation: The development of a new method, idea or product.

Installed Capacity (ICAP): Installed Capacity) represents generating capacity that is physically on the ground and has a defined value determined by a valid test or other approved evaluation method.

Interconnection: The result of the process of adding a Distributed Generation facility to the distribution network.

Interconnection Online Application Portal (IOAP): A platform for utility-customer engagement that allows for online application submittal, automated management and screening, and greater transparency about the interconnection process.

Interconnection Queue: The interconnection queue is the list of projects that have requested and are awaiting interconnection.

Interconnection Technical Working Group (ITWG): The Joint Utilities working group that focuses on interconnection issues.

Joint Utilities: The six electric utilities involved in REV proceedings and DSIP filings. The group is comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

kW, MW: Kilowatt – a unit of electrical power, equal to 1,000 watts. Megawatt – one million watts.

kWh, MWh: Kilowatt-hour – a unit of electrical energy, equal to one kilowatt (kW) of power used for one hour. Megawatt-hour – one megawatt (MW) used for one hour. An average household will use around 800-1300 kWh per month. Source: Duke Energy Corporation.

Load: The amount of power delivered or required at a point on a system.

LoadSEER: A forecasting tool that incorporates DER and probability into granular load forecasts, assessing the impact on circuits.

Locational System Relief Value (LSRV): These high-value locations provide an opportunity for DER developers to earn credit for development that relieves grid congestion in the area.

Low and Moderate Income (LMI) Customers: A utility's customers who fall under a determined income threshold.

Market Design and Integration Report: A report to be filed by the Joint Utilities, identifying and explaining their jointly planned market organization and functions, along with the policies and resources needed to support them.

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[118] See Appendix B of our 2018 DSIP Report for link.

Appendix A: 2018 DSIP Guidance Requirements

Market Participant: An entity that produces and sells capacity, energy, or ancillary services into the wholesale market.

Market Settlement: Refers to the governance of DER-related contractual, program or tariff obligations and the related transactions.

Measurement & Verification: Refers to the process for quantifying and monetizing energy savings.

Measurement, Monitoring, and Control (MM&C): Refers to the ability to provide real-time visibility of grid status, as well as the ability to control resources. The grid has general MM&C capabilities to manage all resources, but the Companies are also putting in place advanced MM&C capabilities to provide better visibility and control of smaller DER. Microgrid: a group of interconnected loads and DER within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes.

Microgrid: A group of interconnected loads and DER within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes.

Microgrid Management System (MGMS): Refers to an enabling technology (built on the ADMS platform) that will be developed based on the pace of community microgrid installations. Once microgrids begin serving multiple customers over the distribution network, the Companies will need to ensure reliability and service even while islanded. The MGMS will be built as an enhancement to the controls and capabilities in DERMS, but will require increased measurement and control to ensure proper voltage, frequency, load balance, and power quality while islanded and re-synchronizing with the grid.

Net Energy Metering: A billing arrangement that provides credit to solar system owners for the value of the electricity that they add to the grid. The electricity meter runs backwards to provide a credit against the amount of electricity consumed from the grid.

Network: An interconnected system of electrical transmission lines, transformers, switches and other equipment connected together in such a way as to provide reliable transmission of electrical power from multiple generators to multiple load centers. Source: Duke Energy Corporation.

New York Department of Public Service (NYDPS, DPS): The state agency established by law with oversight responsibilities regarding the operation of regulated monopoly utilities.

New York Independent System Operator: The organization that monitors the reliability of the power system and coordinates the supply of electricity around New York State, and facilitates the NY wholesale market.

New York Public Service Commission (NYSPSC, PSC): A five-member Commission within the Department of Public Service with the authority to implement provisions of the Public Service Law.

New York State Energy Research and Development Authority (NYSERDA): An organization governed by a 13-member Board that works with stakeholders throughout NY to develop, invest and foster the development of clean energy.

Non-Wires Alternative: Projects that allow utilities to defer or avoid conventional infrastructure investments by procuring distributed energy resources (DER) that lower costs and emissions while maintaining or improving system reliability.

Appendix A: 2018 DSIP Guidance Requirements

NWA Suitability Criteria: Refers to the criteria developed with the Joint Utilities and other stakeholders in assessing NWAs as an alternative to traditional wires investments.

North American Electric Reliability Corporation (NERC): A not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Off-Peak: The period of relatively low system demand, often occurring in daily, weekly, and seasonal patterns.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Outage Management System (OMS): Refers to a system to manage power outages that integrates automation capabilities for faster outage identification and response.

Peak: Relating to the period of high system demand.

Peak Shaving: Peak shaving is the ability to control your usage from the grid during intervals of high demand in order to limit or reduce demand penalties for the billing period.

Photovoltaics (PV): Devices that generate electricity from sunlight through a process that occurs naturally in semiconducting materials.

Platform Service Revenues: A new source of revenues generated by the DSP from selling value-added products and services to customers or third parties.

Point of Common Coupling (PCC): the point at which other customers are (or could be) connected.

Point of Connection (PoC): the point at which responsibility for ownership and operation of the electrical system passes from the wind farm to the electricity network operator.

Portal: Specially designed Web page that brings information together from diverse sources in a uniform way.

PowerClerk: Refers to an interconnection administration tool.

Power Flow Model: Refers to a simulation that models power flows on the Companies' system, as well as how power flows between the NYISO transmission system.

Power Quality: A measurement of the extent to which a steady supply voltage stays within the prescribed range.

Reactive Power: A component of apparent power (volt-amps) that does not produce any real power (watts). It is measured in VARs volt-amps reactive.

Recloser: Reclosers are small circuit breakers located at the top of distribution poles. They isolate a section of the feeder in fault conditions and thereby minimize the number of customers without service. Since they act as small circuit breakers, they have the capability to restore power automatically in temporary fault situations.

Reforming the Energy Vision (REV): A comprehensive energy strategy for New York, involving informed energy choices, new products and services, environmental protection, and new jobs and economic opportunities. The initiative involves regulators, utilities, and third-party companies.

REV Demonstration Project: Projects developed by the six large NY investor owned electric utilities consistent with guidelines of the Track One REV proceeding. These projects aim to demonstrate new business models for third parties and the electric utilities, testing the potential of different aspects of REV.

Regulators (Voltage): Voltage regulators are electronic circuits providing stable direct current (DC) voltage independent of current, temperature, and/or alternating current (AC) voltage changes.

Reliability: A measure of the ability of the system to continue operation while some lines or generators are out of service. Reliability deals with the performance of the system under stress.

Remote Terminal Unit (RTU): A remotely controlled unit that gathers accumulated and instantaneous data to be telemetered to a specified control center which displays the current status of the generation facility.

Renewable Energy: Energy that is generated from natural processes that are continuously replenished; sources include sunlight, geothermal heat, wind, tides, water, and various forms of biomass.

Request for Information (RFI): a standard business process whose purpose is to collect written information about the capabilities of various suppliers, to facilitate comparison among potential suppliers.

Request for Proposals (RFP): a solicitation, often made through a bidding process, by an agency or company interested in procurement of a commodity, service or valuable asset, to potential suppliers to submit business proposals.

Return on Investment (ROI): A metric that measures the ratio between the net profit and cost of investment resulting from an investment of some resources.

Resiliency: Preparation and adaptation to changing conditions, along with the ability to withstand and recover quickly from disruptions.

Roadmap: A high-level plan and overview to support strategic and long-term planning, accompanied by short-term goals with specific solutions.

Smart Home: A residence that uses internet-connected appliances and devices to enable remote monitoring and management of systems such as lighting and heating.

Smart Integrator: A role the Companies will fill by interconnecting and integrating DER where and when they provide the greatest value.

Smart Inverter: An electronic power converter that converts direct current alternating current (inverting), and provides grid support.

Smart Meter: An electronic device that records electricity consumption and communicates the information to the utility, enabling two-way communication and more granular data.

Smart Partner Program: Partnership with community organizations to test engagement strategies for our LMI customers

Smart Solutions: An on-line marketplace concept that tests ability to connect customers with DER developers.

Stakeholder: a person or party with an interest in a company, operation, or project. This can include customers, regulators, and shareholders.

Standardized Interconnection Requirements (SIR): State requirements that resources must meet in order to connect with the distribution system.

Substation: Facility equipment that switches, changes, or regulates electric voltage. An electric power station serving as a control and transfer point on a transmission system, and serving as a delivery point to industrial customers.

Supervisory Control and Data Acquisition (SCADA): Systems [that] operate with coded signals over communications channels to provide control of remote equipment of assets.

Supplemental DSIP Filing: DSIP report filed by the Joint Utilities in November 2016 as a follow-on to the Initial DSIP filed by individual utilities in June 2016.

Technology Platform: The integrated set of technology investments that enables the DSP to maintain safe, reliable, and efficient operations, while supporting the ability to connect and integrate a large number DER. The technology platform will provide the granular data necessary to enable integrated planning capabilities.

Third-Party Vendor or Supplier: An entity that sells a product or service, who is not otherwise directly involved in the transaction.

Tie Switches: Electrical switchgear that switches all power to the active feeder upon loss of another feeder.

Time of Use (TOU): A pricing approach under which the electric company charges you more for electricity bought during peak hours, usually during the day.

Time-Varying Pricing (TVP): Pricing electricity to vary throughout the day – this can involve a few periods or blocks throughout the day, or more frequent hourly differences. TVP requires advanced metering technology, and may shift demand to lower-priced times.

Track One Order: Also known as the Order Adopting Regulatory Policy Framework and Implementation Plan, a filing issued by the Commission in February 2015 that articulates a transformation to a future electric industry in NY, incorporating distributed resources and dynamic management. The Order requires electric utilities to provide DSP services to enable the integration of DER.

Track Two Order: A filing issued by the Commission in May 2016 that creates a new regulatory model incentivizing utilities to take actions to achieve REV objectives by better aligning utility shareholders' financial interest with customers' interests.

Transformer Load-tap-changers: Refers to a voltage regulating device located on substation transformers.

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

UL 1741: An industry Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.

Uniform Business Practices (UBP): Provides for consistent business procedures for both energy services companies (ESCOs) and electric and natural gas utilities across the New York State.

Use Case: A well-defined application of a technology that identifies the actors, processes involved, and output of the application, sometimes including the goals met or problems solved.

Value of DER (VDER): A new mechanism designed by the NYSPSC to compensate DER, effectively replacing net energy metering. VDER compensates projects based on when and where they provide electricity to the grid.

VAR: Volt-ampere Reactive: A unit by which reactive power is expressed in an AC electric power system. Reactive power exists in an AC circuit when the current and voltage are not in phase.

Voltage: The difference in electrical potential between any two conductors or between a conductor and ground. It is a measure of the electric energy per electron that electrons can acquire and/or give up as they move between the two conductors.

Voltage-Var Optimization (VVO): A process that optimizes circuit performance and reduces line losses, managing circuit level voltage in response to the varying load conditions.

WattPlan: Software developed by Clean Power Research and being tested in AVANGRID's ESC to help predict customer DER adoption.

Whole Building Aggregated Data: Data regarding building energy usage that is provided to building owners to help them benchmark their usage against other buildings while protecting the privacy of individual tenants' energy usage information.

Wholesale Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Zero Emission Vehicle (ZEV): A vehicle that emits no exhaust gas from the source of power.