JOINT UTILITIES

Supplemental Distributed System Implementation Plan

Case 16-M-0411

In the Matter of Distributed System Implementation Plans

November 1, 2016

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Acronyms

AC	Access Control
ADMS	Advanced Distribution Management System
ADR	Automated Demand Response
AICPA	American Institute of Certified Public Accountants
AMI	Advanced Metering Infrastructure
ANM	Active Network Management
BAN	Business Area Network
BCA	Benefit-Cost Analysis
BMS	Building Management System
BPWG	Budget Priorities Working Group
BQDM	Brooklyn Queens Demand Management
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CCA	Community Choice Aggregation
CDG	Community Distributed Generator
CEAC	Clean Energy Advisory Council
CEF	Clean Energy Fund
CES	Clean Energy Standard
CHP	Combined Heat and Power
CIMS	Customer Information Management System
CSRP	Commercial System Relief Program
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DAOP	Day Ahead Operating Plan
DEC	Department of Environmental Conservation
DER	Distributed Energy Resource(s)
DERMS	Distributed Energy Resource Management System
DERP	Distributed Energy Resource Provider
DG	Distributed Generation
DLC	Direct Load Control
DLM	Dynamic Load Management
DLMP	Distribution Locational Marginal Price
DLRP	Distribution Load Relief Program
DMS	Distribution Management System
DNP	Distributed Network Protocol
DPS	Department of Public Service
DR	Demand Response
DRIVE	Distribution Resource Integration and Value Estimation
DSIP	Distributed System Implementation Plan
DSM	Demand Side Management
DSP	Distributed System Platform(s)
EAM	Earnings Adjustment Mechanism
ECC	Energy Control Center
EDI	Electronic Data Interchange
EE	Energy Efficiency
EEI	Edison Electric Institute
EG	Engagement Group

E-ISAC	Electricity Information Sharing and Analysis Center
EMS	Energy Management System
ENERGISE	Enabling Extreme Real-Time Integration of Solar Energy
EPRI	Electric Power Research Institute
ESC	Energy Smart Community
ESCO	Energy Services Company
ESCC	Electricity Subsector Coordinating Council
ETI	Electronic Technology, Inc.
ETIP	Energy Efficiency Transition Implementation Plan
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FCI	Faulted Circuit Indicators
FERC	Federal Energy Regulatory Commission
FICS	Flexible Interconnect Capacity Solution
FLISR	Fault Location, Isolation and Service Restoration
FTP	File Transfer Protocol
GAPP	Generally Accepted Privacy Principles
GBC	Green Button Connect My Data
GBD	Green Button Download My Data
GIS	Geographic Information System
HAN	Home Area Network
I&A	Identification and Authentication
ICAP	Installed Capacity
ICS-CERT	Industrial Control Systems- Cyber Emergency Response Team
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IOAP	Interconnection Online Application Portal
IOT	Internet of Things
IPPNY	Independent Power Producers of New York
IPWG	Interconnection Policy Working Group
ISO	Independent System Operator
IT	Information Technology
ITWG	Interconnection Technical Working Group
kW	Kilowatt
kV	Kilovolt
LMP	Locational Marginal Prices
LMI	Low and Moderate Income
LSE	Load Serving Entity
MAMS	Meter Asset Management System
MDMS	Meter Data Management System
MDPT	Market Design and Platform Technology
M&V	Measurement and Verification
MW	Megawatt(s)
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NGR	Non-Generator Resource
NIST	National Institute of Standards and Technology
NWA	Non-Wires Alternative(s)
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSEG	New York State Electric & Gas Corporation

OMS	Outage Management System
O&R	Orange and Rockland Utilities, Inc.
OT	Operation Technology
PCC	Point of Common Coupling
PCI	Payment Card Industry
PDR	Proxy Demand Resource
PEV	Plug-in Electric Vehicle
PG&E	Pacific Gas & Electric
PII	Personal Identifiable Information
PLCC	Power Line Carrier Communications
PSR	Platform Service Revenues
PV	Photovoltaic
RBAC	Role-based Access Control
REV	Reforming the Energy Vision
REVI	Regional Electric Vehicle Initiative
RFI	Request for Information
RFP	Request for Proposal
RG&E	Rochester Gas and Electric Corporation
ROW	Rights-of-Way
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SCT	Societal Cost Test
SEP	Smart Energy Profile
SGS	Smarter Grid Solutions
SOC	Service Organization Controls
SPP	Solar Program Partnership
SDG&E	San Diego Gas & Electric
SFTP	Secure File Transfer Protocol
SIEM	Security Information and Event Management
SIR	Standardized Interconnection Requirements
T&D	Transmission and Distribution
TO	Transmission Owner
TOU	Time-of-Use
TRM	Technical Resource Manual
UBP	Uniform Business Practices
US-CERT	United States Computer Emergency Readiness Team
VAR	Volt-Ampere Reactive
VVO	Volt/VAR Optimization
WAN	Wide Area Network
WN	Weather-normalized
ZEV	Zero Emissions Vehicle

Executive Summary

The Joint Utilities[1] welcome the opportunity to present their plans for developing the functions and capabilities necessary to evolve into their role as Distributed System Platform ("DSP") providers.[2] This Supplemental Distributed System Implementation Plan ("DSIP") represents extensive collaboration, coordination and engagement among the Joint Utilities and stakeholders. Over the course of several months, the Joint Utilities implemented an ongoing stakeholder engagement process to help inform the Supplemental DSIP and related work. The Joint Utilities initiated this process by inviting input from stakeholders and working together with stakeholders to create a shared vision of the phases and steps required to develop the capabilities the utilities will need in their new role of DSP. In this new role, the utilities will enhance their planning processes and operations to effectively integrate distributed energy resources ("DER")[3] and other clean energy technologies, connect customers with new options to manage their energy usage and energy bills, and facilitate innovation by providing third parties with the information needed to create tailored customer offerings and support investment decisions. These new responsibilities are in addition to the utilities' ongoing obligation to maintain the safety, security, and reliability of electricity delivery to customers.

Transforming utilities into DSPs requires the development of new and enhanced functions and capabilities in the areas of distribution system planning, grid operations, and market development. The Commission outlined a two-phased filing approach to identify the steps and information needed to create the DSP and enable efficient investment in DER by third parties and customers. The first filing, the Initial DSIP, was submitted individually by each utility on June 30, 2016,[4] in response to the New York Public Service Commission's ("Commission") directive in the REV Proceeding.[5] The Initial DSIPs presented a thorough self-assessment of current capabilities, proposed each utility's individual roadmap for technology investments to improve the intelligence of

[1] The Joint Utilities are Central Hudson Gas & Electric Corporation ("Central Hudson"), Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation ("NYSEG"), Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), Orange and Rockland Utilities, Inc. ("O&R"), and Rochester Gas and Electric Corporation ("RG&E"). "Joint Utilities" refers to activities or proposals the Joint Utilities are undertaking as a collective, single group. Used in a general context, "utility" or "utilities" refers to individual actions by the separate companies that comprise the Joint Utilities.
[2] Throughout this document, "DSP" refers to the utilities' role of developing and implementing the distributed system platform.
[3] Case 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) ("Track One Order"), p.3, where the Commission described distributed energy resources ("DER") as a wide variety of resources, including end-use energy efficiency, demand response, distributed storage, and distributed generation.
[4] National Grid subsequently made an errata filing with the Commission on July 1, 2016 to correct certain format issues that occurred in the course of converting the document to a pdf and in so doing filed a revised Initial DSIP in its entirety.
[5] REV Proceeding, Track One Order and Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016) ("DSIP Guidance Order"). The Commission subsequently established Case 16-M-0411 – *In the Matter of Distributed System Implementation Plans* ("DSIP Proceeding") to facilitate the review of both the Initial and Supplemental DSIPs.

the grid and prepare it for higher DER penetration levels, and provided data to bring greater transparency to the planning process and support distribution market development.

The Supplemental DSIP expands on the information provided in the Initial DSIPs and addresses “the tools, processes, and protocols that will be developed jointly, or under shared standards, to plan and operate a modern grid capable of dynamically managing distribution resources and supporting retail markets.”[6] Common and consistent approaches among the utilities are intended to facilitate the creation of efficient, statewide markets for DER products and services and help reduce transaction costs for third-party providers and disparities in market development. The Joint Utilities have strived for standardization where possible, recognizing that the utilities are diverse in their service territories, grid configurations, data availability, and the degree of development of existing capabilities. These differences are noted throughout this document to the extent they may impact the development of a uniform approach. Although some differences will remain, such as service territory characteristics, over time it is expected that these differences will narrow as the utilities implement their investment plans and reach consensus on new analytical and operational approaches.

Taken together, the Initial and Supplemental DSIPs represent, “the first steps toward establishing a grid that can support increasing levels of DERs into the future and ultimately, achieving REV-related goals and objectives.”[7] While the Joint Utilities are in the early stages of what will be an iterative process over several years, the DSIPs make significant progress in outlining roadmaps that will advance REV objectives and lay the foundation for future market growth. These filings will form a basis of specific requests for project approval and associated cost recovery, through which the Commission will contribute to determining the pace and scale of investment in each utility service territory.

The Supplemental DSIP provides a vision for the evolution of the DSP and distribution markets and sets the context for the Joint Utilities’ plans in four critical areas addressed in the filing—Distribution Planning, Grid Operations, Market Operations, and Data Collection, Access, and Security. The Joint Utilities convened stakeholder engagement groups to share information and solicit input on specific topics within these areas. Stakeholder input was valuable in introducing new perspectives and refining the Joint Utilities’ approaches. The utilities commit to ongoing collaboration and stakeholder engagement following this Supplemental DSIP filing.

Stakeholder Engagement Process

The Joint Utilities support stakeholder engagement as an important aspect of the REV Proceeding and appreciate the efforts of stakeholders to participate in the DSIP stakeholder engagement process. A multi-tiered approach was implemented that offered several different forums for stakeholders to learn about the utilities’ efforts, discuss technical details, and provide input. Additionally, the Joint Utilities maintain and regularly update a website dedicated to their

[6] REV Proceeding, DSIP Guidance Order, p. 3.
[7] *Id.*, p. 15.

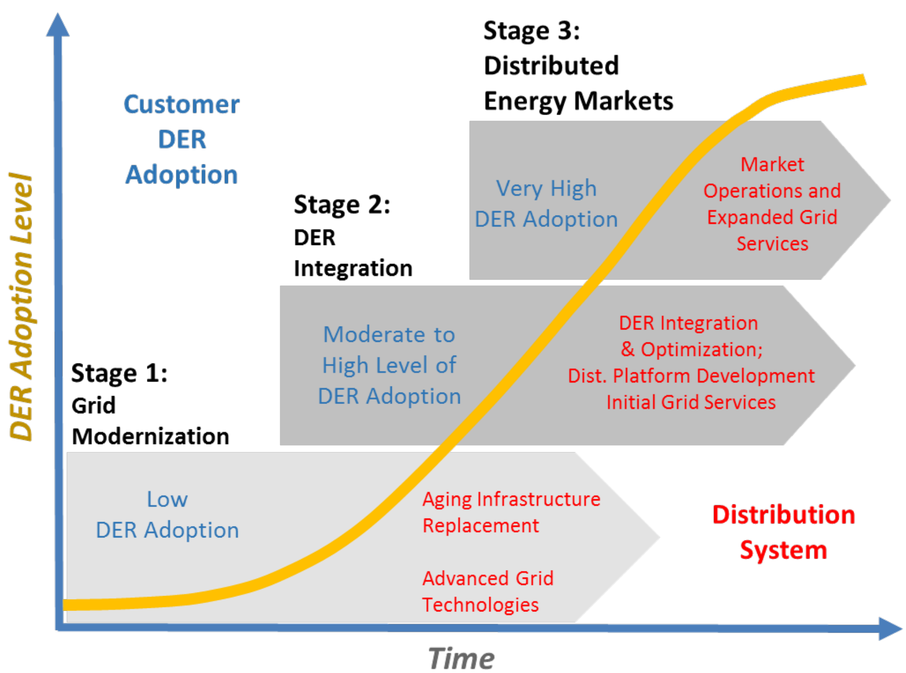
stakeholder engagement efforts for the Supplemental DSIP, including notifications of upcoming meetings and materials from past stakeholder engagement meetings.[8]

Continued stakeholder discussions and engagement are proposed within the Supplemental DSIP to advance specific actions and further develop the plan on an ongoing basis.

Evolution of the DSP and Distribution Markets

DSP implementation and related market development is an inherently iterative process that will continue over the next several years to enable new methods of valuing distribution services. The Joint Utilities envision and support an evolution and transitional model that incorporates three overlapping stages, as shown in Figure ES-1.

Figure ES-1: Three Stages of DSP and Market Evolution



The evolution of the distribution market will require investments in infrastructure, processes, systems, and people to integrate DER and to facilitate value optimization for all customers. Stage 1 is characterized by investments to enhance the grid through replacing aging infrastructure and incorporating advanced technologies that will improve reliability and system resiliency. While these investments are required to achieve grid modernization objectives, many will be complementary to building the distributed services platform to enable more robust integration of DER in Stage 2. Stage 2 is characterized by the addition of more sophisticated functions and capabilities and the emergence of an operational marketplace based on transactions between utilities and DER providers. Value can be captured in Stage 2 through advancements in utility pricing, programs, and procurement (the “Three P’s”). During Stage 2, the utilities will also develop

[8] http://www.jointutilitiesofny.org/

and provide coordination services for DER participation in wholesale markets. These capabilities will be developed through close cooperation with New York Independent System Operator ("NYISO")[9]. Stage 3 is characterized by significantly higher penetrations of DER, which are providing services through multi-party transactions, including the potential for customer-to-customer exchanges.

The Initial and Supplemental DSIPs accelerate Stage 1 progress and move the utilities deeper into Stage 2 over the next five years, which will establish a foundation for moving into Stage 3. As depicted in Figure ES-1, the stages are not mutually-exclusive and there are no clear boundaries between them. Each stage has a degree of overlap with the subsequent stage, highlighting that many activities will occur in parallel.

While the utilities are starting from different points in terms of distribution system capabilities and DSP development, differences in these capabilities are expected to diminish over time as utilities move toward Stage 3 and are supporting more sophisticated market functions.

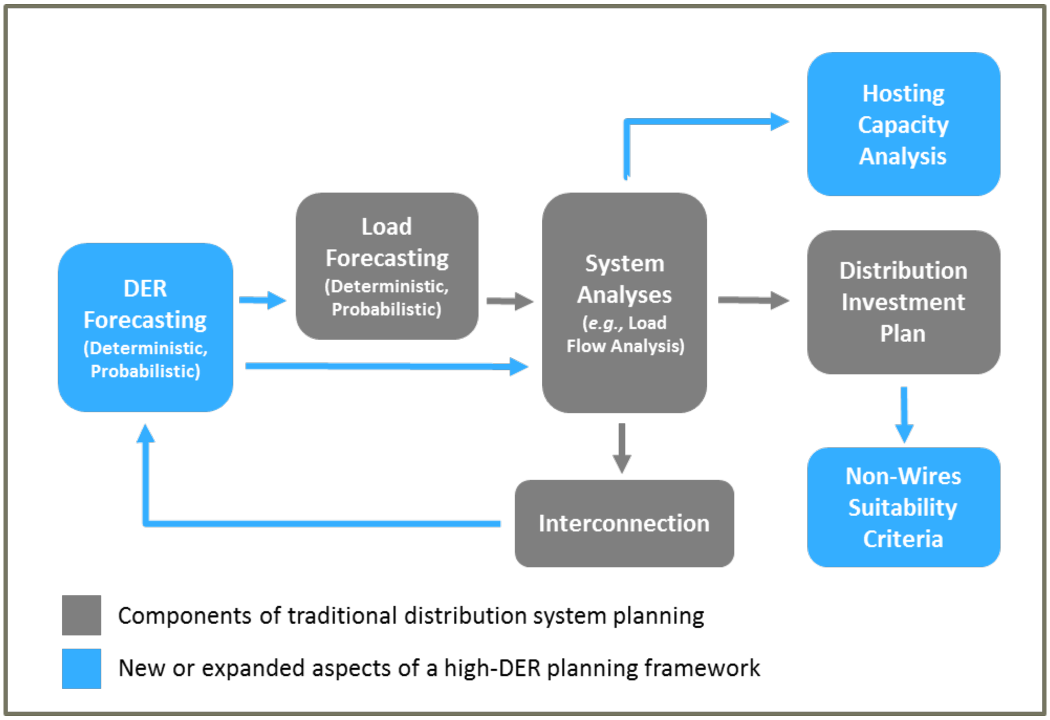
Distribution System Planning

The primary objective of distribution system planning is to design and build the distribution system to safely, reliably, and efficiently deliver electricity to customers within acceptable risk tolerances. Increased DER adoption and integration will prompt the need for expanded and enhanced distribution planning practices that incorporate a broader range of data drivers, additional sources of uncertainty, and a more diverse mix of resources. The Supplemental DSIP provides an initial view of the enhanced planning tools and methodologies that will form the basis of distribution planning in the future and allow for the development of DSP capabilities and integration of higher levels of DER.

Figure ES-2 illustrates enhancements to the distribution planning process, with the gray-shaded boxes reflecting the components of traditional distribution system planning and the blue-shaded boxes representing new or expanded aspects of a high-DER planning framework.

[9] For example, the Joint Utilities are participating in the stakeholder process accompanying NYISO's proposed DER Roadmap initiative. NYISO's draft DER Roadmap is available at: http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/DRAFT%20Distributed%20Energy%20Resources%20Roadmap%20-NYISO%208-17.pdf ("NYISO DER Roadmap").

Figure ES-2: Evolving Distribution Planning Process



Note: This figure reflects a sub-cycle based on aspects of the distribution system planning process addressed in this Supplemental DSIP. The figure is not reflective of all distribution system planning processes or feedback loops that may develop as planning matures.

New and enhanced tools and processes will enable the Joint Utilities to establish a more standardized and transparent planning framework that accounts for the various impacts DER can have on the grid and the value they can provide. To achieve this framework, the Joint Utilities put forth:

- A load and DER forecasting stakeholder engagement process;
- A process for coordination with NYISO on short- and long-term forecasting;
- An NWA suitability framework and forthcoming implementation matrices;
- A detailed roadmap for hosting capacity; and
- An interconnection data platform and process roadmap.

To advance the development of new tools and processes, the Joint Utilities propose several near-term actions to be initiated or completed by the end of 2018, subject to changes resulting from stakeholder engagement or Commission action.

Table ES-1: Hosting Capacity Near-Term Actions

Timeline	Action
2017	• Update indicator maps that provide guidance on the areas where interconnection costs could be higher • Provide feeder-level analysis and heat maps for at least 50 percent of each utility's system in a consistent presentation format • Initiate advanced hosting capacity analysis
2018	• Complete feeder-level analysis and heat maps of each utility's complete system
Ongoing	• Continue to enhance online hosting capacity maps as tool capabilities expand • Refresh hosting capacity analysis at least once per year, with some key data available more frequently • Continue to have Joint Utilities internal working group meetings • Host annual stakeholder meetings

Table ES-2: Interconnection Near-Term Actions

Timeline	Action
2017	• Complete Phase 1 (automate application management) and Phase 2 (automate Standardized Interconnection Requirements ("SIR") technical screening)
Ongoing	• Continue to develop interconnection platform capabilities that will enable completion of Phase 3 • Coordinate Joint Utility efforts through the Interconnection Technical Working Group ("ITWG") and Interconnection Policy Working Group ("IPWG") to streamline the interconnection process and resolve queue management issues

Table ES-3: NWA Suitability Near-Term Actions

Timeline	Action
2017	• Publish utility-specific NWA suitability criteria matrices
Ongoing	• Conduct annual assessments of potential changes to utility-specific suitability criteria in conjunction with each utility's planning process

Table ES-4: Load and DER Forecasting Near-Term Actions

Timeline	Action
2017	• Initiate stakeholder engagement (six meetings by mid-2018)
Ongoing	• Enhance forecasting tools and input data availability • Continue to develop and incorporate more granular forecasts of load and DER on distribution circuits • Conduct quarterly meetings of the NYISO-Joint Utilities Task Force • Continue to have Joint Utilities internal working group meetings • Host annual stakeholder meetings

Grid Operations

The core responsibility of the utilities as grid operators is to maintain the safety, security, and reliability of electricity delivery to end-use customers. Meeting this obligation involves several functions, including managing real and reactive power in normal, outage, and emergency conditions, maintaining distribution equipment, providing power quality, and improving operational efficiency.[10] DER can assist in providing grid services to meet these obligations. Increased operational complexity resulting from power flowing in multiple directions drives an increased need to monitor, measure, coordinate, and control more grid parameters in order to maintain safety and reliability.

The utilities' Initial DSIPs proposed roadmaps for investing in the technologies necessary for reliability and efficiency of operations in a high-DER future. These investments are part of a phased approach to increase operational capabilities, particularly through enhanced visibility, analytics, and operational control. The Supplemental DSIP complements the Initial DSIPs by proposing and defining common standards and protocols that will support the facilitation and integration of DER into distributed grid operations and enable DER to safely provide grid services.

Monitoring and control standards address a range of issues, including DER size, polling frequency, communication protocols, circuit parameters, volt-ampere reactive ("VAR") support, curtailment, notification of DER connection and disconnection, DER performance forecasting, advanced function support, and worker safety. The Joint Utilities anticipate that monitoring and control technologies will continue to advance over time, and the related standards and protocols will also need to evolve to keep pace with market and technology developments.

As DER continue to interconnect to the distribution system and participate in current and future programs offered by the utilities and/or NYISO,[11] additional coordination will be required to ensure the safe, reliable and efficient operation of the transmission and distribution ("T&D") system. NYISO and the Joint Utilities have established a task force, to meet at least quarterly, focused on the coordination needs between NYISO at the bulk transmission level and the Joint Utilities at the distribution level.

[10] These functions are adapted from REV Proceeding, Report of the Market Design and Platform Technology Working Group, (issued August 17, 2015)("MDPT Final Report"), p. 52.
[11] Future programs include those programs available as an outcome of the proposed NYISO DER Roadmap, *supra* note 9.

The following tables highlight proposed near-term actions to be initiated or completed by the Joint Utilities by the end of 2018, subject to changes resulting from stakeholder engagement or Commission action.

Table ES-5: Monitoring and Control Near-Term Actions

Timeline	Action
2017-2018	• Publish joint monitoring and control standards in utility-specific documents
Ongoing	• Joint Utilities form monitoring and control internal working group • Continue stakeholder engagement with one meeting per year • Collaborate with the ITWG

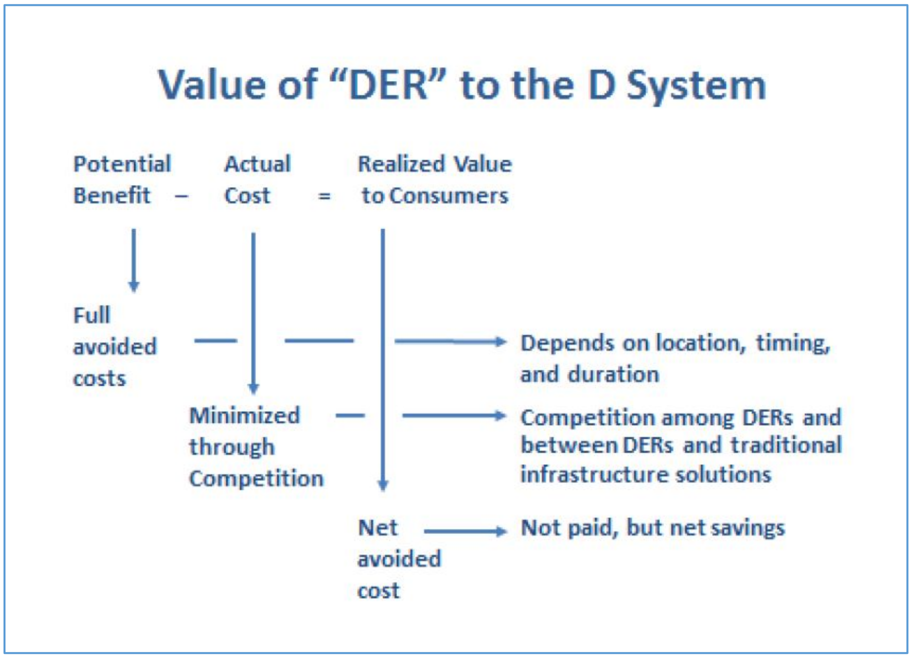
Table ES-6: NYISO/DSP Coordination Near-Term Actions

Timeline	Action
2018	• Conduct quarterly meetings of the NYISO-Joint Utilities task force (potential to extend beyond 2018) • Standardize communication protocols • Share information on behind-the-meter installations • Share information on DER forecasting techniques
Ongoing	• Align dispatch protocols • Develop dispatch interfaces • Share information on resource aggregation

Market Operations

A long-term objective of REV is to animate markets at the retail level. The Joint Utilities are taking initial steps to build the processes and capabilities necessary to support expanded market activities and facilitate the deployment of DER, including electric vehicles ("EVs"). The Joint Utilities support market elements that drive competitive pricing aimed at creating efficiencies for all customers, as illustrated in Figure ES-3 below.

Figure ES-3: Value of DER to the Distribution System[12]



Advancements in utility DER sourcing directly support the broader REV goals of deepening DER penetration, more fully integrating DER into planning and grid operations, and leveraging markets to empower end-use consumers. The Joint Utilities identified potential enhancements to the utility procurement process for NWA as a vehicle for advancing DER sourcing. To date, the utilities have identified over 35 NWA opportunities. Experiences from these early projects will inform future opportunities and procurement approaches. Near-term enhancements include providing common types of system data, establishing bidder pre-qualification where applicable, and establishing common attributes that may form the basis of performance requirements for future NWA solutions.

NYISO's ongoing pilot project on sub-zonal pricing also supports market development. The Joint Utilities will monitor and contribute to developments with NYISO's granular pricing project through a task force comprised of the Joint Utilities and NYISO that will monitor this issue, as well as coordinate on a number of other NYISO-related elements of the Supplemental DSIP.

The following tables highlight proposed near-term actions to be initiated or completed by the Joint Utilities by the end of 2018, subject to changes resulting from stakeholder engagement or Commission action:

[12] Tierney, Susan F., *The Value of 'DER' to 'D': The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability*, Analysis Group, March 31, 2016, p. 21, http://www.analysisgroup.com/uploadedfiles/content/news_and_events/news/value_of_der_to%20_d.pdf

Table ES-7: DER Sourcing Near-Term Actions

Timeline	Action
2017	• Establish common location for posting of NWA solicitations • Implement standardized datasets in NWA solicitations
2018	• Implement bidder pre-qualification process, as applicable • Begin implementing commercial & operational performance standards
Ongoing	• Gather stakeholder input and adjust processes and standards accordingly • Regularly convene a Joint Utilities internal working group to monitor market developments and share individual utility experiences. • Work with stakeholders to address longer-term market needs • Coordinate NYISO and DSP functions

Table ES-8: Electric Vehicle Supply Equipment ("EVSE") Near-Term Actions

Timeline	Action
2018	• Develop EV Readiness Framework
Ongoing	• Refine Framework internally and with stakeholders • Conduct individual utility engagement with municipalities • Regional collaboration (*e.g.,* East Coast Utility EV Initiative) • Pilot/demo projects – identify, refine with stakeholders, implement, report-out • Regularly convene a Joint Utilities internal working group to monitor market developments and share individual utility experiences.

Data Collection, Access and Security

The collection and sharing of system and customer data has been a central theme of REV from the beginning. System data includes grid information such as real and reactive power consumption, calculated hosting capacity, power quality, and reliability statistics, all of which may be collected at various granularities including the system, substation, and feeder level. Customer energy usage data, both at the individual level and in aggregate, is critical to the success of market development under REV, as DER providers seek data that will inform the development and marketing of tailored products and services.

The Joint Utilities support the sharing of useful information to support DER market growth. A significant amount of data is currently available through a number of channels. While there are some differences among utilities as a result of the unique features of their respective service territories, existing information, and operational systems and capabilities, there are a number of data sets that are commonly shared. For example, the utilities make available capital investment plans, load forecasts, reliability statistics, and planned reliability and resiliency projects in various filings with the Commission. Customer data are currently shared with customers and their authorized third parties through various systems, including utility bills, Green Button Download My Data ("GBD") or equivalent, Electronic Data Interchange ("EDI"), online third-party data platforms, Secure File Transfer Protocol ("SFTP"), and online customer engagement platforms.

Data access is also important in the context of developing new market-based revenue streams that are tied to providing value-added services. One example of a potential value-added service is a data analysis service that makes available more granular and customized information to developers and other market participants. The Joint Utilities distinguish between basic data that is available at no incremental cost and value-added data that will be available for a fee. Examples of value-added system data may include forecasted load data, circuit voltage profiles, and power quality data. An example of value-added customer data is aggregated data.

The application of digital communications technologies on the grid and the expansion in available system and customer data present heightened risks of security breaches and highlight the importance of remaining vigilant in protecting system security and customer privacy. The Joint Utilities have developed a common approach to managing cybersecurity risks in the evolving REV environment. The Joint Utilities Cyber and Privacy Framework focuses on people, processes, and technology as being the foundation for a comprehensive cybersecurity and privacy governance program.

To protect individual customer data, the utilities will follow current practices, which require express customer authorization before data is released. For aggregated customer data, the Joint Utilities support the adoption of a 15/15 privacy standard for aggregated data provided by utilities to third parties.[13] The Joint Utilities acknowledge that the 15/15 standard is conservative compared to some privacy standards used elsewhere, but believe beginning with a more conservative standard is appropriate given the nascent state of DER markets in New York.

The following tables highlight proposed near-term actions to be initiated or completed by the Joint Utilities by the end of 2018, subject to changes from stakeholder engagement or Commission action.

Table ES-9: System Data Near-Term Actions

Timeline	Action
2017	• Improve accessibility and format consistency of existing system data
2018	• Identify a forum for facilitating data reciprocity among the Joint Utilities and DER providers
Ongoing	• Provide annual update to stakeholders and regulators on system data development activities • Classify system data based on sensitivity of information • Develop potential fee based structures • Consider web portal enhancements

[13] The 15/15 standard states that an aggregated data set may be shared only if it contains at least 15 customers, with no single customer representing more than 15 percent of the total load for the group.

Table ES-10: Customer Data Near-Term Actions

Timeline	Action
2017	• Begin implementation of basic data protocols and platforms • Implement anonymity standard, creating exceptions as needed
2018	• Implement process for tracking aggregated data requests
Ongoing	• Assess additional data needs whether articulated by stakeholders or embedded in modifications to the national Green Button protocol and consider implementation • Gather stakeholder input and adjust processes and standards accordingly • Share findings from individual utility demonstration projects (*e.g.,* new platforms, online marketplaces)

Table ES-11: Cybersecurity Near-Term Actions

Timeline	Action
Ongoing	• Maintain cyber and privacy framework • Continue participation in the quarterly meetings of the New York State Security Working Group • Share lessons learned and advancements in security technology

Conclusion

Through both the individual Initial DSIPs and the joint Supplemental DSIP filings, the utilities have put forth practical and actionable plans to enhance existing capabilities and develop new tools and processes to meet the goals of REV and be fully responsive to the DSIP Guidance Order. The plans have benefited from the input of stakeholders, who participated in frequent meetings and activities on a broad range of topics. These plans will form the basis of individual cost recovery requests, which will determine the timing and scope of utility investment.

The Joint Utilities commit to further collaboration as a group, including continued development of common standards, protocols, and processes that will support statewide markets and allow for greater convergence of capabilities over time. The Joint Utilities are also committed to continued stakeholder engagement, which will promote ongoing information sharing and the refinement of utility plans in future DSIP filings.

I. Introduction

The DSIP Guidance Order directed utilities to make three related filings in 2016: (1) Stakeholder Engagement Plan, (2) Initial DSIP, and (3) Supplemental DSIP. The Supplemental DSIP is "the vehicle by which improved planning and operations will be defined and implemented."[14] Additionally, the Supplemental DSIP addresses, "the tools, processes, and protocols that will be developed jointly or under shared standards to plan and operate a modern grid capable of dynamically managing distribution resources and supporting retail markets."[15]

The Joint Utilities worked together to define common approaches and methodologies where possible, recognizing that the utilities are diverse in their service territories, demographics, and existing systems and capabilities. These approaches were shaped through an extensive stakeholder engagement process designed to provide transparency into the development of the Supplemental DSIP and invite stakeholder input.

A. DSIP Framework

The foundational element at the center of the REV framework is the DSP. The DSP is defined as:

> an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.[16]

The DSIP Guidance Order outlined a two-phased approach, initial DSIPs followed by a Joint Utilities Supplemental DSIP, to identify the steps and information needed to evolve the capabilities of the utilities and their respective distribution systems to enable efficient investment in DER by third parties and customers. The two phases of filings represent, "the first steps toward establishing a grid that can support increasing levels of DERs into the future and ultimately achieving REV-related goals and objectives."[17]

The Initial DSIPs were filed individually by the utilities on June 30, 2016,[18] and served three primary purposes:

- Provide a self-assessment of current planning processes and system capabilities;
- Identify the foundational near-term investments necessary to support DSP functionality; and
- Provide a base level of data to bring greater transparency to the planning process and support market development.

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[14] REV Proceeding, DSIP Guidance Order, p. 2.
[15] *Id.*, p. 3.
[16] REV Proceeding, Track One Order, p. 31.
[17] REV Proceeding, DSIP Guidance Order, p. 15.
[18] National Grid, *supra* note 4.

The Initial DSIPs act as roadmaps, outlining the incremental steps and technology investments needed to achieve the longer-term vision of creating a dynamic and customer-centric marketplace. These Initial DSIPs cover the five-year horizon of 2017-2021, with regular updates to be filed every two years.[19] While differences exist in the scope and schedule of specific utility investment plans, the utilities share a common focus on grid modernization, distribution system planning, and enhancing access to customer and system data. This includes advanced planning tools and methodologies and enabling technology investments, which will improve data sharing capabilities and drive and support the integration of higher penetrations of DER.

The Supplemental DSIP complements the Initial DSIPs by offering a shared vision on the phases and timeline for DSP development, establishing common Joint Utilities actions and standards to advance specific DSP functions, and identifying areas and plans for continued utility collaboration and stakeholder engagement. The Supplemental DSIP represents the utilities' plan and commitment to work together, and with stakeholders, in the development and evolution of the DSP.

The planned investments identified in the Initial DSIPs and the Joint Utilities' actions and timelines included in the Supplemental DSIP will become a part of individual utility requests for project approval, which are a necessary step to authorize investment and cost recovery. Raising the capital necessary to build the DSP capabilities will require a constructive cost recovery framework that allows for timely and complete cost recovery of the necessary investments and maintains the utilities' financial viability. Differences in the timeline and outcomes of utility rate requests will impact utility-specific implementation plans and schedules.

B. Supplemental DSIP Contents and Organization

The first three chapters, including this Introduction, provide an overview of the Supplemental DSIP's contents and structure, summarize the stakeholder engagement process used to inform the development of the DSIP filings, and offer the Joint Utilities' perspective on market evolution and their transition to DSPs.

The main body of the filing presents the topics in four main chapters, as follows:

- **Distribution System Planning**: describes the foundational planning tools and processes that will form the basis of an enhanced distribution planning framework and allow the development of DSP capabilities and DER markets, consistent with REV policy objectives. These include a load and DER forecasting stakeholder engagement process, a process for coordination with NYISO, an NWA suitability framework, a detailed roadmap for hosting capacity, and an interconnection data platform and process roadmap.

- **Grid Operations**: describes the monitoring and control protocols necessary to maintain system safety and reliability, including DER size, polling frequency, communication protocols, circuit parameters, volt/VAR support, curtailment, notification of DER connection/disconnection, DER performance forecasting, advanced function support, and worker safety. The Joint Utilities also outline a plan for continued collaboration with NYISO on coordination needs.

[19] REV Proceeding, DSIP Guidance Order, p. 9.

- **Market Operations**: describes enhancements to the utility procurement process for NWA as a way to advance DER sourcing. The Joint Utilities also discuss their efforts to monitor and contribute to the development of more granular pricing at the wholesale level, as well as efforts to ready the grid for EVs.

- **Data Collection, Access, and Security**: describes current data sharing practices and plans to expand data access to customers and DER providers, while protecting system security and customer privacy. The Joint Utilities also provide a common framework for distinguishing basic data from value-added data for system and customer data and describe protocols for protecting the privacy and security of data.

II. Stakeholder Engagement Process

The Joint Utilities support stakeholder engagement as an important aspect of the REV Proceeding and appreciate the efforts of stakeholders to participate in the DSIP stakeholder engagement process. The additional perspectives and input provided by stakeholders proved valuable in the shaping of the Joint Utilities' approach to the topics included in this Supplemental DSIP. In many cases, the Joint Utilities and stakeholders were able to reach common ground on aspects of the various topics, which is reflected in the Joint Utilities' proposals included in this filing. Continued stakeholder discussions and engagement are proposed within the Supplemental DSIP to advance specific actions and further develop the plan on an ongoing basis.

The Joint Utilities retained a consultant as a third party to lead stakeholder engagement efforts on their behalf. The consultant, ICF, facilitated stakeholder meetings, provided technical support, documented stakeholder input, and shared relevant experience from other states. The attached Appendix A provides a summary of stakeholder meetings and discussions, including a full list of participating organizations.

A. Stakeholder Engagement Framework

As presented in the Joint Utilities Stakeholder Engagement Plan filed with the Commission on May 5, 2016,[20] the Joint Utilities took a structured approach to provide ample opportunity for stakeholders to participate in the development of DSIP content and to provide input. The Joint Utilities established the following structure to facilitate stakeholder engagement.

Table II-1: Stakeholder Engagement Opportunities

Engagement Opportunity	Purpose
Advisory Group	Guide the Joint Utilities on the priorities and sequence of topics for stakeholder discussions and provide overall feedback to the Joint Utilities on topics relevant to DSIP development
Engagement Groups	Create shared understanding of technical details and strive toward common ground through iterative discussion and feedback
Stakeholder Engagement Conferences	Share engagement group outcomes and other Joint Utilities topic area plans not covered in engagement groups
Joint Utilities Website	Provide transparency into the process and notifications of upcoming meetings
Utility-specific Workshops	Present utility-specific plans for stakeholder discussion

[20] REV Proceeding, Response by the Joint Utilities to the Order Adopting Distributed System Implementation Plan Guidance (filed May 5, 2016) ("Stakeholder Engagement Plan").

As shown in Appendix A, the Advisory Group is comprised of approximately twenty (20) organizations that are representative of the breadth of stakeholder sectors engaged in the REV Proceeding. In addition to the Joint Utilities, the Advisory Group includes representation from New York State Department of Public Service Staff ("Staff"), DER providers, the New York Power Authority ("NYPA"), NYISO, Independent Power Producers of New York, Inc. ("IPPNY"), environmental advocates, and organizations representing large and small commercial and residential customers.

Several engagement groups were formed to address the topic categories identified in the DSIP Guidance Order. The topics were organized into three broad areas: Distribution System Planning, Grid Operations, and Market Operations. The engagement group meetings were open to all interested parties and consisted of a combination of in-person meetings and webinars. In these meetings, the Joint Utilities vetted their initial plans across a range of topics, including hosting capacity, NWA suitability criteria, DER sourcing, system and customer data, and monitoring and control. During these sessions, the Joint Utilities considered stakeholder feedback and, where appropriate, modified initial proposals to reflect that feedback. Documents that supported and describe the engagement discussions were posted to the Joint Utilities website, which notifies stakeholders of upcoming events and posts materials from previous meetings.

In addition to the stakeholder engagement group discussions, the Joint Utilities coordinated five Stakeholder Engagement Conferences held by webinar, in order to introduce a broader range of stakeholders to the engagement process and to discuss and receive feedback on additional topics within the scope of the Supplemental DSIP. The sessions provided an overview of the topic and allowed for questions and discussion. These sessions were in addition to workshops convened by each utility to engage stakeholders on the contents of their specific Initial DSIPs.

All stakeholder meetings operated under ground rules based on the Chatham House Rule and commercial confidentiality. In order to foster open dialogue, comments made at the meetings were not to be attributed to any individual and approval was required before material was shared publically. Additionally, participants were directed not to disclose proprietary information during any stakeholder engagement meeting. Similarly, for strict compliance with applicable antitrust and competitive marketplace rules, participating stakeholders agreed not to use the group as a means for competing companies to reach any understanding, expressed or implied, that may restrict competition, or in any way to impair the ability of participating members to exercise independent business judgment regarding matters affecting competition or regulatory positions.

B. Proposed Plans for Continued Stakeholder Engagement

The Joint Utilities support an open and transparent process for the development of the DSP and future DSIP filings. To support these objectives, the Joint Utilities propose that the structure of stakeholder engagement framework described above continue following the filing of the Supplemental DSIP.

In the near term, it is anticipated that the Advisory Group will continue to meet to discuss the filing and lessons learned in the course of convening the engagement groups and the Advisory Group. Going forward, the Joint Utilities plan to convene the Advisory Group quarterly. The Advisory

Group membership will also be reviewed periodically and potentially rotated for balanced representation across stakeholder interests.

Plans for continued stakeholder engagement are described in each of the topic area sections of this filing. Figure II-1 outlines the frequency of expected stakeholder meetings across these areas over the next five years. This initial plan can be adapted and augmented as necessary to reflect stakeholder interests, utility needs, and emerging activities.

Figure II-1: Expected Future Stakeholder Engagement

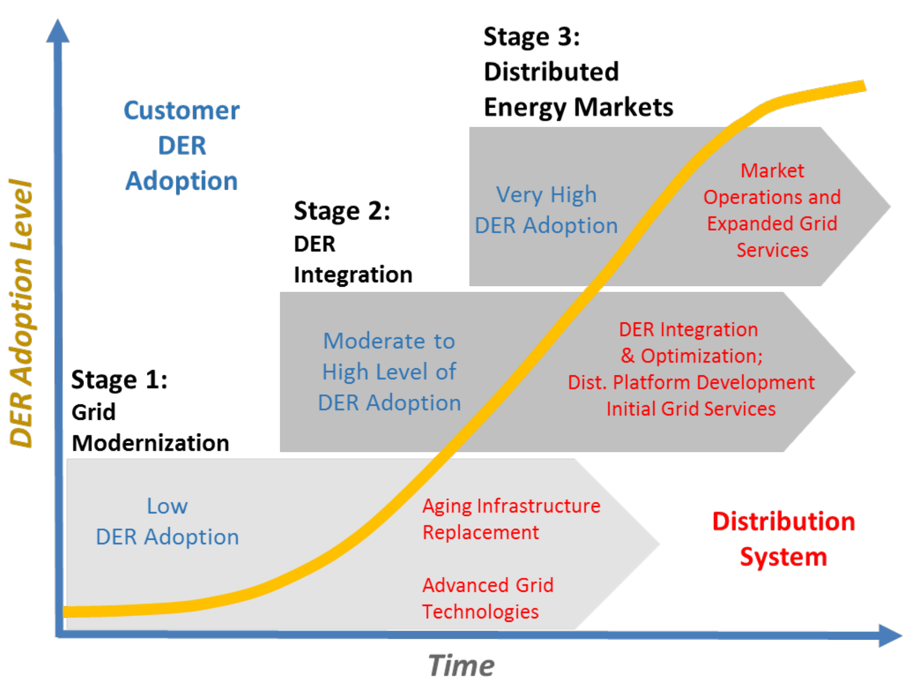
III. Evolution of the DSP and Distribution Markets

As recognized in the Track One Order, achievement of REV objectives will occur over a number of years, through an iterative and phased process that adds capabilities and methodological enhancements to utility planning, operations, and market enablement functions. The Joint Utilities embrace this key objective of REV: developing their new DSP role that integrates DER into the distribution system, realizes the value of DER, and encourages DER growth.

The role of the utilities' individual Initial DSIPs and this joint Supplemental DSIP is to describe the utilities' starting points and initial plans to develop the capabilities necessary to support DSP development and related market evolution. Taken together, these plans present a logical sequence of investments and development of analytical capabilities—many of them informed by demonstration projects that will prove concepts and inform future plans—that support DER integration and set the stage for market development.

The Commission has outlined a vision that includes a future transactive energy market, in which market transactions take place across a broad set of market actors, enabled by a set of control mechanisms will allow for the dynamic and automated balance of supply and demand. The Joint Utilities believe there will be a necessary evolution toward that vision that incorporates three stages. As shown in Figure III-1, the stages are not mutually-exclusive and there are no clear boundaries between them. Each stage has a degree of overlap with the subsequent stage, highlighting that many activities will occur in parallel. Over the next several years, the utilities will complete some Stage 1 capabilities and investments, while at the same time investing to achieve capabilities that are characteristic of Stage 2.

Figure III-1: Three Stages of DSP and Market Evolution



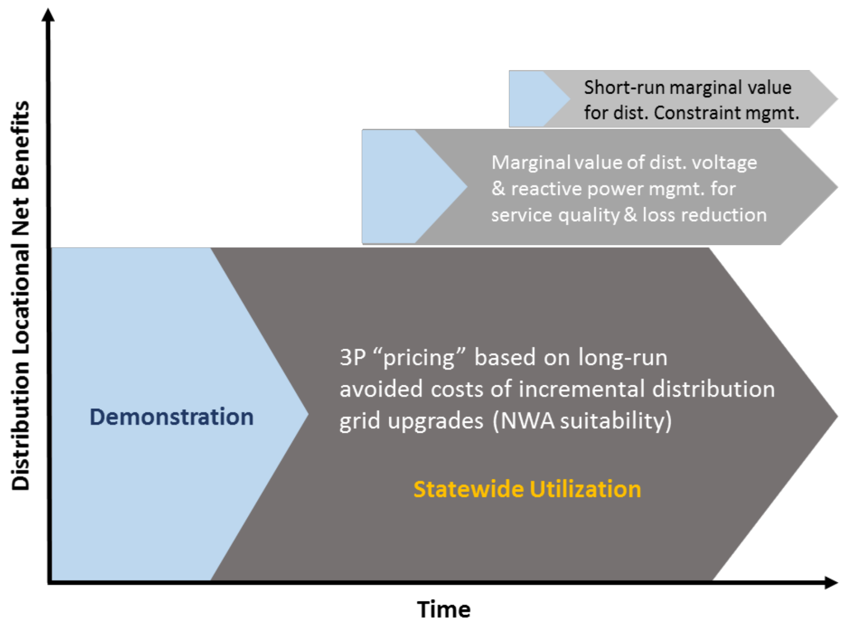
During the next five years, the individual utility DSIPs and this Supplemental DSIP will accelerate Stage 1 progress and move the utilities deeper into Stage 2, thus building the capabilities needed to move into Stage 3. Those capabilities include understanding how to integrate DER while maintaining a safe and reliable system, how to optimize DER integration, and how to develop a working distribution services platform. In the early years, demonstration projects will help the utilities better understand how to realize the value of DER through the Three P's, with an early emphasis on identifying and implementing NWA opportunities.[21] As the utilities increasingly transition through Stage 2, they will also evolve from developing NWA primarily as demonstration projects to integrating NWA—as well as DER pricing and programs—as a standard part of distribution planning and procurement.

The progression through the stages will enable growing realization of system and customer value from DER. Figure III-2 depicts these potential value sources conceptually.[22] Most of the distribution locational net benefits are derived through long-run avoided costs of incremental distribution grid upgrades. The progression of Stage 1 and 2 capabilities over the next five years will enable the utilities to realize this value component—a key goal of REV and the DSIPs. Realizing other sources of distribution value in later stages of DSP evolution, such as the marginal value of distribution voltage and reactive power or the short-run marginal value of distribution constraint management, would present increasing complexity and would require continued investment to implement increasingly sophisticated solutions. There remain uncertainties about when the capabilities to capture these values will be developed and the scale of net benefits that can be derived.

[21] DER value will also be captured in the wholesale market and in societal benefits *(e.g.,* greenhouse gas emissions reduction).

[22] Figure III-2 is not intended to depict an exact relative scale of distribution locational net benefits, nor to map the three stages of DSP and market evolution.

Figure III-2: Locational Net Benefits of DER



A. Distribution Market Evolution

The evolution of the distribution market will require investments in infrastructure, processes, systems, and people to integrate DER and to facilitate value optimization for all customers. Stage 1 is characterized by initial enabling investments, while Stage 2 is characterized by the addition of more sophisticated functions and capabilities and the emergence of an operational marketplace based on transactions between utilities and DER providers. Stage 3 has significantly higher penetrations of DER, which are providing services through multi-party transactions, including the potential for customer-to-customer exchanges.

In Stage 1, the utilities begin to accelerate investments that support reliability and operational efficiency and also lay the foundation for greater value realization from customer investments in DER in Stage 2.

As the utilities progress through Stage 1 and into the overlapping Stage 2, they will capture more of that incremental value of DER in their new role as DSPs. As described above, for the majority of this stage, this will be accomplished through the integration of new DER and the monetization of opportunities to defer traditional distribution infrastructure investments through the Three P's. NWA opportunities, as identified in the utilities' Initial DSIPs represent an early source of value realization in Stage 2. It is noteworthy that while the utilities can capture distribution system benefits from DER, the larger portion of value from DER integration is found in the environmental and bulk power system benefits.[23]

During Stage 2, the utilities will achieve an operational marketplace and develop and provide coordination services for DER participation in wholesale markets. These capabilities will be

[23] Tierney, *supra* note 12.

developed through close cooperation with NYISO as part of their DER Roadmap initiative.[24] Utilities as DSPs will learn how to perform these functions most efficiently through demonstration and pilot programs that allow for experimentation without significant risk to grid safety or reliability.

As distribution system capabilities advance and operational markets continue to evolve, the business economics for DER providers may significantly change as New York's net energy metering ("NEM") rules are replaced and federal tax credits related to DER investment decline and potentially expire. Under this scenario, owners of distributed energy supply resources will need to seek commercial opportunities to maximize revenue potential and manage risk. DER providers will need counterparties beyond the utility for these transactions.[25]

As DER providers begin seeking commercial energy transactions across the distribution system with various wholesale entities, and on the distribution grid with aggregators, load serving entities ("LSE"), and perhaps directly with other customers, there are likely to be small but meaningful early indications of the potential for a transactive distribution market.[26] As more DER are integrated into the distribution system and DSP capabilities are developed, the opportunity for retailers and DER providers, including aggregators, to enter into bilateral forward energy contracts with parties other than utilities for delivery over the distribution network will develop and grow. In turn, the utilities will need to develop the systems and processes to support coordination of such distribution-level transaction schedules in addition to coordination of DER-provided grid services.

Eventually, market participants may signal a need for development of additional commercial transactions in the form of shorter-term spot market products. Such products may be needed to manage distribution system residuals resulting from changes in scheduled energy by the independent transacting parties. Constraint management on the distribution network is likely to be increasingly needed. The timing and particular form of this next step in the evolution of the marketplace will depend on how methods of DER sourcing (*i.e.,* through prices, programs, and procurements) develop in the coming years, including the resolution of some current proceedings related to these issues.

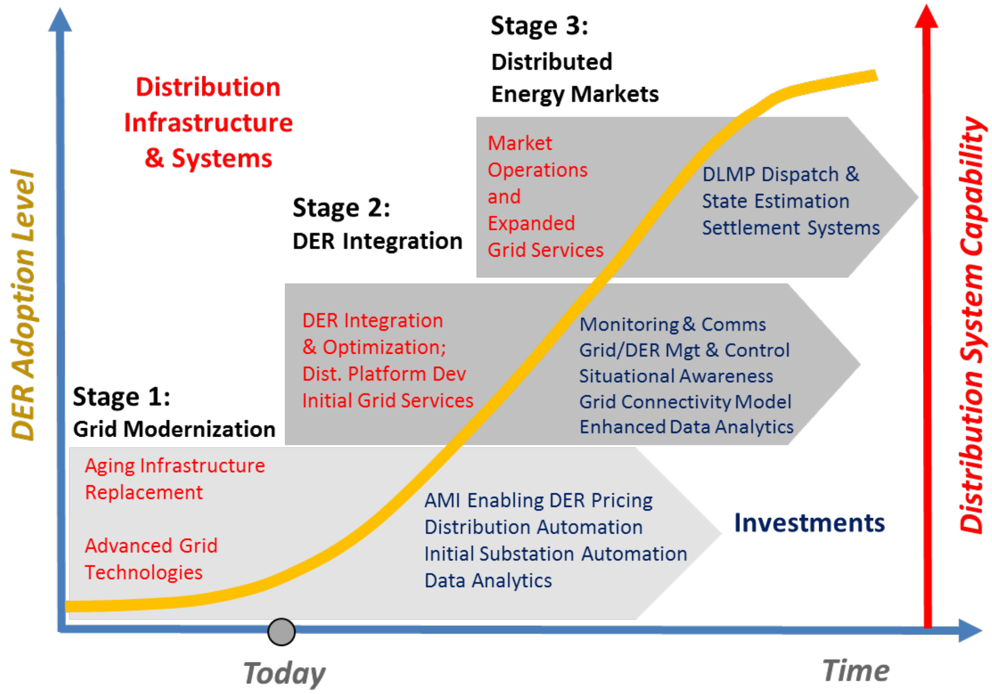
As the need for spot market products arises, the DSP will have to develop the infrastructure and processes needed to provide these services. Spot market transactions at scale would likely lead to a more dynamic management of constraints through DER dispatch.

B. Building the DSP Platform

The three stages of the evolution of the market shown in Figure III-1 require corresponding stages of DSP capability development. Figure III-3 illustrates the planned and logical sequence of investment needs.

[24] Note 9, *supra.*
[25] Viewed from this perspective, the transition away from NEM is necessary to accelerate the move toward a distribution-level transactional marketplace for grid services.
[26] Multi-user microgrids may demonstrate some of these transactional market properties on a small scale.

Figure III-3: Evolution of the Distribution Markets and System Capabilities[27]



The following table provides a more detailed summary of the functional capabilities associated with each stage of market evolution. This table indicates the general timing of when certain functionalities are needed, which highlights the evolutionary nature of utility investments and capability development.

[27] "DLMP" within Figure III-3 refers to the distribution locational marginal price.

Table III-1: DSP Functional Capabilities by Evolutionary Stage

DSP Provider Functions	Stage 1	Stage 2	Stage 3
1. Distribution Planning			
A. Broader and more systematic use of probabilistic distribution engineering analysis		✓	✓
B. DER Interconnection studies and procedures	✓	✓	✓
C. DER hosting capacity analysis	✓	✓	✓
D. Benefit-cost locational value analysis		✓	✓
E. Integrated Resource, Transmission & Distribution planning		✓	✓
2. Grid Operations			
A. Design-build and ownership of distribution grid	✓	✓	✓
B. Switching, outage restoration, and distribution maintenance (including DER for safety and reliability)	✓	✓	✓
C. Physical coordination of DER schedules with NYISO		✓	✓
D. Manage local distribution balancing		✓	✓
3. Market Operations			
A. Aggregation of utility demand response, measurement and verification ("M&V") and settlement	✓	✓	✓
B. Sourcing advanced distribution grid services from DER, M&V, and settlement		✓	✓
C. Optimally dispatch DER-provided distribution grid services		✓	✓
D. Aggregation of non-utility DER for wholesale market participation		✓	✓
E. Enable distribution-level energy markets & real-time constraint management			✓
F. Clearing and settlements for third-party distribution energy transactions			✓
G. Market facilitation services for market participants		✓	✓

In Stage 1, the utilities will make investments to enhance the grid by replacing aging infrastructure and incorporating advanced technologies that will increase reliability and resiliency. While these investments are required to achieve grid modernization objectives, many will be leveraged and complementary to building the distributed services platform in Stage 1 and Stage 2. The need for such utility investment in improving grid management capabilities will continue through and beyond Stage 1. Table III-2 provides an overview of some of the key investments that the Joint Utilities are planning to make and corresponding customer benefits expected over the five-year time horizon of this Supplemental DSIP. These investments were presented in the Initial DSIPs as the means to move each utility through Stage 1 and deeper into Stage 2.

Table III-2: Investment Plans

Investments	Stage 1: Grid Modernization	Stage 2: Operational Market	
	Reliability & Operational Efficiency	Enable DER Integration	DER Value Capture
Advanced Metering Infrastructure	✓	✓	✓
Distribution Automation	✓	✓	
Advanced Distribution Management System	✓	✓	✓
Distributed Energy Resource Management System		✓	✓
Data Analytics		✓	✓
Geographic Information System ("GIS")	✓	✓	
Communications Infrastructure	✓	✓	✓
System Data Platform		✓	✓
Volt/VAR Optimization/ Conservation Voltage Reduction	✓	✓	✓

Utility investment in replacing aging infrastructure and integrating advanced technologies has been underway and will continue through Stage 1 with investments in grid infrastructure and the more traditional utility systems such as Outage Management Systems ("OMS"), Energy Management Systems ("EMS"), Supervisory Control and Data Acquisition ("SCADA"), and others. In Stage 1 and into Stage 2, new systems to integrate and improve management of the grid and DER will need to be developed.

Future DSIP filings and related investment plans will describe the increasingly sophisticated systems and processes that will be required to support the more dynamic market envisioned in Stage 3, and which will be developed based on experience captured in Stage 1 and 2. These may include more advanced DER dispatch systems potentially incorporating distribution locational marginal pricing derived by sophisticated state estimation systems.

It is important to note that each utility is starting from a different place in terms of existing infrastructure, needs, and current investment cycles. While the five-year DSIPs will move the utilities through Stage 1 and deeper into Stage 2, each utility will follow a different pathway based on system and investment needs. However, these pathways will increasingly converge.

Convergence will occur as the utilities implement their investment plans and share lessons learned from their individual experiences adopting advanced technologies and the outcomes of demonstration projects and early DER procurements. The Joint Utilities commit to continued collaboration to achieve greater consistency and standardization across New York State.

IV. Distribution System Planning

The primary objective of distribution system planning is to design and build a distribution system that safely, reliably, and efficiently delivers electricity to customers. This central objective of planning will remain as DER are added to the system and markets evolve. However, planning processes and tools must be adapted and enhanced to incorporate a new set of drivers, additional sources of uncertainty and complexity, and a larger community of market actors and stakeholders, including those at the bulk power level.

In this filing, the Joint Utilities describe the key elements of the distribution planning process and identify enhancements to existing distribution planning practices. New and enhanced tools and processes will enable the Joint Utilities to establish a more standardized and transparent planning framework that accounts for the various impacts DER can have on the grid and the value they can provide. To achieve this framework, the Joint Utilities put forth:

- A load and DER forecasting stakeholder engagement process;
- A process for coordination with NYISO on short- and long-term forecasting;
- An NWA suitability framework and forthcoming implementation matrices;
- A detailed roadmap for hosting capacity; and
- An interconnection data platform and process roadmap.

Developing these planning frameworks and capabilities will provide a number of potential benefits, including:

- A deeper understanding of the various impacts of increased DER penetration on the grid;
- Greater transparency for DER developers and customers into the locations for cost-effective DER interconnection; and
- A distribution system that continues to be reliable and resilient.

The Supplemental DSIP focuses on the planning tools and processes that will form the basis of an enhanced distribution planning framework and allow for the development of DSP capabilities and DER markets, consistent with REV policy objectives.

A. Traditional Distribution System Planning

Traditional distribution system planning has been highly effective at enabling utilities to fulfill their core responsibilities to provide the safe and reliable delivery of electricity to customers while meeting established standards for safety, reliability, and power quality. Traditional distribution system planning focuses on elements such as forecasting load, identifying system needs, identifying potential solutions, and selecting and implementing the preferred solution.

Load forecasting is a central component of the distribution system planning process and informs many of the other analyses that planners undertake. Long-term load forecasting is a highly complex process that addresses multiple sources of uncertainty, such as weather conditions, economic conditions, and customer behavior. Load forecasts have traditionally relied on top-down, deterministic methods to provide projections for peak load levels across the system. Top-down forecasts are based on projections of load across a broad region, which are then allocated to individual areas to reflect the share of load attributable to that area. Some utilities have complemented top-down forecasts with bottom-up approaches to incorporate local influences in the forecast. While this has been an effective and efficient way to plan the system, the increased penetration of DER and its impact on local load shapes require new methods and approaches to understand how load will evolve on a locational basis and how DER may impact system needs.

Development of the load forecast enables distribution system planners to identify a range of system needs to maintain reliability through various system analyses, such as load flow analysis. Identification of system needs guides the development of a distribution investment plan that specifies utility investments to mitigate those needs.

B. Evolution of Distribution System Planning

Achieving the goals and objectives of REV will require enhancements to traditional distribution system planning processes to enable key DSP capabilities. The DSIP Guidance Order provides an overview of how these practices should evolve:

> Enhancements to traditional system planning to better integrate DERs into the distribution system will require the development of appropriate analytical methodologies and tools, collecting and sharing planning data, and the development of an integrated transmission and distribution planning process. A key element of enhanced distribution planning will be the ability of utilities to forecast available and potential DERs, including resource location and their operating characteristics. This will require scenario analysis that recognizes both high- and low-load DER penetration and load growth scenarios. It will also require the development of tools to improve forecasting capabilities. These tools, which should be addressed in the Supplemental DSIP filing, will include a uniform methodology for calculating hosting capacity and plan to increase hosting capability, an approach to move toward probabilistic planning capabilities as DER penetration increases, a plan for better voltage optimization and how it would affect hosting capability, improvements that will result in a more efficient interconnection process, and a uniform methodology for calculating the locational value of DERs. Additionally, the availability of granular system data will encourage the integration of DER in the most beneficial locations on the distribution system and facilitate utility forecasting and planning efforts.[28]

Growing DER penetration across the state raises important questions as to how those resources will impact the core components of distribution planning, including long-term forecasts and system needs determinations. To achieve DSP functionality and meet REV goals and objectives, planning must "consider the location, connectivity, and characteristics of major power system components, DER assets, and loads on the distribution system."[29] Fully integrating DER into the distribution system planning process will require enhanced data availability, better analytical tools, and

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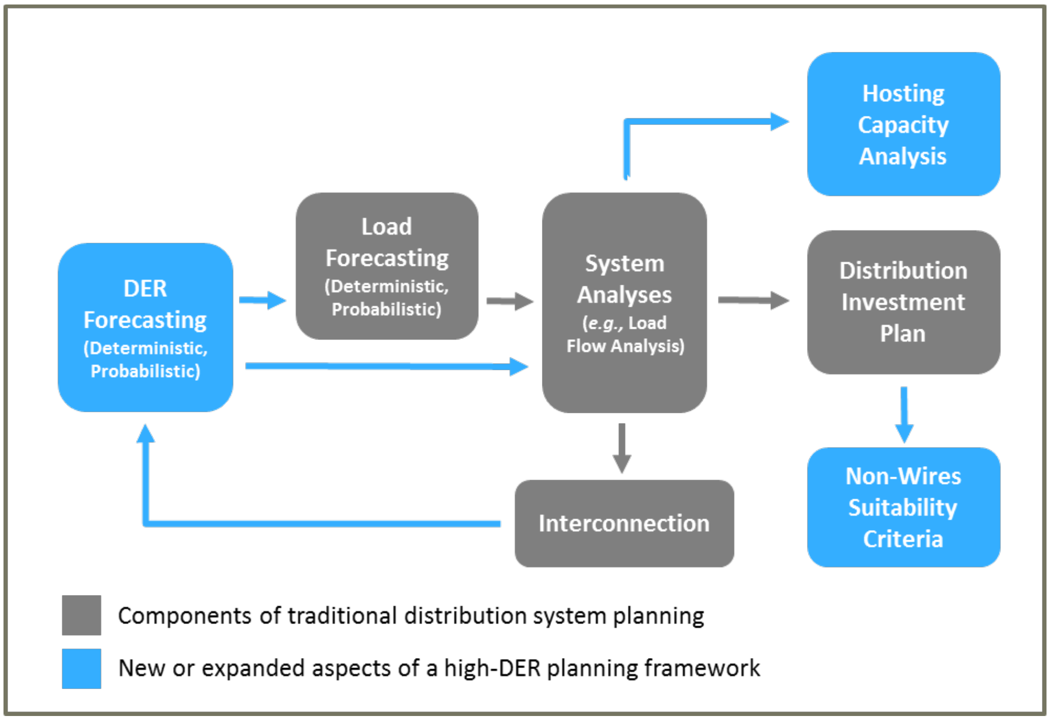
[28] REV Proceeding, DSIP Guidance Order, p. 13.
[29] REV Proceeding, MDPT Final Report, p. 50.

improved processes. These changes are necessary to help maintain system reliability, enable the interconnection of new resources, and to ultimately increase system efficiency.

One of the central challenges facing distribution planners as DER penetration increases is the introduction of new uncertainties and sources of stochasticity into the planning process, such as the variable output of distributed generation ("DG"), such as solar photovoltaic ("PV") arrays, as well as the impact of consumer behavior on DER adoption and load dynamics. Another challenge is that the highly distributed nature of DER will necessitate a transition toward a planning process that complements existing top-down approaches with more granular forecasts. Figure IV-1 illustrates some of the evolving elements of the distribution planning process, with the gray-shaded boxes reflecting the components of traditional distribution system planning and the blue-shaded boxes representing new or expanded aspects of a high-DER planning framework.

Figure IV-1: Evolving Distribution System Planning Processes



Note: This figure reflects a sub-cycle based on aspects of the distribution system planning process addressed in this Supplemental DSIP. This figure is not reflective of all distribution system planning processes or feedback loops that may develop as planning matures.

As shown in the above figure, utilities will enhance existing processes while simultaneously complementing them with new processes to enable DSP capabilities. For example, the increased level of uncertainties will lead to changes in forecasting techniques, which will then change the manner in which system analyses are constructed and undertaken.

The Joint Utilities developed a set of enhanced processes that further incorporate the impact of DER on the distribution system into planning. One process is the implementation of a common method for calculating hosting capacity, the ability of the grid to integrate additional levels of DER without significant infrastructure upgrades. This process will initially provide a hosting capacity analysis for solar PV for each distribution feeder and may expand to include other DER as their penetration increases and as analytical tools are enhanced. In a separate process and upon generation of an investment plan, the utilities can determine which opportunities are best suited for competitive solicitation of NWA. While the utilities have already made efforts to incorporate NWA into planning, each utility will develop a set of criteria to facilitate greater transparency into potential opportunities for NWA to be competitive with traditional utility projects.

The Joint Utilities will also continue to enhance and expand processes that facilitate DER integration. Interconnection application portals are being advanced to further streamline administrative functions while building in technical screening and analysis capabilities. Enhancements in asset and load data quality, availability, and granularity will also improve the interconnection process by increasing efficiency and accuracy of modeling minimum load impacts. Where infrastructure upgrades are required, the utilities are collaborating with developers to mitigate cost impacts. The improvement of interconnection processes more broadly will streamline integration of new distributed energy resources to the grid. Ongoing developments around queue management will likely impact the nature of how the interconnection process feeds into DER forecasting.

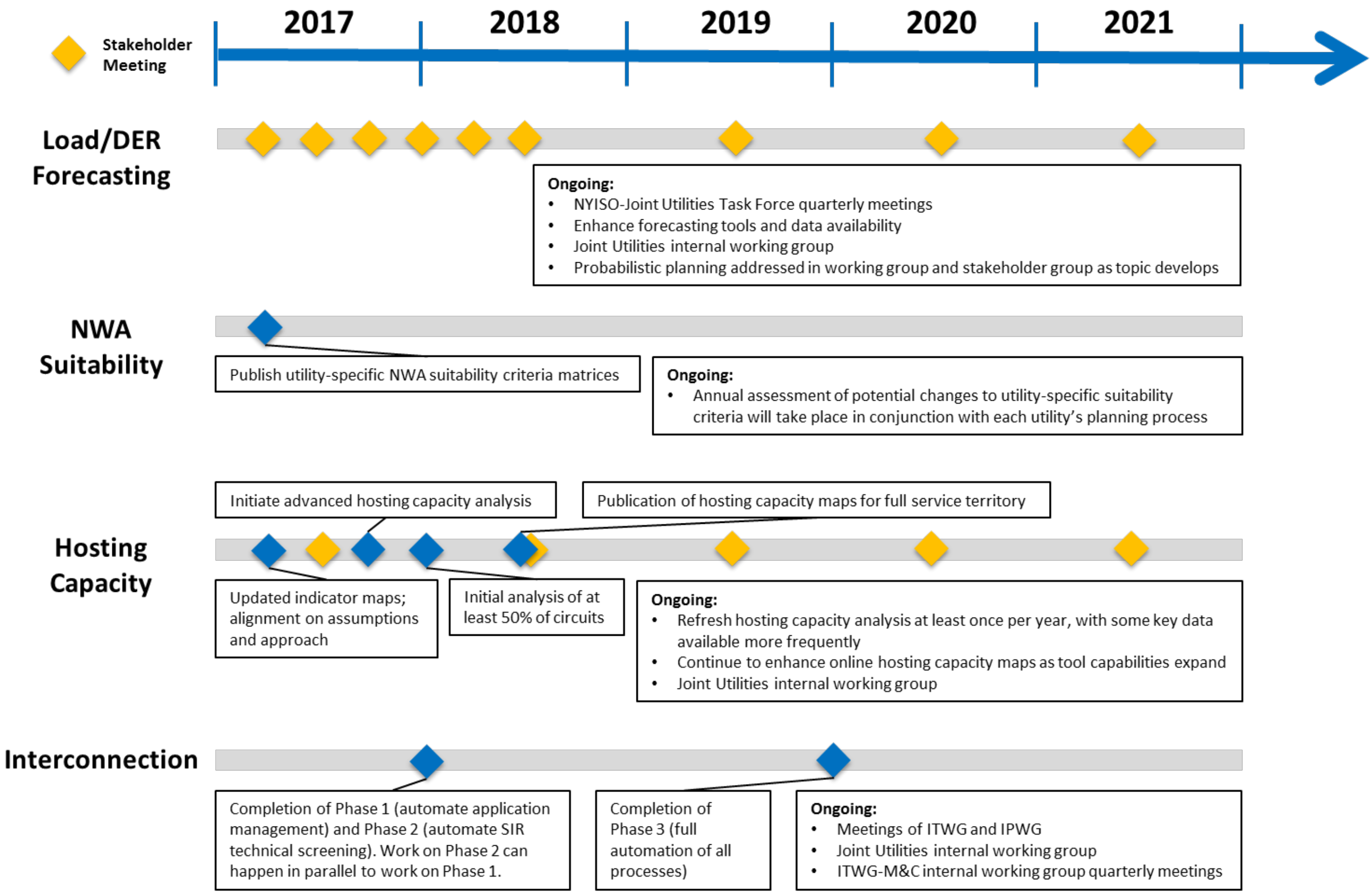
All utilities are moving toward common goals and are aligned in their approach toward meeting these challenges. Progression toward this future distribution system planning process will occur at varying rates both within and across the utilities based on current data availability, tool capabilities, and methodologies. Despite these differences in current capabilities, all of the utilities have begun efforts to improve data quality, availability, and collection processes as identified in their Initial DSIPs (further discussion appears in the *Distribution Grid Operations* and *Market Operations* chapters). These efforts will facilitate development of these newer processes and evolution of the distribution system planning process.

C. Summary of Next Steps

The continued development of these planning tools and methodologies further enhances distribution planning processes and helps enable the development of DSP capabilities and DER integration. The proposed development of these new tools and methodologies reflects key principles, such as the fundamental obligations for maintaining safety and reliability and the evolution of a process to develop and apply new planning tools on a timeline that aligns with DER adoption rates.

Moving forward, the Joint Utilities will coordinate both internally and externally to facilitate efforts to meet the commitments outlined in this Supplemental DSIP. As part of these efforts, the Joint Utilities will host stakeholder engagement sessions, coordinate with external entities like NYISO, and continue internal collaboration. While the roadmaps and commitments vary for each distribution system planning area, ongoing coordination will be a central theme in meeting the milestones proposed and further refining the Joint Utilities' future plans. The following figure summarizes the near- and medium-term high-level actions and coordination efforts proposed by the Joint Utilities over the 2017-2021 timeframe covered by this Supplemental DSIP.

Figure IV-2: Summary of Distribution System Planning Next Steps



Load and DER Forecasting

A. Introduction

The development of long-term load forecasts is one of the central functions of distribution system planning and forms the basis for the identification of system needs. Historically, many utilities have relied on top-down forecasting methodologies that project load across a broad area and allocate these projections to individual areas to reflect the share of load attributable to demand in that area. Planners incorporated DER, particularly energy efficiency ("EE") and demand response ("DR"), into their forecasts through the application of load modifiers that are subtracted from gross load.[30] These approaches have been an effective and efficient tool for planning purposes and will continue to be a valuable element in future planning processes.

For purposes of this filing, load refers to power consumption measured on the utility side of the meter, while demand indicates electricity consumption measured on the customer side of the meter. In addition, gross load and gross demand refer to aggregate electricity consumption while net load and net demand are defined as electricity consumption net of reductions from distributed generation and other demand-side resources.

Although top-down, deterministic approaches have been adequate for modest levels of customer-sited DER, increasing levels of DER interconnected to the grid will drive the need for forecasting of future net load levels at more granular levels. Increased adoption of DER will introduce new challenges for maintaining forecasting accuracy due to uncertainties associated with the variability of DER output, its evolving correlation with net load, and the impact of geographic diversity on aggregate DER output. These new DER will have locational-specific impacts determined in part by the ways in which penetration rates evolve in each part of the distribution system.

For example, the temporal characteristics of DER output will determine the extent to which they will reduce, increase, or shift net load at the local level. Furthermore, the impact of DER on the shape of circuit load curves implies that the peak load impact of DER could be dynamic and will evolve over time as DER penetrations change. As a result, where and when DER will be installed will be increasingly important for planning studies, especially because DER adoption can be concentrated in localized pockets. In addition, enhanced spatial and temporal granularity will enable forecasts to better reflect the impact of geographic diversity on the combined output of an aggregate set of distributed resources.

As a result of these factors, there is a greater need to complement top-down econometric forecasting approaches with more granular forecasts, which will enable planners to more accurately evaluate distribution system needs as DER penetration increases. These more detailed load forecasts consider economic indicators and analyze load shapes based on the characteristics of individual loads or local areas as opposed to top-down approaches, which start with system-level loads and allocate those down to the local areas. The development of these approaches for

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[30] Load modifiers are an estimate of the impact of DER on load. The use of static load modifiers implies that system planners will estimate the impact of DER on load as a fixed fraction of the amount of installed DER that is independent of location, physical resource characteristics, the load curve on the particular circuit, or the impact of DER penetration on DER peak coincidence.

forecasting both load and DER output will enable more accurate representation of the system at varying load levels to help planners understand when and where constraints may emerge.

Usage of these granular forecasts to inform the allocation of top-down forecasts will contribute to a more accurate projection of prospective loading characteristics on the system. Additionally, as DER penetration levels increase, and as the sources and magnitudes of uncertainties increase, there may be a value in incorporating probabilistic approaches into the planning process.

The utilities have begun efforts to complement top-down forecasts based on econometric regressions and other high-level inputs with the incorporation of more granular data. The spatial granularity and pace of development and implementation of these more granular forecasts will depend on each utility's distribution system design, system information and modeling capabilities, and the internal development roadmap for forecasting, including improved tools, methodologies, and data resources. As such, the current availability and level of development of granular forecasts varies across the utilities.

Despite these disparate starting points, each utility is developing new capabilities and tools and moving toward more granular forecasting approaches that can better reflect the impacts of DER on system needs. As part of these efforts, each utility is currently addressing key data gaps, implementing new tools, and/or undertaking efforts to develop additional capabilities internally. These efforts are all aimed at enhancing the granularity and accuracy of long-term load forecasts, but the tools, methodologies, and processes will be tailored to the specific business needs and system configuration of each utility.

B. Current State

Current penetration levels of DER have already resulted in material impacts on net load levels for some utilities and future DER growth will likely impact all utilities. Although utilities are starting from different places with respect to data availability and analytic capabilities, each is taking steps toward the implementation of more advanced forecasting methods with higher degrees of both temporal and spatial granularity. Table IV-1 provides a summary of how the utilities currently conduct load and DER forecasting and how DER forecasts impact net load, as provided in each utility's Initial DSIP. As noted in the table, National Grid has already begun an effort to project load and DER growth patterns for all customers, while O&R already leverages circuit-level forecasts in combination with its top-down system forecast. This diversity in approaches reflects the forecasting methods that work best within each utility's planning processes and existing system, and tools as each utility moves toward advances in the tools and methods for load and DER forecasting.

Table IV-1: Current State of Load and DER Forecasting

Utility	Topic	Current State
NYSEG/RG&E[31]	**Load Forecasts**	NYSEG and RG&E are in the process of deploying metering equipment to prepare more granular load forecasts and currently have corporate-level load forecasts.
	DER Growth Forecasts	Currently compiling, validating, and storing data on connected DER to create a valid GIS-based DER database with a prospective focus on econometric modeling techniques.
	DER Impact on Load Forecasts	Reflecting DER (*e.g.*, EE, DR, and the impact of rooftop solar PV and other customer-owned generation or storage) in load and energy forecasts by assuming that existing DER are captured in the econometric methodology and subtracting an estimate of the impact of future demand-side programs
Central Hudson[32]	**Load Forecasts**	Central Hudson develops a top-down econometric system level forecast and also develops bottom-up granular 8760 load forecasts at the substation level. Hourly (8760) load data is available electronically for 78 percent of substations, and is anticipated to be available for over 90 percent of substations within the next five years. In addition to the bottom-up forecast, Central Hudson uses forecast probability bands
	DER Growth Forecasts	Currently focus on forecasts of EE, solar PV, and EV. For EE, Central Hudson has a database of historical retrofits of certain programs in its EE portfolio. For solar PV, currently installed solar capacity at each substation is available using a database of historical solar PV interconnections. For EV, Central Hudson projects adoptions by leveraging historical EV registrations in the company's territory and select market data. Forecasts are currently completed at the system level.
	DER Impact on Load Forecasts	Beyond what is currently available for EE, solar PV, and EV, Central Hudson plans to set processes to track installation and adoption of other types of DER and their specific locations, and separately set up a process to track when and where DER resources were dispatched (*e.g.*, battery storage or DR) and the magnitude of the resources dispatched.
Con Edison[33]	**Load Forecasts**	Weather-normalized ("WN") detailed forecasts are available at the system and substation level. Yearly circuit-level forecasts are calculated in the planning cycle. SCADA monitoring is available at the substation, circuit, and distribution transformer level, producing five-minute data.
	DER Growth Forecasts	DER are forecasted using primarily bottom-up methodologies by counting projects or program totals for both system and network forecasts. On the system, DG, including all solar, combined heat and power ("CHP"), and energy storage are forecasted using cumulative historical penetration, known queued projects, and extrapolated future DER growth rates for outer years.

[31] DSIP Proceeding, New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation Distributed System Implementation Plan (filed June 30, 2016), pp. 49-51.
[32] DSIP Proceeding, Central Hudson Distributed System Implementation Plan (filed June 30, 2016), p. 68, Appendix p. 780.
[33] DSIP Proceeding, Con Edison Distributed System Implementation Plan (filed June 30, 2016), pp. 46, 68.

	DER Impact on Load Forecasts	The demand side management ("DSM") forecast accounts for the magnitude, delivery date, operation, availability, and geographic distribution of the projected future load reductions. Forecasts of all types of new DG are also allocated by network and over time by project in-service dates; existing DG is accounted for as a contribution to reducing net load. The projected impact of DER is included as an explicit component of Con Edison's long-range load forecast.
National Grid[34]	**Load Forecasts**	Utilizes a top-down econometric forecast at the company, zonal, and county levels that incorporates three levels of weather scenarios (50/50, 90/10, and 95/5).[35] Currently building archetype models to project load patterns onto all customers.
	DER Growth Forecasts	National Grid is developing a multifaceted forecasting approach that is comprised of top-down (econometric and growth models) and bottom-up (customer-specific demand and DER growth models) forecasting methodologies that are modeled independently and then integrated utilizing a hierarchical or integrated methodology to form a unified and consistent view. While the approach has been determined, it has not been fully implemented. Implementation will be consistent with the timeline provided in National Grid's Initial DSIP filing.
	DER Impact on Load Forecasts	Post-model adjustments are made for current and projected DER at the "top-down" level. National Grid is in the process of developing a complementary "bottom up" view that provides for probabilistic forecasting of customer activities, behaviors, and decisions and their impacts on the distribution system. The top-down and bottom-up view will be integrated through the use of a hierarchical model that will enable alignment of the top-down and bottom-up forecasting approaches.
O&R[36]	**Load Forecasts**	Currently using detailed, WN five-year forecasts for substations and WN two-year forecasts for circuits annually. SCADA monitoring is available at the substation and circuit level, producing five-minute to hourly data. System load (top-down) forecast includes solar PV and DSM forecast, but circuit (bottom-up) forecast does not at this time.
	DER Growth Forecasts	DER have historically been included in the process as the various corresponding technologies have reached a substantial impact on the forecast. DG/CHP, solar PV, battery storage, EV, and DR were included for the first time for the 2015 system peak load.
	DER Impact on Load Forecasts	In the near term, O&R expects to maintain and refine the existing processes for projecting load growth and modifying the net load to account for DER factors. The latest system peak load forecast credits DER as reducing net load for those DER which have been installed in the time period between summer peak and completion of forecast.

[34] DSIP Proceeding, National Grid Distributed System Implementation Plan (filed June 30, 2016), pp. 53-56.
[35] Weather scenarios can be implemented to determine the probability of a peak load forecast being under- or overachieved by the actual peak load. For example, a 90/10 forecast has a 10 percent probability of being lower than the actual peak load.
[36] DSIP Proceeding, Orange and Rockland Distributed System Implementation Plan (filed June 30, 2016), pp. 41-42.

C. Summary of Next Steps

The Joint Utilities acknowledge the importance of maintaining accurate forecasts as distribution planning processes evolve. The DSIP Guidance Order directed the utilities in future DSIPs to "assess the accuracy of prior substation and system-wide forecasts as an element of determining if there are inherent biases that may need to be addressed in their forecasting techniques."[37] The utilities will continue to improve the quality and refine the accuracy of their load and DER forecasts and make them reflective of historic and prospective trends, including a set of evolving market, technology, and policy trends. The accurate reflection of DER adoption trends in the load forecast is a critical component of the planning process as both under- and overestimating DER growth may significantly impact other aspects of planning. Underestimating DER growth could impede efficient allocation of resources to address DER integration needs, whereas overestimation of DER growth could result in lower projected load growth that could meaningfully reduce opportunities for NWA procurement and reduce the value attributed to the system-wide dynamic load management ("DLM") program.[38]

As utilities increasingly apply the more granular approaches in load and DER forecasting, location-specific forecasts may be crosschecked against the system-wide forecasts so that all methodologies are consistent and to further enhance the accuracy of these more granular forecasts. For example, Con Edison already compares its top-down system-wide peak load analysis to its bottom-up network peak load analyses as a mechanism to verify the allocations of load in its annual peak load forecast.

Advances in forecast granularity could also include increased temporal specificity to look at seasonal, daily, or hourly forecasts. The utilities may enhance their planning processes by developing 8760 forecasts that provide forecasted load for every hour in the year. One of the key challenges associated with applying this type of temporal granularity to long-term planning forecasts is the quality associated with inputs such as weather data. The value that such forecasts can provide will ultimately depend on the quality and accuracy of these inputs.

Efforts to enhance existing forecasting capabilities and tools could also extend beyond more granular forecasts and include the development of new approaches such as scenario analysis and probabilistic planning. Scenario analysis would take system forecasts beyond a single, deterministic view of load and DER growth and instead provide a range of scenarios that consider variations in market conditions, policy initiatives, econometric drivers, or other variables. Another possible avenue for enhancing long-term forecasts is to incorporate probabilistic methods into the planning process. While scenario analysis can provide a way to look at the implication of a discrete set of outcomes, probabilistic planning methodologies provide systematic approaches for comprehensively addressing the uncertainties introduced by high rates of DER penetration, weather variability, and other factors.

There are some efforts currently underway to incorporate probabilistic methods into various aspects of planning. For example, as a way to build a bottom-up adoption forecast, National Grid

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[37] REV Proceeding, DSIP Guidance Order, Attachment 1, p. 15.
[38] Case 14-E-0423 - *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs,* Order Adopting Dynamic Load Management Filings with Modifications (issued June 18, 2015).

is evaluating the likelihood that customers will deploy solar PV. Inputs for this probabilistic DER forecast model include the building's suitability for solar PV installation, the design of the optimal system for the customer, financial factors, the rate of adoption by other customers in the general vicinity, and local and broader market considerations, such as zoning ordinances and incentives. Separately, some of the utilities also use a probabilistic approach to conduct load forecasting by developing econometric forecasts that are weather-adjusted for varying degrees of weather impacts on load.

In addition, the incorporation of new data inputs has the potential to further inform the development of forecasts by supplementing the data resources utilities currently employ to guide their analyses. Currently, utility DER forecasts incorporate utility program goals, active and planned DER, as well as a host of econometric studies and other inputs. The utilities also consider external sources of market data to inform industry trends and policy impacts (*e.g.,* NY-Sun Incentive Program[39]) reflected in planning forecasts. New data inputs such as DER forecasts from developers may be considered as an additional input for the development of utility DER forecasts if such sources are made available to utilities. To fully transition to locationally-specific DER forecasts, spatially-based software tools will need to mature in parallel with incorporation of the new inputs to allow for consideration of land- and roof-based potential.

Validation and benchmarking of developer forecasts will facilitate their incorporation into utility DER forecasts similar to the way all other data inputs are validated and benchmarked for inclusion into the forecast. This will further inform each utility's views on market trends related to the rate and locations of DER adoption.

The roadmap for the development of each utility's forecasting capabilities and the incorporation of these new tools and methods will be critically informed by the experience gained through the current efforts summarized above as well as outreach to NYISO and other stakeholders.

1. Continued Coordination with NYISO

A crucial factor in maintaining accurate load and DER forecasts is ongoing communication and coordination between the utilities and NYISO. The Joint Utilities believe that the exchange of data and other information is critical to sustaining effective long-term forecasting processes and to enabling DSP capabilities. Existing avenues of coordination must be maintained and new avenues identified for utilities and NYISO to work together on key topics. Such coordination with NYISO is vital for achieving integrated transmission and distribution planning and can help to:

- Base various resource planning studies and related activities on consistent and up-to-date inputs;
- Maximize utilities/NYISO coordination in the development of key assumptions and study approaches;
- Meet New York's energy and environmental policy goals (*e.g.,* Clean Energy Standards ("CES")) and facilitate other ongoing REV efforts; and

[39] New York State Energy Research and Development Authority ("NYSERDA"), *Program Opportunity Notice ("PON") 2112 – NY-Sun Financial Incentives*. https://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities/PON-2112-Solar-PV-Program-Financial-Incentives.aspx.

- Evaluate the possibility of pursuing scenario analysis by identifying possible approaches for the development of DER and load growth scenarios and exploring the potential value of such an approach.

As is described in the *NYISO/DSP Roles, Responsibilities, Interaction and Coordination* section, NYISO and the Joint Utilities have established a task force that will meet at least quarterly to identify changes that need to be made to existing coordination processes and establish a process for information sharing and protocols. These enhanced coordination efforts between NYISO and utilities will help maintain the consistency of load forecasting results so that the impact of DER on net load will be better reflected in NYISO's zonal forecasts and its related planning processes. Additionally, there will be efforts for broader coordination between the utilities and NYISO that encompass elements of operations and other utility activities outside of distribution system planning (discussed further in the *Distribution Grid Operations* and *Market Operations* chapters).

2. Stakeholder Engagement

The Joint Utilities recognize the importance of ongoing engagement with stakeholders to facilitate further enhancements to forecasts. As part of this effort, the Joint Utilities commit to host six engagement group meetings by the middle of 2018 and then annually from 2019 to 2021 to focus on the utilities' roadmaps for the continued development of long-term load and DER forecasts. Stakeholder input will facilitate efforts by the utilities to align on common objectives and outcomes for forecasting. Additionally, the Joint Utilities will solicit input from stakeholders on potential use cases for 8760 forecast data.

Load Flow Analysis

A. Introduction

A central component of distribution system planning is load flow analysis, or a steady-state power-flow study of the distribution system. This analysis is critical for understanding how system characteristics, such as voltage, current, and real and reactive power, will vary under different scenarios over a study's horizon.

This analysis drives the identification of system needs based on constraints and planning criteria. For example, consideration of potential emergency operating conditions could help planners determine if additional enhancements to the system are needed for safety and reliability. Planners evaluate the identified system needs by applying criteria, such as meeting reliability needs, anticipating operational challenges, maintaining safety, and addressing uncertainty in load forecasts. After evaluating system needs on the basis of these criteria, distribution planners develop a distribution investment plan that specifies the set of solutions that are best suited to effectively manage risk and address anticipated needs in the most cost-effective manner.

B. Overview of Load Flow Analysis

The increasing penetration of DER and its impact on load curves will challenge the ability of traditional system analyses to accurately assess system needs. In order to comprehensively account for the impacts of DER on circuit load flows, the methods and inputs to utility load flow cases will need to evolve. This implies a more detailed and rigorous process for forecasting load and DER at a more detailed level and also implies enhancements to the load flow modeling approaches.

Load flow analysis using utility models is already utilized through analysis of peak load cases, and in some cases the development of minimum load cases and other scenarios. As the penetration of DER continues to increase, there will be an emphasis on implementing methodologies for carrying out load flow analyses beyond the peak load scenario that facilitate modeling of DER in the system with sufficient specificity to address integration challenges. In addition, as system voltage profiles become increasingly dynamic and complex, the accuracy of meter and system asset data inputs such as conductor size, phasing, and equipment ratings will become more critical. Ultimately, in order for load flow analysis to be an effective tool for processes like interconnection screening and hosting capacity analysis, load flow models need to be updated in a timely and efficient manner, with increasing granularity of scenarios and data supporting it.

As a result of increasing levels of DER, the identification of system needs as part of load flow analysis will have to account for changes in net load profiles and resource variability as the mix of DER on the system changes. Future enhancements to the planning and forecasting processes and tools will allow for the inclusion of a richer set of load flow cases to assist planning. For example, analyzing the impact of light-load conditions could become important on circuits with high penetrations of solar PV. The impact of DER on net load will be driven by considerations of where DER is interconnected, at what level, and the variability in resource characteristics on both an individual and aggregate basis. As DER penetration creates situations where circuit level issues could drive future system needs, the need for granular, bottom-up data to feed into these load flow cases will become increasingly critical. Enhancements made to both load and DER forecasts, including leveraging bottom-up forecasts to inform allocation of top-down forecasts, will facilitate a greater ability to incorporate the impacts of DER in the identification of system needs.

Just as forecasting processes rely on improved system monitoring data and information and enhanced analytical tools, the success of load flow analysis depends on three critical factors: input data, tool capabilities, and the ability to leverage the tool. Table IV-2 outlines the key requirements of each component.

Table IV-2: Necessary Components of Load Flow Analysis

Component	Requirements

Input Data	• Addressing data gaps (*e.g.,* drag arm reading frequency, insufficient monitoring points)
	    ▪ Near-term: Addressed through using advanced analytics to develop archetype load profiles and project them onto the customer base
	    ▪ Longer-term: Move from estimated load profiles to development of more granular load profiles by leveraging Distribution SCADA (“DSCADA”), knowledge at the customer premise, etc.
	• Incorporating field monitoring data into planning
	    ▪ Preplanning tools (*e.g.,* advanced analytical tool sets) needed to use data for preplanning of load curves and preparation of forecasts
	    ▪ Data must match planning needs driven by DER penetration (*e.g.,* peak hour, peak day, or peak and minimum load days)
	• Identify specific data accuracy requirements (evolving accuracy needs)
	• Ability to clearly identify all existing DER installations and understand the likelihood of where and when future installations could be made

Tool Capabilities	• Device library completeness and accuracy (*e.g.,* smart inverter control and response) • Ability to coordinate with real-time monitoring and control systems • Ability to do “what-if” scenario analysis and optimization • Ability to carry out hosting capacity on a large number of circuits in an automated fashion • Comprehensive unified simulation environment that provides a spatial and temporal view of load at any point in time and with any system configuration
Ability to Leverage Tool	• Utility personnel sufficiently trained to use the tool • A business process to leverage tools • Scalability of analysis methodology • The tool is able to provide actionable information • Planning needs are well aligned with the data and tool capabilities • Alignment with the goals and requirements of the probabilistic planning process • Ability to inform data/tool needs • Existence of an advanced computing and presentation environment to support these tools • Data is available and linked properly • An interactive environment for system planners to leverage advanced planning

Meeting the requirements for these components, such as having trained staff, enhanced business processes, and other enabling technologies and capabilities, will ultimately drive the future evolution of load flow analysis and enhance the ability of planners to identify prospective system needs in a high DER future. Importantly, this analysis will need to account for variations within each utility with respect to input data. For example, within a single utility service territory there may be significant differences in the data availability for a 4 kV rural feeder versus an urban area with SCADA. Although the tool capabilities and ability to leverage the tools are constant within a utility, variability of input data may create differences in the robustness of the load flow analysis for certain areas within a service territory.

C. Summary of Next Steps

As the distribution system planning process evolves, load flow analysis will be a critical input for processes such as the identification of beneficial locations and determination of NWA suitability to defer or replace a traditional utility investment to meet system needs. Additionally, load flow analysis and tool development will be a critical enabler of hosting capacity because this analysis requires the development of a low-load case to investigate voltage impacts of solar PV (discussed further in the *Hosting Capacity* section). Plans to develop input data, tools, and capabilities were included in utility Initial DSIPs and will be further developed during Stage 2 of hosting capacity analysis.

Load flow analysis, along with other system analyses, drives the identification of system needs through consideration of constraints and planning criteria. Enhancements to load flow analysis and the availability of more granular data will allow planners to continue identifying system needs with a high level of confidence, thereby continuing to meet reliability and safety requirements. The incorporation of detailed load and DER forecasts into load flow analysis will enable planners to identify system needs with increasing levels of specificity.

Once system needs are determined, locations may be identified as beneficial when 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. Beneficial locations might also be identified where there are prospective system needs but where no specific utility solutions have yet been identified. With the continued evolution of load and DER forecasting methods and the application of probabilistic modeling methodologies, beneficial locations will be better assessed through identification of the types of constraints and violations likely to arise on the system.

NWA Suitability Criteria

A. Introduction

Upon completion of load flow analysis, distribution planners consider alternatives, identify solutions, and recommend projects for capital budget approval to meet identified needs. Historically, these implemented capital projects have been primarily infrastructure-based, including smaller-scale reconfiguration projects and larger-scale projects such as substation upgrades or new feeders. NWA represent opportunities to defer or avoid a subset of traditional “wires” investments, potentially resulting in cost savings for customers and/or environmental benefits while maintaining reliability and resiliency. An NWA is defined as any action or strategy that addresses the defined system need while deferring, reducing, or eliminating the need to construct or upgrade distribution infrastructure.[40]

The nature and characteristics of the distribution system needs identified in the planning process are primary considerations regarding whether a given project is suitable for an NWA. There are numerous factors that utilities consider when determining whether a proposed solution, or portfolio of solutions, has the characteristics that would effectively resolve the system need, including the lead time with respect to the system need date, the economics of the project, any additional positive reliability impacts of the traditional project beyond the identified planning need, and whether the identified project matches up with a specific NWA opportunity to address the same system need.

The Joint Utilities have proposed a common framework to identify those projects that are most suitable for NWA 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. The framework primarily focuses on three factors: project type, timeline, and cost. These criteria reflect the goals of: (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.

To be clear, the objective is to direct developers to the highest potential opportunities and streamline the procurement process for all parties, and not to unduly restrict or exclude projects from consideration. This objective underscores the importance of identifying the best subset of suitable traditional projects.

It is also critical to note that the suitability criteria described in this section are not inclusive of the full set of factors that utilities may use to evaluate NWA bids in the context of a competitive procurement. These criteria are meant to provide a transparent means of prioritizing utility projects according to their suitability for a competitive NWA solicitation and, therefore, do not replace performance attributes or pre-qualification elements which may be used in the NWA procurement processes described in the *DER Sourcing* section of the *Market Operations* chapter to meet specific system needs.

[40] In addition to electric distribution system infrastructure, other infrastructure under Commission jurisdiction may be subject to NWA suitability review.

In developing the suitability criteria, the Joint Utilities consulted with stakeholders, including several DER providers. The Joint Utilities worked with stakeholders to develop a set of criteria that are more inclusive of project types and sizes than the ones outlined in the Joint Utilities' Benefit-Cost Analysis ("BCA") white paper comments filed in August 2015.[41] Additional detail on the stakeholder discussions is provided below and in Appendix A.

In their Initial DSIPs, the utilities identified their interim approaches to suitability criteria, which are refined and expanded here as a common platform on which the utilities can base their individual implementations of NWA suitability criteria.

B. Overview of NWA Suitability Stakeholder Process

The Joint Utilities solicited feedback from stakeholders to more fully understand opportunities to provide additional value to stakeholders with respect to the identification of projects suitable for NWA procurement. The Joint Utilities sponsored stakeholder engagement sessions on the application of NWA suitability criteria to utility distribution investment plans, including three face-to-face meetings and two webinars. There was agreement between the stakeholders and utilities around the potential value for well-designed criteria to identify the best projects for NWA procurement. Specifically, stakeholders and utilities agreed that NWA suitability can be guided by criteria related to the type of work, the timeline of the need, and the size of the solution.

Building on the agreement that well-defined criteria will provide value to both stakeholders and utilities, stakeholders requested more specification on the principles and contents of the NWA suitability criteria. In addition, they wanted to better understand how these criteria will be incorporated into utilities' planning processes, a component of which aims to identify the greatest opportunities for soliciting feasible NWA solutions as alternatives to traditional investment. In response, the Joint Utilities agreed to provide utility-specific criteria matrices to provide more transparency as to how each utility will define and incorporate the criteria.

There was extensive discussion with stakeholders on the need to be inclusive with respect to the types of projects considered for NWA procurement. The detailed criteria that each utility will publish will provide greater insight into how project type will guide suitability, but there was agreement among the stakeholders and utilities that load relief projects and a subset of reliability projects are likely to provide the best early opportunities for NWA to compete. In addition, stakeholders expressed the view that the DER procurement processes for bid evaluation should look at a broad range of characteristics of DER. The framework for evaluating NWA bids and the need to develop commercial and operational performance standards are described in the *DER Sourcing* section of this filing.

Stakeholders further suggested this framework should continue to evolve and that achievement of public policy targets for environmental compliance and economic development could be included as well. The Joint Utilities commented that such factors will be included for review in the CES

[41] REV Proceeding, Initial Comments of the Joint Utilities to Staff White Paper on Benefit-Cost Analysis (filed August 21, 2015).

review process and other related proceedings. To the extent utility programs are created to achieve environmental compliance and economic development, each utility will propose new programs via the appropriate regulatory proceedings. Because the non-wires suitability framework described in this section focuses on the evaluation of current projects, these types of policy-based projects are not currently included. However, as new policy initiatives are implemented, and to the extent that there is a case for doing so, the utilities will evaluate the potential to incorporate new aspects into their planning processes. New planning procedures could produce new types of projects for utilities to evaluate with respect to their suitability for non-wires solicitation. This further underscores the need to make these criteria adaptive and evolve as lessons are learned.

C. Proposed NWA Suitability Criteria

NWA suitability criteria will lay a solid foundation for the success of an NWA solicitation by enabling utilities to identify those projects with the greatest opportunity for success, including providing sufficient time to solicit and implement an NWA, and selecting projects on the basis of their potential cost-effectiveness relative to traditional infrastructure projects. These criteria provide a line of sight toward a broader, more flexible, and efficient approach to procuring NWA.

The criteria will allow developers and utilities to more efficiently use time and resources. NWA solicitation will become a more routine aspect of each utility's planning process and its effectiveness will increase over time as utilities enhance data quality and availability, develop benchmarking systems, and more fully understand the performance metrics of DER.

Based on an assessment of the three criteria (project type, timeline, and cost), load relief (or capacity) projects and some types of reliability projects are expected to be the best candidates for NWA in the near term. This is because: (1) the category references investment needs due to load increases and system expansion requirements; (2) the project needs for these types of projects are typically identified far enough in advance to provide sufficient lead time for a solicitation; and (3) the scale of investment of the project can influence the likelihood of an NWA being cost-effective.

1. Project Type Suitability

Looking at categories of traditional projects that might share similar attributes can help identify projects most suitable for NWA solicitation. Projects are assigned to categories based on the type of work needed, such as new business, system expansion, risk reduction, and asset replacement. Within each project category, it is likely that these projects have similar suitability characteristics because the projects leverage similar technologies and address related needs. For example, projects focused on load relief may typically utilize solutions including reconductoring/circuit rebuilding, transformer upgrades, station expansions, new regulators, and capacitor installations. Despite some differences, the fact that these projects address quantifiable system needs that can in some cases be met through other non-traditional resource types lends this project category to consideration of a competitive solicitation where bids can be evaluated on the basis of their net benefit and ability to meet the identified system need. By contrast, other project categories like public requirements projects or non-T&D infrastructure projects cannot be replaced with an alternative resource on an equivalent basis and, therefore, these categories do not lend themselves to an NWA solution. Because not all categories of work are well-suited for NWA, clarifying the type of work with the greatest potential for NWA minimizes the time and resources dedicated by both developers and utilities to NWA solicitations for traditional utility projects that are unlikely to be deferred or replaced by NWA solutions.

Table IV-3 below summarizes the primary utility capital investment project categories and characterizes the potential applicability of each for NWA solutions, with load relief and reliability being the project categories most applicable for NWA. It is important to note, however, that these categories are not reflective of the criteria upon which potential solutions in a competitive bidding situation will be evaluated or the range of values to be ascribed to potential NWA, but rather they simply explain the framework by which classes of utility projects are characterized and the relative suitability of each category for competitive procurement. The procurement mechanisms and the evaluation of solutions are discussed separately in the *DER Sourcing* section.

Table IV-3: Project Types and NWA Applicability

Budget Category	Type of Work	Applicability for NWA
Load Relief	System enhancements to address capacity concerns (thermal load, voltage constraints, power quality) at the branch, feeder, substation, and transmission levels. Projects may include feeder reconductoring/circuit rebuilding, transformer upgrades, new substations and station expansions, new regulators, and capacitor installations.	DER impacts on network or circuit load curves can be verifiable, quantified, and benchmarked. Utilities are making progress through current and planned projects to create frameworks for the evaluation of NWAs with respect to their ability to meet this type of system need. This is likely the category of greatest applicability for NWA.
Power Quality	Address voltage flicker, harmonics, motor starting/inrush – can be conductor replacement, new construction, or upgraded transformation.	To be applicable for NWA, power quality projects would require new standards, visibility/control, and validation. These would establish the frameworks for smart inverters to be able to defer utility investments for power quality needs. Policy implications of technologies needed to resolve conditions often created by new DG would need to be considered as well.
Conservation Voltage Reduction ("CVR")	CVR lowers the voltage level of the electrical distribution system to reduce peak loads and energy consumption.	Potential applicability depends on the ability of smart inverters to provide voltage control. Some circuits have lower upper-voltage bounds already as prescribed by regulation. In general, this can become applicable if DER products can effectively control voltage, have adequate monitoring and control tools, and can integrate with future utility distribution management platforms.
Reliability	System enhancements that could prevent the interruption of service and/or respond to an interruption in service in order to achieve targeted system average interruption frequency index ("SAIFI") and customer average interruption duration index ("CAIDI") objectives.	The ability of projects to reduce the likelihood of outages could create the opportunity for NWA to provide reliability benefits, making this an applicable project type. These projects are designed to "prevent the event."

Resiliency	System enhancements to respond to an interruption in service in order to achieve targeted CAIDI. Examples include adding circuits and or switching points or station expansion projects to “firm” a substation.	Measures to reduce outage times, such as storm hardening and similar efforts, are difficult to displace through NWA. These impacts are more challenging to quantify, making it less applicable for NWA.
Damage Failure	Reactionary repair or replacement of damaged or deteriorated equipment that has failed or is not fit for duty and must be addressed with limited time for planning.	This work is extremely short-cycled and may not generally be conducive to NWA opportunities.
Asset Condition	Planned repair, replacement, or enhancement of existing infrastructure to maintain minimum safety and reliability performance.	NWA are not likely to improve the condition of existing T&D assets that must remain in service as part of the NWA alternative. Therefore, NWA in this area must also include the repair or replacement of the assets that were driving the need for the project recommendation. However, some projects may have components which need to be reconstructed and other components which may be suitable for NWA.
New Business	Physical connection of customer facilities to distribution system to support a new service request.	Best opportunities for NWA to participate in meeting new business needs may be for DER providers to work directly with customers prior to the issuance of their load letter to modify the impact of the developing loads and embed things such as EE and DR at the time of service request.
Service Upgrade	Replacement of existing connection of customer facilities to distribution system.	To address the incremental needs from a single customer, provider would need visibility of existing load, EE, DR, and NWA providers and programs. Customer confidentiality and timelines are a concern.
Public Requirements	Relocation of existing facilities to accommodate the terms of rights-of-way (“ROW”), permits, or licenses.	Scope of work requires the physical relocation of an asset and is seldom influenced by the capacity or performance of the asset, and therefore this type of project is not suitable for NWA.
Non-T&D Infrastructure	Investments in equipment and systems in support of T&D operations (*e.g.*, telecommunications, tools, systems, information technology (“IT”)).	This budget category is not applicable for NWA. It is likely that this budget category will need to expand to accommodate the integration requirements of DER. Some of the items in this category directly support DER platform development.

2. Timeline Suitability for Competitive Procurement

There are two process components involved in a competitive solicitation: procurement and implementation. The process of procurement can be broken into four stages:

- Request for Proposal (“RFP”) development (including initial procurement engagement);
- Vendor response;
- Technical review of vendor proposals (including any ranking/scoring of proposals); and
- Contracting for services.

The time associated with each of the first three stages will vary, with solution complexity, and scale strongly influencing timeframes for each step. As is the case for traditional utility projects, the entire timeline associated with an NWA solicitation must be factored into the timeline criteria used by utilities.

In addition to scheduling an appropriate procurement period, the utilities must also account for implementation timelines. The first component of this timeline entails the actual integration of resources being utilized in the NWA project implementation. The time to implement this element is highly dependent on the size and complexity of the project. Greater experience will further inform how these suitability criteria should evolve.

The utilities will develop timeline suitability criteria to assess whether there is sufficient time to conduct an NWA solicitation and implement the chosen solution before the required in-service date. Overall, these timelines are likely to vary depending on factors such as project size, complexity, and customer demographics. Ultimately, very large contracts have additional complexity in achieving all requisite approvals.

Based on recent experiences of the Joint Utilities, the NWA solicitation and implementation process may need to begin up to 60 months before the required system need for the largest projects. The necessary lead time, and consequently the timeline suitability criteria, may be reduced as DER sourcing is refined and implementation experience is gained. Similar to the other criteria discussed here, the timeline criteria will need to be designed with sufficient flexibility such that its specific application can be adaptive to specific conditions and evolve as greater experience is gained.

3. Cost Suitability

One of the key factors in determining whether or not to solicit NWA is the cost of the identified utility project. Based on discussions in the stakeholder engagement group, the Joint Utilities propose that company-specific cost floors for various project types serve as a guideline for NWA suitability. The cost suitability criteria is intended to indicate a threshold above which NWA are more likely to be cost-competitive and able to overcome the transaction and opportunity costs associated with smaller scale projects. By using cost suitability criteria to identify where the NWA is more likely to be cost-effective, DER providers will be able to focus efforts on solicitations around projects where NWA are likely to compete. The criteria developed by each utility may serve as a guideline, rather than a bright line test, to build in flexibility and minimize the risk of excluding potentially viable NWA projects. Greater experience will further inform how this kind of suitability criteria should evolve.

D. Summary of Next Steps

The categories of NWA suitability criteria presented herein will provide a common framework for the identification of NWA opportunities. To provide greater clarity to DER developers on potential opportunities for NWA, each utility will publish an implementation matrix that provides the utility-specific criteria design for the criteria outlined above. Separately, the Joint Utilities will continue exploring ways in which the suitability criteria and feedback loop in the process occur through DER sourcing.

1. *NWA Suitability Criteria Implementation Matrices*

The utilities will complete an NWA suitability criteria matrix within four months of the filing of this Supplemental DSIP. Additionally, the Joint Utilities agreed that each individual utility will conduct annual assessments of potential changes to utility-specific criteria in conjunction with each utility's planning process.

These matrices will provide a common set of criteria across the utilities while allowing for differences in the specific criteria design between the utilities. Additionally, differences may occur within each utility on the basis of project attributes (*e.g.,* project size). These matrices will be guided by each utility's unique budget structure to address project types, identification of minimum costs for DER that can provide the relevant solution, and timeline for implementation of the NWA solicitation and project based on its experiences thus far. While not an exhaustive list, Table IV-4 outlines some of the elements that could be addressed in the development of each utility's criteria design. The elements in this table are illustrative and each utility's criteria could include a subset of these and additional elements.

Table IV-4: Potential Elements of Utility-Specific NWA Suitability Criteria Design

Criteria	Potential Elements Addressed
Project Type Suitability	• Project categories and their relative applicability for NWA • Guidelines or procedures for the application of suitability based on project type
Timeline Suitability	• Minimum lead times to need date for projects based on project size and/or other criteria • Guidelines or procedures for the application of lead time criteria
Cost Suitability	• Cost floors for projects based on project size and/or other criteria • Guidelines or procedures for the application of cost criteria

Each project has its unique cost and timeline that could be influenced by factors such as type (*e.g.,* complexity of project and scope) and scale of work. For example, cost and timeline suitability criteria applied to large load relief projects focused on subtransmission asset overload will likely be very different from the criteria used to assess the suitability of a smaller scale project focused on conductor upgrades on a distribution feeder. As such, the utilities will design NWA suitability criteria that are tailored to evaluating projects of varying types and sizes.

2. *Relation to DER Sourcing*

The Joint Utilities will leverage the experience gained from NWA procurements to inform future solicitations and modify the NWA suitability criteria over time to allow for a continued evolution of the process. The Joint Utilities will continue exploring ways in which the suitability criteria and the feedback loop in the process occurs through DER sourcing. As these processes evolve to become a more central aspect of planning, each utility will establish a framework enabling it to provide stakeholders greater visibility with respect to prospective system needs and the characteristics of those needs. This will be enabled by having a well-established process with clearly-defined avenues for information sharing to support competitive solicitations, which is one of the goals of the REV Connect initiative described in the *Data Collection, Access and Security* chapter. This increased transparency will also help to inform stakeholders and support their participation in competitive procurements.

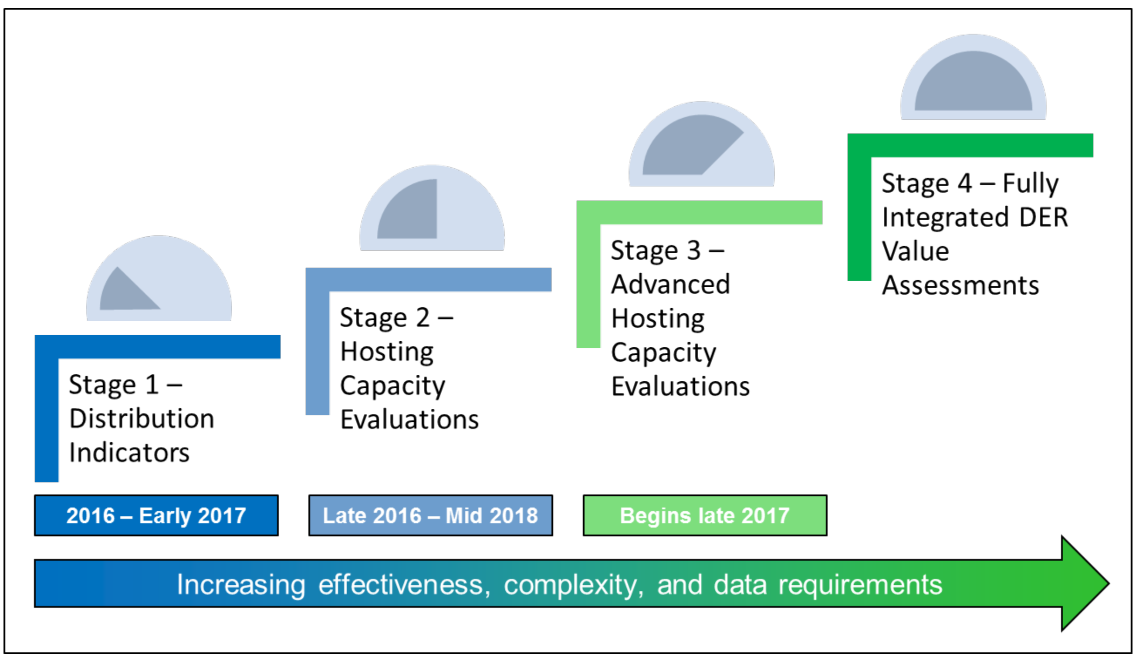
Hosting Capacity

A. Introduction

In order to effectively integrate DER, it is necessary to understand the distribution system's ability to host DER. Information about how much DER can be interconnected to various parts of the system will help guide DER investments and marketing activities. Hosting capacity is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line voltage and/or secondary network system.[42] Published hosting capacity maps will guide project developers to interconnect DER where interconnection costs are likely to be lower, with increasing granularity over time. Carrying out a hosting capacity analysis across a service territory will enable more advanced targeting and evaluation of beneficial locations for DER. While hosting capacity analysis aims to be inclusive of all types of DER, the impact of solar PV is the near-term focus for the Joint Utilities as it is currently the most prominent DER type that would benefit from this type of analysis.

As outlined in Figure IV-3, the Joint Utilities are adopting a four-stage approach for developing hosting capacity analysis capabilities in order to provide information to the extent possible as tools, models, and processes evolve.

Figure IV-3: Joint Utilities Hosting Capacity Roadmap[43]



[42] 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.
[43] *Id.*, p. 5.

B. Overview of Hosting Capacity Stakeholder Process

The Joint Utilities convened a series of six stakeholder meetings to more fully understand DER developers' data needs with respect to distribution system hosting capacity. As part of this process, the Joint Utilities hosted three face-to-face meetings and three webinars to discuss this topic and solicit input from stakeholders. In response to stakeholder requests for insight into the timeframes and data requirements for the development of each of the four stages of hosting capacity analysis, the Joint Utilities worked with stakeholders to provide more details about their proposed roadmap for the development of hosting capacity analysis capability throughout the state.

Stakeholders expressed a desire for the Joint Utilities to show progress on hosting capacity analysis in the near term and indicated a preference for approaches that offer near-term progress rather than complex processes that might impose longer timeframes on the release of new information. To facilitate decisions on a common approach, stakeholders reviewed the relative merits of various approaches for hosting capacity analysis and discussed their relative computational complexity and scalability. The approach adopted by the Joint Utilities is responsive to the stakeholder input: (1) a streamlined approach was chosen to reduce computational complexity and time dedicated to the analysis; (2) the analysis will be initiated at the feeder level and undertaken in stages to start providing data more quickly and to facilitate early progress on this issue; and (3) the Joint Utilities are working to incorporate consistency in approaches.

Stakeholders also expressed a desire for the inclusion and implementation of innovative approaches for increasing hosting capacity, including stakeholder description of the merits of several technologies. In response, the Joint Utilities outlined multiple REV demonstration projects focused on increasing hosting capacity that are currently underway. The Joint Utilities also laid out a set of potential methods for increasing hosting capacity and acknowledge the need to continue reviewing the ability of these and other methods to safely and reliably increase hosting capacity.

Additionally, there were two major pieces of feedback from stakeholders that the Joint Utilities will address in future engagement efforts. First, stakeholders have an interest in exploring the possible implementation of interconnection use cases for hosting capacity and second, there was a desire to further clarify how emerging approaches to increase hosting capacity will be implemented.

C. Hosting Capacity Analysis Roadmap and Methodology

The DSIP Guidance Order requires the Supplemental DSIP to include a timeline and methodology for calculating and improving circuit-level hosting capacity data.[44] To that end, the Joint Utilities have outlined a four-stage roadmap for the implementation of hosting capacity analyses, with each subsequent stage increasing in effectiveness, complexity, and data requirements:

- Stage 1: Distribution Indicators
- Stage 2: Hosting Capacity Evaluations
- Stage 3: Advanced Hosting Capacity Evaluations
- Stage 4: Fully Integrated Value and Hosting Evaluations

[44] REV Proceeding, DSIP Guidance Order, p. 18.

As indicated in their Initial DSIPs, the utilities presented the results of the Stage 1 indicator maps and will focus on enhancements to this stage and commencement of Stages 2 and 3 in the near term. Some aspects of Stage 3 and achievement of Stage 4 will be a longer-term focus.

1. *Distribution Indicators - Stage 1*

Stage 1 includes the "red zone" indicator maps published by each utility as part of their June 2016 Initial DSIP filings. Based on available data, these maps have provided indications of where interconnection costs might be relatively higher.[45] The inputs applied in this stage, such as the estimated level at which substation transformer backfeed may occur, feeder voltage class, and whether the system is radial versus networked, help to identify "red zones" that provide insightful information to stakeholders.

Table IV-5 summarizes some of the material filed in the Initial DSIPs and includes details of where the utilities stand today with respect to the development of these maps.

Table IV-5: Currently Available Indicator Maps

Company	Details
NYSEG/ RG&E[46]	The utilities' Distributed Interconnection Guide Map can aid customers and developers on identifying locations to avoid for large (greater than 300 kW) DER systems due to the potential for high interconnection costs. The locations highlighted fall into one of two categories: all single-phase distribution circuitry, or feeders from a substation transformer experiencing interconnection facilities and/or request at or above 75 percent of thermal capability of the facilities.
Central Hudson[47]	Central Hudson's interactive DER System Indicator Map (GIS format) illustrates the areas/circuits across the system where DER have a greater likelihood of not being easily accommodated on the distribution system. This can be used to aid customers and developers on locations to avoid for large (greater than 300 kW) DER systems due to the potential for high integration costs. The highlighted locations include: all single stage circuitry, low voltage circuitry (5 kV class), feeders where minimum load is anticipated to be significantly exceeded, and feeders emanating from a substation transformer that is anticipated to experience significant backfeed.
Con Edison[48]	In Con Edison's map, triangles represent locations where Con Edison anticipates it can accept solar DG output with little to no additional cost to the project. The larger the triangle, the higher the likelihood there will be no or little additional cost to interconnect in that area. Con Edison has initially focused on developing maps for its low-voltage network areas and expects to provide maps of its non-network system in conjunction with timelines for other utilities.

[45] Con Edison's network system entails significant differences from the other utilities' radial systems. As a result, Con Edison issued low voltage mesh hosting capacity maps in its Initial DSIP.
[46] NYSEG/RG&E Distributed Interconnection Guide Map. http://iusamsda.maps.arcgis.com/apps/webappviewer/index.html?id=93c86fbf9fbc47219f34aa303a724257.
[47] Central Hudson DER System Indicator Map. http://centralhudson.com/dg/DERmap.aspx
[48] Con Edison: Distributed Generation. http://www.coned.com/dg

National Grid[49]	System data provided includes: feeder number, substation name, operating voltage, summer rating (Amps), peak load and peak ratio (2015 & 2016), DG connected and in queue, 10-year forecasts of load, and feeder load curves.
	This interactive map (GIS format) indicates general areas/circuits where the cost to interconnect DG greater than one MW in capacity will be higher due to low minimal daytime load, aggregated DG already interconnected, smaller conductor (wire size), operating voltage, and/or the number of DG applications in the queue on the circuit exceeding daytime load. As hosting capacity maps become available, this map will be replaced.
O&R[51]	The Distributed Generation Interconnection Circuit Map (GIS format) indicates general areas/circuits where the cost to interconnect greater than one MW will be higher due to low minimal daytime load, aggregated DG already interconnected, smaller conductor (wire size), operating voltage and/or the number of applications in the queue on the feeder exceeding daytime load. As hosting capacity maps become available, this map will be replaced. Circuits with a high cost to interconnect are represented on the map in orange and include all circuits with unique substation configurations that are 2.4 kV, 4.8 kV, 4.16 kV, and 34.5 kV, and with 10 MW or more of applications in the queue. Single phase circuits are represented in blue. All other circuits are separately indicated.

Inclusion of this information in the utilities' Initial DSIP filings addresses the requirement in the DSIP Guidance Order to establish indicator maps that present relevant system information.[52]

As part of their hosting capacity roadmap, the Joint Utilities have begun an interim step that provides additional data and improved consistency in approach among them. Efforts to enhance indicator maps aim to address stakeholder requests to gain further insight into the method and data used for the hosting capacity analysis. This next iteration of the indicator maps will meet stakeholder requests in the near term by providing an expanded set of data and greater alignment on the methodology and approach.

Additionally, the utilities have begun this alignment and will complete implementation of the enhanced indicator maps by early 2017. Table IV-6 outlines the considerations, timeframe, and output data for each component of the first stage of the hosting capacity analysis.

[49] National Grid – New York: System Information Data Portal. http://ngrid.maps.arcgis.com/apps/MapSeries/index.html?appid=4c8cfd75800b469abb8febca4d5dab59&folderid=8ffa8a74bf834613a04c19a68eefb43b

[50] National Grid – New York: System Information Data Portal. http://ngrid.maps.arcgis.com/apps/MapSeries/index.html?appid=4c8cfd75800b469abb8febca4d5dab59&folderid=8ffa8a74bf834613a04c19a68eefb43b

[51] O&R Distributed Generation Interconnection. http://www.arcgis.com/home/item.html?id=75b1ed93a84b4c5290be8a46ef8666e5

[52] REV proceeding, DSIP Guidance Order, p. 18.

Table IV-6: Hosting Capacity Implementation Roadmap for Stage 1

	Stage 1 – Distribution Indicators
Considerations	• Preliminary indicators for the interconnection process were included as part of each utility's Initial DSIP • Enhanced red-zone indicator maps with additional data and more aligned methodology
Timeframe	• Preliminary indicators completed • Enhanced red-zone indicator maps to be completed in early 2017 (in the next quarterly update of the hosting capacity indicator maps)
Output Data	• Published red-zone maps which indicate locations with potential high interconnection costs (part of each utility's Initial DSIP filing on June 30, 2016) • Enhanced indicator maps with additional data and more consistent representation across the Joint Utilities • Line voltages will be included in the updated hosting capacity indicator maps as a data enhancement; other enhancements to the maps will be left to the discretion of each utility on the basis of data availability and tool capabilities

2. Hosting Capacity Analysis – Stage 2

In September 2016, the Joint Utilities initiated Stage 2, which focuses on a common implementation of hosting capacity analysis across all relevant circuits of a utility's system. The first component of this process is working to arrive at a level of alignment among the utilities on the specific implementation of the streamlined hosting capacity methodology and how the approach will be applied within each utility.

The Joint Utilities will employ a streamlined hosting capacity[53] analysis method for Stage 2 with less computational complexity than iterative power flow approaches that evaluate every combination of size and location of DER on a circuit. [54] This approach is scalable and facilitates hosting capacity analysis for a service territory. The utilities' implementation of Stage 2 analysis will use the EPRI Distribution Resource Integration and Value Estimation ("DRIVE") tool. The DRIVE tool leverages existing circuit models in a utility's native distribution planning software to carry out a streamlined analysis of hosting capacity.

In addition, because the central aim of the Stage 2 maps is to inform DER integration and guide the commercial activities of DER developers, the utilities will carry out this analysis by modeling the impacts of larger, more centralized solar PV installations rather than looking at smaller rooftop solar PV systems dispersed throughout a given area. Stakeholders have expressed the need for increased visibility into hosting capacity for larger-scale solar PV systems that often target rural areas where land is available, but where hosting capacity can vary substantially from site to site. Therefore, the utilities will utilize the large, centralized solar PV analysis approach, rather than the distributed approach that focuses around existing load.

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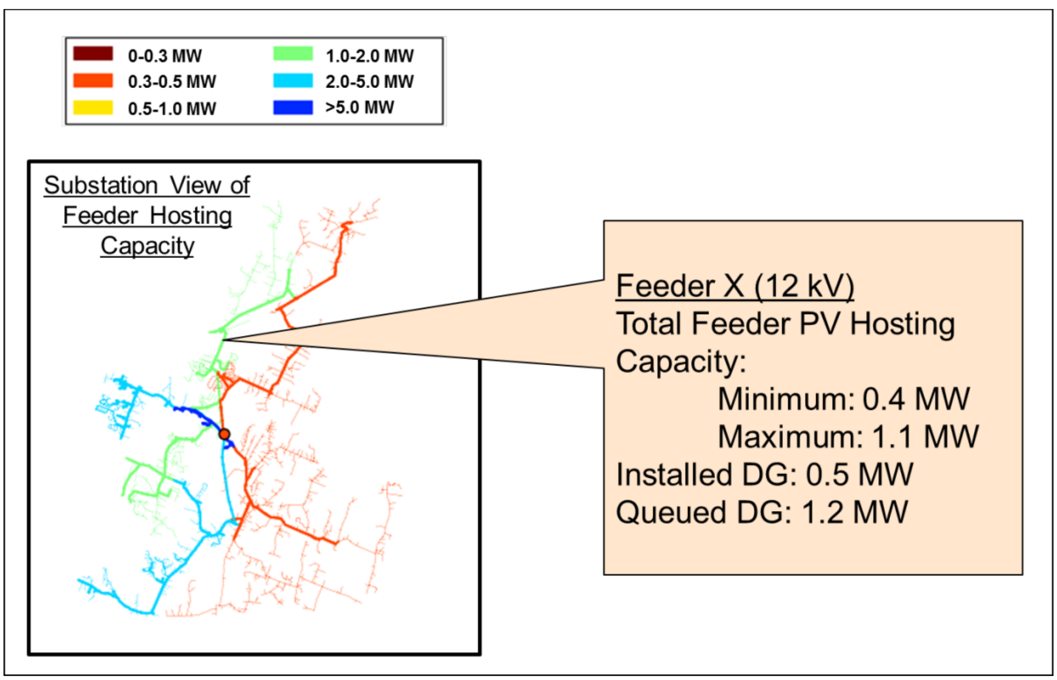
[53] EPRI, *Integration of Hosting Capacity Analysis into Distribution Planning Tools,* Report Number 3002005793, December 2015. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005793.

[54] EPRI, *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV*. Report Number 1026640, December 2012. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000000001026640.

To facilitate a common functionality for users, the Joint Utilities have aligned on three main aspects of presentation format of the hosting capacity map and associated data. First, the heat maps will display the gross hosting capacity by feeder calculated for large (greater than 300 kW) distribution-connected solar PV systems interconnecting on a three-phase node, as opposed to small rooftop PV distributed throughout a given feeder. As part of this, the maps will be colored according to the upper limit of the range of minimum gross three-phase feeder-level hosting capacity. Second, the Joint Utilities have agreed to use a common coloring scheme for the three-phase sections of the feeders, ranging from minimum values (dark red) to maximum values (dark blue). Breakpoints in the coloring scheme will include: less than 300 kW, 300-500 kW, 500-1,000 kW, 1,000-2,000 kW, 2,000-5,000 kW, and greater than 5,000 kW. Finally, there will be data "pop-ups" for each feeder to provide the following information in a tabular format: voltage level of the feeder and other data shown in the Stage 1 indicator maps; current and queued DG (MW); and the range of gross three-phase feeder-level hosting capacity (MW) bounded by the least and greatest minimum hosting capacity value of any three-phase node on that feeder. These pop-ups will provide greater insight into how much of the hosting capacity may be utilized by queued solar PV projects.

Figure IV-4 illustrates the visual format for these heat maps.

Figure IV-4: Feeder-Level Hosting Capacity Heat Map[55]



Because hosting capacity information is dynamic and varies as load, DER capacity, and circuit configurations change, the analysis must be refreshed on a periodic basis. The Joint Utilities have committed to refresh the hosting capacity maps at least annually. However, the refresh rates will

[55] United States Department of Energy ("DOE") and EPRI, *Operational Simulation Tools and Long Term Strategic Planning for High Penetrations of PV in the Southeastern United States*, Final Technical Report for Solar Utility Networks: Replicable Innovations in Solar Energy Project. Report Number: DOE-EPRI-06326 ("DOE-EPRI Report 06326"), July 2016. http://energy.gov/eere/sunshot/operational-simulation-tools-and-long-term-strategic-planning-high-penetrations-pv

be set on the basis of interconnection volumes, capabilities, and resources of each utility. Additionally, the current and queued DG data in the associated pop-up boxes will be updated monthly, which aligns with each utility's submission of this data to the Commission. Although the actual refresh rate of the data may differ between utilities and be driven by integration of the DRIVE engine into an individual utilities' distribution load flow program, the timing of the updates and potential changes over time will be transparent to third parties. The Joint Utilities are continuing to evaluate aspects of streamlined hosting capacity analysis and develop a common approach on a broader range of inputs to the calculations.

All utilities will have completed an analysis of hosting capacity at the feeder level for at least 50 percent of the circuits on their system and will publish the results of these analyses on their respective websites by the end of 2017. The selection of target circuits for this milestone will be based on the availability of data and circuit models needed to carry out the analysis and the level of solar PV developer interest in the corresponding areas of each utility's territory. The completion of Stage 2 with an analysis of the full system and the complete maps with the format and functionality described above will be completed by June 30, 2018. This stage of the hosting capacity roadmap will fulfill the requirement in the DSIP Guidance Order calling for substation level hosting capacity data and will provide this information at a greater level of granularity with distribution feeder-level specificity.[56]

Table IV-7 summarizes the considerations, timelines, and outputs associated with Stage 2.

Table IV-7: Hosting Capacity Implementation Roadmap for Stage 2

Stage 2 – Hosting Capacity Evaluations	
Considerations	• The Joint Utilities will leverage EPRI's DRIVE tool; reach a level of alignment on the algorithm used, data inputs, and tool requirements for hosting capacity; and determine an aligned platform view and data format for maps. A new version of this tool is scheduled for delivery in July 2017. • Design and timing of batches for carrying out the full-circuit analysis will be determined by each individual utility. • The refresh rate of Stage 2 hosting capacity heat maps will occur at least once a year and be set by each individual utility depending on the interconnection volumes, capabilities and resources of each utility, along with capabilities of the DRIVE tool and integration into existing distribution load flow software. Specifically, the current and queued solar PV data in the pop-up boxes will be updated monthly, in alignment with each utility's submission of this data to the Commission.
Timeframe	• A full analysis for all relevant circuits using the EPRI streamlined approach will be carried out over a period of one year. • Analysis of at least 50 percent of the circuits will be completed by end of 2017. • Full-circuit analysis will be completed by all utilities by mid-2018.
Output Data	• Heat maps of the gross hosting capacity by feeder calculated using large centralized solar PV scenarios. Maps will be colored according to the upper limit of the range of minimum gross three-phase feeder level hosting capacity.

[56] REV Proceeding, DSIP Guidance Order, Attachment 1, p. 19.

	• Coloring of the three-phase sections of the feeders will range from minimum values (dark red) to maximum values (dark blue). Breakpoints will include: less than 300 kW, 300-500 kW, 500-1,000 kW, 1,000-2,000 kW, 2,000-5,000 kW, and greater than 5,000 kW. • Data pop-ups for each feeder will provide information in tabular format: voltage level of the feeder and other data shown in the Stage 1 indicator maps; current and queued solar PV (MW); and range of gross three-phase feeder level hosting capacity (MW) bounded by the least and greatest minimum hosting capacity values of any three-phase section on that feeder.

The Joint Utilities will continue exploring additional opportunities for alignment on implementation factors, including data inputs, tool requirements, and presentation format of the hosting capacity data.

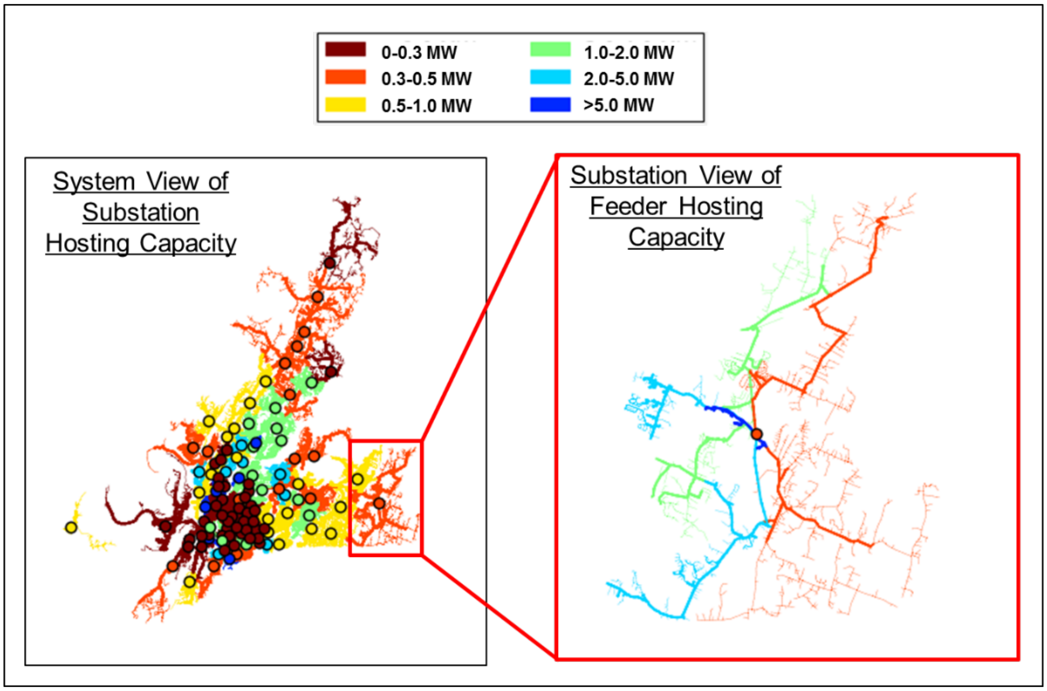
3. Advanced Hosting Capacity Analysis – Stage 3

As the development of the tools facilitates more advanced analyses, the utilities will continue to enhance the information provided through their online hosting capacity maps. The first step in advancing the analysis beyond the Stage 2 analysis described above will be to increase the spatial granularity of the hosting capacity values provided. An evolution to this more detailed hosting capacity analysis will enable planners to more specifically identify locations along a feeder with higher levels of hosting capacity and determine how sub-feeder-level hosting capacity is impacted by current and prospective DER interconnections on the system.

Completion of this stage will depend on the successful resolution of several other processes. First, resolution of the queue management proposal (or specific guidance emanating from the IPWG) is necessary to inform the utilities about how to treat capacity in the queue and how to reflect that capacity in the hosting capacity analysis and maps. Second, this move to advanced hosting capacity analysis is tentatively scheduled to begin in late 2017, but that timeframe is contingent on the resolution of queue management issues and the development of an enhanced version of the EPRI DRIVE tool that is capable of incorporating the impacts of interconnected DER into sub-feeder-level hosting capacity calculations. EPRI expects to have this enhanced tool available by mid-2017.

Figure IV-5 depicts what the maps may look like as part of Stage 3.

Figure IV-5: Sub-Feeder-Level Hosting Capacity Heat Map[57]



Building on this advanced hosting capacity analysis, the utilities can continue to iteratively add advanced capabilities to the hosting capacity analysis. Additional modeling and coordination with substation/transmission engineering are needed for more advanced hosting capacity evaluation. In addition, there is a need to account for operational flexibility in a hosting capacity analysis to account for situations where a planner or operator might be limited in switching to serve a portion of one feeder from another on a temporary or permanent basis due to voltage, thermal, or protection issues arising from the changing impacts of DER to the system with changes in topology. This is of particular interest as utilities implement their advanced distribution automation plans. This type of analysis requires hosting capacity to be determined for multiple feeder conditions. Additional analysis that captures the substation-level impact of aggregate DER across multiple feeders into the substation will ensure proper operation of all feeders in the area. Completion of this stage will be a longer-term focus for the utilities based on lessons learned from previous stages and the availability of enhanced analytical tools to conduct this type of analysis.

4. *Fully Integrated Value and Hosting Evaluations – Stage 4*

The capabilities in this fourth stage extend beyond the formal definition of hosting capacity analysis and build on its foundation to perform fully integrated value assessments.[58] The impacts of DER on the electric grid may vary depending on particular attributes of the DER, the location at which the DER is interconnected to the electric grid, and the configuration of the electric network. These impacts may be positive or negative; therefore, it is important for utility planners to identify the locations where the deployment of DER (or a portfolio of DER) has the highest potential to reduce overall net cost of operating the system. The value of DER on the distribution system is locational,

[57] DOE-EPRI Report 06326.
[58] EPRI Roadmap, p. 14.

and, therefore, may be associated with a particular distribution substation, an individual feeder, or a combination of these.

Value assessments that quantify the full set of benefits from DER require enhanced analytical tools and resolution of relevant REV proceedings. The evolution toward this type of integrated DER value assessment will require the development of new data, tools, methods, and a deeper understanding and characterization of salient value metrics driving such analyses. In the longer term, the utilities will work on developing the valuation methods and tools necessary for achieving the objectives of this stage.

D. Increasing Hosting Capacity

There are numerous methods and approaches available to increase hosting capacity through strategies, such as DER capabilities, that mitigate limiting factors. Because hosting capacity is localized in nature, efforts to increase hosting capacity will also have localized impacts.

Efforts aimed at increasing hosting capacity are separate and distinct from the hosting capacity analysis, where the latter is aimed at enabling the capabilities to develop hosting capacity evaluations that inform planning. These two processes can proceed in parallel and will ultimately be informed by one another.

1. Methods for Increasing Hosting Capacity

The result of a hosting capacity analysis coupled with information regarding the queue and results from submitted pre-application reports, utilities and DER developers can target areas of the system to increase hosting capacity to allow additional interconnection of DER so that system reliability is maintained. While prior implementation of utility projects has primarily been focused on addressing existing system needs, some have already had the co-benefit of increasing hosting capacity, such as voltage conversions, reconductoring, and improving asset information and metering data. When these projects fit within a utility's distribution investment plan and timeline, the utility can realize the added benefit of increasing hosting capacity.

In many cases a single solution or technology will not be able to address the full range of issues (*e.g.,* voltage, thermal, and protection) that can ultimately limit hosting capacity. This requires a utility to tailor approaches for increasing hosting capacity to a specific location and condition. One example for increasing hosting capacity is the Joint Utilities' support for "additional inverter functionality, such as frequency and ride through functionality or upgradeable firmware for power factor control in order to enable higher penetration rates of solar photovoltaic (PV) technologies."[59]

Methods for increasing hosting capacity can be described in terms of three broad categories: grid-side enhancements, operational changes, and customer solutions. Table IV-8 summarizes some methods for increasing hosting capacity.

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[59] Case 15-E-0557 – *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less* ("SIR Proceeding"), Comments of the Joint Utilities on the Proposed Modifications to the Standardized Interconnection Requirements (filed January 11, 2016), p. 6.

Table IV-8: Three Classes of Activities for Increasing Hosting Capacity[60]

Category	Method	Description
Grid-side Enhancements	Line reconductoring	This is one way to increase the short-circuit strength and increase the ratio of reactance to resistance. If the voltage fluctuation is caused by changes in active power, replacing the conductors (*i.e.*, distribution lines) will help—but if the voltage fluctuations are the result of reactive power changes, it will not.
	Transformer replacement	One solution for mitigating a customer-induced secondary overvoltage is to replace the service transformer with a larger one, increasing grid capacity at the customer level. Some service transformers have no-load-tap adjustment settings. Changing the tap to a lower setting could also mitigate overvoltage.
	Voltage Uprating	If the voltage of the system were increased by a factor of two, the capacity of the system would increase by a factor of four, resulting in a significantly higher capacity on the system—and increasing the feeder's hosting capacity for DER when voltage or thermal ratings are the limiting factor. Upgrading the system voltage requires the installation of new assets such as insulators, arresters, switches, and transformers.
	Communication /control (curtailment)	Awareness of DER operation at any given time would assist in performing load transfers to avoid problems. If coordinated with existing utility voltage regulation, DER issues involving voltage problems can be remedied—or at least somewhat abated. Moreover, if DER can provide needed services when called upon, they could also provide beneficial support to the grid.
	Additional relaying	This can prevent situations of sympathetic tripping of the feeder or line reclosers on a circuit caused by a large generator near a substation. This situation arises when a fault occurs on adjacent feeders serviced by the same substation on which DER are connected.
Operational Changes	Voltage Regulation	Several technologies are available that can help regulate voltage on a distribution feeder with DER, including traditional, mechanically-switched regulation equipment (line regulators), solid state transformers or other grid-edge distributed volt/VAR control, and advanced, static-controlled regulation to increase hosting capacity.
	Relay setting modification	The largest impact that DER have had on existing protection practices is on the coordination of feeder protective device settings. For example, in some cases DER-induced reverse power flow can cause inadvertent tripping of protection equipment, requiring the use of direction-based protection schemes, or directional relaying.
Customer Solutions (longer-term)	Smart Inverters	One approach to mitigating many of the voltage issues caused by DER is to allow the DER to provide power factor, or VAR control. Nearly all large DER interconnecting to the grid have power factor control capability. When high DER output and low load cause feeder voltage to rise too high, reducing the active power output of the DER may reduce overvoltage. Therefore, reducing the active power output of DER systems through localized voltage conditions may allow more of the PV to "share" the voltage headroom on the distribution transformer.
	Distributed VAR control	Inverter-based reactive power control allows the utility to regulate potential adverse voltage changes that can be caused by load or DER. These technologies have been used to mitigate voltage flicker issues caused by rapidly varying loads such as chippers, arc furnaces, and car crushers. Because this technology is inverter-based, it can regulate voltage much more quickly than mechanically based regulation. In addition, it is not subject to the same wear and tear as found in regulators.

[60] Sources include: EPRI, *The Integrated Grid: A Benefit-Cost Framework.* Report No. 3002004878, Palo Alto, CA: 2015. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878. EPRI, *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV*. Report No. 1026640, Palo Alto, CA: 2012. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026640. EPRI, *Principles and Practice of Demand-Side Management*. Report No. TR-102556, Palo Alto, CA: 1993. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=TR-102556.

	Dispatchable DER	Dispatchable DER, such as energy storage and demand response, can increase distribution system capacity by supplying power during peak load periods. Separately, dispatchable resources can be paired with renewable generation to mitigate inherent fluctuations in renewable generation output. In certain cases, these fluctuations may result in voltage concerns and increased operation of voltage regulation devices.
	PV panel orientation	A key component in accurately assessing the impact of distributed solar PV on the distribution system is accurately representing the nature of the solar PV systems themselves, including the array size and solar irradiance which inherently drives the solar PV output. Based on characteristics of pending solar PV systems, installations can be coordinated to orient the systems in a way that allows for higher levels of hosting capacity.
	Passive DER	Passive DER technologies, such as DSM, affect the amount and timing of customer electricity use. Relevant programs include peak clipping programs, strategic conservation programs, load shifting programs, valley filling programs, and strategic load growth programs.

2. *Current Efforts to Increase Hosting Capacity*

Demonstration projects currently underway or in the proposal stage could provide valuable data, experience, and lessons to inform future efforts to increase hosting capacity. Current projects are providing new insights in numerous ways, such as focusing on curtailment of DG and coordinated dispatch of DER. For example, NYSEG/RG&E's REV demonstration project, Flexible Interconnect Capacity Solution ("FICS"), tests a new model for interconnection of large-scale controllable DER.[61] This project focuses on whether NYSEG/RG&E's ability to potentially curtail the delivery of electricity that is generated by a DER can provide an alternative to traditional infrastructure upgrades by creating a less expensive and potentially faster interconnection alternative. The most recent quarterly report is provided as Appendix D.

Con Edison has piloted several advanced technologies with third-party partners that can increase hosting capacity, either by permitting DG interconnection in areas previously off-limits or increasing the maximum nameplate capacity of an interconnection application. One project provides a lower-cost alternative to traditional direct transfer trip ("DTT") by applying a phase comparison anti-islanding solution (further discussion on DTT is in the *ITWG and IPWG* subsection). Additionally, cost certainty in the interconnection process can benefit developers' business cases, and ultimately lead to greater DER penetration. As a result, Con Edison plans to propose a demonstration project that offers interconnecting customers these options with new technologies as well as a fixed interconnection price based on the size of the DER (discussed further in Appendix B).

Another project proposed by O&R seeks to implement variable export schemes with DG customers. The proposed demonstration project will provide the opportunity to use alternate approaches to increase hosting capacity and facilitate greater DER penetration. The proposed project will implement alternate interconnection schemes with interconnection applicants facing significant system upgrade costs associated with interconnection. Rather than expensive upgrades to O&R's local distribution system to accommodate these interconnection requests, O&R is proposing to work with the customers, developers, and third parties to utilize inverter functionality coupled with supporting technology to maximize the proposed DG project's ability to

[61] DSIP Proceeding, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation DSIP (filed June 30, 2016), pp. 89-90.

export back to the grid while also mitigating any impacts the interconnected DG would have on the system. This project will demonstrate alternatives to high interconnection costs, encourage higher DG penetration on select constrained circuits, and allow O&R to gain valuable experience with advanced technologies and their impact on the electric distribution system (discussed further in Appendix C).

Central Hudson and NYPA, together with EPRI, are building a solar plus energy storage system at the State University of New York at New Paltz to provide electricity on campus during times of high load and emergencies, as well as to demonstrate how battery storage and smart inverter functionality can mitigate the intermittency impacts of solar PV and the potential for increasing hosting capacity. [62] EPRI has also applied for a DOE Enabling Extreme Real-Time Integration of Solar Energy ("ENERGISE") grant, with Central Hudson as the host utility, to enhance its Distribution Management System "DMS" functionality to improve hosting capacity. Central Hudson is currently a finalist in that process.

National Grid is evaluating multiple power line carrier communications ("PLCC") technologies to reduce the cost of DTT and increase hosting capacity. A project was completed in 2014 to install a voltage pulse PLCC technology and additional projects are now underway to install and test a frequency pulse PLCC project on both a 23 kV subtransmission system and on a 13.2 kV feeder in the same geographic operating area. In addition, a third PLCC technology is being installed and evaluated for increasing the hosting capacity on a secondary spot network system in conjunction with NYSERDA PON 3026.[63]

Other projects not directly aimed at increasing hosting capacity can nevertheless be valuable to inform aspects of DER system impacts. One such example is Con Edison's Clean Virtual Power Plant, in partnership with SunPower Corporation and Sunverge Energy, which examines how aggregated stored DER can be leveraged as an asset for distribution systems.[64] Another example, which is part of potential future demonstration projects, is a Request for Information ("RFI") issued jointly by Con Edison and O&R to solicit responses from third parties to deliver innovative energy storage solutions. Projects like these can have a material impact on future efforts to increase hosting capacity.

In addition to these projects, efforts by each utility to increase its analytical capabilities will facilitate opportunities to increase hosting capacity. For example, as the utilities continue to move toward 8760 metering data, data accuracy will increase and fewer assumptions will be required. As a result, utilities can provide more precise calculations of hosting capacity which will have the effect of increasing hosting capacity above previously identified levels which were based on minimum hosting capacity values for each feeder.

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[62] New York Power Authority, *NYPA Partners with SUNY New Paltz on Solar Generation and Battery Storage Project*. Accessed on October 7, 2016. http://www.nypa.gov/Press/2016/050916.html.
[63] NYSERDA, *PON 3026 Electric Power Transmission and Distribution (EPTD) Smart Grid Program*. https://www.nyserda.ny.gov/Funding-Opportunities/Closed-Funding-Opportunities/PON-3026-Electric-Power-Transmission-and-Distribution-Smart-Grid.
[64] *See* REV Proceeding, Con Edison, REV Demonstration Project Implementation Plan: Clean Virtual Power Plant (filed December 11, 2015).

Separately, developments from the ITWG could inform potential opportunities to increase hosting capacity. For example, as is described in the *Interconnection* section, the Joint Utilities, in collaboration with Staff, NYSERDA, and developers, are exploring opportunities to reduce the need for DTT, which could lead to opportunities for increasing hosting capacity.

E. Summary of Next Steps

The Joint Utilities will continue to advance efforts toward implementing a streamlined approach for calculating hosting capacity. Future efforts for advancing hosting capacity analysis will occur both among the utilities and through stakeholder engagement.

1. Continued Cross-Utility Collaboration

In the near term, the utilities will implement Stages 1 and 2, which will provide new data and alignment on methodologies and result in a fully integrated hosting capacity analysis that provides an indication of how much DER can be interconnected on a feeder without requiring significant upgrades. As part of these near-term efforts, the utilities will complete feeder-level hosting capacity analysis for 50 percent of each utility's system by the end of 2017 and the analysis for the full system by June 30, 2018. Efforts on Stage 3 sub-feeder-level hosting capacity analysis are planned for late 2017, contingent on resolution of the queue management and the availability of EPRI's DRIVE tool. As the utilities progress through the roadmap, they will continue to evaluate ways to improve and build on hosting capacity analysis for the benefit of their customers and to realize DSP functionality while maintaining safe, reliable, and efficient electric services.

In the long term, efforts by the utilities to develop the tools and capabilities to conduct robust hosting capacity analyses will have the additional benefit of simultaneously informing efforts to increase hosting capacity. The utilities will also leverage and share amongst themselves the data and lessons learned from demonstration projects aimed at increasing hosting capacity.

2. Continued Stakeholder Engagement

The Joint Utilities have agreed to continue stakeholder engagement efforts by hosting at least one meeting annually. The Joint Utilities acknowledge that elements of hosting capacity analysis will evolve and continued stakeholder engagement will provide a forum for collaboration on future progression of this analysis. In particular, the Joint Utilities have initially identified three areas for further discussion, all of which were raised by stakeholders during previous engagement sessions:

- Further identification and evaluation of solutions for increasing hosting capacity;
- Potential additional use cases for hosting capacity, including those related to interconnection processes; and
- Determination of a cost allocation structure for future efforts to increase hosting capacity.

The frequency and focus of future stakeholder engagement efforts are subject to change based on ongoing feedback from stakeholders.

Interconnection

A. Introduction

The Track One Order highlights the importance of an efficient, timely, and transparent DG interconnection process that maintains the safety and reliability of the system.[65] In connection with this goal, the Commission and NYSERDA engaged EPRI to assess state interconnection procedures in *New York Interconnection Online Application Portal Functional Requirements* ("IOAP Report").[66] This report defines a set of functional requirements for the interconnection online application portal ("IOAP") with respect to automation of the various processes and outlines a roadmap for the utilities to develop their respective IOAPs.

The utilities have already made progress toward achieving automation of various components of the DG interconnection process and continue to explore opportunities for further automation. As included in their Initial DSIPs, some utilities are currently benchmarking or studying the benefits of automating portions of the interconnection study process. The Commission directed utilities without a fully functioning portal at the time of their Initial DSIP filing to include plans to complete this functionality.[67] This Supplemental DSIP expands on these plans and also outlines where the utilities stand with respect to automation of the various interconnection processes and their plans to progress toward automation of the remaining components.

Achieving the functionality outlined in the IOAP Report will be affected by other efforts. For example, the utilities began formal collaboration with developers, NYSERDA, and Staff through ongoing discussions of the ITWG and IPWG. The ITWG supports the continued evolution of the SIR by engaging in discussions on technical issues surrounding the interconnection process. It is anticipated that several solutions will be developed through this working group. Additionally, the IPWG, which is co-chaired by Staff and NYSERDA DG Ombudspersons, explores non-technical items relevant to interconnection, such as application queue management, consistency in application processing, and additional tools to help developers cost-effectively install generation. Each working group will continue to meet after the filing of this Supplemental DSIP and will provide a valuable forum for stakeholder feedback on the interconnection process.

B. Current State

As indicated in each utility's Initial DSIP, they have all made significant progress on streamlining their interconnection processes. Current application portals adhere to the requirements outlined in the Web-Based Standard Interconnection Requirements section of the March 2016 version of the SIR.[68]

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65 REV Proceeding, Track One Order, p. 53.

66 EPRI, *New York Interconnection Online Application Portal Functional Requirements*, September 2016 ("IOAP Report"). http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf.

67 REV Proceeding, DSIP Guidance Order, p. 11.

68 *Id.,* pp. 16-17.

While each utility has a current web-based portal, differences in functionalities and presentation exist. For example, while some utilities built their portals on existing internal infrastructure, O&R recently purchased the PowerClerk® Interconnect software for processing applications. Each utility is in the process of developing and implementing a roadmap from this current state to achieve consistent near-term functionality outlined in the IOAP Report and supported by the DER developer members of the ITWG during its September 27, 2016 meeting.

C. Roadmap for Achieving IOAP Functionality

In response to the REV objective to streamline the DG interconnection process, the IOAP Report identifies a set of functionality requirements that the utilities must meet to increase the proliferation of DG. The overarching goal of IOAP functionality is to allow for "online application submittal, along with automated management and screening—including any needed impact studies such as load flow or fault level based on the distributed generation (DG) penetration levels."[69] Achievement of this functionality will equip customers and developers with greater transparency into the interconnection process and increase the speed in which DG can be connected to the grid. The near-term functionality requirements are outlined in Table IV-9.

The utilities have all made significant progress on, and in some instances already completed, the requirements for application submittal and tracking, user restrictions, reporting capabilities, and providing a flexible, scalable, and transparent portal. To further facilitate efforts to automate the DG interconnection process, the utilities continue to engage with vendors as to the current state-of-the-art software capabilities and software integration requirements. Although some of the functionality requirements present challenges for the utilities in the near term, the utilities have begun efforts on nearly all of the functionality requirements.

Table IV-9: Near-Term Functionality Requirements for IOAP[70]

Functionality Requirement	Description
Application Submittal	The main purpose of the public-facing portal is to allow applicants (customer or developer) to fill out and submit an application online
Application Validation and Approval (utility facing)	Ability to validate the application fields for basic characteristics. Ability to approve applications that are less than 50 kW based on well-defined set of parameters.
Application Tracking	Allows user (public- and utility-facing) to view the status of their application
User Restrictions (limited public facing)	For privacy and security, allows different users to have different access based on need to know and roles
Cost Estimates, Status of Payments, and Pay On-Line (limited public facing)	Allow applicants visibility on cost, status and to submit payments online
Update utility tools and initiate meter install processes (utility facing)	Ability to push application information to utility GIS, work management system and meter department to initiate meter set process, and to customer information system for

[69] IOAP Report, p. 1.
[70] *Id.*, pp. 21-24.

	updated billing
Viewing Maps (public facing)	Allow the public to view maps of the system where it may be better or worse to install DER
Reporting Capability and Options (utility facing)	Allow utility to run reports on applications and to export for sharing results with other entities such as NYSERDA and NY Department of Public Service
Interoperable with Utility Systems (utility facing)	Allow the public-facing portal to integrate with utility tools through an application programming interface to enable automation
Expandable portal architecture that is flexible, scalable, and transparent (both public and utility facing)	Future ability to adapt to Phase 2 and 3 of the roadmap to integrate more with utility systems and streamline interconnection
Implement SIR Technical Screens A through F	Screen A: Is the point of common coupling ("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

The evaluation of the readiness to meet the IOAP automation goals of REV included four components: (1) speed of application processing, (2) ability to validate system data, (3) thoroughness of technical review, and (4) time to integrate with utility systems. The IOAP Report included an evaluation of vendors' readiness to provide key functionalities and determined that no single solution is currently capable of meeting all requirements. Additionally, the IOAP Report determined that although many steps in both application management and technical review activities can be automated, some will still require manual review by experienced engineers and technical staff. This is due to the current state of vendor platforms and the format of utility system data across the utilities. As the utilities further update their data systems, the ability to automate portions of the interconnection process should increase.

In light of current vendor and utility capabilities, the IOAP Report included a phased roadmap for achieving the various functionality requirements:[71]

- Phase 1: Automate Application Management (scheduled for completion by 2017)
- Phase 2: Automate SIR Technical Screening (scheduled for completion by 2017)
- Phase 3: Full Automation of All Processes (scheduled for completion by 2019)

The goal of the first phase is to achieve semi-automation by automating the application management portion of the process. Utility efforts during this phase will focus on automating both the public- and utility-facing components of application management.

During the second phase, utilities will achieve automation of the SIR technical screens. Because this phase requires an expanded data set and integration of various utility tools, following initial

[71] *Id.*, pp. 13-17.

completion, the utilities plan to progress through roll-out of this phase at varying rates across each service territory based on current utility system data availability, software vendor capabilities and internal system integration challenges. To fully achieve the desired phase 2 outputs, integration with billing, customer information systems, work management systems, GIS, and load flow software programs will be required, at a minimum.

Finally, the third phase calls for automation of all processes including the integration of the interconnection process into the broader distribution system planning process. Like the second phase, the utilities expect to progress through this stage at varying rates based on their ability to close data gaps and integrate the DG interconnection process with other planning processes.

It should be noted that many of the capabilities outlined in Phase 2 and all of Phase 3 are not currently commercially available. Among other items previously identified, implementation will require integration of back-end load flow software programs with front-end portals, frequently developed by two separate vendors. O&R received a grant from NYSERDA to work with Electrical Distribution Design and Clean Power Research on a project with the objective of building a seamless DER Interconnection Assessment Application that consists of the PowerClerk® front-end application processing integrated to a back-end engineering analysis tool. The result will be similar to an online application for a credit card with a notification on the spot for approval or required follow-up. O&R's project to integrate Distribution Engineering Workstation and PowerClerk® is in its early stages and will provide valuable lessons for the utilities as they progress into more advanced stages that may impact how they achieve the overarching goals of the IOAP.

The Joint Utilities are committed to working in parallel to achieve automation of the various components of the interconnection process in the timeframes outlined in the IOAP roadmap. In line with the IOAP roadmap, automation in this context entails a near-term focus on automation of the IT components of the DG interconnection process while allowing for checks by engineers or technical staff on some of the screens as each utility works through the data roadmap as outlined in its Initial DSIP. While selected vendors and interfaces may vary by utility based upon current state, the Joint Utilities will work together to implement consistency in functionality where technically feasible.

D. Ongoing Efforts Impacting Future Interconnection Processes

The phases of the IOAP roadmap reflect an evaluation of current functionality requirements and vendor and utility capabilities. However, ongoing developments in policy initiatives, individual utility initiatives, and other related forums may necessitate adjustments to this roadmap. In particular, the ITWG and IPWG are tasked by the Staff with engaging various parties to determine any necessary changes to the DG interconnection process.

1. ITWG and IPWG

The ITWG and IPWG will assist the utilities in developing future interconnection plans, including any changes to the interconnection process. The ITWG's job is to focus on consistent standards across the utilities to address technical concerns affecting the DG community and interconnection procedure. Ultimately, the ITWG seeks to maintain a collaborative approach among the utilities, Staff, NYSERDA, and developers in addressing the technical components of the DG interconnection process while also providing reliability and safety.

One major undertaking through the ITWG has been the development of a Joint Utilities position statement on anti-islanding protection measures that focuses on reducing the need for DTT for the interconnection of inverter-based systems, identifying lower-cost alternatives to DTT where risk to public safety and service reliability is adequately mitigated, and reducing cost impacts when DTT is required. There are other efforts underway to investigate alternate methods for mitigating the risk of unintentional islanding associated with synchronous engines such as Con Edison's phase comparison demonstration project and Central Hudson and National Grid's PLCC frequency signal system pilots (see the *Current Efforts to Increase Hosting Capacity* subsection). In addition to its focus on DTT, the ITWG has focused on topics including substation transformer backfeeding (thermal, voltage, and ground fault voltage or current zero sequence protection ($3V_0$ or $3I_0$) requirements, the technical screening process, monitoring and control requirements, cybersecurity, and smart inverter technology and adoption. To further enhance transparency on these topics, the Joint Utilities have produced matrices on positions regarding many of these key technical issues.

In a separate forum, the IPWG's goal is to explore non-technical issues related to the processes and policies relevant to the interconnection of DG in New York. Specifically, it has developed proposals for interconnection queue management of DG and associated cost sharing mechanisms. These two solutions are timely in addressing the statewide utility backlogs created after the introduction of community DG programs[72] and remote net metering requirements.[73] Additionally, the DG Ombudsperson role at each utility was established to primarily assist DER developers and utilities to resolve interconnection-related questions and disputes. The Ombudsperson's main goals are to improve communication between the developers and the utilities, improve interconnection process transparency, and identify and resolve interconnection process issues.

The DG interconnection process and the SIR are expected to change over time. It is anticipated that both the ITWG and IPWG will be key platforms for suggesting improvements to the SIR. Discussions and outcomes from these working groups will impact the application management and technical review activities associated with the interconnection process. This will have a direct effect on the IOAP roadmap for the Joint Utilities. To the extent that developments from these groups modify the proposed IOAP roadmap, the utilities will evaluate the necessary changes to their respective DG interconnection processes and plans. For example, if a more complex technical screen is proposed, the process for automating this screen may have to be modified or extended.

[72] Case 15-E-0082, *Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program,* Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015)("CDG Order").
[73] Case 15-E-0082, *Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program,* Order Granting Reconsideration in Part (issued October 16, 2015)("CDG Implementing Order")

V. Distribution Grid Operations

The core responsibility of the distribution utility in its role as grid operator is to maintain the safety, security, and reliability of electricity delivery to end-use customers. Meeting this obligation involves operating the grid in normal and emergency conditions, which entails several functions, including real and reactive power flow management, voltage management, outage restoration, distribution equipment maintenance, power quality assurance, and operational efficiency improvements.[74] DER can assist in providing these grid functions, but as the penetration of DER grows and power flows in multiple directions across the grid, operating the grid becomes more complex. This increased complexity in grid operations drives an increased need to monitor, measure, coordinate, and control grid parameters to maintain safety, and reliability. As noted in the MDPT Final Report, "to manage this increased complexity, the system operator will need new analytical tools that will provide improved situational awareness and controls to keep the system optimized on a real-time basis."[75] Additionally, as monitoring and control evolves in conjunction with market development, this infrastructure will provide opportunities for DER providers to ascertain, and in some cases monetize the value they can provide to the system. The increased complexity will also drive the need for increased coordination among NYISO, the utilities as DSPs, and DER providers and for enhanced visibility of the distribution system.

Each utility's individual DSIP proposed roadmaps for investing in the enabling technologies necessary for reliability and efficiency of operations in a proliferated DER future and also to enable future market development. These investments are part of a phased approach to increase operational capabilities, particularly through enhanced visibility, analytics, and operational control. For example, the utilities identified investments in DMS and distribution automation ("DA"), which will enhance monitoring and control capabilities of the system. The utilities also propose to develop plans to establish a communication and IT infrastructure investment framework that would further support the integration of the different components of DMS and/or ADMS. Additionally, all utilities, with the exception of Central Hudson, are implementing or have submitted business cases that support Advanced Metering Infrastructure ("AMI") investments. Many of these investments have implementation periods that extend beyond the five-year horizon of the initial DSIP filings and all investments are subject to Commission review and approval prior to implementation.

The enhanced capabilities, many of which rely on digital technologies and connect through communications networks, must be paired with strong security measures to protect against the release of sensitive information and breach of utility systems by unauthorized users. The Joint Utilities' approach to cybersecurity and privacy protection is discussed in further detail in the *Data Collection, Access and Security* chapter.

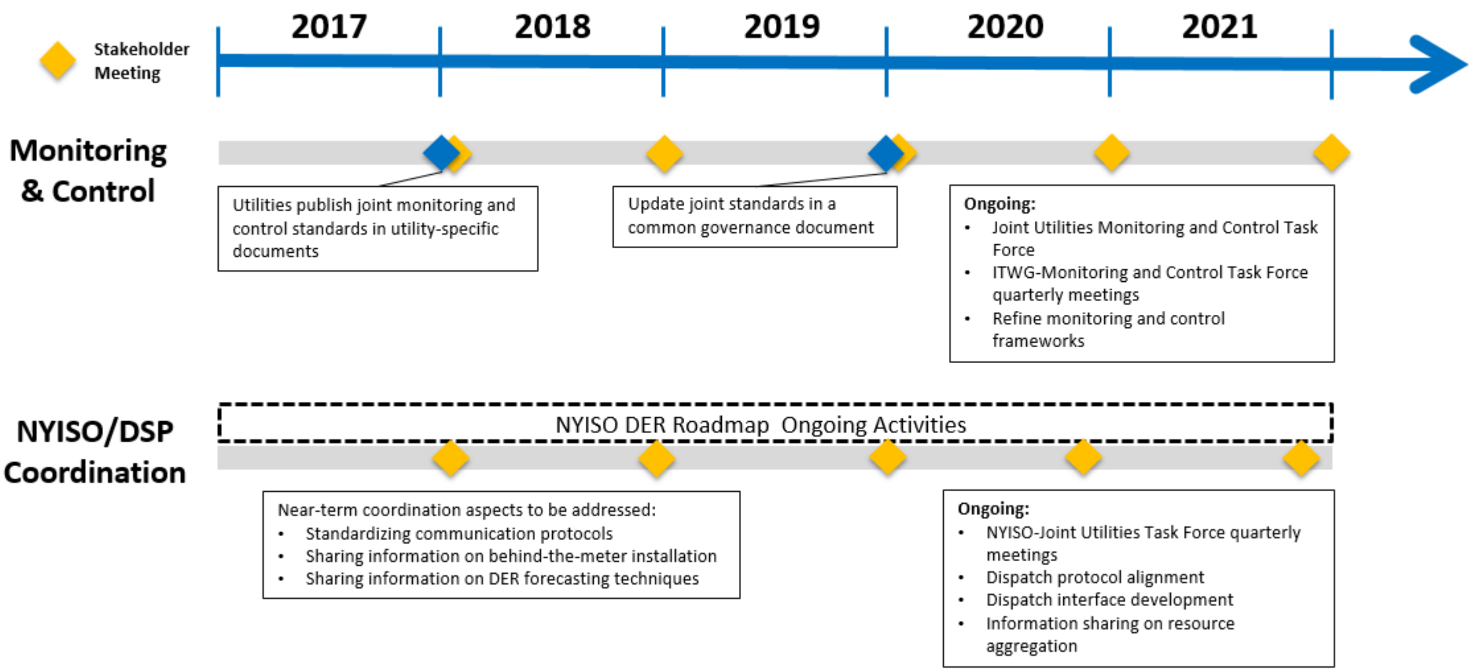
To maintain system reliability, the operations of the transmission system need to be coordinated with the distribution grid. In New York, NYISO is responsible for the operation and planning of the bulk grid, while the individual utilities are responsible for the maintenance, operation, and planning of their own respective transmission and distribution grids. The increased penetration of DER is

[74] These functions are adapted from REV Proceeding, MDPT Final Report, p. 52.
[75] *Id.*

expected to expand the scope of current coordination that exists between NYISO and the utilities. Thus, to support enhanced coordination, the Joint Utilities establish a functional understanding of the evolving roles and responsibilities of NYISO and the utility as DSP and outline a plan for continued and improved collaboration. It is expected that the development of enhanced operational standards and protocols will facilitate the integration of DER into distribution grid operations.

Figure V-1 summarizes the near- and medium-term high-level actions proposed by the Joint Utilities over the 2017-2021 timeframe covered by this Supplemental DSIP.

Figure V-1: Summary of Distribution Grid Operations Next Steps



Monitoring and Control

A. Introduction

Large-scale implementation of DER and growing operational complexities are expected to drive the need for the evolution of the distribution system from a relatively manual system to an automated system that can respond to the various dynamics of the electric grid. This automation will maintain or increase the reliability and efficiency of the grid under conditions created by the proliferation of DER.

As DER penetration increases, enhanced monitoring and control capabilities are needed for continued safety, security, and reliability and to support other REV objectives, such as resiliency and system efficiency. Monitoring is the ability to observe the performance of various assets on the distribution system. Enhanced utility monitoring capabilities increase the situational and performance awareness of DER on the utility grid, which can inform short- and long-term planning, help ascertain the value that DER can provide to its system, and promote reliable, flexible, and efficient operations. For example, enhanced monitoring tools can help identify adverse real time conditions, while enhanced monitoring tools coupled with predictive analytical capabilities and appropriate control measures can potentially preempt emergency conditions on the system. Technologies that enable enhanced monitoring include DMS (*i.e.*, DSCADA and associated advanced applications) and their supporting infrastructure.

Control refers to the manual or supervisory signaling and resulting control of distribution assets to satisfy system operational goals in real time. Where the operations of the distribution asset impact the bulk electric system, there must be continued collaboration between the NYISO and utilities. The control of DER assets provides the needed responsive capability for preserving safety and reliability on both the distribution and bulk electric systems.

The Joint Utilities support monitoring and control initiatives that enable and enhance the safe and reliable operation of the distribution and bulk electric grid. To that end, the Initial DSIP filings individually submitted by the utilities included plans for enabling investments in monitoring systems, control systems, and distribution infrastructure upgrades to support DSP capabilities, including the measurement and verification of DER performance.[76] For this Supplemental DSIP, the Joint Utilities have developed common monitoring and control standards, which will be formally documented by each utility, in its respective interconnection documentation. These standards are required to continue to operate the system in a secure manner, while maintaining reliability, safety, and power quality.

The Joint Utilities anticipate that monitoring and control technologies will continue to advance over time, and the related standards and protocols will also evolve to keep pace with market and technology developments. Additionally, as markets develop and mature, DER providers may offer new products and services to the utilities and/or to NYISO (see *NYISO/DSP Roles, Responsibilities, Interactions and Coordination* section). This changing product and service environment may require that specific monitoring and/or control standards be modified for the

[76] The Initial DSIPs provide the information requested in items 2.a.ii and 2.a.iii of the DSIP Guidance Order, Attachment 1.

proper engagement, monitoring, and settlement of qualified resources. Thus, continued collaboration among the utilities to provide standards consistent with ongoing developments will be critical going forward.

The following sections detail the process followed by the Joint Utilities to develop the common monitoring and control standards, and the utilities' individual plans to add capabilities to their existing operational systems and the grid. The monitoring and control standards, discussed subsequently, consider the utilities' existing and planned capabilities, along with the flexibility of implementation in the future.

B. Development of Monitoring and Control Standards

The Joint Utilities reviewed current practices across the utilities. Their review included recently identified monitoring and control needs, and the expected opportunities and challenges for monitoring and control requirements related to the continued penetration of DER. This included an analysis of current and expected near-term developments in associated technology, along with the review of monitoring and control practices and standards implemented by other utilities across the country. Additionally, the Joint Utilities coordinated with the work of other groups, including the ITWG, as applicable.

1. Review of Current Practices and Capabilities

Through a self-assessment, the utilities evaluated the monitoring and control technologies that are presently deployed in their territories, as well as future plans. The technologies considered were AMI, SCADA systems, OMS, DMS including advanced applications, EMS, and Distributed Energy Resources Management System ("DERMS"). The degree of deployment of these operational tools varied among utilities, as has been dictated by their respective network topologies and operational characteristics. The Joint Utilities shared roadmaps, derived from their Initial DSIPs, highlighting milestones for the deployment of these technologies.

This process allowed the utilities to identify principal areas of alignment, which helped establish a baseline for the Joint Utilities' common monitoring and control standards. Importantly, this process also identified the need to continually reassess developments related to monitoring and control, including assessing technological developments that could assist with the important function, and assessing the need for changes to the monitoring and control standards as conditions on the system change.

2. Benchmarking Process

As a part of the benchmarking activities, the Joint Utilities examined the extent to which the technologies and tools mentioned above had been deployed by other utilities in the country. The utilities' review included Duke Energy, Pacific Gas and Electric ("PG&E"), San Diego Gas & Electric ("SDG&E"), Austin Energy, CenterPoint Energy, and Southern California Edison ("SCE"). The Joint Utilities also examined recommendations from California's Electric Rule 21,[77] and the Institute of Electrical and Electronics Engineers ("IEEE") 1547, which is the standard for

[77] The California Public Utilities Commission adopted Electric Rule 21 as the tariff for the interconnection of distributed generation to each regulated utility. http://www.cpuc.ca.gov/General.aspx?id=3962

interconnecting DER with electric power systems.[78] Lessons learned from this benchmarking are incorporated throughout this section.

The Joint Utilities reviewed the standards and protocols employed by Independent System Operators ("ISOs") to monitor and control generators interconnected to the system they manage. Additionally, to understand the monitoring and control implications for DER aggregation following an ISO's dispatch signal, the Joint Utilities studied the California distribution utilities' comments on the California Independent System Operator's ("CAISO") Distributed Energy Resource Provider ("DERP") proceedings.[79]

The benchmarking process indicated limited coordination across multiple utilities in individual areas in the United States. In part, standards are driven by individual utility conditions and capabilities, and the benchmarking results reflected the need for flexibility on the part of utilities to consider local conditions. In the case of California, some progress has been made to establish high-level common standards. The review of the California utilities' comments on the DERP proceedings highlighted that utilities need to understand and analyze the impact of individual DER on the distribution system, even though the DER may be part of an aggregate.

3. Stakeholder Engagement Process

In developing the standards, the Joint Utilities convened a stakeholder engagement group of DER providers and public interest groups to provide input and feedback on the subject of monitoring and control of DER. The topics for the engagement group discussion included:

- Determine monitoring requirements of DER;
- Explore the impact of DER on real-time grid operations that include scheduling, operation, and dispatch;
- Explore potential control signals to align NYISO and utility needs for generation or load reduction;
- Discuss operational standards for DER aggregation; and
- Discuss DER response to emergency and contingency events.

The Joint Utilities considered these discussions while developing the monitoring and control standards. At a high level, there was general agreement among parties that monitoring and control standards will need to evolve as technologies mature. For example, smart inverters may be expected, in the future, to provide additional grid services and capabilities, including variable VAR support.

DER providers expressed a desire to have a better understanding of the situations in which monitoring and control may be required, especially for small DER. The Joint Utilities have communicated that monitoring and control below the one MW threshold may be required in order to have situational awareness and to provide local reliability in areas where small DER may cause an adverse operational impact.

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[78] http://grouper.ieee.org/groups/scc21/1547/1547_index.html

[79] Federal Energy Regulatory Commission, Docket Number ER16-1085-000, California Independent System Operator, Order Accepting Tariff Revisions Subject to Conditions (issued June 2, 2016).

Specific examples of monitoring and control equipment requirements are provided in the standards below.

The stakeholders also provided feedback on communication protocols, while expressing a preference for wireless cloud-based communications standards. Several stakeholders described the benefits to DER providers arising from the adoption of a standard set of communication protocols on a national level. They pointed to the California example of movement towards the adoption of standards such as OpenADR and SEP 2.0 (IEEE 2030.5).[80] One of the advantages referenced by stakeholders was that of cross-functional capability and design, allowing communications to interface with a wider suite of DER technologies, such as energy storage, inverters, and energy management systems, and the lower infrastructure needs associated with their use. While some protocols are being developed to encompass inverters and a broader suite of DER technologies, further study is needed to validate performance, security, and compatibility with existing systems and equipment, along with the benefits, costs and the cost recovery mechanism associated with implementing a new standard.

To facilitate continued discussion, the Joint Utilities will convene a utility working group to discuss important issues, such as the adoption of emerging protocols, an implementation timeline for the monitoring and control standards, and enforcement procedures. The working group will aim to provide certainty on the evolution of monitoring and control standards to the DER providers going forward. The Joint Utilities are committed to engaging with NYISO, as well as stakeholders to better understand their perspectives and concerns, and to seek solutions consistent with objectives around DER participation, grid reliability, and safety.

C. Assessment of Current and Planned Capabilities

1. Variability in Current Capabilities

Presently, each of the utilities' monitoring and control capabilities vary. This can be partly attributed to their legacy systems and electrical topography, as well as the characteristics of the customer base they serve. For instance, the technical architecture for electric delivery in New York City is completely different from the system architecture in rural parts of upstate New York. The systems not only vary among different utilities, but also within utility service territories. National Grid serves the older downtown communities of Buffalo, Albany, Syracuse, and Schenectady using an underground secondary network, while most of its other areas are served using an above ground system. Urban areas often have a high density of loads, which when combined with high

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[80] IEEE 2030.5 is a standard for communications between the smart grid and consumers. The standard is built using Internet of Things ("IoT") concepts and gives consumers a variety of means to manage their energy usage and generation. Information exchanged using the standard includes pricing, demand response, and energy usage, enabling the integration of devices such as smart thermostats, meters, plug-in electric vehicles, smart inverters, and smart appliances.

IEEE 2030.5 further defines a framework to support these applications to enable a secure, interoperable, and plug-and-play ecosystem of smart grid consumer devices. Particular emphasis will be given to the integration of distributed energy resources as IEEE 2030.5 has been recommended as the default protocol for smart inverter communications for California's Electric Rule 21.

demand, causes high equipment utilization factors (such as on transformers and cables), while rural areas are characterized by larger geographical coverage and lower load density and thus longer lines, high network impedances, and lower equipment utilization factors.

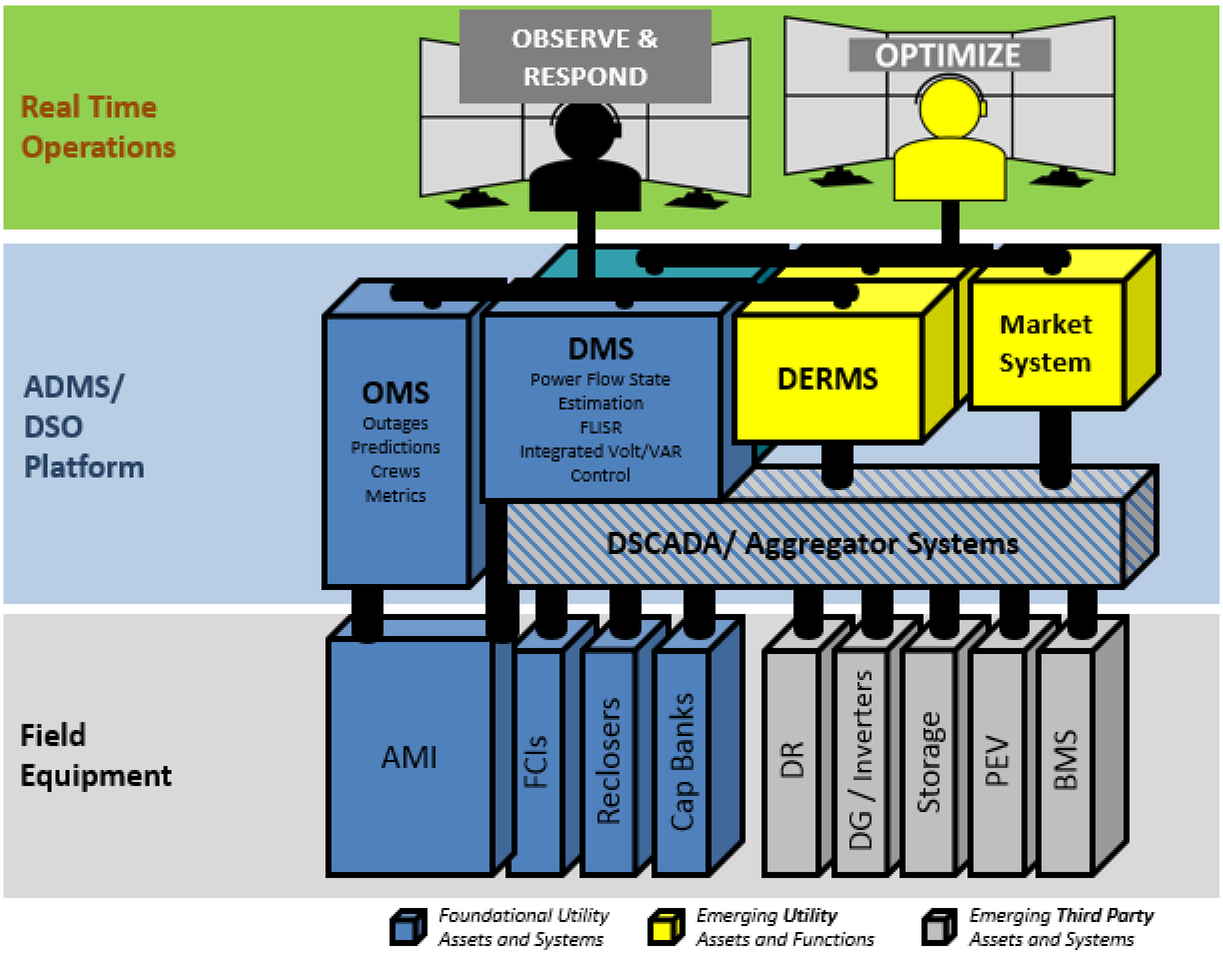
Each utility's communications infrastructure for monitoring and control also depends on variations in physical terrain and customer concentration, as communication infrastructure backbones such as fiber optics and radio network development have varied. The relative requirements for monitoring and control based on risk of faults or reliability concerns naturally differ. As a result, the degree of monitoring and control capabilities may vary across areas. Additionally, the range of customer types across a variety of geographic densities further impacts the voltage profile and the exposure to outages from circuit to circuit across a utility system.

The variation in monitoring and control capabilities is also attributable to the systems in place for distribution system management at each utility and the pathway by which such systems have developed over time. Historically, systems have been homegrown or developed at alternate points based on needs-based drivers. Linkages between outage management systems and fault detection systems, for example, have developed at different rates for the utilities. The distribution grids in place today throughout New York have been designed and operated in a one-way direction from transmission substation to end user, with predictable flows and fault potential, and as a result, the automation, and monitoring and control capabilities included have been designed to support this environment.

2. *Planned Technology Investments*

The Joint Utilities are reviewing their current energy management systems and developing roadmaps and requirements to meet the evolving demands of the DSP role and focusing on "no regrets" investments that are likely to produce benefits under a range of expected future outcomes and timeframes. As described in the Initial DSIP filings, each utility requires investment in management systems, technologies, and processes to augment their future capabilities as a DSP. Specifically, many of these management systems would benefit operations by providing enhanced visibility into system conditions through monitoring, and enhancing security and performance through advanced control functionality. The Joint Utilities identified that the overall technology approach to implement advanced monitoring and control functions could be further distilled into near-term and long-term deployment plans. While each utility's approach is somewhat unique, Figure V-2 illustrates the management systems and field technologies that are needed to support operations in an environment with increasing DER penetration.

Figure V-2: Enabling Technologies[81]



Currently, the utilities monitor and control the distribution system using a range of field equipment, which are integrated with existing control systems like OMS via DSCADA. At low- to moderate levels of DER penetration, investments are needed in technologies like AMI and DMS to enhance the capabilities and visibility of the distribution system. These systems also enable increased granularity of information to be available to the system operator, thus facilitating better operational decision-making. At very high levels of DER adoption, the utility would need to invest in capabilities like DERMS, as the utility begins to see substantial interactions with markets. At high DER penetration levels, utility operations require substantial automation as the utility begins to optimize DER performance on the grid.

Over the 2017-2021 timeframe, the utilities plan to improve upon and implement new technologies in their service territories to support DSP integration, subject to Commission approval. For example, some individual utilities will deploy or propose to deploy AMI across their respective

[81] Adapted from a National Grid-commissioned study on an Operations Control Center Roadmap. "FCIs" refers to Faulted Circuit Indicators. "PEV" refers to plug-in electric vehicles. "BMS" refers to building management system.

service territories. By 2021, the utilities also plan to either deploy, partially deploy, or test the deployment of a DMS in their service territories (consisting of DSCADA and ADMS), including the communication and IT infrastructure investment framework that would support the integration of the different components of the DMS and ADMS. ADMS is expected to increase situational awareness and the usability of monitored system metrics, and help mitigate real-time and predicted emergency system conditions. Additionally, locational deployment of DER could be facilitated with the improved system visibility arising from the DMS.

Utilities will also be able to interface their DMS with GIS, which will provide a geographic representation of the electric distribution system, thus improving system visibility and visualization. Further detailed studies and experience with DMS will be needed for optimizing DER dispatch and system configurations. Additionally, using the DMS system as a foundation, utilities may commission and incorporate additional software platforms such as DERMS.[82] The purpose of a DERMS is to integrate a suite of applications into DMS to actively manage and control a diverse set of DER, thus maintaining system security and possibly allowing the ability to undertake economic dispatch of DER. The need for DERMS is being evaluated across the state. The timeline to implement DERMS (subject to Commission approval) will vary by utility, and will depend on system topology, DER penetration, and other technical considerations. The utilities are carrying out demonstration projects and pilots to test DERMS, and will share the lessons learned to support their future efforts in this area.

While playing an important role in the monitoring and control of DER, ADMS is expected to assist in several other distribution grid operations as well. The ADMS provides operators the opportunity to monitor and control the distribution system from a single platform, and increases the efficiency of deploying and integrating new systems. The installation of an ADMS is expected to yield economic and operational benefits, due to lower system monitoring and data acquisition costs. This is because the ADMS' single platform can be used to observe multiple operational parameters, thus eliminating the need for dedicated portals for each application. An ADMS can also provide advanced grid management services such as automated Fault Location, Isolation and Service Restoration ("FLISR") (distributed or centralized), Volt/VAR optimization, DA, and predictive load flows to assist in switching operations.

The timing to commission new systems and their integration with the existing systems for each utility is subject to obtaining the necessary investment approvals and the associated rate recovery mechanisms.

Table V-1 below provides a utility-specific snapshot of planned technology investments into systems or demonstration systems within the next five years and beyond. Furthermore, the table displays the timeline for the initiation of these programs only, and not the proposed end date of deployment across the utility service territory. It is expected that the deployment will be undertaken in a phased manner as seen in the case of current AMI programs. The individual utilities' Initial DSIPs and rate cases provide more specific details.

[82] There are presently are no commercial vendors that can offer an "off-the-shelf" DERMS solution. Further, the DERMS offered by vendors will need to be customized and modified per individual utility needs, prior to the systems' installation and deployment. As a result, the various technologies that are installed as a part of the DERMS package will vary by utility, as dictated by each utility's needs and requirements.

Table V-1: Planned Utility Technology Investments

Utility	2016	2017	2018	2019	2020	2021	>2021
NYSEG/ RG&E	Working on a business case for AMI	ADMS automation and AMI pilot programs within the Energy Smart Community (“ESC”)		AMI integration with Energy Control Center (“ECC”) to start Volt/VAR Optimization, Closed loop voltage control, Power flow management, Communication Infrastructure developments			Advanced DMS functions
Central Hudson	Develop DSCADA/DMS links to other systems (*e.g.*, OMS, EMS, GIS); development of training simulator.	Develop and roll out Volt/VAR control and FLISR Develop Distribution Control Center			Implement OMS features of DMS		Advanced DMS functions
Con Edison	AMI deployment approved	Phased DERMS studies (end in 2020) AMI deployment to begin (end in 2022)		DMS functionality testing			Advanced DMS functions
O&R	Implement Meter Data Management System (“MDMS”), Implement Meter Asset Management System (“MAMS”), IT integration (*e.g.*, Customer Information Management System (“CIMS”), OMS) Establish AMI Operation center	AMI deployment to begin		DMS functionality testing			Advanced DMS functions

National Grid	Working on a business case for AMI	Review MDMS Plan	Begin AMI implementation (end beyond 2022) DMS (DSCADA and ADMS) Deployment and Testing	DERMS

In their technology assessments, the utilities realize there is no one-size-fits-all solution, as distribution networks are heterogeneous in terms of grid equipment and DER density at different voltage levels. Every distribution network should be assessed individually in terms of its network structure (*e.g.*, customers and connected generators) and public infrastructures (*e.g.,* load and population density), and system development should be in line with the individual needs. With this in mind, it is expected that specific monitoring and control practices will have variations across utilities and even within utilities based on area characteristics. Acknowledging this fact, the Joint Utilities propose common monitoring and control standards to facilitate uniform participation of DER across the utility territories in the future.

D. Monitoring and Control Standards

The Joint Utilities developed a set of standards that makes the most efficient and cost-effective use of their existing networks and systems, while transitioning to an automated operational platform. To maintain adequate monitoring and control over the system to ensure safety and reliability, the Joint Utilities establish the following parameters pertaining to the monitoring and control of DER, as standalone resources or in aggregate.

With this filing, the Joint Utilities have developed common monitoring and control standards, which will lay the foundation for the evolution of the distribution system. The Joint Utilities expect that these standards will be reflected in the relevant monitoring and control related documents at the individual utility level in the next 12-15 months.

Based on operational experience, the Joint Utilities have established a size threshold that triggers monitoring and control requirements. All DER sized at one MW or above will require standard monitoring and control (such as a recloser). Under certain system conditions, the utilities may require monitoring and control of DER below the one MW threshold in order to mitigate system impacts. The level of monitoring and control for DER below the threshold may vary based on system topography, location, and other constraints. In general, it is not expected that residential and small commercial systems would trigger monitoring and control requirements.

For aggregated DER systems, monitoring data for individual DER will be required to enable the utilities to identify the locations of DER to maintain the safety and reliability of the distribution system.

Understanding that markets and technology will evolve, existing and future DER will be expected to comply with the monitoring and control standards in effect at any given time. This evolution may necessitate that DER update their equipment to comply with the monitoring and control standards in effect at that time in order to participate in new markets or services. Additionally, the Joint Utilities expect that as DER penetration increases and inverter capabilities and communication protocols consolidate and mature, the one MW minimum level will evolve to a lower threshold for monitoring of solar PV systems to meet future planning and operating needs. The Joint Utilities propose working with the solar PV developers through the ITWG to mitigate the cost impact of this monitoring by leveraging inverter capabilities.

The Joint Utilities developed a list of elements that will comprise the monitoring and control standards. Table V-2 aids in categorizing the elemental influence on monitoring and control. It should be noted that monitoring and control have a reinforcing relationship, such that enhanced control requires increased monitoring and increased monitoring facilitates better control. The elements listed are not exhaustive and may be expanded in the future in accordance with system and technology evolution. These control elements are applicable where monitoring and control is required, unless noted otherwise.

Table V-2: Categorizing Monitoring and Control Elements

Elements	Influence on Monitoring	Influence on Control
Polling Frequency	✓	
Communication Protocol	✓	✓
Circuit Parameters	✓	
VAR Support	✓	✓
Curtailment		✓
Notification on DER connection and disconnection		✓
DER Performance Forecasting	✓	
Advance Function Support	✓	✓
Worker Safety		✓

1. *Polling Frequency*

DER will require monitoring at regular polling frequency, with near constant communication between the DER and the applicable monitoring system. The monitoring frequency and sampling rate currently varies from two to 60 seconds, depending on the technical capabilities of the system (*e.g.*, the SCADA scan rate), DER size, and grid services being provided by the DER. Furthermore, the scan rate may vary within an individual utility's service territory, depending on system topology and circuit configuration. Each utility will establish scan rates based on their system technologies and requirements.

2. *Communication Protocols*

DER will communicate with utility communications systems by means of generally accepted, industry-established communications protocols such as Distributed Network Protocol ("DNP"), Modbus, International Electrotechnical Commission ("IEC") 61850, and others. The exact protocols specified and used may differ depending on each utility's communications technology infrastructure.

The Joint Utilities envision that communications standards and protocols will evolve over time, and recognize initial industry movement toward the expanded use of serial communications channels. While practical limitations exist today given current system configurations and capabilities, the Joint Utilities are committed to working with vendors and stakeholders to consider alternate communication pathways as the individual utilities' systems develop over time. The Joint Utilities believe that such considerations should include a review of the capabilities of the protocols and standards, the proven application of such protocols and standards, the acceptance of such standards/protocols by product vendors, the impact on real-time operations (*e.g.,* latency issues and packet transfer rates), enhanced security measures required to be in place (*e.g.*, firewalls), and ultimately cost implications to consumers versus benefits to grid operations.

3. Circuit Parameters

DER will be subject to monitoring of circuit parameters. The Joint Utilities currently require, and will continue to require, information on DER and circuit parameters such as but not limited to power factor, real power, reactive power, phase current and voltage, hot line tags, and device status (open, close, or lock-down). The parameters listed are not exhaustive and will evolve as markets and technologies advance. As the DER participate in utility or NYISO programs, communications regarding monitoring and control will be directed through the utility, similar to the current requirements associated with transmission operations. Protocols will need to be established such that utilities understand the system impacts of third parties' direct participation and communication with the NYISO.

4. VAR Support

The utility is currently providing, and will continue to provide, reactive power or VAR support to the distribution grid. In the future, as technology and market evolution occurs, DER may also provide VAR support on a dynamic basis as requested by the utility. For advanced technologies that can provide VAR support, such as smart inverters, certain utilities plan to implement demonstration projects to vet the technology and fully understand its functionality to ascertain monitoring and control requirements prior to the technology's wider application for VAR support. For any wide-scale deployment, a revision of the UL 1741 testing standard to include this functionality will need to be made.

5. Curtailment

For DER 50 kW or above (standalone or in aggregate), the utility may limit the operation, or disconnect, or require the disconnection of the DER from a utility's distribution or transmission system at any time, with or without notice, in the event of real or predicted abnormal operating conditions, so that the safety and reliability of the system is preserved.[83] For planned and scheduled maintenance events, prior notice (typically 48 hours in advance) will be provided whenever possible.

The utility will follow non-discriminatory practices when curtailing DER for safety, reliability, or maintaining the distribution system's operating parameters, and curtailment will not be undertaken for the purpose of hindering the participation of DER in any markets or utility programs. In the stakeholder engagement meetings concerns were raised by DER providers with regard to DER curtailment. The Joint Utilities acknowledge this concern, will put non-discriminatory processes in place, and intend to continue to address such processes for unbiased treatment. Such processes already exist at the transmission level, and the Joint Utilities anticipate that adoption of similar

[83] SIR Order, Exhibit A, pp. 24-25.

practices. The technicalities of adopting a similar framework at the distribution level will be subject to continuing utility and stakeholder discussions.

6. Notification of DER Connection and Disconnection

In order to maintain a safe and reliable system, the utility needs to be informed of the current and forecasted operating status of a DER. DER sized 50 kW or greater (standalone or an aggregate) shall notify the utility when disconnecting/reconnecting to the distribution system, regardless of enrollment in NYISO-administered wholesale markets.

As the system evolves, each individual utility will refine connect and disconnect notification requirements based on the size of a DER and its impact on local reliability. The notification requirements may vary by utility. Prior to formal publication of utility interconnection procedures, the requirements will be compared to the SIR for consistency.

Communications between DER providers and the utility regarding the status of a device or any other matter will continue to utilize existing procedures and protocols. For example, the DER operator will provide information in a timely manner via telephone communication with the utility.

7. DER Performance Forecasting

Utilities may require a short-term (*e.g.*, week-ahead, day-ahead, real-time) forecast for individual facilities' expected output for use as an input to the day-ahead planning process to secure the distribution systems for local reliability. This will be especially important as DER are dispatched in response to a signal from the markets instead of just serving customer needs. This will also be important as the level of DER increases and these resources reveal their own levels of operational reliability.

A breakdown of aggregated forecasts may be required for the utility to determine impacts on local reliability. In areas where local reliability issues are not impacted, an aggregated forecast may be acceptable, as determined and communicated by the utility.

8. Advanced Function Support

The utilities will support advanced DER functions, such as smart inverter functionality and electricity market participation, in the future. The utilities will set monitoring and control standards and requirements for enabling such advanced functionality, as needed. For technologies that can carry out advanced functions, certain utilities have indicated their intention to implement plans and roadmaps for demonstration projects to adequately test and verify the technology prior to any wide scale deployment within their service territory. Each utility's technical system capabilities will evolve at a different pace. Thus, the timeline to attain the optimal end point of advanced function support will vary. However, for any wide-scale deployment, the UL 1741 testing standard will need to evolve to include the specific smart inverter technology required in New York.

9. Worker Safety

The utility and field crews will have the option to take any DER offline (irrespective of the size) with or without notice to the DER provider in order to establish clearances and to prevent back feeding or inadvertent energization of elements being maintained or repaired. The decision to take a DER offline will be made on a case-by-case basis, with consideration for worker safety and system reliability.

These standards have been developed with the intention that it is and it will continue to be important for the utility to be aware of DER operation at any given time, as it would assist the utility to perform the requisite load transfers to avoid any system reliability and safety issues. The Joint Utilities also expect that as DER penetration increases, DER providers and utilities will gain more experience and there will be opportunities to further refine this initial set of monitoring and control requirements.

E. Implementation Approach for Monitoring and Control Standards

While the Joint Utilities will strive for standardization where possible, there is no "one-size-fits-all" approach or solution that can be adopted for the integration of DER within the Joint Utilities' service territories. As was detailed in the utilities' Initial DSIP filings, each service territory is unique in electrical topography, load profile, and demographics, and as such, the DER requirements, siting capabilities, and impacts are expected to vary, all leading to varying levels of monitoring and control requirements. Further, the Joint Utilities anticipate that monitoring and control requirements will evolve in conjunction with changes to distribution planning and market operations to provide the necessary data to plan and operate the system, and to facilitate market participation. Similarly, given the roadmaps of the utilities considering the phasing in of new technologies and system tools, there is likely to be an evolution of standards consistent with the progress of automation and control capabilities of the utilities.

The Joint Utilities recognize the complexities of designing detailed standardized protocols that capture the multiple differences across systems technologies. The monitoring and control standards are designed with both current limitations and future flexibility in mind. At present, the Joint Utilities intend to implement these standards through this filing and individual utility interconnection requirements for DER. Prior to the formal publication of the standards in the individual utility interconnection documents, the utilities will compare the listed standards to the existing standards and guidelines in the SIR and certain exceptions may be noted. An effective policy mechanism to implement the monitoring and control requirements will likely follow a tiered approach: the incorporation of high level requirements in a common platform or document (such as the SIR), followed by utility-specific processes as laid out in the individual utilities' interconnection requirements. This will provide enhanced flexibility in adapting these requirements for technology, market, and system evolution in the future.

A key challenge will be the implementation and enforcement of standards. It is expected that going forward, contracts and agreements that define the interaction of DER with the distribution grid (such as the interconnection agreement), will be amended in a timely manner so that standards are implemented. The Joint Utilities plan to remain in close coordination with each other to develop relevant standards that promote the goal of a safe and reliable electric grid.

The Joint Utilities plan to adopt these standards; however, to the extent that the individual utilities' current standards provide more specificity than the discussion this filing, the utility standards will continue to apply.

F. Summary of Next Steps

The Joint Utilities are aware of the need to constantly revise existing standards and to develop new standards related to monitoring and control to reflect the evolution of markets and technologies. The Joint Utilities identify three key steps going forward. First, the individual utilities will each publish these common standards in their respective interconnection requirements, with appropriate modifications for individual system conditions identified. Second, it is necessary for the Joint Utilities to continue to engage with each other to further develop the framework. Third, continued stakeholder input will be helpful to the process of developing effective standards. Accordingly, the Joint Utilities anticipate continuing a stakeholder engagement process. Finally, the Joint Utilities commit to the active engagement of staff in industry forums to facilitate the awareness and understanding of technology development and applicability to utility operational practices.

1. Documentation of Common Standards

The Joint Utilities intend to implement this framework through: (1) this filing; and (2) individual utility interconnection requirements for DER, allowing for noted exceptions within utility documentation. Each utility intends to update their appropriate documentation within the next 12 to 15 months.

Going forward, the Joint Utilities will develop and propose effective policy mechanisms to implement the requirements in the standards. This will likely follow a tiered approach as mentioned above: the incorporation of high level requirements in a common document, followed by utility-specific processes.

2. Continued Collaboration of Joint Utilities

The Joint Utilities have put a forward-looking internal plan in place to continue to collaborate after the completion of this filing. As a part of this continued collaboration and beginning in January 2017, the Joint Utilities will meet every two months discuss important issues, such as the adoption of emerging protocols, an implementation timeline for the monitoring and control standards, and enforcement procedures. The utilities will also collaborate with the ITWG and other Joint Utilities' working groups to maintain consistency. The coordination shall entail reviews of technical standards, as well as to identify implementation instruments, and to develop a timeline to amend and revise these identified instruments to enforce the expanded monitoring and control framework. It is anticipated that reviews with the ITWG will be on a quarterly basis beginning the second quarter of 2017. Updates regarding the discussions will be provided in the subsequent DSIP filings by the utilities.

3. Continued Stakeholder Engagement Process

Stakeholders identified and raised several points in the initial engagement sessions that warrant further discussion and consideration. These topic areas include communication protocols, inverter technology capabilities, and visibility into the development of monitoring and control standards. Conversations with stakeholders will be part of an overall continuing engagement process envisioned to cut across multiple areas.

4. Ongoing Education and Information Review

The Joint Utilities recognize the quickly evolving nature of multiple aspects of the distribution sector. In order to effectively disseminate information to operators and planners, the Joint Utilities believe that it is important to share information and lessons learned across utilities to help gain a common understanding of new technology performance and functionality. As a result, the utilities are committed to the ongoing education of their respective staffs through participation in industry forums including conferences, seminars, internal training programs, and other technology demonstrations. The utilities have also agreed to share information gleaned through utility demonstration projects and technical experiments amongst themselves.

Additionally, the ongoing education effort will further prepare utility staff to assess the benefits and capabilities of new technologies and protocols as they are introduced by vendors into the marketplace. This may potentially reduce the lag between the introduction of new technologies and their adoption. However, it should be noted that as the utilities install new systems and technologies, detailed studies will need to be undertaken to validate performance, security, and compatibility with existing systems and equipment, and to understand the benefits and costs of adopting a new technology. This review process will be applied to emerging communication protocols as well.

NYISO/DSP Roles, Responsibilities, Interaction, and Coordination

A. Introduction

The NYISO is responsible for operating the bulk transmission system, administering the competitive wholesale electricity markets, conducting comprehensive long-term planning for the wholesale bulk power system, and advancing the technological infrastructure of the bulk power grid. The New York utilities provide a parallel function of planning and operating their respective transmission and distribution systems.

Traditionally, operational coordination between the utilities and NYISO has largely focused on: (1) net load forecasts, particularly during projected critical peak conditions, (2) calls on distributed demand response resources, and (3) dispatch of generation participating in NYISO wholesale bulk power marketplace but interconnected to the utility's distribution system. As DER continue to penetrate the utilities' distribution systems and participate in NYISO programs,[84] additional coordination will be required for safe, reliable, and efficient operation of both the transmission and distribution system. Thus, the DSIP Guidance Order directs the utilities to "begin to define the obligations and actions that will be needed to ensure seamless and reliable operations of a dynamic transmission and distribution grid."[85]

Current coordination efforts can be enhanced further to support DER and market and technology developments. The lessons learned from current practices can be adapted to the evolving DER development. The Joint Utilities and NYISO agree that expanded engagement and dialogue is necessary to advance operational coordination for customer and system benefits.

The NYISO-Joint Utilities Task Force will meet at least quarterly and focus on the coordination needs between NYISO at the bulk transmission level and the Joint Utilities at the distribution level. This task force will identify changes to existing coordination processes and new areas of coordination as technologies and markets develop and will develop approaches to maintain system reliability, security, and safety while supporting increased DER activity. The task force will work toward establishing a formal process of information sharing and protocols to support coordination necessary to help new technologies enter the marketplace.

B. Current State of Coordination

1. Background

The electric grid is comprised of three major components working in tandem to serve load: generation, transmission, and distribution. The safety and reliability of the electric grid as a whole depends on the safe and reliable operation of its components. NYISO is responsible for securing, controlling, and planning the bulk electric system. NYISO also ensures there are appropriate and timely wholesale price signals produced through the overall market construct, including the Installed Capacity ("ICAP") market to incent the entry of new generators. The utilities are responsible for operating, planning, and managing their respective T&D systems safely and reliably. Utilities interact with NYISO in multiple capacities. First, utilities in their role as a

[84] This would include any new programs available as an outcome of the proposed NYISO DER Roadmap.
[85] REV Proceeding, DSIP Guidance Order, Attachment 1, p. 20.

transmission owner/operator ("TO") interact with NYISO to provide for the reliability, safety, and security of their respective transmission systems. Second, utilities in their roles as LSEs interact with NYISO to procure energy and capacity from NYISO's wholesale markets for customers who do not choose a competitive supplier.

The interconnected nature of the electric grid warrants extensive coordination among the entities operating and planning each component, as faults or issues at either the bulk grid or distribution level can potentially cascade through the system. For example, the utilities as TOs coordinate with NYISO on both the operational and planning aspects of their systems with consideration of dispatch feasibility on an intra-day/real-time basis and reliability planning on a long-term basis.

Currently, the utilities coordinate with NYISO on DR, which is viewed as net load reduction by the system operators. There is also experience to a lesser extent with certain DER such as micro-CHP units, which can be viewed as net generation. Currently a few DER (mostly CHP units) are interconnected to the utility distribution system with the ability to participate in the NYISO wholesale market. DER proliferation expected under REV will increase the need for enhanced coordination between NYISO and the distribution utility. In part, expanded coordination is needed due to the increasing presence of resources that can either export to the grid or serve as load modifiers.

2. *Current State of Coordination*

a. Load Forecasting

In terms of day-ahead load forecasts, the merchant arm of each utility, in its role of LSE, procures energy and capacity from wholesale markets operated by NYISO. The load bids placed by LSEs into NYISO's day-ahead market are comprised of a net load (MW) forecast and net energy requirement (MWh) by the hour. Each LSE submits its load bid to NYISO, where NYISO can compile the LSE forecasts and compare them to its own internal, independently developed day-ahead forecast for the control area under NYISO. After the day-ahead market clears, a Day Ahead Operating Plan ("DAOP") is produced by NYISO, which includes a comprehensive list of committed generation for every hour. This anticipated operating plan for the actual delivery day is shared with the utilities, which as TOs, assess the impact of wholesale dispatches on the reliability of their system. The utilities as TOs may also choose to communicate their respective control area day-ahead load forecasts to NYISO, though it is not required.

In real-time operations, especially on peak load days, there is more frequent communication, typically by conference call, between NYISO and the utilities' control rooms concerning peak load forecasts, time of peak, and capacity and reserve requirements. This communication facilitates increased operational and system awareness between the utilities and NYISO.

As noted in the *Load and DER Forecasting* section of the *Distribution System Planning* chapter, the utilities as TOs and in their planning-related coordination with NYISO share their respective 10-year peak load forecast with NYISO in December of each year to facilitate long-term planning. The 10-year peak load forecast from the utilities also presents the utility outlook on the anticipated DER levels in their service territories. As such, NYISO can consider the utility load forecasts when they develop their zonal outlook for load growth to inform transmission planning.

The Joint Utilities and NYISO rely on their independently developed load forecasts to meet their reliability obligations, although certain common assumptions are shared. The Joint Utilities expect closer coordination and more information sharing with NYISO going forward, which should help improve forecasting.

Table V-3 summarizes the operational coordination pertaining to load forecasting.

Table V-3: Peak Load Forecasting and Operational Coordination Details

Coordination Aspect	Coordination Details	Mode of Coordination	Frequency of Coordination
Load Forecast			
Day-Ahead	Utilities as LSEs with market functions forecast and procure required energy from NYISO's wholesale energy market on a day-ahead basis.	Utilities as LSEs indicate their zonal hourly load expectation to NYISO through the portion of their bid in the day-ahead market	Daily
Intra-Day/Real-Time	Utility (as TO) and NYISO control rooms communicate frequently on peak load days	Telephone conference call	As needed, with high frequency of communication occurring on peak load days
Long-Term	Utility (as TO) resource planners provide NYISO 10-year load forecast	Annual report	Annually (December of each year)

3. *DER including Demand Response*

Demand-side resources (including behind-the-meter generation) in New York can be classified into four major categories based on their program participation:

- Net-metered resources, such as roof-top solar PV, that do not participate in any utility or NYISO market;
- Resources participating in utility DR programs (*e.g.*, Demand Response Resources Commercial System Relief Program or Distribution Load Relief Program) or servicing system needs through an NWA solicitation;
- Resources participating in NYISO's DR programs (*e.g.*, Special Case Resources or Emergency Demand Response Program) and ancillary services program (*e.g.*, Demand-Side Ancillary Service Program); and
- DG enrolled in NYISO or Distribution Utility Tariff.

a. Net Metered Resources

These generation resources are generally viewed as load modifiers, because they are not dispatchable and tend to be small. Thus, these resources are generally not monitored directly and historically have limited visibility from an operational basis.

b. Demand Response Resources

Currently, utilities and NYISO independently run, operate, and dispatch their respective DR programs based on what is needed on the systems they operate. Resources may participate in utility-administered programs only, in NYISO-administered programs only, or in both. Utilities allow participation of resources in utility and/or NYISO tariff-type programs, providing demand side resources the opportunity to participate in multiple programs.

NYISO and the utility distribution operators coordinate regarding resources participating in either NYISO-only programs, utility-only programs or both. Identification of resources within the NYISO programs is an important first step in coordination. NYISO currently shares information regarding resource enrollment in its DR programs on a monthly basis with utilities that request it. Similarly, the utilities also share information on all the resources enrolled in their respective DR programs with NYISO. This is done through the DR program offices at the NYISO and the utilities. This coordination permits evaluation of DR that are enrolled in both programs and their ability to perform for the relevant program terms for the compensation.

It is necessary for the utilities and NYISO to have a sound understanding of the resources that are enrolled in their respective DR programs. In the event that utilities activate their respective programs at the same time as NYISO, there must be operational awareness on which resources are likely to receive performance notification from these entities and which resources are exclusively available to only a subset of the entities for serving their respective system needs.

The operational coordination pertaining to DR can be classified into three categories: pre-event, actual event, and post-event. The term “event” means that resources enrolled in the DR program have been notified to reduce load per the instructions of the system operator and the program requirements. The details of coordination include:

- <u>Pre-Event</u>. When a DR event is called, depending on system peak load and conditions, the pre-event coordination includes information exchange on the expected time and duration of the DR event. This information is shared on a day-ahead basis and also two hours prior to actual event activation. The coordination occurs through automated emails, as well as phone calls between the utilities and NYISO. This is in addition to the monthly exchange of information regarding which customers are enrolled in each program.
- <u>During Event</u>. The utilities and NYISO notify each other when a DR event (test or actual) is activated. The information is relayed through phone calls between the control centers and automated emails.

<u>Post-Event</u>. The coordination post-event focuses on assessing resource contribution and performance verification. The utilities and NYISO share information to identify resources that were called, their enrolled capacity (MW), and their actual performance. This analysis for NYISO reconstitutes load and assesses resource contribution accurately for the resources that undertook concurrent or overlapping reductions. Load reconstitution is an important exercise for forecasting purposes as it influences NYISO’s demand curve for the ICAP market. Table V-4 summarizes the details on operational coordination undertaken for the purpose of DER.

Table V-4: DER and Operational Coordination Details

Coordination Aspect	Coordination Details	Mode of Coordination	Frequency of Coordination
Demand Response			
Dispatch	NYISO and the utilities operate respective DR programs, but they notify each other when an event (test or actual) is scheduled to be called	Pre-DR Event: Day-Ahead Operating Report with wholesale resource information is shared through emails DR Event Activation: Automated emails and phone calls relayed between the utility and NYISO control rooms	Pre-DR Event coordination occurs on a daily basis DR Event activation coordination is dependent on frequency of an event being called
Actual Penetration/Available Capacity	DR enrollment information is shared between utilities and NYISO	DR enrollment report is created by utilities on a monthly and annual basis	Monthly, as DR resource enrollment in NYISO changes on a monthly basis
Penetration Forecast	Provided with 10-year load forecast	Email with details in Excel format	Annual
Performance	Post-DR event, overlapping resource capacity is computed. NYISO and the utilities have different baselines for assessing resource performance.	DR enrollment report created by utilities and shared with NYISO. DR resource performance is not generally shared. The utilities file a DR performance summary with the Commission.	Monthly basis with NYISO Annual basis with the Commission

c. Distributed Generation Enrolled in NYISO or Utility Distribution Tariff

DG resources in New York can provide energy to the grid by either participating in a NYISO or utility distribution tariff. Currently, very few DG resources participate in the NYISO wholesale market, making sophisticated coordination unnecessary. These resources follow NYISO's dispatch signal for serving wholesale market needs. These resources are currently operating under existing NYISO/utility TO processes and procedures.

NYISO indicates the status of the contracted schedule for these resources through the DAOP. The DAOP is shared with each of the utilities on a daily basis. These resources, in accordance with the NYISO Control Center Requirements Manual, transmit and receive communications (comprised of actual, desired generation and basepoints) through the utility TO. These communication requirements are required for the utility to maintain system reliability and understand the impacts of dispatch on local reliability.

In certain instances when dispatch of these resources by NYISO creates potential reliability issues on the utility distribution system, the utility may curtail output to secure the system. In all cases the utility informs NYISO of the curtailment.

It is expected that this aspect of coordination is going to become more important going forward. In May 2016, NYISO amended its behind-the-meter generation tariff to address the unique characteristics of these resources. The changes provide additional flexibility, such as allowing a resource to enroll with a single generator or an aggregation of generating units, or a single facility to split into several distinct behind-the-meter resources.[86] The Joint Utilities will continue to work with NYISO and to assess the growth of these types of resources to strengthen coordination practices.

C. Forward-Looking Coordination Requirements

A number of factors will influence what coordination is needed and its implementation, as well as the necessary standards and protocols. For example, technological developments will likely pose new coordination questions. Additionally, development of new market products and services that enable DER participation will create new coordination requirements. For example, in August 2016, NYISO proposed a roadmap for DER participation in its wholesale markets, with plans to integrate DER (mainly through aggregation) as dispatchable resources in the wholesale energy and ancillary services markets.[87] Apart from implications to the utility distribution system, the dispatch, which will be determined based on economics and transmission system reliability constraints, would allow DER to inject power into the bulk power system by way of the distribution network. NYISO's dispatch does not currently account for potential reliability impacts of the dispatch on the distribution system.

Similarly, with capabilities such as DERMS, the utilities as DSPs expect to utilize DER by dispatching them appropriately to service grid needs at the distribution level. At high penetration levels, the dispatch of DER on the distribution system is likely to influence the transmission system as well. This may require expanding the scope of communication between the utility distribution control center and the utility TO, along with increased coordination with NYISO.

The existing communication practices will require deliberation going forward as DER penetration reaches substantial levels. DER penetration can impact the supply-demand fundamentals that have defined and shaped the grid in terms of its technical architecture and market construct. The Joint Utilities recognize that DER with diverse operating characteristics can impact the conventional load shape for which the system was planned, designed, and operated. Additionally, the integration of DER potentially causes bi-directional energy flow on the system, thus increasing variability in grid conditions. For example, a situation could arise where the autonomous behavior of DER on the utility distribution system is not communicated with NYISO, potentially creating system reliability issues. Similarly, utility distribution system issues can arise if NYISO dispatches DER without understanding the utility distribution grid impacts.

While the existing communication practices around DR and load forecasting can inform future protocols, additional actions will be needed to identify and resolve more complex coordination issues that are anticipated to expand due to deployment and use of more flexible resources and

[86] Federal Energy Regulatory Commission (FERC), Docket Number: ER16-1213-000, Order Accepting Proposed Tariff Revisions Subject to Condition (Issued May 17, 2016) https://www.ferc.gov/CalendarFiles/20160517162720-ER16-1213-000.pdf
[87] NYISO DER Roadmap.

technology in the future. The extent of these requirements is difficult to gauge at this point given limited experience and data points to inform the requirements. While exact requirements cannot be known now and will need to be developed as market rules and products develop, there are benefits to engaging in identifying and planning the procedures and tools that will be needed to establish formal coordination among the Joint Utilities and NYISO.

1. Identifying Areas of Near- to Medium-Term Coordination

The Joint Utilities identify three major areas in which coordination can be improved in the near to medium term: (1) standardizing communication process, (2) information sharing, and (3) forecasting capabilities.

a. Standardizing Communication Processes

The current coordination efforts between the utilities and NYISO pertaining to load forecasting, DER/DR performance forecasting, and DER/DR dispatch coordination are voluntary. The utilities are focused on formalizing communications processes and procedures and expanding the information that is shared between NYISO and the utilities. It is expected that formalizing, standardizing, and codifying communication processes by amending or updating existing operations manuals utilized by NYISO and utilities will encourage timely and consistent information sharing, which can improve the efficiency of coordination and support ongoing governance. Projects with DER that require the coordination of the utilities and NYISO can be vehicles for determining the appropriate communication protocols under circumstances with increased DER penetration.

b. Information Sharing

Currently, NYISO has limited visibility of behind-the-meter net-metered resources. It may be beneficial for NYISO to capture the impact of these resources, at least at a zonal level, to improve zonal load forecast for operations and planning processes. The Joint Utilities can share information on the adoption of behind-the-meter solar PV systems, which can inform and improve NYISO's modeling. However, to enable this information sharing, the Joint Utilities will need to evaluate customer privacy implications.

c. Forecasting Capabilities

Higher levels of DG penetration can create challenges related to system operations and sub-hourly ramping needs and voltage fluctuations. These operational challenges can be better anticipated and addressed through sub-hourly and hourly forecasting. Currently, NYISO is working to develop its own tools to assist in bulk system operations. In addition, individual utilities and NYISO are simultaneously expanding their solar forecasting capabilities. This is an opportunity to share information on the capabilities being developed. Awareness of these capabilities will help model assumptions and outputs, which will benefit operational coordination. The Joint Utilities believe that enhanced visibility of net-metering type resources coupled with improved system modeling and forecasting methodologies will improve operational awareness leading to higher efficiencies and benefits in the near to medium term.

d. Identifying Areas of Medium- to Long-Term Coordination

The evolution of the NYISO DER Roadmap noted above will likely influence coordination needs between the DSPs and NYISO going forward. In particular, the aggregation of DER for dispatch introduces operational implications to be understood and resolved. The Joint Utilities are participating in the stakeholder process on the NYISO DER Roadmap. The Joint Utilities and NYISO anticipate amendments to NYISO tariffs will be required to incorporate DER dispatch and such amendments may also formalize coordination requirements between NYISO and the utilities in their role as DSP.

In addition, the development of markets at the distribution level will allow increased opportunities for dual participation of DER in both wholesale and utility distribution level markets, which will require enhanced visibility into DER performance on the distribution system. Additionally, the ability to modify the behavior of DER with the use of instructions and controls as needed to maintain reliable operation would be an important concern.

In the medium term, a new layered operational architecture of the grid may be required. To maximize system and consumer benefits, the evolution of operational architecture should follow an incremental approach, which will address:

- Information Sharing on Resource Aggregation. Resource sharing protocols and a standard interface will facilitate the sharing of granular resource aggregation among DSPs and NYISO for operational and planning purposes.
- Dispatch Protocols. NYISO and DSPs will coordinate to establish dispatch and the alignment of control signals for DER deployment to meet particular system needs.
- Dispatch Interface Development. The Joint Utilities and NYISO will need to develop an operating interface that matches the need for market coordination.

e. Benchmarking with CAISO[88]

As part of stakeholder engagement, to understand emerging coordination issues, the Joint Utilities and NYISO discussed with CAISO the coordination issues that CAISO and the California distribution utilities have experienced due to increasing DER penetration. The discussion with CAISO sought to identify best coordination practices for potential adoption.

Under CAISO's current operational framework, the following information is either generated or utilized in its current market construct:

- Bids from DER providers or aggregators;
- Day-ahead and real-time schedules;
- DER installed capacity;
- T&D system topology and conditions; and
- Transmission system feasibility of DER dispatch.

Currently, CAISO and the DER providers have no visibility to the impact of CAISO's dispatch signal and the subsequent DER response to the signal on the distribution system. CAISO, DER providers, and the utilities need to be aware of operational constraints that dispatch of DER on the utility distribution system may cause. This will be necessary to avoid DER curtailments, which may be undertaken in case DER dispatch by CAISO impacts distribution system reliability and safety. The Joint Utilities recognize this as an important area of coordination going forward.

[88] The California Independent System Operator is that state's analog to NYISO.

CAISO also identified the following major factors that will influence coordination aspects:

- Market evolution will be contingent upon technology and policy evolution; and
- Information exchange among independent system operation, distribution utilities, and DER providers on the evolving T&D interface.

The key takeaways from the discussion with CAISO[89] that will inform the NYISO-DSP coordination issue include:

- It will be important to understand the impact of DER dispatch on distribution system based on the ISO signals. The utilities, along with the NYISO, will need to consider a mechanism to communicate any distribution system or DER operating constraints to inform a proper DER dispatch.
- The evolution of technology, markets, and services provided by DER will influence coordination. The Joint Utilities expect that future NYISO pilot projects will provide lessons and information to shape the scope of operational coordination between NYISO and the Joint Utilities.
- The coordination discussion is expected to be influenced by:
    - Definition of eligible services that can be provided by DER;
    - The procurement methodology used to identify DER for the identified service(s);
    - DER performance expectations; and
    - Penalties for non-compliance and/or non-performance

Discussions on this issue should continue on this broad, evolving topic. Thus, the Joint Utilities will continue to engage with NYISO to facilitate the sharing of information and to develop effective practices and plans that account for a high DER penetration future.

2. Stakeholder Engagement Discussion

In addition to engaging CAISO, the Joint Utilities convened a broad range of stakeholders for input on the issues concerning NYISO-DSP coordination, as described in greater detail in Appendix A. The stakeholder input was helpful for understanding whether and how advancing DER technologies can enhance further coordination between the utilities and NYISO.

There was general stakeholder agreement that discussions are in the early stages and will require sustained efforts. The stakeholders agreed that the near- to medium-term coordination areas identified by the Joint Utilities, which include standardization of communication protocols, increased information sharing on net-metered type of resources, and enhanced forecasting capabilities, are steps in the right direction to improve efficiency of current coordination. It was also generally agreed that enhanced transparency in current operations can enhance coordination among the utilities, NYISO, and DER providers.

In the near future, transparency should be enhanced through technical advances such as improved metering infrastructure, which will improve DER operational visibility. In the medium to

[89] The Joint Utilities expect that this issue will need comprehensive discussion under the proposed NYISO DER Roadmap.

long term, it is expected that transparency can be enhanced through pricing signals, which can quantify operational and technical constraints, thus allowing effective DER participation. For example, Locational Marginal Prices ("LMPs") at the bulk grid level are effective in quantifying transmission grid constraints caused by the loss of generation or demand spikes and addressed by congestion pricing. These pricing signals then influence the operational decisions undertaken to maintain grid reliability. Similar pricing signals at the distribution system are expected to inform operational coordination going forward. While this aspect is a Stage 3 market development consideration, it is also noted that efforts in this area are in turn dependent on such related activities as the NYISO DER Roadmap, the Value of DER Proceeding,[90] and the DSP's technical evolution.

In addition to highlighting the importance of transparent coordination, the stakeholders also wanted to understand the implications of enhanced coordination on DER participation in existing programs at the NYISO level and the prospective programs at the DSP level. The stakeholders were concerned whether additional coordination functions would restrict their ability to participate in multiple markets at the same time. Acknowledging those concerns, the Joint Utilities indicated that improved operational coordination should mitigate such simultaneous or overlapping signals from the utilities and NYISO and stated that the goal of improved coordination is to improve system efficiencies and not restrict DER participation.

The stakeholders were supportive of quarterly discussions between NYISO and the Joint Utilities. Stakeholders also expressed their interest in receiving annual updates on the NYISO and Joint Utilities discussions.

D. Summary of Next Steps

The Joint Utilities commit to ongoing coordination with NYISO to identify, discuss, and resolve emerging issues. The Joint Utilities propose to engage with NYISO on a quarterly basis to discuss upcoming coordination issues. The Joint Utilities plan their own regular meetings on this issue. Proposed topics for regular discussion will include:

- Information exchanges between the utility and NYISO on content, format, and timing, and communication method;
- Short-term forecasting (for operational purposes including real-time, day-ahead, week-ahead) of net load and autonomous DER behavior;
- Long-term forecasting for planning purposes as highlighted in the "Continued Coordination with NYISO" discussion under the *Load and DER Forecasting* section;
- Ability to forecast system impacts of NYISO dispatches of DER (*i.e.*, "feasibility" of NYISO dispatches);
- Standard market jurisdiction and operations interface development between utilities and NYISO; and

[90] Case 15-E-0751 – *In the Matter of the Value of Distributed Energy Resources* ("Value of DER Proceeding").

- Situational awareness, such as monitoring, data types and granularity, and methods of communication. Operating procedures to monitor and control the dispatch of DER in normal and emergency conditions (real time and contingent).

VI. Market Operations

A long-term objective of REV is to animate markets at the retail level. These markets are intended to promote innovation, value creation, and more efficient investment. As the DSP, utilities will play a leading role in animating markets by creating consistent platforms for the buying and selling of products and services among a broad set of market actors.

The DSIP Guidance Order also seeks to further the broader REV goals of deepening DER penetration, capturing DER value, and leveraging markets to empower end-use consumers with respect to EVs.[91] The Joint Utilities believe that increased EV adoption can help achieve many of REV's objectives, such as reducing local air pollution and greenhouse gas emissions, and facilitating future EV markets in New York.[92]

Although the transition to potential transactional markets is a long-term consideration, the Joint Utilities understand that NYISO's ongoing pilot project on sub-zonal pricing may inform and advance this transition. A brief discussion of this project is provided later in this chapter.

A. Focus on DER Sourcing and NWA Procurement

New York distribution system energy markets, and the utilities' role in operating them in their role of DSP, will evolve through a process of planning, demonstration, evaluation, and implementation represented by the three stages of market evolution as described in the *Evolution of the DSP and Distribution Markets* chapter and illustrated again in Figure VI-1. As the framework for calculating the total value of DER as it evolves, as part of their DSP role, the utilities will develop the tools, processes, systems, and other capabilities to reveal this value and develop the market.

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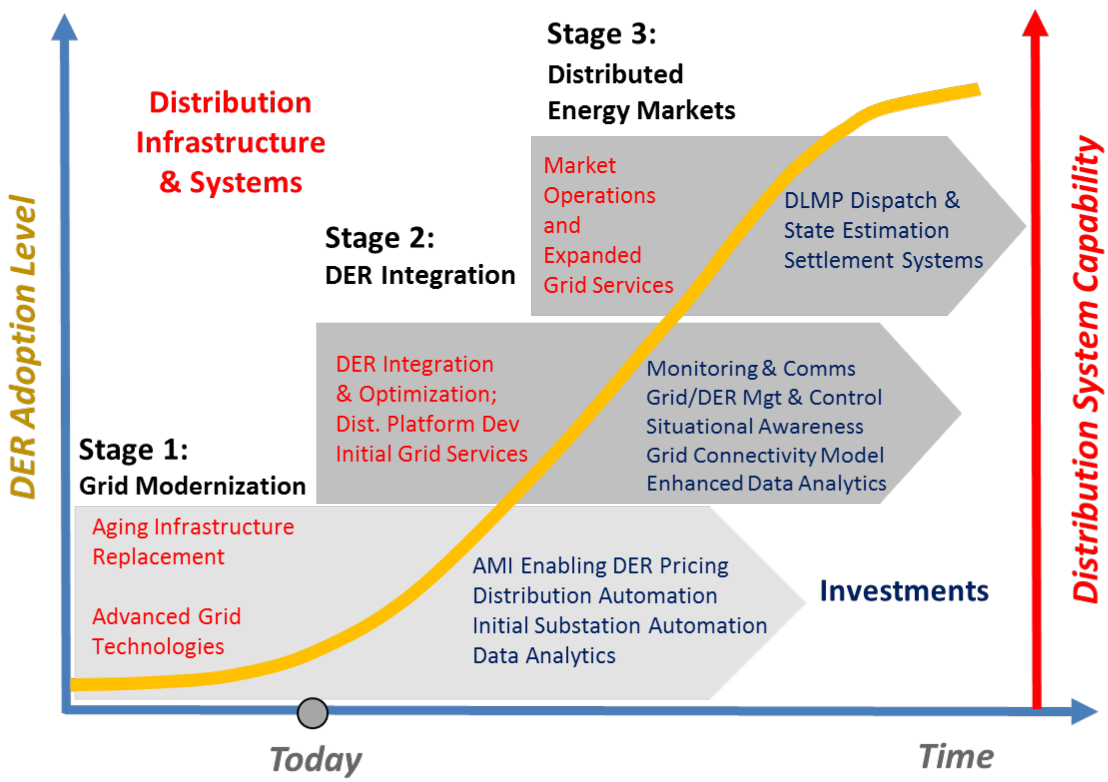
[91] *See* REV Proceeding, DSIP Guidance Order, p. 25, "[o]ne such opportunity that should be addressed in the Supplemental DSIP is planning for, and enabling increased deployment of, electric vehicle supply equipment (EVSE)." EVSE refers to EV charging stations and accompanying infrastructure, such as electrical panels and cables.

[92] The Joint Utilities note that sufficiently high levels of EV penetration may also affect distribution system planning and operations (to the extent that EVs provide aggregated demand response services to the grid). However, at present EVs have minimal impacts on the utilities' system planning practices; for this reason, the Joint Utilities address this topic in the *Market Operations* chapter.

Figure VI-1: Evolution of the Distribution Markets and System Capabilities



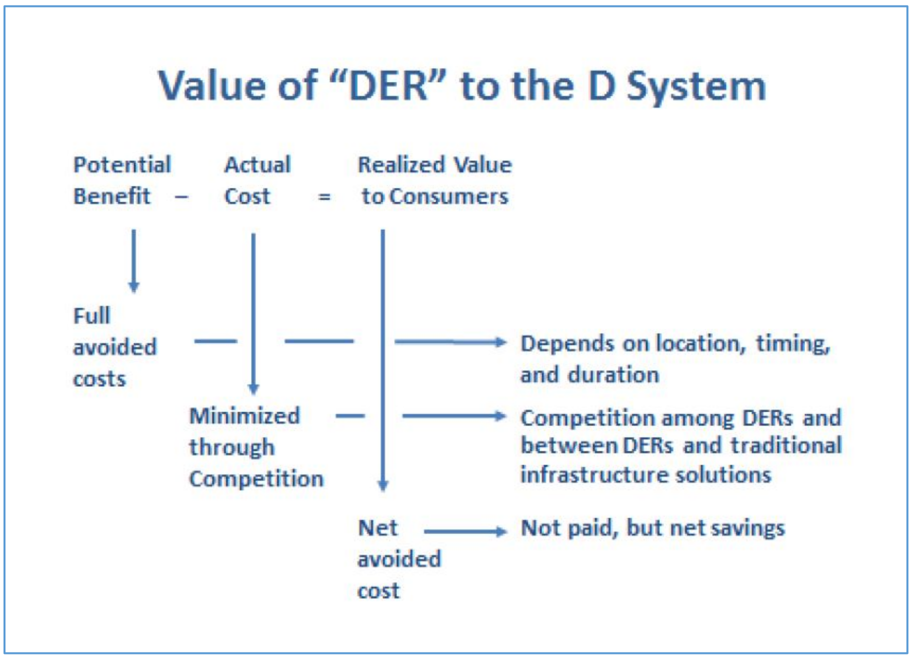
The Market Operations focus of this Supplemental DSIP is on DER sourcing. The Joint Utilities define "DER sourcing" as market actions taken by the utility to increase the amount of installed DER on its system. These actions or mechanisms are summarized as the Three P's. The first is Pricing—developing a more accurate representation of value streams for DER grid services, such as a successor approach to NEM and Time-of-Use ("TOU") rates. The second is Programs—enhancing and expanding distribution-level utility DER programs, such as demand response and energy efficiency programs to increase customer adoption and optimize system benefits. The third is Procurements—initiating targeted solicitations for NWA and incorporating NWA into utility decision-making on necessary grid investments.

Outside of the DSIP process, other REV and related proceedings are currently underway that may have significant implications for how DER are sourced by the utilities in the future. In fact, outcomes from these proceedings may influence multiple DER sourcing mechanisms simultaneously. For example, the demarcation among the Three P's of Pricing, Programs, and Procurement may blur in the future as DER sourcing becomes a more dynamic, market-based process that is integrated into grid planning and operations. As such, the emphasis of DER sourcing in the near term is on meeting system needs through NWA procurement.

Currently, the utilities are in the early stages of procuring DER as alternatives to traditional utility infrastructure solutions. This is partly because DER penetration is relatively low in New York. The utilities will use current and upcoming NWA solicitations to learn from the marketplace and begin to gradually enhance and standardize the procurement process. Over time, procurement is expected to mature into a portfolio optimization approach, where DER are consistently integrated into the planning and operation of the grid. Con Edison's Brooklyn Queens Demand Management ("BQDM") project[93] is the first example of portfolio optimization. BQDM is unique in terms of its scope and size and generally not representative of anticipated NWA opportunities going forward. However, the utilities expect to learn from the portfolio optimization aspects of Con Edison's experiences and evolve their own procurement practices. For purposes of this filing, the Joint Utilities identify tools for making near-term progress on NWA procurement processes.

Today, utilities are making NWA investments through open competitive procurements. The competitive process ensures market discipline when determining actual compensation for DER resources. It can also maximize the net benefits of DER, which in turn can be shared with other customers as depicted in the following figure.[94]

Figure VI-2: Value of DER to the Distribution System



The initial utility NWA pilot projects and improvements to the procurement process will drive future increased DER adoption, support the development of capabilities required for market progression, and pave the way for a more routine and consistent process for identifying NWA opportunities.

B. Interdependencies with Other Proceedings

The Joint Utilities are deferring to other relevant proceedings for decisions by the Commission regarding enhancements to current Pricing and Program mechanisms, where topics such as DER valuation and compensation principles continue to evolve independent from the DSIP process.

[93] Case 14-E-0302, *Petition of Consolidated Edison of New York, Inc. for Approval of Brooklyn Queens Demand Management Program.*
[94] Tierney, *supra* note 12.

These proceedings seek to further important public policy objectives (*e.g.*, greenhouse gas reduction and improved system efficiency). A listing and description of the relevant proceedings and related activities is included in Table VI-1 below. As part of the stakeholder engagement process, the Joint Utilities discussed these proceedings with stakeholders and the Advisory Group to inform them of the related DER sourcing dependencies. The Joint Utilities will remain active participants in those forums and coordinate on implementing the policy outcomes that emerge from these proceedings.

Table VI-1: REV and Related DER Sourcing Interdependencies

Name	Description
CES[95]	Approved on August 1, 2016, the CES directs the State of New York to obtain 50 percent of its electricity from renewable energy sources by 2030, and establishes a crediting system for certain existing nuclear plants. Certain types of DER are eligible to help satisfy this requirement. The Commission will work with NYSERDA to create a New York-certified clean energy product.
Clean Energy Advisory Council ("CEAC")[96]	Established by the CEF Proceeding, the CEAC's "[p]rimary objective is to support innovation and collaboration for an effective transition from current program offerings to post-2015 clean energy activities and on-going delivery thereafter." The goals of the CEAC are to support innovation and collaboration leading to the development of the most impactful clean energy programs and to transition from current clean energy program offerings to enable an effective and coordinated portfolio with focus on energy efficiency, DER and NWA.
Value of DER[97]	The proceeding aims to establish a market construct that articulates and compensates based on the full value of behind-the-meter DER to all market participants (*i.e.*, beyond simply the supplier). Within this proceeding, interim successors to NEM tariffs have been proposed by several stakeholder groups, including the Solar Program Partnership ("SPP"). The SPP proposal presented by the Joint Utilities, SolarCity, SunEdison and SunPower would establish an interim valuation framework, including grandfathering conditions and transitional payments from solar developers to the utilities. Staff recently filed a report and recommendations with the Commission on an interim successor to NEM tariffs. Initial comments are due on December 5, 2016 and reply comments are due on December 19, 2016.
DER Roadmap[98]	NYISO is developing a plan for integrating dispatchable DERs into wholesale operations and evolving current wholesale-level DR programs over the next three to five years. Its key objectives include enabling real-time scheduling, aligning with REV goals, and aligning payments with performance. A draft

[95] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* ("CES Proceeding").
[96] Case 14-M-0094, *et al.*, *Proceeding on Motion of the Commission to Consider a Clean Energy Fund* ("CEF Proceeding"), *et al.*, Order Authorizing the Clean Energy Fund Framework (issued January 21, 2016), p. 53.
[97] *See* Value of DER Proceeding.
[98] Distributed Energy Resources Roadmap Presentation Feedback, NYISO, June 21, 2016, http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2016-06-21/DER%20Roadmap%20Presentation%20Comments%202016.pdf

Name	Description
	whitepaper was released by NYISO to stakeholders on August 17, 2016 for stakeholder comment and feedback. The NYISO DER Roadmap will be published at the end of 2016 and implemented over the 2017-2021 period.
TOU Rates[99]	The Track Two Order requires each New York State utility to propose Smart Home Rate demonstration project proposals by February 1, 2017 in order to realign rates with customer preferences and to stimulate customer engagement and promote REV activities. In addition, the Track Two Order requires each utility to reexamine existing TOU rates "with reference to rates in other jurisdictions that have higher participation" and to "develop improved promotion and education tools." Separately, some utilities may propose additional TOU rates as well.
Distribution-level Demand Response[100]	As part of the DLM Proceeding, the utilities have developed consistent program offerings for demand response at the distribution level. All utilities now offer some combination of three programs within the DLM portfolio: Distribution Load Relief Program ("DLRP"), Commercial System Relief Program ("CSRP"), and Direct Load Control ("DLC"). As noted in the *Current State of NWA Procurement* subsection, coordination between future DER Sourcing activities and these tariff programs is essential.
Energy Efficiency[101]	The Track One Order requires the utilities to annually file Energy Efficiency Transition Implementation Plans ("ETIPs") on a three-year rolling cycle. The ETIPs are intended to give the utilities more flexibility to design market-based approaches to more cost-effectively meet their energy efficiency targets. The Joint Utilities are also directed to maintain a collective Technical Resource Manual ("TRM") that contains the formulas and methodologies for performing future energy savings calculations on a standard basis across program administrators, as well as to file a three-year Budgets and Metrics Plan for the upcoming three-year cycle on an annual basis. These activities are overseen by the CEAC.
BCA Framework[102]	The utilities collaborated on the development of consistent utility-specific handbooks, reflecting the Commission's BCA framework and detailing the BCA calculation methods and assumptions in compliance with the BCA Order on June 30, 2016. At the time of this filing, the BCA Handbooks are under Commission review. The BCA Handbooks are to be applied to: (1) any competitive process proposals, (2) EE programs, (3) tariff pricing, and (4) utility DSP infrastructure proposals. The framework in the BCA Handbooks will be applied to the evaluation of NWA proposals. This framework uses the Societal Cost Test ("SCT") as a primary indicator, which quantifies the impacts of a DER or other measure on society as a whole to estimate a solution's cost-effectiveness.
DER Oversight[103]	This proceeding is considering the applicability of the Uniform Business

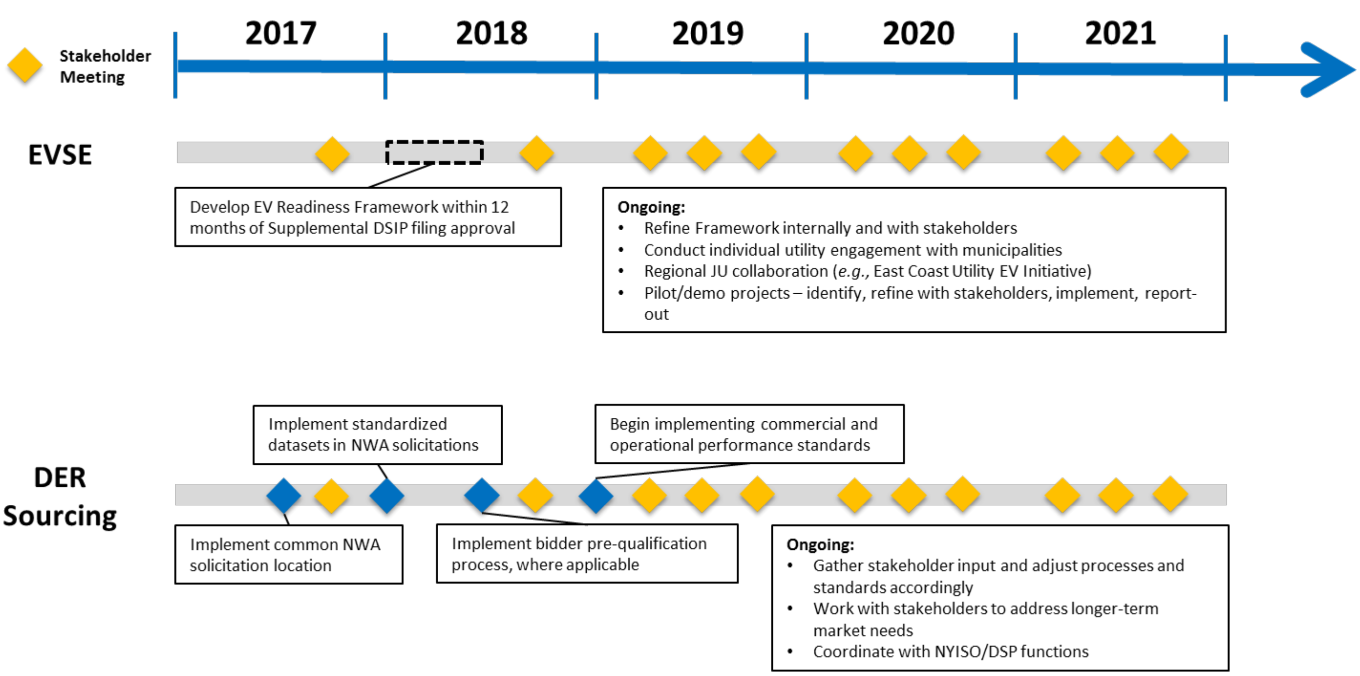
[99] REV Proceeding, Track Two Order, p. 27.
[100] *See* DLM Proceeding.
[101] *See* Case 15-M-0252 – *In the Matter of Utility Energy Efficiency Programs.*
[102] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework ("BCA Order") (issued January 21, 2016).

Name	Description
	Practices ("UBP") for ESCOs, or similar rules, to DER providers in order to ensure consumer protection and fair competition in current and future DER markets. The outcomes of this proceeding will likely govern interactions between utilities and DER providers, and significantly affect the manner in which utilities source DER.
REV Demonstration Projects	The goal of demonstration projects such as Con Edison's Virtual Power Plant, National Grid's Distributed System Platform, Con Edison's Connected Home and Building Efficiency Platforms, O&R's Customer Marketplace, Central Hudson's CenHub, and NYSEG/RG&E's Energy Smart Community is to test the potential of new business models and revenue stream opportunities for utilities and third parties. NYSERDA's proposed REV Connect initiative will serve as a means for the utilities to develop additional demonstration projects in collaboration with market participants. The Joint Utilities expect that these projects and efforts will be valuable to future DER sourcing activities.

C. Summary of Next Steps

Figure VI-3 summarizes the near and medium-term high-level actions proposed by the Joint Utilities over the 2017-2021 timeframe covered by this Supplemental DSIP.

Figure VI-3: Summary of Market Operations Next Steps



[103] Case 15-M-0180 – *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products.*

DER Sourcing

A. Introduction

The Joint Utilities explored enhancements to the utility procurement process for NWA as a way to advance DER sourcing. In considering enhancements, the Joint Utilities solicited input from stakeholders through an engagement group process. The general topics for engagement group discussion included:

- Describe and discuss dependencies with other REV and REV-related proceedings;
- Share existing NWA plans and challenges/lessons learned; and
- Discuss potential refinement of the NWA Procurement approaches to improve efficiency and effectiveness and the potential for implementation of some common elements across the utilities.

The refinements discussed with stakeholders include providing common types of system data, bidder pre-qualification where applicable, and performance attributes that may form the basis of performance requirements for NWA solutions. While related, the development of NWA suitability criteria was considered primarily a distribution planning issue and is covered in the *NWA Suitability Criteria* section of this filing.

The following sections provide a summary of existing NWA procurement-related activities and planned refinements to the NWA procurement process to improve efficiency and effectiveness.

B. Current State of NWA Procurement

The utilities are each at various stages of procuring DER through NWA solicitations. For example, Con Edison's BQDM project has completed a variety of solicitations to meet reliability needs in the years 2016 through 2018. Other utilities have recently released NWA RFIs or RFPs, and each utility discussed potential additional NWA opportunities in filings in compliance with the Track One Order and/or in their Initial DSIP filings. All utilities maintain a public and transparent procurement process, and are currently posting NWA solicitations under the applicable docket on the Commission's website.

While it is premature to definitively cite lessons learned for most of the utilities, the Joint Utilities offer some initial observations below.

1. *NWA Procurements To-Date*

The following table provides an overview of the utilities' individual NWA procurements to date. The statuses of these procurements are described using the following terminology:

- <u>Identified/early stages</u>: the utility has identified a potential NWA opportunity and is exploring the possibility of developing a corresponding NWA solicitation.
- <u>Under development</u>: the utility is in the process of developing an NWA solicitation for an identified need.
- <u>Reviewing responses</u>: the utility is currently reviewing the key characteristics and potential merits of received responses to its solicitation.

- Technical review: the utility is conducting a detailed review of the prospective NWA solution(s)' technical aspects.
- Implementation: the utility is working with the NWA provider to deploy the NWA solution(s).
- Did not pursue: the utility has decided not to develop a solicitation for a previously-identified potential NWA opportunity due to suitability reasons.

Table VI-2: NWA Procurements To-Date

Company	NWA(s)	Type	Status	Notes
NYSEG/RG&E	• Java Station • Station 43	RFP	• Technical Review • Reviewing responses	Identified seven additional potential NWA projects in Initial DSIP filing which warrant consideration for future RFPs
Central Hudson	• Northwest Area • Philips Road • Meritt Park • Coldenham • Ohioville	RFP	• Implementation • Implementation • Implementation • Under development • Did not pursue	• Ohioville was included within the initial NWA procurement, but was not cost justified. • Coldenham was identified in the DSIP as a potential NWA that is currently being evaluated.
Con Edison	Brooklyn-Queens Demand Management ("BQDM")	RFI, RFP, RFC, RFQ, Auction	Implementation	• Solicitations have led to executed agreements and commitments to pursue and implement customer projects by the years 2017 and 2018. • Identified nine additional potential NWA opportunities in Initial DSIP filing.
National Grid	• Baldwinsville • Kenmore	RFP	• Reviewing responses • Implementation	Identified seven additional potential NWA projects in Initial DSIP filing.
O&R	• Pomona • Wurstboro • Monsey Substation	RFI	• Implementation • Identified/early stages • Identified/early	• Plans to issue subsequent RFPs for solutions identified in the

Company	NWA(s)	Type	Status	Notes
			stages	Pomona portfolio development process. • Released an expanded RFI due to limited responses to the initial RFI.

2. *Early Lessons Learned*

As previously mentioned, thus far the utilities have had fairly limited experience with procuring NWA solutions. Nonetheless, they have made several important observations about the procurement process from their recent experiences that will help guide future practices, as described below.

- Timing. Some of the Joint Utilities have observed that the RFP process can be very time-intensive with respect to both the time that DER providers require to develop bids, as well as the time that the utilities require to review and analyze RFP responses. Some utilities observed that releasing a solicitation too close to the time of need dampened response rates. This experience is reflected in the utilities' proposed NWA suitability framework included in the *Distribution System Planning* chapter.
- Data and Information Exchange. Selecting and assembling the specific localized system data to be supplied to bidders has also required significant internal utility resources. Stakeholders have noted that system and area information is needed for them to develop sufficient proposals. At least one utility is drawing upon external resources to help with system data and area analysis to help inform the DER/solution RFP. The analysis vendor will characterize the area need based on the utility engineer's inputs and will develop demographic and customer profile data to provide additional information to the bidders. As this process is further developed, the Joint Utilities expect the additional information will reduce the number of questions from bidders and will help them better associate appropriate DER to the system needs.
- Compensation. When assembling a portfolio of NWA solutions to meet a given need, the utility must determine the appropriate amount of DER to secure from each DER provider. Different resources types may have different benefit profiles (*e.g.*, temporal availability of the solution relative to the timing of the need) and thus may be entitled to different levels of compensation from the utility. In certain instances, utilities taking this portfolio approach have had to clarify how different types of resources would be compensated differently within the same portfolio.

- Coordination with Tariff Programs. The Joint Utilities have observed that certain NWA opportunities may introduce offers to customers that compete with existing tariff programs (*e.g.,* DLM). The utilities will work with internal and external stakeholders to clarify rules delineating between NWA and other related programs and attributions, and to ensure coordination across programs, including the participation of a single resource in multiple programs.

C. Proposed Refinements to NWA Procurement Processes

The following enhancements are largely inspired by utility experiences to date, and many were well received by stakeholders at an engagement session on this topic. Based upon the discussions in these engagement sessions, the Joint Utilities will work to streamline current NWA procurement approaches by including a standard set of system data (to the extent available) and requested DER performance characteristics in their solicitations, maintaining updated lists of their own current NWA opportunities on their respective websites, exploring a single website solution for posting NWA opportunities, and considering a vendor pre-qualification process(es) if appropriate and useful.

1. *System Data*

DER providers rely on certain elements of system data to help decide whether and how to respond to an NWA solicitation. For example, a thermostat vendor may wish to know approximately how many customers in the need area are billed at residential rates. A solar developer may wish to confirm that the need area's peak load is sufficiently aligned with the solar resource's typical availability period. A demand response aggregator may seek to verify that the system need is sufficiently large to merit developing a bid response. In all of these examples, the DER provider will typically only submit a bid if the expected commercial opportunity outweighs the transaction costs associated with constructing the bid.

The Joint Utilities believe that establishing a common set of system data points to be provided in NWA solicitations, including information about the timing, location, and size of the reliability need, will help DER providers assemble more informed bid responses. This outcome ultimately benefits both parties: the developer avoids wasting resources on responding to opportunities that may have otherwise turned out to be commercially unattractive, and the utility receives more tailored and potentially actionable bid responses.

The Joint Utilities will work within 12 months to include a common set of system data points in NWA solicitations in order to facilitate more informed bid responses; examples of these system data elements are provided in Table VI-3 below.

Table VI-3: Illustrative Example of System Data to Be Included in NWA Solicitations

Type of System Data	Illustrative Example
Size of the need	1 MW
Seasonality	June – August
Temporal profile of need	Between the hours of 1 and 4 PM, for no more than three consecutive days
Duration of deferral	Five years
Geographical characterization of need area	A map showing the approximate boundaries of the need area, perhaps labeled with zip code information
Customer characterization of need area	Approximately 2,000 customers, split 80 percent residential and 20 percent commercial and industrial

The Joint Utilities emphasize that while a common set of system data elements will be included in all NWA solicitations, the granularity and description of each element may vary according to the capabilities and systems of each utility and the nature of the project. For example, some utilities may have the capability to further characterize customers in the need area by their percentage contribution to peak load. This information may be provided where available and of value to the procurement process. The utility may alternatively provide a high-level characterization as part of the solicitation and subsequently provide more detailed demographic data to short-listed respondents.

2. Bidder Pre-Qualification

Bidder pre-qualification establishes a pool of bidders that satisfy pre-defined baseline conditions for responding to NWA solicitations.[104] This early step of pre-screening bidders may have several benefits for bidders and utilities. For example, pre-qualification may help market development by reasonably assuring that there will be enough suitable bidders for a specific NWA opportunity to support a competitive solicitation at any one point in time. Pre-qualification also allows bidders to demonstrate the viability of, and their experience with, new technologies, and also allows the utilities to proactively identify vendors that may face challenges (related to either financing or construction/implementation) with implementing their solutions. Additionally, pre-qualification may provide an opportunity to streamline the procurement process for NWA projects that are more routine in nature, have shorter lead-times, or both. In instances of auction procurements, pre-qualification will be necessary for the validity of the auction results and confirming that the auction winners can meet their award obligations. Finally, a pre-qualification approach may serve as a forum for developing and refining common terms that reflect the needs of the evolving marketplace.

As an example, Con Edison recently used a bidder pre-qualification specifically for its BQDM demand response descending clock auction to identify a pool of acceptable bidders. Elements of the pre-qualification included:

- Submittal of bidder's development/implementation plan, including targeted customer types, technologies to be used, and timeline;
- Requirement for successful bidders to post initial security once the auction clears, with the balance due prior to the contract start date; and
- Disclosure of key financial and legal information such as:
    - Existing, pending, or past adverse rulings, judgments, litigation;
    - Contingent liabilities;
    - Revocations of authority;
    - Administrative, regulatory (*e.g.*, state, FERC, Securities Exchange Commission, United States Department of Justice) investigations; and
    - Matters relating to financial or operational status arising from sale of load relief products over the past three years.

The utilities will consider whether a pre-qualification process may be appropriate for their NWA opportunities and, if so, may consider potential elements to include. Sample pre-qualification

[104] The Joint Utilities emphasize that this process is not to be confused with a pre-certification approach, which would be used to identify, certify, and recommend vendors to other market participants. The Joint Utilities are not proposing to implement a pre-certification process at this time.

elements are summarized in Table VI-4 below. The utilities will also work to avoid the use of future pre-qualification requirements that may become an impediment to innovative technologies.

Table VI-4: Sample Pre-Qualification Elements

Pre-Qualification Element	Description
Detailed Company Information	Key financial, legal, and other information
Description of Commercially-Proven DER	Enables bidder to demonstrate that the proposed DER is a commercially-proven technology
Customer & Technology Experience	Description of the types of customers with whom the vendor typically works (*e.g.,* residential, small commercial) and the technologies deployed
Deployment Experience	Description of previous vendor deployments of the given DER solution as well as experience with deployment in the specific geographic area covered by the NWA opportunity
Flexibility/Availability of Technology	Information that helps the utility determine if the solution proposed meets the need profile
Timeliness of Deploying the DER	An estimate of the time normally needed to deploy the DER solution upon contract award
Vendor Security Requirements	Credit, collateral (*e.g.,* delivery and performance bonds) and other similar requirements

3. Performance Attributes

Some DER technology types may be better suited to address a given NWA need than others due to criteria such as timing and availability of the resource, all of which are important to the distribution planning process. The Joint Utilities expect that the alignment between technology performance, the system need, and ongoing utility obligations to maintain safety and reliability will be increasingly relevant as the market develops and new DER technologies emerge. Achieving this alignment will provide some assurance to potential bidders that their technology type is applicable to the need under review and will provide an early indication to utilities that the technology has the potential to reliably meet the identified system need.

One approach is for the Joint Utilities to establish specific performance requirements for NWA projects during the solicitation process. This approach would clearly signal to the market the operational performance requirements for the proposed NWA solution(s). However, because the utilities are in the very early stages of procuring DER as NWA solutions, it would be premature to impose common specific performance requirements in this manner now. Some operational experience, including development, implementation, and validation of the utilities' DER monitoring and control capabilities (see *Monitoring and Control* section) will be necessary before the Joint Utilities can fully understand NWA performance and how specific operational performance requirements can be effectively translated into appropriate commercial terms. These may include contract terms for operations and delivery, as well as a performance verification and commensurate compensation methodology tied to delivered performance.

The Joint Utilities have identified several performance attributes that are indicative of criteria that utilities could each use to evaluate potential NWA solutions.

Table VI-5: Performance Attributes

Performance Attribute	Definition
Availability	The extent to which a resource is able to provide capacity, considering limitations such as seasonality, length of call windows, environmental restrictions, or other known factors that limit the performance of the resource. Example Performance Requirements (*for illustrative purposes only*) • Delivery months must include at least June, July, August • Must be able to reduce load during at least 3 consecutive weekdays • Must be able to deliver dispatched load reduction at least 4 consecutive hours with at least 2 of those hours within the 13:00 – 19:00 EPT time period
Intermittency	The degree to which resource output is limited by unpredictable factors such as solar irradiance or wind.
Dispatchability	The ability of a dispatch-based resource to respond quickly in times of capacity or T&D needs and the extent to which the resource can be called repeatedly within a given time period. Example Performance Requirements (*for illustrative purposes only*) • Must be able to provide load relief within 20 minutes, 2 hours, or 24 hours of dispatch order • Maximum number of dispatch requests per day • Maximum dispatch hours per week/month/year
Coincidence	The resource's ability to perform when localized, system, or statewide load peaks typically occur.

The Joint Utilities reiterate that the elements in Table VI-5 are representative performance attributes and not requirements at this time. However, the attributes will be used over time to develop specific performance requirements applicable to future NWA solutions. The Joint Utilities understand that some utilities in other jurisdictions (*e.g.*, SCE) have already issued NWA solicitations with such performance requirements. Given that utilities will now be depending on DER NWA in lieu of utility infrastructure investments to meet reliability needs in certain instances, those DER will be expected to meet more stringent performance requirements. The utilities will similarly work so that these performance requirements are developed in close consultation with their respective system planning groups.

4. Sharing of NWA Opportunities

The Joint Utilities and stakeholders have agreed that there is value in providing a consistent method for sharing NWA opportunities. The utilities will each create and maintain on their respective websites an updated list of their respective current NWA opportunities for DER providers. Consistent with feedback received from stakeholders, the Joint Utilities will also pursue opportunities to present NWA opportunities at a centralized location, such as the REV Connect portal.

5. Provision of Cost of Traditional Solution

The Joint Utilities propose to provide the capital cost of the traditional solution in NWA solicitations on a utility-by-utility, case-specific basis. In discussions with stakeholders, it was suggested that the utility disclose the capital cost of the traditional solution to the grid need in its NWA solicitation. Stakeholders believe this would be a useful preliminary indicator for determining whether to bid. However, some utilities are concerned that DER markets may not be sufficiently competitive and that revealing the traditional solution cost could result in suboptimal results to the detriment of utility customers. While the traditional solution cost may have been previously provided in certain utility capital plans (listed in the Initial DSIP filings) and NWA solicitations, whether each utility will continue to provide such information going forward is an open question.

The Joint Utilities understand DER providers' interest in receiving information that will allow them to evaluate the commercial viability and attractiveness of an opportunity, and have developed NWA suitability criteria to direct developers to the highest potential opportunities. The cost suitability criteria, in particular, are intended to indicate a threshold above which NWA are potentially cost-competitive and able to overcome the transaction and opportunity costs associated with smaller-scale projects (see *NWA Suitability Criteria* section and *System Data* section). As a result, developers should have a reasonable expectation that the projects identified for NWA are commercially viable without direct disclosure of the traditional solution cost. As NWA procurement continues to evolve along with continued stakeholder discussions, there is opportunity for further consideration of this issue.

D. Summary of Next Steps

The Joint Utilities will work together to consider and implement the above procurement process enhancements in a consistent matter. Specifically, the Joint Utilities will form an NWA procurement working group that will implement the proposed actions and further develop standardized practices over time (where appropriate), such as:

- Standard data sets for short-term and longer-term NWA procurements;
- Bidder pre-qualification requirements and standards where applicable;
- Notification of current NWA opportunities; and
- Commercial and operational performance standards.

This working group will include experts from the Market Operations, Grid Operations, and Distribution System Planning functions, so that cross-cutting issues (*e.g.,* data sharing) are consistently addressed. The working group will meet with stakeholders at least once a year to share Joint Utilities' plans and solicit input and feedback. The group will also meet with Staff to provide an annual update.

The Joint Utilities are committed to working with stakeholders to address longer-term market developments, particularly implications of the evolving proceedings identified in Table VI-1. Similarly, the Joint Utilities plan to progress toward enabling low-income customer access to DER by engaging with these customers and testing the resulting findings in a demonstration project environment.

NYISO's Plan to Expand Sub-zonal LBMPs

Also under the purview of Market Operations is NYISO's initiative to explore the development of more granular pricing at the wholesale level. NYISO provides day-ahead (hourly) and real-time (five-minute) location-based marginal prices for every supplier location and load zone. NYISO started a pilot project to explore including a limited number of sub-zonal buses in the calculation of locational-based marginal prices; these prices have been published on the NYISO website since late June 2016.

The Joint Utilities coordinated a meeting with NYISO and interested Advisory Group stakeholders on June 28, 2016 to discuss NYISO's current LMP methodology and provide input to NYISO's phased approach to expanding sub-zonal LMPs to select buses. NYISO calculates these prices by simulating additional "dummy" generators at each bus. Currently, NYISO publishes 35 out of the approximately 550 sub-zonal buses located in the utilities' service territories (see Table VI-6 below). NYISO intends to develop a budget and timeline through its Budget Priorities Working Group ("BPWG") to integrate the remaining 515 buses.

Table VI-6: NYISO Granular Prices by Utility (Current)

Utility	Sub-zones with granular prices
Con Edison	14
NYSEG/RG&E	7
Central Hudson	6
O&R	5
National Grid	3
Total	35

Integrating these real-time sub-zonal bus prices significantly increases data processing and storage requirements, and expanding to all sub-zonal buses will require substantial system upgrades. Similarly, to the extent granular sub-zonal bus pricing is applied to distribution-level products, the Joint Utilities will also need to consider IT storage capabilities and systems upgrades. For this reason, and to allow time for market participants to consider the benefits of the near-term expansion, the Joint Utilities and other stakeholders engaged as part of this filing generally support NYISO's phased implementation approach. The Joint Utilities will work with NYISO and the broader group of stakeholders to continue to investigate the most appropriate level of pricing granularity that provides beneficial price signals to the marketplace.

Additionally, the Joint Utilities will monitor and contribute to developments with NYISO's granular pricing project through the formation of a Joint Utilities and NYISO working group that will also coordinate a number of Supplemental DSIP plan elements on an ongoing basis.

Electric Vehicle Supply Equipment

A. Introduction

The EV market in New York is currently supported by a variety of measures, including state and federal policies, research and development initiatives, public-private partnerships, private investment, and utility pilot and demonstration projects. These activities are taking place at the local, state, regional, and federal levels, but to date, EV adoption in New York remains low relative to state policy targets (see *Current State* subsection). The Joint Utilities and stakeholders believe close collaboration among all market participants, including utilities, will become increasingly important to increasing EV adoption and achieving state and regional EV adoption and market objectives.

The utilities have several tools for facilitating EVSE infrastructure and encouraging EV adoption, but the challenge is to identify which utility-specific and joint actions can create statewide impacts. For example, stakeholders posited that the relative scarcity of publicly-accessible charging infrastructure in New York poses a significant barrier to EV adoption, and offered varying views on the role of utilities in facilitating this growth. Some stated that as EVs achieve greater range capability and increase consumer demand for charging services, the market will spur investment in public charging infrastructure. Other stakeholders suggested that utilities are uniquely suited to help remedy this "chicken-and-egg" problem, given their familiarity with distribution systems and access to capital. Some stakeholders also suggested that EVSE investment may become more viable if multiple value streams, such as environmental and societal benefits, can be more fully identified and captured by market participants.

The EV market is evolving, requiring EVSE investments made today to yield both immediate and longer-term benefits. Considerations such as the type of investment (*e.g.*, Level 2 or DC Fast Chargers) and its location (*i.e.,* workplace, multi-family, or other) must be carefully evaluated in order to create benefits for both EV users and other ratepayers. The quality of EVSE deployments is essential, because poorly-chosen installations could yield low returns and have a negligible impact on EV adoption.

The Joint Utilities consider utility facilitation of EVSE to be a utility-specific issue that depends on factors such as current EV adoption levels, local incentives, electric distribution system configuration, and customer demographics. In general, the Joint Utilities seek to prudently invest utility customer funds in opportunities where the expected benefits resulting from increased sales outweigh the capital revenue requirements. The Joint Utilities acknowledge that strategically deploying EV charging infrastructure in key areas can increase EV adoption, and over time will develop approaches for determining the prudency and market impact of potential deployment approaches.

In concert with stakeholders, the Joint Utilities have developed a set of guiding principles for utility involvement in facilitating increased EVSE deployment and supporting EV adoption in New York. These principles will form the basis of the Joint Utilities' forthcoming joint EV Readiness

Framework.[105] The EV Readiness approach will effectively leverage the utility's core business functions (*i.e.,* forecasting, system planning, interconnection, customer communication, and education), and its extant business relationships with a wide variety of market participants. This approach will also emphasize demonstration and pilot projects as a means for the utilities to evaluate EVSE technologies and develop and test deployment approaches in the near-term, while EV adoption remains relatively modest. Through increased participation in local, regional, and state-wide EV market development activities, the Joint Utilities will prepare for and support future EV growth.

In this section, the Joint Utilities briefly summarize the state of the EV market in New York and outline the proposed Guiding Principles and joint EV Readiness Framework. Many of the Framework elements are intended to remove barriers to the deployment of EVSE.

B. Current State

1. Key Policies

On May 29, 2014, New York and seven other states agreed to the Multi-State Zero-Emission Vehicles ("ZEV") Action Plan, which sets a collective goal for 3.3 million ZEVs by 2025.[106] This equates to an estimated 800,000 ZEVs on the road in New York by 2025, though vehicle manufacturers can choose to meet this goal with fewer vehicles by producing more long-range

The Charge New York program created in 2013 is a collaborative among NYSERDA, NYPA, and Department of Environmental Conservation ("DEC"). In addition to implementing the Multi-State ZEV Action Plan, Charge NY aims to drive the installation of 3,000 PEV charging stations in support of an anticipated 30,000-40,000 PEVs by 2018. The initiative is also developing best practices for municipal EVSE regulations, providing vehicle incentives such as reduced bridge tolls, and reducing regulatory obstacles for installing EVSE at parking lots.[107]

On September 8, 2016, Governor Cuomo announced $3 million in funding for municipalities to encourage the purchase or lease of ZEVs through rebates. The rebate program, administered through the DEC, provides reimbursement of up to $5,000 per vehicle for purchasing and leasing, and up to $250,000 per facility for the installation of EVSE.[108]

Additionally, NYSERDA is currently developing a new consumer EV rebate of up to $2,000 per vehicle, which is expected to be launched by early 2017. This rebate was approved as an addition to New York's annual budget on March 31, 2016.[109]

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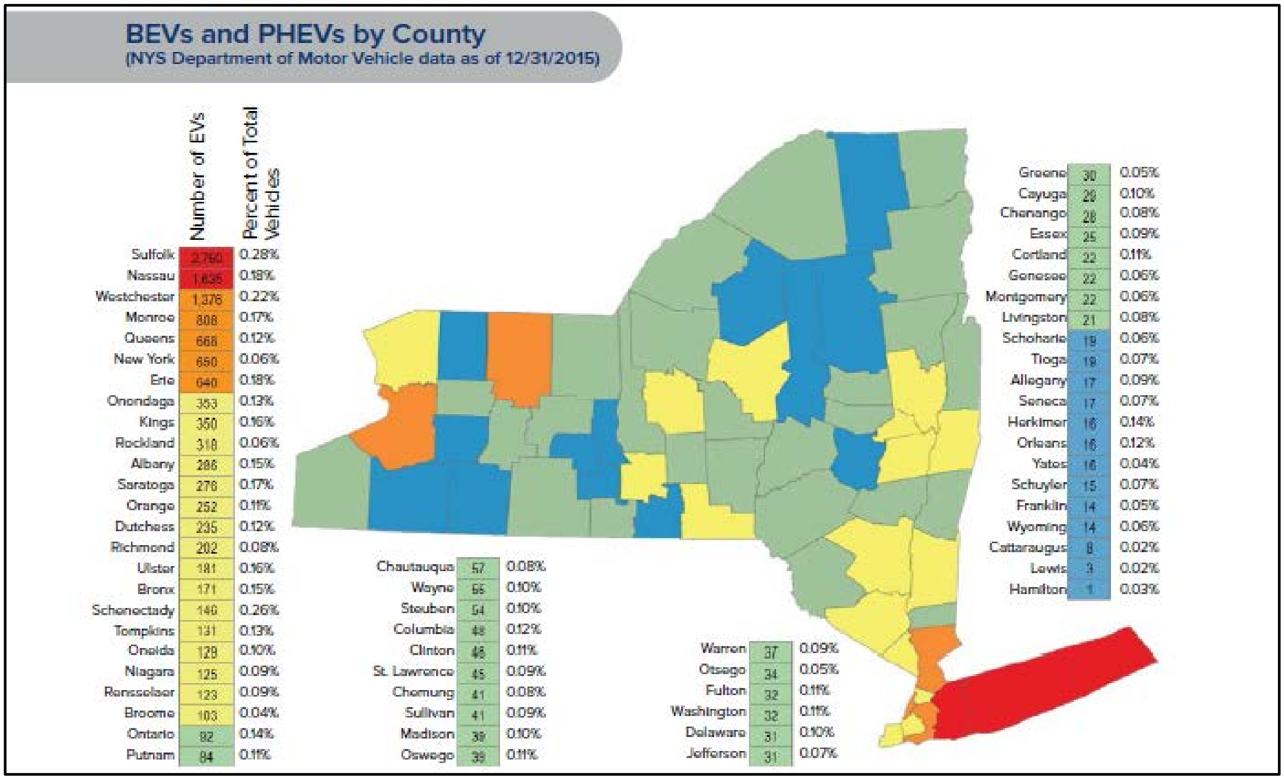
[105] The concept of EV Readiness has been successfully applied in several states to date such as California and Texas, and additionally in cities such as New York City. *See, e.g.*, Ari Kahn and Christina Ficchia, *The New York City Electric Vehicle Readiness Plan: Unlocking Urban Demand*, Empire Clean Cities and the Mayor's Office of Long-Term Planning and Sustainability, New York, 2012.
[106] *See* https://www.governor.ny.gov/news/governor-cuomo-announces-multi-state-plan-increase-number-zero-emission-vehicles-us
[107] *See* https://nyserda.ny.gov/All-Programs/Programs/ChargeNY
[108] https://www.governor.ny.gov/news/governor-cuomo-announces-3-million-available-municipalities-zero-emission-vehicles-and-charging
[109] *See* http://legislation.nysenate.gov/pdf/bills/2015/S6408C

2. *Current EV Adoption in New York State*

At the end of 2015, there were 12,903 registered EVs (both battery-powered and plug-in hybrid types) and 1,062 public Level 2 charging outlets in New York.[110] The spatial distribution of these vehicles is depicted in Figure VI-4.[111]

Figure VI-4: Distribution of Battery-Powered and Plug-In Hybrid EVs



3. *Consideration of EV Adoption Forecasts in Utility System Planning*

In general, over the five-year Supplemental DSIP time horizon, current and expected near-term levels of EV adoption do not significantly impact utility system planning scenarios and related distribution system investment plans. The incorporation of forecasted EV penetration and adoption rates into the system planning process varies by utility. Some utilities are developing internal models and EV adoption scenarios to estimate when EV adoption may begin to impact utility system planning. Others currently use EV adoption forecasts as inputs to system planning, for which resulting investment plans identify distribution system investments needed over the following three to five years. The utilities will use the EV Readiness Framework to develop individual programs and processes for identifying thresholds at which EV adoption levels become more salient to the system planning process.

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[110] NYSERDA, *2015 Annual Data Summary: New York State Electrical Vehicle (EV) Charging Station Deployment Program*, June 2016, p. 4.

[111] *Id.*, p. 8.

4. *Outreach and Education*

The current EV market in New York is relatively nascent and small. Many prospective customers may lack familiarity with EVs and their benefits, as they represent a relatively new offering in the automotive marketplace. Prospective buyers may also not be fully aware of, or understand, financial incentives available for their vehicles. Finally, during the course of stakeholder engagement, some parties implied that sales staff at car dealerships may lack sufficient familiarity with EVs to promote their benefits and explain their various charging options to customers. The Joint Utilities have identified these issues as ones where utility customer engagement strategies and Joint Utilities planning may be valuable. Incentives from auto manufacturers for the dealership sales force to promote EVs could enhance these utility outreach efforts as well.

5. *EVSE Projects To-Date and Other Initiatives*

Some New York utilities already have some experience supporting EV adoption and EVSE deployment. For example, Con Edison has implemented a number of projects including the Branch Circuit Energy Management Device pilot project[112] and has partnered with EPRI on various pilot projects.[113] National Grid currently operates 66 public Level 2 stations in its service territory, which have been used by more than 1,200 drivers to date.

In addition, several utilities are party to the Edison Electric Institute ("EEI") Fleet Electrification Commitment. This represents a company's commitment to dedicate at least five percent of its annual fleet acquisition budget to EVs.[114]

In addition, some utilities may have or plan to offer TOU rates specifically for EVs. TOU rate programs encourage drivers to shift their charging to off-peak hours, thereby potentially saving them money and also improving distribution system efficiencies. Con Edison currently offers a TOU rate to customers who own EVs and is in the process of obtaining regulatory approval for an additional stand-alone EV rate and an incentive-based EV program that encourages off-peak charging through rebates. National Grid has proposed revisions to its SC-1 whole-house Voluntary TOU rate as a one-time, 12-month trial option.

Several utilities participate in stakeholder groups such as the Regional Electric Vehicle Initiative ("REVI") and the East Coast Utility EV Initiative. The utilities believe such groups are an important means of increasing regional coordination and shared understanding among utilities and stakeholders on EV issues, and will remain active participants where practical and appropriate.

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[112] *See* http://www.landisgyr.com/con-edison-deploys-landisgyrs-intelligent-switches-ev-charging-stations/

[113] *See, e.g.*, *Open Vehicle-Grid Integration Platform*, July 8, 2016 at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008705

[114] *See EEI Announces Industry Commitment to Fleet Electrification at White House Roundtable*, Edison Electric Institute, November 18, 2014, http://www.eei.org/resourcesandmedia/newsroom/Pages/Press%20Releases/EEI%20Announces%20Industry%20Commitment%20to%20Fleet%20Electrification%20at%20White%20House%20Roundtable.aspx

C. Proposed EV Readiness Framework and EVSE Demonstration Projects

1. Guiding Principles for Utility Involvement in EVSE

The Joint Utilities recognize EVs as one of many valuable tools for achieving state clean energy objectives, and seek to support and encourage EV adoption to the extent practicable and cost-effective. Given the size of the current EV market, the Joint Utilities believe the most effective way for utilities to facilitate increased EVSE deployment and by extension EV adoption is through a readiness and demonstration approach. Early collaboration among the utilities, and between the utilities and stakeholders, will mean that the utilities have the appropriate tools, processes, and capabilities in place for when the EV market begins to grow more rapidly. By actively participating in conversations about EV market and technology development, the Joint Utilities will remain responsive to changing market conditions and be able to modify their approaches as needed.

Through a robust and collaborative stakeholder engagement process, the Joint Utilities have developed the following Guiding Principles for Utility Involvement in EVSE, which will form the basis of the joint EV Readiness Framework:

- The Joint Utilities will facilitate EVSE growth and encourage EV adoption in New York by increasing their collective readiness for future market development;
- The resulting EV Readiness Framework will be aligned with and responsive to New York initiatives for advancing the adoption of EVs;
- The development of the EV Readiness Framework will be directed by federal, state, and Commission policies for advancing the adoption of EVs;
- The Joint Utilities and each utility are stakeholders that must collaborate to support the achievement of state and regional EV market objectives;
- The utilities will seek to maximize long-term net benefits to utility customers by enabling the improved asset utilization that EVs offer, while mitigating incremental peak load impacts and supporting local, state, regional, and federal energy policy goals; and
- For the near-term, demonstration and pilot projects will be the primary means for the utilities, in concert with stakeholders, to develop and test different EVSE deployment approaches.

2. EV Readiness Framework

The Joint Utilities will develop a joint EV Readiness Framework, which will inform subsequent individual utility initiatives, within 12 months of completion of the comment process for this Supplemental DSIP filing. The Framework will favorably position the utilities to support increases in EV adoption, and will be aligned with and responsive to New York initiatives for advancing the adoption of EVs. The development of this Framework will be directed and guided by federal, state and Commission policies for advancing the adoption of EVs (*e.g.*, State Energy Plan goals and requirements under the Clean Air Act §177 Zero-Emission Vehicle Program).

The utilities anticipate that elements of the forthcoming EV Readiness Framework can be implemented in the near term, in order to pave the way for future market growth. This may include proactively identifying and addressing, in concert with stakeholders, key infrastructure planning considerations such as service connection processes, building codes, and local ordinances. The implementation of other Framework elements will likely be contingent on a specific degree of market maturity and utility-specific territory considerations. For example, some potential utility actions may not be practical or economical until the overall EV market in New York achieves certain thresholds or a certain sustained annual growth rate.

The utilities will use the EV Readiness Framework to identify useful indicators for assessing market performance, as well as thresholds at which distribution system impacts or benefits of EVs may become more significant. While the Joint Utilities will develop a common EV Readiness Framework, the market indicators, plans, and timelines taken by individual utilities will vary due to utility-specific factors. Many of the following objectives of the proposed EV Readiness Framework were developed through robust conversations with stakeholders, as well as over the course of the utilities' routine EVSE business operations.

a. Infrastructure Planning

The utilities will support accelerated EV adoption by identifying and addressing the key infrastructure considerations that have historically hindered EV market growth. Stakeholders and the utilities identified several factors that can delay or prevent the completion of an EVSE project, and that the utilities may be favorably positioned to help ameliorate.

i. *Service Connection Requirements and Processes*

Stakeholders commented that current service connection wait times are largely untenable for EVSE developers, often exceeding several months. The utilities will look for ways to clarify, streamline and/or augment the service connection process and requirements for EVSE in a consistent manner. Additionally, the utilities will work so that EVSE developers can easily identify and contact appropriate utility personnel, in order to expedite the process.

ii. *Local Ordinances, Building Codes and Design Guidelines*

Local ordinances, building codes, and design guidelines for EVSE may enable easier and less costly EVSE installation. For example, building codes requiring EVSE conduit to be installed during new construction can avoid higher costs that would otherwise be incurred by installation post-construction. The utilities will participate in discussions of local ordinance and building code development, and will provide their perspective on EVSE deployment experiences to date. However, the Joint Utilities note that any updated or new ordinances and regulations will also require clear and accountable enforcement mechanisms in order to be effective.

iii. *Interoperability and Standardization*

Because EVs are an emerging market area, there are many different, non-standardized EVSE protocols and technology configurations. Some of this variation exists at the level of the charge plug itself (*e.g.*, competing plug types for Direct Current Fast Charging). Other variation among public EVSE transaction systems requires EV drivers to carry multiple membership cards for public networks with different payment systems. Still more variation exists in the communication architectures and protocols used by EVSE manufacturers and service providers to communicate between EVSE stations and utility back-office transaction and station management platforms.

These issues require further investigation by the utilities and stakeholders; accordingly, the utilities will monitor technology developments and seek to support approaches which offer interoperability and standardization, both for the benefit of drivers and for potential future communication between EVSE hardware and utility operational software systems.

b. Demonstration and Pilot Projects

Several of the utilities are developing demonstration and pilot projects to test new EV technologies, capabilities and deployment approaches. For example, NYSEG/RG&E's Energy Smart Community project will assess workplace charging and public charging stations in the Ithaca region, fleet services for businesses, and private ownership models and technology partners. Con Edison plans to release a RFI for an EVSE REV demonstration project in Q4 2016, and Central Hudson is developing a project aimed at reducing driver "range anxiety." O&R is in the early planning stages of developing a demonstration project focused on EV.

The utilities will support the near-term advancement of EVSE objectives under REV through the identification and implementation of demonstration projects. As findings from these projects begin to emerge, and as the EV market develops, the utilities will also seek to collaborate with stakeholders on larger potential projects.

c. Low-Income Customers

The utilities will explore approaches to serving EV-related offerings to low-income or underserved customer groups or locations.

d. Education and Outreach

The utilities seek to create a positive customer experience, beginning with education and outreach. The utilities will identify and develop communication channels for outreach through utility programs as well as through collaboration with stakeholders. These channels will be used to share information about electric transportation options and charging options. The most suitable type of channel for a given use case will likely depend on the information's recipient(s). For example, the utilities might find it advantageous to communicate with prospective EV buyers through vehicle dealerships.

e. EV Penetration Forecasting Approach and Methodology

As EV adoption grows, the utilities will leverage more granular EV adoption and locational data (to the extent available) and learnings from the marketplace to develop and enhance their individual EV forecasting methodologies in an iterative manner. The utilities will work so that their system infrastructure can accommodate EV growth as the market develops.

D. Summary of Next Steps

The Joint Utilities will develop and publish a joint EV Readiness Framework within 12 months of completion of the comment process of this Supplemental DSIP filing. Subsequent individual utility initiatives will be guided by this Framework while advancing individual utility-specific priorities. Meanwhile, the utilities will continue to support the identification and implementation of EV demonstration and pilot projects.

Increased coordination among the utilities, as well as between the utilities and stakeholders, will enable a number of market development actions that can increase EV adoption. The Joint Utilities commit to forming a utility working group to collaborate on EV and EVSE issues in New York. This group will meet with stakeholders on a periodic basis to share and inform utility plans, beginning with the development of the EV Readiness Framework. At the regional level, the utilities will continue to participate in groups such as the East Coast Utility EV Initiative. Finally, the utilities will design and conduct individual utility engagement activities with local governments and municipalities.

VII. Data Collection, Access, and Security

The collection and sharing of data has been a central theme of REV since its inception and this theme is reiterated in the DSIP Guidance Order, which states, "At the core of the new model is improved information – improved both in its granularity, temporal and spatial, and in its accessibility to consumers and market participants."[115] This information, including enriched system data and detailed customer data, is expected to facilitate market participation and DER deployment by signaling where DER products and services can provide the greatest value to customers and the grid, aiding in the development of DER business cases, and guiding investment decisions of third parties and customers.

The Joint Utilities support the sharing of useful information to support DER market growth. For data to be useful, it must be processed, analyzed, and interpreted. Individual data points and uncommented data streams related to utilities' distribution systems are generally not self-explanatory. Data regarding individual customers' energy usage, while easier to understand and utilize, also requires validation in order to be deemed "bill quality" data. As such, the Joint Utilities believe that information sharing should incorporate relevant data commentary and data analytics to provide useful information leading to meaningful results. This will mitigate the risk of users unknowingly misinterpreting data. Additionally, understanding the context or the premise for a data request will enable a utility to meet the functional need underlying the data request by providing viable alternatives for the requested data, thereby reducing efforts and costs.

Data sharing is also important in the context of developing new market-based revenue streams that are intended to offset utility service costs and align utility financial interests with achieving REV's objectives. Under the REV regulatory framework, utility revenues will be increasingly tied to providing consumer value. As stated in the Track Two Order, "utilities should be expected to derive a growing share of net income from market-based earnings in exchange for value-added services that they provide to the market."[116] An example of a potential value-added service is a data analysis service that makes available more granular and customized information to developers and other market participants.

Whereas the utilities' Initial DSIP filings focused on providing a base level of utility system and planning data, the Supplemental DSIP's data focus is on common data access practices for system data and customer data, including the type and level of data shared, methodology and rules, and frequency of updates. Additionally, this Supplemental DSIP addresses issues related to cybersecurity and data privacy.

A. Defining System Data and Customer Data

System Data includes grid information such as real and reactive power consumption, calculated hosting capacity, power quality, and reliability, which can be collected at various granularities including the circuit, feeder, substation, and system level. System operators, planners, and designers have relied on system data to generate useful information for planning and for safe and

[115] REV Proceeding, DSIP Guidance Order, p. 2.
[116] REV Proceeding, Track Two Order, pp. 40- 41.

reliable grid operations. As discussed in the *Monitoring and Control* section, the availability of system data is closely linked to the presence of monitoring and sensing technologies and AMI. The utilities' Initial DSIP filings included implementation roadmaps that presented the technology investments needed to develop enhanced monitoring and control capabilities and the associated timelines.

Customer information includes customer energy usage data, customer-sited generation data, account and load profile information, results from customer-specific analyses, end-use information, and other elements. The availability of customer energy usage data, in particular, is critical to the success of market development under REV, as DER providers seek data that will inform the development and marketing of tailored products and services. As discussed in each utility's Initial DSIP filing, the utilities are taking steps to offer enhanced access to more granular customer usage data, including the development of AMI business cases and common data sharing practices.

B. Data Access

A significant amount of data is currently available through a number of channels. While there are some differences between utilities as a result of the unique features of their respective service territories and existing information and operational systems and capabilities, there are certain data sets that are commonly shared. For example, the utilities each currently provide fundamental system data that aid in identifying opportunities for DER providers. Specifically, the utilities make available capital investment plans, load forecasts, reliability statistics, and planned reliability and resiliency projects in filings submitted to the Commission. Other recently developed sources of system data include solicitations for NWA, SIR pre-application information, and Initial DSIP filings.

Customer data is currently shared with customers and their authorized third parties through various systems, including utility bills, GBD or equivalent, EDI, online third-party data platforms, SFTP, and online customer engagement platforms. As AMI is deployed and experience is gained, more granular data will be available on a more frequent basis.

The REV Connect initiative being led by NYSERDA and Staff may provide another forum for knowledge, idea and data sharing, including solicitations for NWAs. As described in the RFP, REV Connect,

> will offer a central forum for third parties to submit project ideas and receive expert guidance, feedback and facilitation, and will match ideas with customers, communities, and utilities to advance high quality REV demonstrations, non-wire alternatives and other innovative projects, while enhancing the culture of innovation in NY State.[117]

The Joint Utilities will remain engaged in the development of the REV Connect forum.

[117] *See* https://www.nyserda.ny.gov/Funding-Opportunities/Closed-Funding-Opportunities/RFP-3229-REV-Connect

C. Basic and Value-added Data

The Joint Utilities have developed a common framework for distinguishing basic data from value-added data for system and customer data. While there are some nuances unique to the type of data being considered, the following general framework applies.

1. Basic Data

The Joint Utilities propose that basic data will be available to the requestor at no charge beyond the costs that are already included in base rates and includes data that is readily available, in the public domain, and provided without additional analysis or processing. For system data, this includes, but is not limited to, capital investment plans and reliability assessment reports. For customer data, the definition of basic data is drawn from the Track Two Order, which defines it as "the usage for each applicable rate element, including usage bands specified in the applicable tariff."[118] Basic data represents "the level of data necessary to render, reconstruct and understand the customer's bill."[119] Basic data[120] for non-interval-metered customers includes cumulative kWh, net kWh, and maximum recorded kW (if a demand meter is present). Basic data for interval-metered customers includes energy use (kWh, net kWh, kW, kVAR) at intervals specific to the customer's meter, as well as cumulative kWh, minimum/maximum kW, and kVAR.

2. Value-added Data

Value-added data will be available for a fee determined through utility-specific fee structures. These fees may vary by each utility tariff based on its value to the consumers and market. Value-added data goes beyond basic data by having one or more of the following characteristics:

- Is not routinely developed or shared;
- Has been transformed or analyzed in a customized way (*i.e.,* aggregated customer data);
- Is delivered more frequently than basic data;
- Is requested and provided on a more ad hoc basis; and/or
- Is more granular than basic data.

Examples of value-added system data may include forecasted load data, voltage profiles, and power quality data. Additionally, examples of value-added customer data may include providing timelier interval meter data to DER providers or ESCOs, or aggregation of customer data by zip code or tax code for CCAs. Value-added customer data will be enabled to a large degree by AMI investments, which will increase the granularity and timeliness of usage data collection for various use cases such as demand response. The Joint Utilities expect that the classification of data elements as value-added will develop over time as the utilities enhance their data management systems and analytical capabilities. For example, the Joint Utilities have recently been in the process of developing data elements in response to the REV proceedings and DSIP Guidance Order. These are ongoing efforts and elements that have been developed already and elements currently being developed will be evaluated as to whether they should be classified as value-added or basic. This may result in the utilities developing fees for data that had previously been provided

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118 REV Proceeding, Track Two Order, p. 142.
119 *Id.*
120 At the utility's discretion, basic customer data may include a minimum level of analysis.

at no additional charge. Similarly, the Joint Utilities leave open the possibility that what may presently be characterized as value-added data may become part of basic data in the future.

D. Cybersecurity and Data Privacy

The application of digital communications technologies on the grid and the expansion in available system and customer data highlight the heightened risks of security breaches and the importance of remaining vigilant in protecting system security and customer privacy.

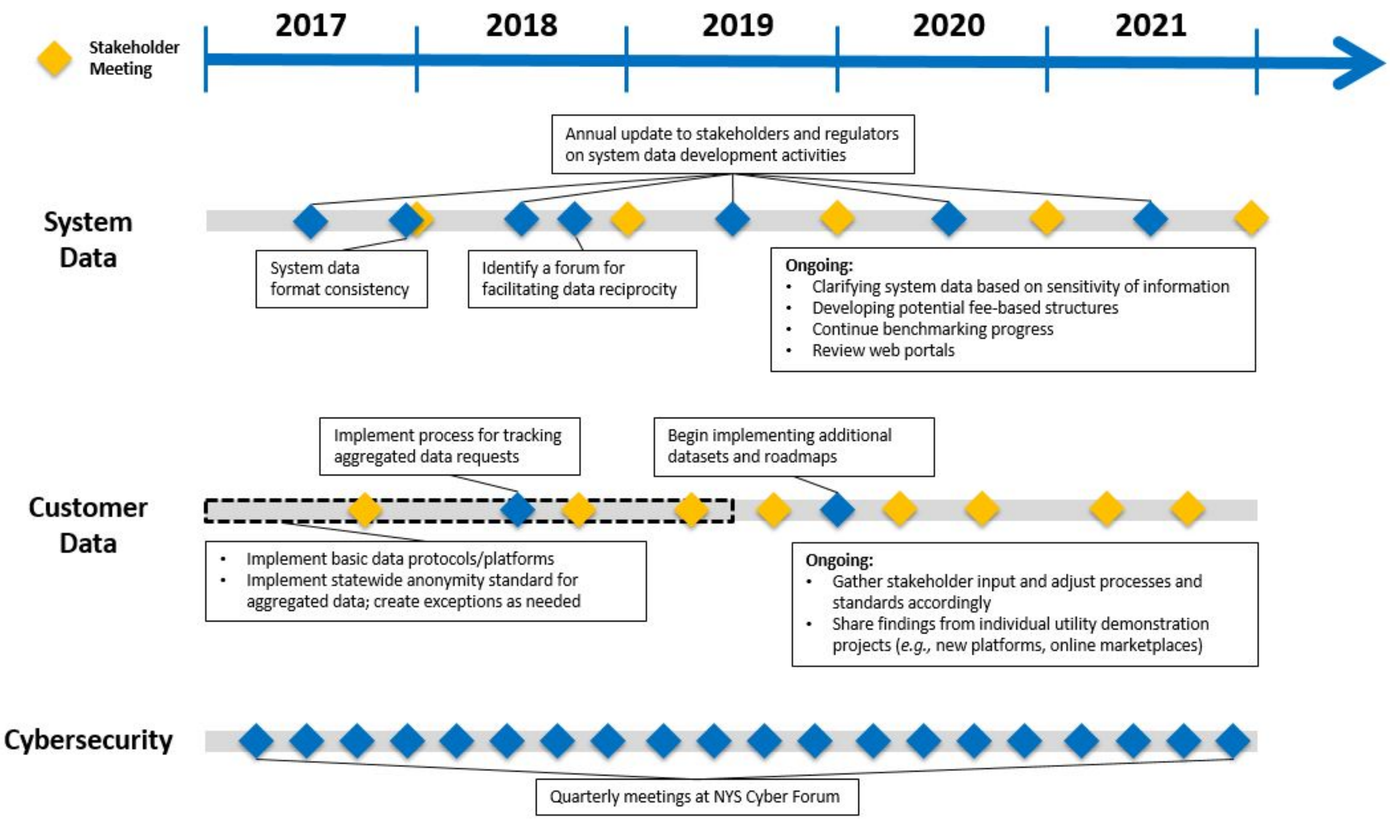
The Joint Utilities have developed a common approach to managing the cybersecurity risks that is applicable to the expanded data sharing in the evolving REV environment. The Joint Utilities Cyber and Privacy Framework focuses on people, processes, and technology as being the foundation for a comprehensive cybersecurity and privacy governance program.

To protect individual customer data, the utilities will follow current practices, which require express customer authorization for data to be released to other than utility contractors or vendors or by law or Commission order. The Joint Utilities propose the adoption of a 15/15 privacy standard for aggregated customer data provided by utilities to authorized third parties other than utility contractors or vendors by law or Commission order. Under a 15/15 standard, an aggregated data set may not be shared unless: (1) it consolidates data from at least 15 accounts, and (2) no one account represents more than 15 percent of the total load for the data set. The Joint Utilities acknowledge that the 15/15 standard is conservative compared to privacy standards used elsewhere, but believe beginning with a more conservative standard is appropriate given the nascent state of DER markets in New York and the utilities' commitments to protecting customer privacy.

E. Summary of Next Steps

Figure VII-1 summarizes the near- and medium-term high-level actions proposed by the Joint Utilities for system data, customer data, and cybersecurity over the 2017-2021 timeframe covered by this Supplemental DSIP.

Figure VII-1: Summary of Data Collection, Access, and Security Next Steps



System Data

A. Introduction

A central objective of REV is to make system data available in the granularity and timeliness that will facilitate market development and greater DER penetration. System data includes grid information such as real and reactive power consumption, power quality, and reliability, which can be collected at various levels including the feeder, substation, and system level. Historically, system data has been used by utilities to generate useful information to aid in planning and operations. For example, distribution system operators use system data to facilitate real-time grid operation decisions and maintain system reliability and service quality, including reducing the frequency and duration of outages. System planners use system data to perform planning analysis, such as load flow analyses, load forecasting, investment planning, and other needs-based analyses.

System data also has value to DER providers, who can use it as an input to their technical and business decisions, such as where to market services or locate resources to support grid needs, and how to best respond to NWA solicitations. The Joint Utilities support the sharing of information to aid the decision-making of third parties for deployment of DER. In order to facilitate this, the Joint Utilities have:

- Formed a collaborative cross-utility working group to consider a variety of issues related to the collection, analysis, and release of data collected and maintained by the utility;
- Engaged stakeholders, both individually and as a group, to focus on the development of a consistent level of sharing of system data and analysis generated through the use of system data;
- Provided common sets of information such as historical hourly loads; and
- Began efforts to define two distinct categories of data—basic data and value-added data—and have initiated stakeholder discussions on this distinction.

The Joint Utilities have made significant progress to enhance their capabilities to share useful system information both in the near and longer term. As the Joint Utilities develop additional data, tools, and methods, they will be able to expand data access to customers and developers. In particular, the utilities will be better positioned to identify areas where more DER can be accommodated on their systems, where DER provide the greatest value, and where system challenges may be resolved through installation of DER. In light of variations in existing systems and capabilities, the Joint Utilities recognize that creating the capabilities to collect and share additional useful system information is a stepwise process that will require utility-specific implementation and investment roadmaps and cost recovery plans, which must be approved by the Commission in order to proceed.

The following sections highlight the collective progress made by the Joint Utilities in identifying and supporting system data requests. Although there is a significant amount of system data available currently, the Joint Utilities recognize that to support REV objectives, additional efforts are needed to expand information availability beyond its current state. The efforts will need to address which system data elements need to be prioritized for immediate value to DER providers, how data access and use can be made convenient for stakeholders, and what security standards and protocols need to be in place for facilitating data exchange and reciprocity between the utility and DER providers. Going forward, in an effort to demonstrate progress in this area, the Joint Utilities will communicate with DER providers on a regular basis.

B. Overview of System Data Stakeholder Process

To understand data requests from DER developers, the Joint Utilities requested input from multiple parties and conducted independent research on data availability and uses in other jurisdictions. Central to the stakeholder conversations was the identification of the highest value information that can be supplied to DER providers to make effective decisions, and to satisfy specific planning and analysis needs, both today and into the future. Consistent with the DSIP Guidance Order, the Joint Utilities sponsored stakeholder engagement sessions on System Data including three face-to-face meetings and a summary webinar. The Joint Utilities had an opportunity to exchange ideas with multiple stakeholders regarding specific areas of interest under system data including: (1) availability, (2) granularity, (3) accessibility, (4) importance, (5) services, and (6) security. The individual utilities also sponsored company-specific stakeholder sessions related to system data.

These engagement sessions provided useful information to the Joint Utilities to guide the future processes needed to provide data that can enable DER developers to offer solutions to improve grid efficiency and reliability. A critical insight from these conversations was the realization that the gap is much narrower than initially believed between the majority of information requests by DER providers and the information the utilities are able to provide given current capabilities. That is, the utilities already have available, or are in the process of making available, information that the DER providers agreed would be helpful in assisting in their development efforts. The Joint Utilities propose to reduce the information gap for several of these currently available data sets to make them more accessible to third parties.

Additional outcomes of these discussions included general agreements that:

- Enhancing the transparency of modeling or planning methodologies may reduce the need for specific data requests;
- System data collection and provision will be an evolving process as the individual utilities make various capital and other investments to collect and standardize data;
- Utilities are responsible for system planning and maintaining the reliability, resilience, and safety of the grid, while providing opportunities for DER providers to connect to the grid and offer services; and
- Data security and confidentiality are legitimate considerations accompanying provision of some system data.

Ultimately, the Joint Utilities and stakeholders agreed that data sharing is an important step to enable effective resource location and design that provides value to electric customers in New York, and that a proper balance of information sharing and security awareness is necessary for security and customer protection.

The discussions also identified challenges to sharing information, such as the fact that data availability varies by individual utility, system configuration, technologies employed, and planning needs. With this knowledge, the Joint Utilities believe that a collaborative working process will enhance their ability to provide useful information. That is, rather than receiving a request for raw data, which may not be available or may require strict security review to share, the utility may be able to facilitate alternate solutions that may enhance value to the DER providers, if the utility understands the need behind the data request.

Stakeholders also commented on value-added data and clarified that value-added data can be further segmented into “static” data and “dynamic” data. Static data would include 8760 hour system/meter data, system limitations, and pricing data. Dynamic data would consist of, for example, real-time and forecasted load and generation information. While there was general agreement that the utility as DSP may provide value-added data services to DER providers, stakeholders lacked agreement on the interpretation of value-added data. Stakeholders also did not agree on how value-added data may be available or distributed over time. Overall, all parties agreed that further exploration of a value-added structure for system data is needed. Efforts are underway to identify avenues to share value-added data and to develop appropriate pricing mechanisms.

The Joint Utilities have begun to explore alternative means of utilizing fee-based structures for value-added data services. For example, as a part of Stage 1 of the NY Prize competition,[121] the Joint Utilities received funding from NYSERDA to provide value-added data, which enabled third parties to perform feasibility analyses for their proposed microgrid projects across New York. Likewise, the SIR process recently implemented a fee-based structure for data requestors. The Joint Utilities will continue to seek out new revenue and earning opportunities consistent with the Track Two Order.

C. Current State of Data Sharing

To understand the current availability of data across utilities and the potential to consistently share such data, the Joint Utilities assessed the data currently available at the individual utility level, as well as expectations for the expansion of data collection capabilities. The utilities conducted internal surveys and assessments of their current data collection and analysis processes. While this process identified the diversity in the data collection and availability among individual companies, the process also identified that a significant amount of common information is already available and provided by the individual utilities through filings and/or production of other information sources. The common information provided across the utilities is mainly comprised of:

- 8760 hour historical load data;
- DER contribution to peak load by technology type;
- Overview of potential beneficial locations for DER;
- Initial hosting capacity data indicators such as interconnection/maps; and
- Five-year investment plans.

[121] *See* http://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Competition-Structure

Each utility currently provides fundamental information and services that aid in identifying opportunities for DER providers on the distribution system. The data noted in Table VII-1 has historically been provided at a fairly consistent level of detail and frequency across the utilities.

Table VII-1: Historically Available System Data

Data Type	Frequency	Granularity	Availability	Format Available
Capital Investment Plan – General Overview	Annual, 5 year forecast period	System	Public, Annual CapEx Report	Static Image
Load Forecast	Annual, 5 year forecast period	System	Provided on Request, forecast period may vary by utility	Static Image
Reliability statistics (SAIFI, CAIDI)	Annually	Feeder level	Public, Annual Reliability reports filed with the Commission	Static Image
Planned resiliency/ reliability projects	Annually	Varies by project	Public, Annual Reliability reports filed with the Commission	Static Image

As a result of the System Data stakeholder engagement sessions, the Joint Utilities identified significant overlap in the data requested by DER providers and the data already available, particularly as related to planning and project-specific data.[122] However, stakeholders had limited awareness of the available information. The Joint Utilities shared available information sources as described in Table VII-1 as well as steps recently taken to make data available through a variety of additional venues, including:

- NY Prize competition,
- Solicitations for NWA,
- Demonstration projects, and
- Collaborations with research and academic institutions.

As an outcome of these discussions, the Joint Utilities and stakeholders believe additional stakeholder review and input on the relevance of the data available to DER processes and potential alternate data formats would be valuable.

In addition, the utilities have taken steps to consolidate data sources where possible on company-specific data portals, allowing for easier access to available data sources.

[122] Project-specific data includes information such as planned project name, location and primary needs served; planning data includes information such as reliability statistics and load profiles.

After identifying each utility's ability to provide such data, the Joint Utilities identified formats that could be easily generated by all utilities to provide a consistent presentation of the data sets. In such efforts, the Joint Utilities also considered the usability of such data by third parties and attempted to provide machine readable formats that could be readily accessed and interpreted in commonly available desktop software applications.

D. Ongoing Data Sharing Enhancements

The REV initiative continues to create a wealth of opportunities for participants, including the Joint Utilities and their customers, to actively engage in the modern information economy. The Joint Utilities are currently moving forward to implement this change. Initial roadmaps toward this vision were discussed in the individual utility Initial DSIP filings. As the utilities are starting from different places based on their existing IT systems, their expected development is following different paths to the goal of utilizing system data and data analytics to better manage the distribution grid. As such, some differences in the granularity, frequency, and accessibility of data available from individual utilities are expected in the near term. However, efforts are underway to align the format of data outputs for consistency and ease of use. An example is detailed in the *Hosting Capacity* section of this filing, in which the utilities will establish an aligned platform view and presentation format of hosting capacity data by early 2017.

Table VII-2 provides a summary of the frequency, granularity, and format of system-related information that has recently been developed by the Joint Utilities. It should be noted that the Joint Utilities are still in the process of developing approaches to supply similar or enhanced information going forward. As part of this process, the Joint Utilities will consider the potential classification of this data as value-added and propose appropriate fee structures.

Table VII-2: Recently Developed System Data

Data Type	Frequency	Granularity	Availability	Format Available
Load data	Varies by utility	Varies by utility	Available in initial DSIP or system data portals or by request	Readable data file
Distribution Indicator Maps for Hosting Capacity (Stage 1 Indicators)	One-time publishing, with updates in accordance with Hosting Capacity Analysis roadmap	Varies by utility	Initial indicators available via utility websites; development of enhanced capabilities to determine and present hosting capacity underway (see *Hosting Capacity* section)	Web accessible; format varies by utility
Beneficial Location	Varies by utility	Varies by utility	Available via web portals or Initial DSIP	Web accessible portals, static

				reports, other formats dependent on utility
DER Already Connected	Varies by utility	Feeder (current)	SIR Pre-Application Report, Enhanced Indicator Maps for Hosting Capacity (made available as part of Stage 1 of the Hosting Capacity Analysis Roadmap)	Interactive Map
SIR Pre Application Information	One-time, project specific	Feeder level	On Request, Provided to Applicant	Static image/ report
Circuit Capacity/ Design Criteria[123]	Static (updated as projects are implemented)	Feeder level	Currently available	Tabular or Static Map

The formats, modes, and methods to make system data available in the near term include a variety of alternatives. The Joint Utilities are actively considering mapping or GIS formats for information that would benefit from visual/geographic presentation to third parties. To the extent possible, the Joint Utilities will use individual company web portals in the near term to share data. However, access to information will be subject to review of data classification (value-added or basic), as well as to any security limitations placed on release of individual data elements going forward.

The key aspects of the individual utilities' current and near-term activities to ensure data availability are shown below.

1. Con Edison

Con Edison has provided 24-hour peak load duration forecasts and 24-hour minimum load historical curves, as well as the underlying historical 8760 load data. Con Edison has also shared network-level maps of Phase 1 hosting capacity determinations, highlighting network locations where sufficient minimum load exists to enable DER interconnection at little to no additional cost.[124] Con Edison plans to enhance its network hosting capacity map and develop a non-network feeder hosting capacity mapping environment to be made available through our web portal. Con Edison also plans to engage with NYISO and other stakeholders in understanding the potential usefulness of 8760 substation and circuit level forecasts for long-term planning, because such forecasts are very dependent on the quality and accuracy of inputs, such as hourly weather forecasts that typically do not exist or are highly variable.

[123] Circuit capacity is available in multiple venues including the SIR pre-application report and also in the capital planning analysis for specific projects. Design criteria is available for individual utilities and may vary based on historical experience and system configuration. Circuit capacity data is typically available on a project-specific basis.
[124] Con Edison's Initial DSIP, p. 235.

2. National Grid

National Grid has developed a System Data Portal that will make data available to third parties and customers. The portal will provide National Grid's reliability data, hourly (8760) distribution system load profiles (where available), current load and DER forecast, and planned capital projects. In addition, information with regard to the ability of the distribution system to host additional DER and to identify the areas of the distribution system where DER may best be located to provide grid benefits will be presented via online interactive maps.[125] This is an essential first step in visualizing hosting capacity. A detailed analysis on hosting capacity is currently underway. The system data portal will continue to evolve with additional information and enhanced functionalities over time.

3. NYSEG/RG&E

The information that will be shared in the near term by NYSEG/RG&E includes Stage 1 hosting capacity indicators, beneficial locations, hosting capacity and the results of planning studies.[126] Stage 1 indicators as defined by NYSEG/RG&E are maps that identify areas where DER are not easily accommodated on the distribution system.

4. Central Hudson

Central Hudson has hourly (8760) load data available for 54 distribution load serving substations where detailed metering information was available, including five years of historical data (where available) and five years of forecast data with uncertainty bands. Central Hudson also has available up to five years of historic hourly (8760) load data for each of approximately 270 circuit feeders where data is available. Existing historical data is available currently, but requires an explicit request to be delivered to entities. Data will be extracted and delivered to entities requesting it on a first come, first serve basis, and may take up to two weeks to deliver.[127]

5. O&R

O&R provides granular historic, actual, and forecasted data. In terms of historic data, O&R provides one year of hourly load data at the substation load area level.[128] O&R also provides the actual 24-hour minimum load curves by substation load area for 2015. O&R shares near-term forecasts, specifically 24-hour peak load curves by substation load area for 2016. O&R also shares a five-year forecast of 24-hour system peak day load curves. O&R requires a participant to register in order to obtain the data from its System Data portal located on its distributed generation website.[129] O&R is currently looking to expand the System Data portal to other types of information that is already publically available through regulatory filings and reports but not readily accessible. O&R plans to engage with NYISO and other stakeholders in understanding the potential usefulness of 8760 substation and circuit level forecasts for long-term planning, because

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[125] National Grid's Initial DSIP, p. 6.
[126] NYSEG/ RG&E's Initial DSIP, p. 76.
[127] Parties should submit data requests to DSIP@cenhud.com.
[128] 2013 hourly system data is provided as it is the most reflective of O&R's optimal system configuration. O&R's Initial DSIP, p. 40.
[129] *See* http://www.oru.com/solar

such forecasts are very dependent on the quality and accuracy of inputs, such as hourly weather forecasts that typically do not exist or are highly variable.

E. Opportunities to Enhance Data Sharing

The Joint Utilities remain committed to supporting the REV goals of enabling enhanced access to information, which will support increased penetration of DER on the grid for the benefit of consumers. To determine what data can be shared and how it can be shared in the near, medium and long term, the Joint Utilities participated in extensive stakeholder discussions.

In the stakeholder sessions, DER providers expressed an interest in receiving detailed and granular system data as frequently as possible to support the integration of DER solutions. These requests covered a wide range of information, which can be classified into three major categories: (1) capital projects-related data, (2) planning-related data, and (3) market development-related data. Capital projects data includes information on planned capital investments on the distribution system, along with the identified need driving the particular investment. In terms of future planning data, DER providers requested some components of hosting capacity calculation, including circuit models, circuit node loading, and voltage and thermal rating of the equipment. With respect to market development based data, DER providers requested information on DER growth forecast, power quality, reliability, and resiliency statistics, as these metrics could support their business development activities to attract new customers.

As previously stated, stakeholder engagement was useful in helping to identify common ground and areas of additional work. Through this forum, the Joint Utilities were able to discover data elements that are both available today, as well as present on the stakeholders' information request lists, such as reliability statistics, resiliency statistics, and planned capital investments. Although the granularity for this data may vary by individual utility, the ability to provide this data in a more useful and accessible format represents a near-term opportunity the Joint Utilities intend to pursue further with the stakeholders. The Joint Utilities noted that although substantial overlap exists between the data requested and data provided, some data requests are expected to be categorized as value-added data and such information may incur charges in the future.

Additionally, the stakeholder discussions revealed the DER providers' interest in gaining an understanding of the methods and approaches used by the utilities in their planning analysis. The stakeholders indicated that they would derive additional value from understanding and interpreting the solutions proposed by the utilities, as well as the potential for their own proposals to serve the same need. Stakeholders indicated that transparency of the modeling techniques could help alleviate the desire for data which would be used to test utility analyses. The Joint Utilities provide further discussion regarding planning analytics and methodologies within other sections of this Supplemental DSIP, and recognize that these methodologies and approaches will evolve over time. The Joint Utilities propose to continue to work to define methodologies and analytical approaches and to continue to communicate with stakeholders to understand their interests in these processes.

1. Near-term Opportunities

DER providers will benefit from the improved access to specific and granular system data from upcoming NWA solicitations. As highlighted in the *DER Sourcing* section of this filing, this project-specific system data will enable DER providers to ascertain the value that a portfolio of DER can provide to the system. The Joint Utilities believe that to have the largest impact in the shortest period of time, it is important for DER providers to share meaningful feedback regarding their immediate needs and uses for data, to allow the Joint Utilities to work collaboratively to satisfy those needs through alternate data or analysis.

In addition to individual efforts pertaining to NWA solicitations, the Joint Utilities are collectively proposing measures to advance the sharing of system data while focusing on the highest value information that can be supplied to DER providers to make effective decisions in the near term. Specific areas the Joint Utilities are focusing on in the near term include:

- Improving access to the historically available information discussed in the previous section;
- Enhancing the analysis and output of indicator and hosting capacity data (see *Hosting Capacity* section);
- Streamlining approaches to data development including the presentation format of the hosting capacity data;
- Creating an interconnection platform; and
- Making data available via the SIR pre-application report.

2. Medium- to Long-term Opportunities

The types of data sought by stakeholders ranged from detailed system information that forms the basis of system needs and project identification to the results of such analysis. Types of requested data included:

- Physical attributes. The physical attributes of a distribution system may include network topology (radial or mesh network), power quality, the voltage limits of distribution lines and transformers, the ratings of circuit breakers and fuses, and the characteristics of DER already connected to the grid, among others. This data is fairly comprehensive and highly sensitive.
- Protective devices. Protective devices are needed to minimize the duration of an electrical fault, and to minimize the number of consumers affected by a fault. Distribution grid protective devices include reclosers, sectionalizers, fuses, and circuit breakers. This information may be valuable to DER providers when combined with other information, to identify locations where added DER may avoid faults, and/or where added DER would be added in a stable environment with limited potential for curtailment.
- Voltage profile. At the feeder level, the voltage profile indicates the drop in voltage as the distance from the substation increases. This drop in voltage is due to line impedance, and the rate of voltage drop decreases farther away from the substation. This information may be valuable to DER providers interested in providing voltage support.
- Circuit Impedance Models. These are simulations of the distribution system developed using power engineering software tools that demonstrate line impedances at the feeder level. The data supporting such models is highly sensitive.

In their respective Initial DSIP filings, the utilities detailed their plans for technology and infrastructure upgrades to capture system data in an increasingly effective manner. While current capabilities vary, it is envisioned that the utilities' capabilities will eventually converge in the long term to the point where they may be able to provide the same granularity and quality of system data. Table VII-3 provides a snapshot of data elements that the utilities can provide in the medium- to long-term timeframe. The full availability of such data will be tied to the ability of utilities to both install and actively utilize new systems and processes, the outcome of security and risk assessments, and Commission approval for the necessary investments. Table VII-3 summarizes the current status and availability of these data types.

Additionally, the Joint Utilities will continue to develop methods for presenting hosting capacity data, including elements of Stages 2 and 3 of hosting capacity analyses. In the process, the Joint Utilities will continue to examine the availability and presentation of common elements and outputs of the hosting capacity analysis.

Table VII-3: Medium to Long-term Data Availability

Data Type	Frequency	Granularity	Availability	Format Available
Physical Attributes	Static (updated as projects are implemented)	Node level	Subject to data security classification review	Within circuit models
Protective devices	Static (updated as projects are implemented)	Feeder level	Subject to data security classification review	Within circuit models
Voltage profile	Static (updated as projects are implemented and with changes in load information)	Feeder level	Subject to data security classification review	Within circuit models and would need to be updated more frequently
Circuit impedance models	Static (updated as projects are implemented)	Feeder level	Subject to data security classification review	Within circuit models – would require further information to make usable

3. Long-term Data Platform and Data Format

The Joint Utilities and stakeholders agree that value can be attained through consideration of similar or common templates for data structures where the opportunity exists. However, the development of a single cross-utility platform would require a new, concerted effort on the part of the Joint Utilities to address the many issues raised by a single platform. For example, questions of accessibility, corporate compliance, systems integration, costs, and development risks would need to be identified and addressed. Additionally, issues of data security and data confidentiality will need comprehensive review.

The incremental benefits arising from a common platform may not be commensurate with the efforts that need to be undertaken to develop, maintain, and enhance the platform. Based on these considerations, the Joint Utilities and stakeholders agree that value can be attained more quickly through utility-specific solutions and the development of similar or common templates for data structures where the opportunity exists. This topic is evolving and will require sustained engagement among the Joint Utilities. The Joint Utilities will revisit the challenges and issues associated with such a platform over time and within ongoing proceedings.

F. Need for Cooperative Data Sharing and Communications

The responsibility to operate the distribution grid in a safe and reliable manner rests with the utility. Data reciprocity is necessary to meet that responsibility. As mentioned in stakeholder engagement sessions, the utility will need data from DER providers for provision of safe and reliable grid operation. Currently, there is very limited data sharing between the utilities and DER providers. For the Joint Utilities to effectively perform their functions as DSPs, which includes performance measurement and verification of DER, it is imperative that data on DER performance and operations is shared with them. Additionally, to aid in system planning, it will be beneficial for the Joint Utilities to understand how DER providers plan to scale their operations.

For operational planning and forecasting purposes, the utility must be aware of what DER facilities are serving the grid on a day-ahead basis. The utility will require advanced notice prior to the connection and/or disconnection operations undertaken by DER operators. For any generators sized larger than one MW, the Joint Utilities request information on the real and reactive power characteristics of the generator. As devices such as smart inverters are used in greater numbers, the utility will need to be informed of their technical intricacies and capabilities prior to their deployment. As has been mentioned in the *Monitoring and Control* section of this filing, the utility shall reserve the right to conduct field tests and demonstration projects for such devices, prior to their deployment and usage on the distribution system. The Joint Utilities believe mutual cooperation between the utilities and the DER providers will bring benefits to customers. The Joint Utilities also recognize that the current channels of coordination and communication between the utilities and the DER providers are limited in their ability to facilitate this discussion. Thus, developing or identifying processes that enable such data interchanges will be important going forward, as discussed in the following section.

G. Summary of Next Steps

While the Joint Utilities have made significant progress to identify available data and to create accessible and useable information for third-party developers, additional steps are needed to continue to expand the opportunities and achieve the goals of the REV initiative. Thus, the Joint Utilities have identified four important areas for continued advancement of system data development: (1) collaboration and coordination on the part of the Joint Utilities; (2) continued stakeholder engagement; (3) identifying a forum for facilitating data reciprocity; and (4) regular coordination and check-ins with Staff.

1. Continued Cross-Utility Collaboration

System data represents a broad-based topic with multiple aspects and increasing complexity. The Joint Utilities anticipate system data to be a rapidly evolving area and believe that ongoing efforts across not only the Joint Utilities, but also across functional areas of the utilities, will be necessary going forward. While specific topic areas will evolve over time, the Joint Utilities recognize the need to establish open communications on topics such as:

- Classifying system data based on sensitivity of the information, both as a stand-alone data item and packaged with additional information;
- Defining value-added and basic data including developing potential fee based structures for data services;
- Benchmarking progress across the utilities as well as developments in other jurisdictions, such as California, including review of utility requests or information, and expansion of data processing methodologies; and
- Reviewing web portals including assessing look and feel, data availability, access of common companies, and frequency of data access. The assessment would be used to provide feedback to portal development and allow for features with best performance/public reception to potentially be shared on all platforms. The review may include an assessment of the demand/value/cost/risk of a single platform maintaining all of the Joint Utilities' content and will incorporate lessons learned from collaborative processes such as the interconnection application portal.

2. Continued Stakeholder Engagement

The Joint Utilities are committed to continuing stakeholder engagement to discuss opportunities to enhance authorized third-party data access. The Joint Utilities have identified near-term opportunities for such discussions related to enhancing the currently available data into a useable format for DER providers. The Joint Utilities also recognize benefits of continuing discussions into the longer term.

Within the next 12 months, the Joint Utilities envision the following three-step process to enhance the ability to utilize available data:

<u>Step 1</u>: The Joint Utilities will provide a comprehensive comparison of data available in static filings, such as rate proceedings and capital investment plans to interested stakeholders. The comparison will show each utility's available data sets and include a description of the location, format, and frequency of such data. The Joint Utilities will suggest common formats for the common data elements identified.

<u>Step 2</u>: The Joint Utilities will seek stakeholder input on the data formats and their priority for development of the data suggested in Step 1. The Joint Utilities will also seek stakeholder input on priority elements desired by stakeholders in their business development efforts.

<u>Step 3</u>: The Joint Utilities will provide a final sample format for data elements accounting for comments received in Step 2. The Joint Utilities will also provide a schedule for provision of new data series in the format as per comments received in Step 2.

While this engagement and timeline is focused on near-term activities, feedback on formats will also be useful in developing incremental data sets going forward as well. Engagement groups may continue into the future as further needs are identified.

In the medium- to long term, the Joint Utilities propose an ongoing, annual needs assessment that will seek stakeholder feedback on their portals, quality of data supplied, ease of access to information, and other aspects of the stakeholder experience. The feedback received will be used to determine areas where further accessibility and transparency may benefit future data and information release. The feedback would also provide valuable input into future DSIP filings.

3. Identifying a Forum for Facilitating Data Reciprocity

The Joint Utilities believe that achieving the objectives for REV will require concerted efforts from utilities and all relevant stakeholders. To realize the benefits of DER at the system and consumer level, it is necessary that information is exchanged among all relevant entities going forward. The Joint Utilities realize that the forums needed to facilitate information exchange among the utilities and the DER providers do not yet exist. It is increasingly realized that a formalized forum for sharing of data among the Joint Utilities and DER providers will enable the data reciprocity needed for designing, operating, and planning the grid with high levels of DER penetration. The continued stakeholder engagements on this issue will be utilized to develop a charter and define the governing principles of the proposed forum.

4. Regular Updates

The Joint Utilities will update stakeholders and Staff regarding data development activities, including requests received from stakeholders and utility responses on an annual basis.

Customer Data

A. Introduction

DER market development can be improved when both customers and DER providers have access to customer information. Customer information includes customer energy usage data, customer-sited generation data, account and load profile information, results from customer-specific analyses, end-use information, and other elements. The availability of customer energy usage data, in particular, is critical to the success of market development under REV, as DER providers seek data that will inform the development and marketing of tailored products and services.

In addition to fostering market product and service offerings, the Joint Utilities are aware of other use cases for customer data, both individual and aggregated, in the marketplace today. A variety of these use cases were discussed during stakeholder engagement sessions. For example, building owners need aggregated whole-building data to comply with Local Law 84 benchmarking requirements in New York City. Additionally, academic institutions, state agencies, and local governments use aggregated energy usage data to analyze prospective policies, develop action plans, and build inventories of data for tracking and reporting purposes. While use cases for customer data may vary, it is clear that timely access, additional data elements beyond usage data, and higher granularity will be important aspects of customer data going forward.

As discussed in each utility's Initial DSIP filing and summarized herein, the utilities have been taking steps to offer enhanced access to customer usage data, based on their current and planned technical capabilities. For example, utilities with AMI deployment plans expect to provide basic customer usage data to customer-authorized third parties using the Green Button Connect My Data ("GBC") specification or a comparable platform. Basic usage data from AMI meters will be reported in increments of between five minutes to one hour, and made available no later than within 24 hours of collection. These utilities also plan to enhance existing customer data platforms, which will leverage AMI data (if applicable) and open opportunities for new services and products.

To inform their thinking on customer data topics, the Joint Utilities convened an engagement group to educate stakeholders on current practices, better understand stakeholder perspectives, and solicit input on key customer data issues, including data collection, reporting frequency and availability of usage data, aggregation of usage data, additional data needs, and data privacy. The discussions helped the Joint Utilities understand different use cases for data, anticipate technical and implementation issues with data platforms, and consider a broad spectrum of perspectives on privacy standards for data.

B. Current State

The following section draws on the information filed in each utility's Initial DSIP filing to summarize current customer data capabilities, AMI investment plans, and data privacy practices.

1. *Current Platforms and Capabilities*

Customer data platforms are essential tools for engaging utility customers and creating viable commercial opportunities for DER providers. The utilities currently share customer data with customers and their authorized third parties through various systems. These include utility bills, GBD or equivalent, EDI, online third-party data platforms, SFTP, File Transfer Protocol with PGP Encryption, and online third-party data platforms. Each data sharing platform may be designed with a different audience in mind, have unique access requirements, and be used to convey different kinds of information. The following table provides an overview of current data platforms and their recipient types, by utility.

Table VII-4: Current Data Platforms

Platform	Data Recipients	Companies
GBD	Customers and authorized third parties	Con Edison, O&R, National Grid, Central Hudson
EDI	ESCOs	All
SFTP	Authorized third parties	Con Edison, O&R, Central Hudson
FTP with PGP Encryption	ESCOs, EDI Vendors	Central Hudson
Online third-party data platforms	Utility-specific	All

2. *AMI Investment Plans*

For most of the utilities, AMI is foundational for their evolution into DSPs. Investments in AMI will enable new opportunities for energy services from utilities and third parties, and will likely facilitate the emergence of future utility business models. Utilities and stakeholders have identified that interval data provided by AMI will have applications in the DER market. Nearly all of the Joint Utilities plan to invest in AMI solutions to some extent.[130] Table VII-5 below summarizes the AMI deployment plans.

Table VII-5: AMI Deployment Timelines[131]

Utility	AMI solution description	Meter Deployment Schedule
Con Edison	Full deployment (4.7 million electric and gas meters)	2017 – 2022
National Grid*	Full deployment (2.4 million electric and gas meters)	2019 – 2024
O&R	Full deployment (362,000 meters)	2017 – 2019 (Rockland County), 2018-2020* (Orange and Sullivan counties)
NYSEG/RG&E*	Full deployment (1.8 million electric and gas meters)	2018 – 2021
Central Hudson	Opt-in demonstration project	2017 and beyond

* Proposed

[130] The exception is Central Hudson for which AMI deployment was not found to be cost-effective
[131] For more information, see individual utility Initial DSIP filings.

3. *Provision of Aggregated Data*

Aggregated data is data that has been summed or otherwise combined across a group of accounts. It is used by market participants, customers, and policymakers for a variety of applications such as developing and implementing Community Choice Aggregation ("CCA") programs,[132] establishing energy consumption metrics to inform policy decisions, and developing dynamic greenhouse gas emissions inventories. Aggregated data also enables a DER provider to ascertain high-level characteristics of a given area, as a precursor to a more detailed analysis that may ultimately inform the developer's decision to deploy a DER solution in a given area. Aggregated data is not customer-specific and, as such, a government entity or market participant does not have to obtain individual customer authorization before requesting the data from the utility, except in cases where the data could be used to deduce customer-specific information, as described below.

To date, requests for aggregated data have been fairly *ad hoc* and limited in number. For this reason, the utilities currently fulfill most requests manually and, in some cases, charge a fee to the requestor. Not all of the utilities have received requests for aggregated data in the past, but all have filed proposed tariff amendments for CCA data services and plan to provide aggregated data, in addition to customer specific data, to CCA Administrators for a fee going forward.

C. Proposed Collection and Sharing of Customer Data

In this section the Joint Utilities explain their proposed approach to collecting and sharing customer data and then address issues raised in stakeholder discussions. The Joint Utilities' goal in developing this approach is to balance several factors, including market needs, technological capabilities, utility resources, the evolving utility business model, and privacy safeguards. The Joint Utilities will continue to work together and engage stakeholders in an ongoing dialogue to address emerging market needs for customer data.

1. *Interval and Reporting Frequency*

The Joint Utilities seek to provide customers and/or their authorized third parties with timely access to granular customer usage data, which is made possible through investments in AMI infrastructure. This is often termed "real-time" or "near real-time" data, though its precise definition may depend on the use case. For example, some DER providers may consider any data delivered within 24 hours of collection to be real-time, while others may only consider data whose reporting frequency is less than 24 hours to be real-time. The general industry standard for AMI implementations in the United States has been to make bill-quality interval data available within 24 hours of collection.

The utilities implementing AMI will initially be capable of providing basic interval data and some value-added interval data in intervals of between five minutes to one hour, and will make this bill-quality data available for customer and authorized third party access within 24 hours of collection, depending on the specific utility's systems and capabilities. Current basic data collection and

[132] Case 14-M-0224 – *Proceeding on Motion of the Commission to Establish Community Choice Aggregation,* ("CCA Proceeding"), Order Instituting Proceeding and Soliciting Comments (issued December 14, 2014) ("CCA Order").

reporting practices will continue until AMI solutions are in place. For utilities not implementing a full AMI solution, customer usage data will be reported in bill-ready quality at the end of the billing cycle (*e.g.,* monthly), and existing practices for interval-metered customer data sharing will continue.

The Joint Utilities understand that some DER providers are requesting data with enhanced reporting frequencies and that new use cases for this data may arise as the market evolves. For example, some stakeholders identified several demand response use cases that require low-latency customer data. The utilities are addressing these needs in their individual utility AMI business plans through the development of flexible, technology-specific AMI infrastructure designs that can be managed over time to support the near-real time usage data needs of the evolving market.[133] Considering the nascent state of the market, different utility AMI deployment timelines and technology designs, and the unique requirements of different use cases, it is not practical or useful at this time for the Joint Utilities to espouse a singular definition of near real-time data access. The Joint Utilities plan to continue to collaborate with each other and with stakeholders in this area as AMI is deployed and experience is gained.

a. Data Streaming

Stakeholders noted that streaming low-latency (*i.e.,* "real-time") and high-granularity usage data already have several applications in the marketplace today, and will likely have significantly more in the future. Identified use cases for real-time data include device monitoring and control at the meter premise, demand response, DER dispatch, and settlement. The Joint Utilities also understand that, at present, some customers and DER providers are interested in streaming usage data from the utility meter for the purposes of interfacing with on-premise devices (*e.g.,* building management systems) or offering energy management and related services in order to optimize energy consumption and lower energy bills.

There are several possible methods of streaming real-time data to customers and DER providers. One is to wirelessly stream the data from the customer meter (via ZigBee or similar protocol) to the customer's Home Area Network ("HAN") or Business Area Network ("BAN") and its connected devices, such as in-home displays and smart thermostats.[134] Another method currently used by building owners and many DER providers is to install local energy use recorders that capture real-time data from the utility meter.[135] Some stakeholders expressed interest in receiving more frequent meter readings via utilities' planned AMI networks to capture more granular data (*e.g.,* one-, two-, or five-minute intervals) on a more frequent basis (*e.g.,* every five minutes) which would be made available to customers and DER providers through a utility interface (*e.g.,* internet portal or GBC). Some stakeholders commented that this particular approach is attractive from the

[133] *E.g.*, Con Edison and O&R plan to provide 15-minute interval data for residential customers with AMI meters and five-minute interval data for commercial customers with AMI meters, on a 24-hour lag in 2017 and in near-real time (30-45 minute after the interval ends) beginning in mid-2018. Near-real time data will be reported as partially validated, edited, and estimated, because more time is required to elevate the data to bill quality.

[134] More Than Smart and Mission:Data, *Got Data? The Value of Energy Data Access to Consumers*, January 2016, p. 6. http://www.missiondata.org/news/2016/2/2/got-data-report-shows-benefits-of-consumer-access-to-their-energy-data

[135] *E.g.*, local data access via utility meter KYZ output.

customer's perspective, because it would not require any additional onsite metering and communications hardware or complicated device pairing/provisioning.

The Joint Utilities note that the optimal streaming solution for each utility will depend on utility-specific considerations and may require further analysis of specific use cases and business cases (including the potential for incremental fees) to support its additional cost. The technical and economic challenges associated with providing streaming data as envisioned by some stakeholders are substantial and will require each utility to consider the costs and benefits carefully. The Joint Utilities will revisit these issues as they gain experience with AMI systems and can better assess market demand for streaming data services.

2. Data Platforms

Platforms are the means by which customer usage data is distributed to customers and authorized third parties. The need for standardized data platforms and processes has been a consistent theme in discussions with stakeholders as part of the DSIP process as well as in other REV and related proceedings. The Joint Utilities all plan to enhance their respective customer data platforms to address data sharing needs in a consistent manner.

For most utilities, AMI will be the cornerstone of new energy information services and tools. Utilities implementing full AMI solutions plan to provide basic customer usage data to customers via online platforms and to customer-authorized third parties using the GBC standard or a comparable specification. Utilities not implementing full AMI solutions expect to provide basic customer usage data to end-users via GBD or an alternative specification.

Additionally, Con Edison has been required by the Commission to develop a new EDI transaction to provide interval data to ESCOs at the end of the billing period for each customer. As explained in Con Edison's Initial DSIP filing, interval data also will be provided more frequently using RESTful Application Program Interfaces ("API"), to the extent that ESCOs are interested in more frequent data and willing to invest in API functionality. Other utilities are considering similar changes. The below table summarizes the GBC deployment plans by utility.

Table VII-6: Green Button Connect Deployment Plans

Utility	GBC plans
Con Edison	Will implement GBC for basic data sets by the end of 2017 and will explore adding additional data fields starting 2018
NYSEG/RG&E	Will implement GBC or comparable specification as part of its Energy Manager web-based tool
O&R	Will implement GBC for basic data sets by the end of 2017 and will explore adding additional data fields starting 2018
National Grid	Will implement GBC as part of its AMI deployment program
Central Hudson	No plans to implement GBC in the near future. Will continue to provide customers with access to their data through GBD (via the CenHub online portal) as well as bills.

While standardization is a desirable goal, it may be difficult to achieve in the near term given the variation in the utilities' starting points. As noted in the Joint Utilities' response to questions in the notice following the July 28, 2015 Staff White Paper on Ratemaking and Utility Business Models, "the method for providing customer-specific and aggregated data must be determined by evaluating a variety of factors for each utility, including, but not limited to, meter infrastructure, customer service systems, website capabilities, and service territory."[136] Furthermore, future capabilities and platforms are dependent on individual utility investments and rate case outcomes, which will also evolve at different paces.

In addition to Green Button, the utilities will continue to leverage existing platforms, including EDI, SFTP and online customer engagement platforms. Finally, the Joint Utilities note that the DER Oversight proceeding[137] is a key dependency for designing and developing the configuration of GBC.

3. Aggregated Data

A number of use cases for aggregated data exist today and others are expected to develop over time. To meet the needs of stakeholders such as academic institutions, state agencies, city governments, and market entities that use aggregated energy usage for policy and planning purposes, the Joint Utilities are proposing to provide a uniform level of aggregated data. The Joint Utilities define the uniform aggregated data offering as kW and/or ICAP, customer counts, and kWh data that is aggregated by zip code and/or tax district, and segmented by rate class. For rate classes with TOU periods, kW and kWh data will be aggregated by TOU periods and in total. The Joint Utilities anticipate that the required data elements may evolve over time with the changing energy marketplace, and will work together for consistency among their individual offerings.

Beyond the uniform aggregated usage data offering, the utilities are working to provide aggregated usage data for other defined use cases such as CCA and whole-building data. As described in the Companies' individual progress reports on automation of aggregated data,[138] most aggregated data requests are currently fulfilled with manual or customized solutions. The Joint Utilities, where appropriate and based on request volumes and cost considerations, will streamline and automate the provision of this data over time. The utilities are currently working to automate the provision of CCA data consistent with the CCA Order and the Track Two Order.

As previously discussed, all aggregated customer usage data is considered value-added data and will be subject to a fee reflective of the value of the data. Fees for aggregated customer usage data will be set forth in each utility's tariff(s) based on the cost and type of data being requested and the data's value to the market.

a. Aggregated Customer Data Privacy

The Joint Utilities are not required to seek customer authorization when sharing aggregated data with third-party requestors or building owners, as long as individual customer data cannot be identified. However, stakeholders in this forum and elsewhere in the country have raised the concern that some aggregations are more anonymous than others. For example, it may be fairly

[136] REV Proceeding, Track Two Order, Appendix C, p. 285.
[137] REV Proceeding, See Case 15-M-0180, *In the Matter of Regulation and Oversight of Distributed Energy* Resource Providers and Products.
[138] See REV Proceeding, individual utility submittals (filed September 1, 2016).

straightforward to isolate and deduce the identity of a relatively large commercial account in a small customer sample, because that account's consumption may constitute most of the sample's total load. This is particularly relevant for aggregated whole-building data, where a single occupant can be responsible for an overwhelming majority of the space in a building.

As a result, several utilities and regulatory bodies in other states have developed aggregation standards, which require that an aggregated data set meet certain criteria before a utility may share it. All standards require the data set to contain a minimum number of accounts, and some standards impose additional restrictions, such as limits on the percent of load represented by any single account in the data set. For example, a 4/80 standard requires data to be drawn from a minimum of four accounts and limits the load of any single account to 80 percent of the total load for the data set. The below table summarizes current aggregation standards for selected utilities.

Table VII-7: Aggregation Standards

Utility (State)	Aggregation Standard	Applicability	Originator
Austin Energy (TX)[139]	4/80	Whole-building data	Utility
Commonwealth Edison (IL)[140]	4 or more individually-metered electric accounts	Whole-building data	Utility
Pepco (DC)[141]	5 or more individually-metered electric accounts	Whole-building data	Utility
Public Service Co. of Colorado (CO)[142,143]	15/15; 4/50	All aggregated data reports; Whole-building data	Statute
Southern California Edison (CA)[144]	15/15	Whole-building data	Utility
Southern California Edison, Pacific Gas & Electric, San Diego Gas & Electric (CA)[145]	15/20	All aggregated data reports for residential, commercial or agricultural customers requested by local governments/municipalities	Utility commission
Southern California Edison, Pacific Gas	5/25	All aggregated data reports for industrial customers	Utility commission

139 http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23786.pdf
140 OV Livingston, et al., Commercial Building Tenant Energy Usage Data Aggregation and Privacy, Pacific Northwest National Laboratory, October 2014, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23786.pdf
141 https://www.pepco.com/pages/myhome/energymanagement/energybenchmarking.aspx
142 Colorado Code of Regulations 3033.(b) https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=6747&fileName=4%20CCR%20723-3
143 Colorado Code of Regulations 3034.(a)
144 https://www.energystar.gov/sites/default/files/tools/Web_Services_Fact_Sheet_02042016_508_0.pdf
145 California Public Utilities Commission, Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data, D. 14-05-016 (issued May 1, 2014), p. 34.

Utility (State)	Aggregation Standard	Applicability	Originator
& Electric, San Diego Gas & Electric (CA)[146]		requested by local governments/municipalities	

The Joint Utilities propose the adoption of a 15/15 privacy standard for aggregated data provided by utilities to third parties, other than utility vendors or contractors or required by law or Commission order. While that standard is being implemented, the Joint Utilities will each work so that their current anonymity policies are sufficiently rigorous, and will retain the right to deny any requests for aggregated data where the data cannot be sufficiently anonymized.[147]

Numerous stakeholders offered strong views on aggregation standards during stakeholder engagement sessions. Some stated that the 15/15 standard poses an overly-restrictive threshold that data sets from certain customer classes, particularly small buildings with fewer than 15 tenants, are unlikely to meet. Conversely, other stakeholders insisted that privacy concerns are critical to commercial and industrial customers, and outweigh any increased difficulty that parties might experience with obtaining aggregated data sets. It is important to keep in mind that customer data can always be provided to a third party with the customer's express consent. The Joint Utilities acknowledge that if aggregated data is provided for a smaller group of customers, such as for buildings or at the circuit level and further segmented, some groupings may not meet the 15/15 standard. Data provided at a higher system level, or over a broader geographic area, has a greater likelihood of meeting the 15/15 standard.

The Joint Utilities emphasize that they are purposefully starting with a conservative approach to aggregated data privacy, so that the utility continues to protect customer information, and may be open to revisiting this approach as the market matures. The Joint Utilities will also establish exceptions to the 15/15 standard in order to facilitate compliance with existing laws and ordinances such as Local Law 84 in New York City.

4. Additional Data

Applications that leverage customer data are likely to proliferate as the energy marketplace progresses under REV. The utilities implementing AMI will play an enabling role by gradually providing additional data sets to market participants over time, as Con Edison and O&R have already begun doing as part of their AMI Customer Engagement Plan filing effort.[148] The utilities implementing AMI will individually and/or jointly seek to remain consistent as they incorporate additional data sets, beginning with bill cost data, once their enhancements to protocols for transmitting basic data sets (*e.g.*, GBC) are fully developed and implemented. Those utilities eventually may consider additional data sets, which may include proposed enhancements to the

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[146] http://www.energydataalliance.org/wp-content/uploads/2011/07/IMT_Report_-_Utilities_Guide_-_March_2013.pdf

[147] REV Proceeding, Track Two Order, p. 153 and CCA Proceeding, CCA Order, p. 44.

[148] Cases 15-E-0050 and 16-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. Electric Service*, Letter filing Con Edison and Orange and Rockland AMI Engagement Plan (filed July 29, 2016)("Con Edison/O&R AMI Plan"), p. 36.

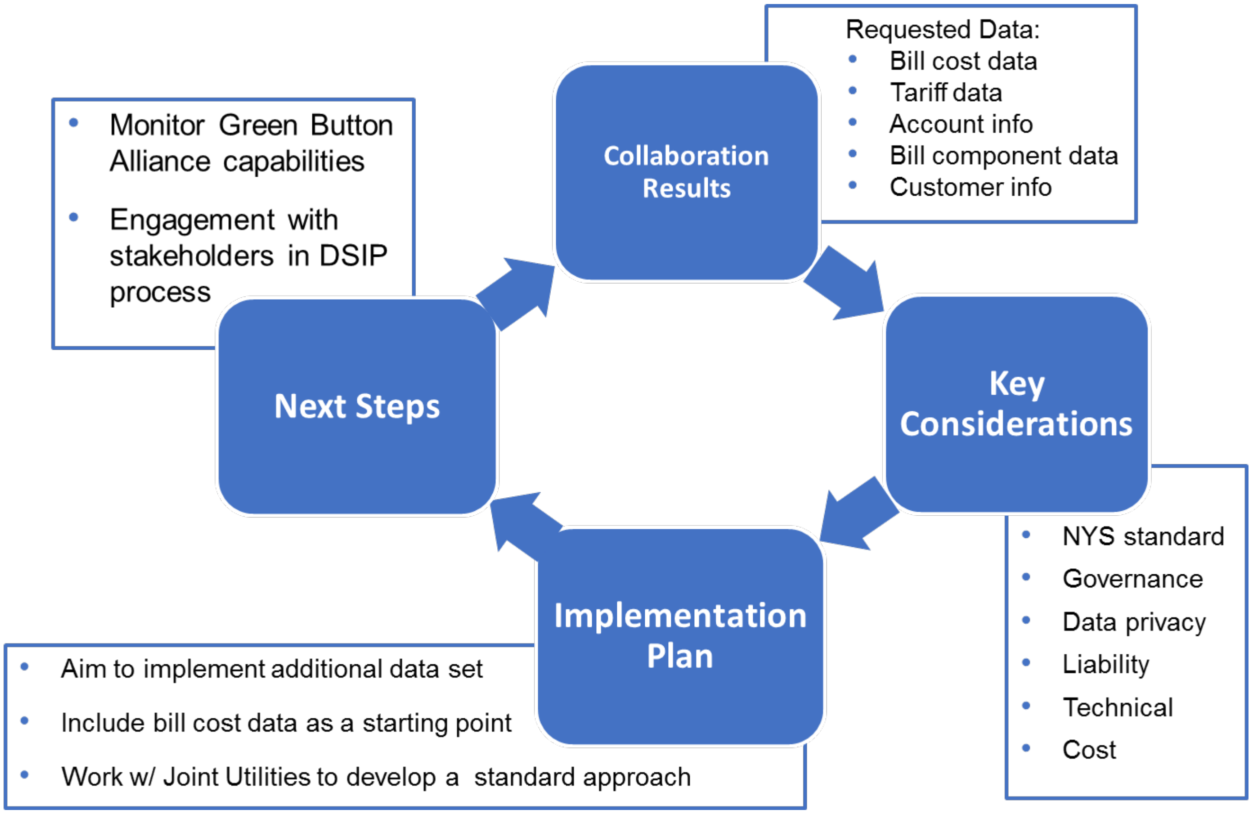
national Green Button protocol (currently under consideration), as well as items identified by stakeholders such as billing history components (*i.e.,* total bill dollars), net-metered customer indicators, customer addresses, and machine-readable tariffs.

The utilities plan to follow the process illustrated in Figure VII-2 below, which was developed by Con Edison and O&R in their AMI stakeholder collaboration and also shared with stakeholders as part of the DSIP effort. As this figure illustrates, there are several practical reasons to favor a gradual approach to exploring additional data sets. For example, some new data sets may be impractical to incorporate into existing protocols at this time and would be contingent upon the development of new common sharing standards for New York that could later be eclipsed by national standards. Similarly, additional data sets may require potential modifications to the utilities' governance structure[149] (including privacy and liability rules), and to the underlying technology platforms that support data gathering, storing, and transmission. Finally, the full costs of implementing additional data sets in this manner, and corresponding financial terms, must be carefully explored prior to implementation.[150]

The Joint Utilities commit to work together to develop specifications for transmitting any additional data fields beyond what is provided through the current Green Button Connect standard. Current and future stakeholder input will help to inform the Joint Utilities' consideration of additional data sets.

[149] A governance structure for sharing data sets will outline the responsibilities of the utilities, third parties, and customers.
[150] Con Edison/ O&R AMI Plan, p. 43.

Figure VII-2: Illustrative Utility Approach to Additional Data[151]



D. Summary of Next Steps

AMI is an enabling investment for some utilities that will allow for the collection of more timely and granular customer usage data. As described in the utilities' Initial DSIP filings or other AMI business plans, the utilities, with the exception of Central Hudson, propose to deploy AMI systems including GBC over the next several years. As the utilities gain experience with AMI and more fully understand its capabilities, technological requirements, and associated use cases, they will make the data available in accordance with the terms approved by the Commission.

Over the next few years, the Joint Utilities expect there will be more market participants offering customers a greater number of products and services that rely on customer data. DER providers will likely request additional data fields through existing platforms, increased granularity of and frequency at which data is made available, more aggregated data sets, and greater streamlining of these applications. The Joint Utilities will address these emerging market needs in a phased approach, consistent with the overall concept of an initial period for foundational planning and learning.

This approach is also intended to keep pace with the gradual evolution of the market itself. For example, DER providers currently seek access to a wide variety of both individual and aggregated

[151] Adapted from Con Edison/O&R AMI Plan Presentation, July 15, 2016.

customer usage data; however, it would be impractical for the utilities to develop systems to automatically fulfill every type of data request, especially because some future needs and applications cannot yet be envisioned. Rather, as markets develop, the utilities will be positioned to identify the most common types of customer data requests and make those data sets available to third parties. This incremental approach will effectively address market needs while promoting data sharing alignment among each of the utilities and avoid passing unnecessary costs to customers. In the meantime, current data collection and reporting practices will continue as the necessary experience is gained.

The Joint Utilities will form a Customer Data working group, which will meet periodically to share outcomes from utility-specific projects and initiatives, as well as to report on its findings to stakeholders and Staff. This group will consult with and include as necessary utility representatives from the Grid Operations and Distribution System Planning functions for consistency. The working group will consider:

- Assess additional data needs, whether articulated by stakeholders or embedded in modifications to the national Green Button protocol, and consider their implementations (once existing protocols Share learnings from individual utility REV and other demonstration projects;
- Develop a common process for tracking aggregated data requests and responses. This will allow the group to identify, define, prioritize, and schedule for implementation requests for non-standard aggregations that are of high value to stakeholders;
- Share learnings from individual utility REV and other demonstration projects; and
- Monitor and evolve the anonymity standard for aggregated data, and engage periodically with stakeholders to share ideas and gather input.

Finally, the Joint Utilities will continue to participate in the EDI Collaborative working group.

Cybersecurity and Privacy Protections

A. Introduction

Tackling cybersecurity is essential to improving the security and reliability of the electric grid. Historically, the isolation of the grid provided protection from malicious attacks. The grid of the future lends itself to increased interconnectivity and data exchange. As the grid modernizes, new technologies bring about new cybersecurity risks. These cybersecurity risks are related to increased data sharing between utilities, vendors, and customers.

Of particular concern to the utilities at this time is the potential for the use of system data to identify patterns and draw conclusions that can be used to harm grid infrastructure. Currently, while the North American Electric Reliability Corporation ("NERC") and FERC provide regulatory guidance on critical infrastructure protection for the bulk power system, no such parallel standards exist for the distribution system. Further, without appropriate aggregation or anonymization, customer-related data becomes exposed and may allow for the re-identification of the data with individuals or individual firms and entities. This would potentially compromise confidential business plans and adversely affect utility customers as well as the utilities.

Utilities currently adhere to strict standards for the protection of infrastructure and customer data and intend to continue to actively mitigate growing risks in part through careful attention to cyber and privacy practices. Additionally, the Commission regulates practices for sharing customer data with ESCOs through the UBP, and is considering extending some or all of those requirements to DER providers in a separate proceeding addressing regulation of DER.[152] The Joint Utilities expect that the Commission will provide guidance on addressing third-party data privacy obligations, and requirements in this proceeding, the outcome of which may impact current practices and require additional privacy protections and related processes. Once guidance from the Commission on the revised UBP is available, there will be greater clarity regarding the breadth of customer data privacy protections and the companies can design and develop authorization processes accordingly.

The Joint Utilities have developed a common approach to managing these new cybersecurity and privacy risks in the evolving REV environment. Each utility has a Cybersecurity and Privacy Program in place to manage cybersecurity risk to an acceptable level in line with the REV Cybersecurity and Privacy Framework (the "Framework"). The Framework focuses on people, processes and technology as being the foundation for a comprehensive cybersecurity and privacy governance program. The Framework requires the implementation of an industry-approved risk management methodology and an alignment of control implementations with the control families in the National Institute of Standards and Technology ("NIST") Special Publication (SP) 800-53 revision 4. The utilities also have privacy and security protections in place to protect sensitive system data and customer data, both at the individual level and aggregated data.

[152] *See* Case 15-M-0180 - *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products*.

B. Current State

1. Utility Cybersecurity Programs

Each utility has a holistic Cybersecurity and Privacy Program in place to manage cybersecurity risk to an acceptable level in line with the Framework. Each utility leverages results from internal risk assessments to protect systems and detect potential vulnerabilities. Participation in industry working groups provides relevant information and current trends relating to potential threats and available countermeasures. The utilities utilize risk management practices from their current Cybersecurity and Privacy Programs to identify and prioritize the investment and incorporation of improved technologies in support of the REV initiatives.

2. Joint Utilities Cybersecurity and Privacy Framework

The Joint Utilities Cybersecurity and Privacy Framework requires the implementation of an industry-approved risk management methodology and an alignment of control implementations with the control families in the NIST Special Publication (SP) 800-53 revision 4. SP800-53 is a comprehensive control set that is mapped to other industry standards including ISO/IEC 27001 and ISO/IEC 15408. This control mapping allows for flexibility in control implementations relative to the assessed risk with alignment with the Framework. Flexibility is crucial to the individual utility having the ability to design their control implementations around current cyber/privacy capabilities while still meeting the intent of the Framework. Should a utility be unable to meet the control requirement, an adequate compensating control must be in place. A compensating control is any management, operational, or technical control implemented in place of the recommended control that offers comparable protection. The acceptance of compensating controls must be vetted by the utility risk management assessment process. Should no compensating solution be available, the utility must specifically accept the risk of operation without the recommended safeguards.

In many areas, the NIST control set appears to be redundant. This overlapping is not intended to require additional development or implantation efforts, but to reinforce the security requirements from the perspective of multiple controls. For example, configuration management considerations may overlap with System Information and Integrity considerations.

3. Customer Data Privacy Protections

The Joint Utilities take very seriously the obligation to protect customer privacy when providing customer data, either customer-specific or aggregated, to the marketplace. For individual customer data, the utilities do not share individual customer information without express customer authorization, except to their agents or representatives as permitted by Commission order. The utilities are not required to seek customer authorization when sharing aggregated data with third-party requestors or building owners, as long as individual customer data cannot be identified. Where there is not sufficient anonymization, the Track Two Order directs the utilities to "follow their current internal policies in addressing the anonymity issue for ensuring that aggregated data is sufficiently anonymous."[153]

[153] REV Proceeding, Track Two Order, p. 157.

C. Security Control Recommendations

The following security controls recommended by the Joint Utilities and the Framework propose a collection of countermeasures and protections. These countermeasures and protections are adaptable enough to address both IT and Operation Technology ("OT"). This could include a corporate information system and its associated technologies (*e.g.*, Windows, UNIX), as well as Industrial Control Systems (*e.g.*, DSCADA). When considering risk, the term "system" is inclusive of both IT and OT. The Framework also sets a requirement for authorized third parties and business partners inclusive of ESCOs, DER providers, CCAs, and Community Distributed Generators ("CDGs"), to design their cybersecurity and privacy programs to address each of the control family topics identified in this section. Each utility reserves the right to include contractual language to put in place certain security and privacy controls, policies, and practices. This contractual language will also consider potential financial loss due to the mishandling or inadvertent loss of data.

These Joint Utilities' security recommendations focus on security capabilities required for successful integration of DER to the distribution systems and the protection of information, irrespective of the information technologies that are implemented. The Joint Utilities have agreed to continually address security and privacy concerns as the REV initiative evolves for continued alignment with REV objectives.

1. Program Management

Utilities should develop and maintain an organization-wide information security and privacy program. A governance program, led by senior management, should be established to reinforce the business need for an effective, holistic, and risk-based approach to managing cybersecurity and privacy, so that best practice and controls are part of REV initiatives.

2. Access Control

Utilities will define a process to manage access control based on system sensitivity and importance. The process should consider:

- Which information systems/components require authentication;
- An account management process;
- Access control schemes (*e.g.*, role-based access control ("RBAC"));
- Restrictions on access controls (least privilege/separation of duties); and
- Remote access requirements.

3. Cyber and Privacy Awareness Training

Employees of the utility and, where relevant, contractors and business partners, including but not limited to ESCOs, DER Providers, CCAs, and CDGs should receive appropriate cybersecurity and privacy awareness education, training, and regular updates regarding cybersecurity and privacy guidelines, rules, and procedures. .

4. Audit and Accountability

Utilities will develop a process that identifies the systems and system events that are subject to auditing based on system sensitivity and importance. Critical systems will log:

- What type of event occurred;
- When and where the event occurred;
- The source and outcome of the event;
- The identity of any individuals or subjects associated with the event; and
- Considers the frequency and circumstance under which logs will be analyzed. (*e.g.*, troubleshooting, incident reporting/ response).

For the purposes of auditing and accountability, a system event is any identifiable occurrence (*e.g.*, logon). A security event is an event that violates defined security policies (*e.g.*, 10 failed logon attempts)

5. Security Assessment and Authorization

Utilities will have in place a process that provides cybersecurity and privacy leadership with the information required to authorize the operation of information systems. This process should consider:

- How often security controls will be assessed for effectiveness;
- The plan in place to correct weaknesses; and
- Process/procedures used to assess weakness (*e.g.,* penetration tests, vulnerability scans)

6. Configuration Management

Utilities will define a process to identify systems components designated for configuration control (*e.g.*, identify the systems that have recently undergone significant change, such as new hardware, software, and configurations). The process shall consider a:

- Standard and approved configuration;
- Process to identify and inventory assets based on importance and sensitivity; and
- Formal change management process which tracks and approves changes and correlates the changed systems with the business processes they support.

7. Contingency Planning

Each utility will develop plans and procedures to address the continuity of operations in the event of a system disruption. Utilities should ensure that backup procedures are established that define the requirements for backup of cyber-infrastructure information, software and systems, and should include retention and protection requirements.

8. Identification and Authentication

Utilities will define an identification and authentication management process that considers how users and devices will be identified, the range of authentication methods available (passwords, multifactor authentication, smartcards, *etc*.), and the management of those identifiers and authentication methods. Each utility will consider which devices and users require authentication and the level of authentication required (*e.g.*, user ID's and passwords). The management process must be based on the risk associated with the particular application or services.

9. Incident Response

Incident response plans should exist and must be exercised. The plan must include roles and responsibilities when an incident is identified through the lifecycle of recovery. Utilities should implement an incident handling capability for security events, including detection and analysis, containment, and recovery.

10. Maintenance

Utilities will develop a maintenance process that considers frequency, prioritization, and the technical feasibility of applying patches and up-to-date antivirus signatures. Utilities will also consider a process to identify those system components (*e.g.*, sensors, transformers) requiring a maintenance agreement. Supportable technology versions should be used where technically feasible.

11. Media Protection

Procedures and controls must exist to define process and procedures for the access to, protection of, transport, and disposal of information system media. Procedures and controls should be commensurate with the sensitivity of the information. Utilities will define the types of media to which such processes and procedures apply (*e.g.*, USB drives, removable hard drives).

12. Physical and Environmental Protection

The utilities will develop processes and procedures to identify the requirements to protect, identify, and monitor utility information system resources from physical and environmental threats in order to reduce the risk of loss, theft, damage, unauthorized access, or interference with operations. Appropriate physical and environmental security controls will be applied commensurate with system sensitivity and importance

13. Planning

Utilities will take an enterprise risk management approach to protecting the confidentiality, integrity, and availability of utility information and information systems inclusive of system and customer data. This approach specifically focuses on the security planning required to maintain optimal operations and to prevent or recover from system interruptions. The approach should include:

- A plan to include security/privacy in the utility's enterprise architecture;
- Adequately document/ describe information system architecture and security controls; and
- Requirements for individual user roles and responsibilities.

14. Personnel Security

Utilities will manage the risk of permanent, temporary, or contract staff through the use of pre-employment screenings, and on-boarding/off-boarding practices regarding the suitability of personnel authorized to access resources. The utilities will consider the principle of least privilege and timely account revocation in on-boarding and off-boarding practices.

15. Risk Assessment

The utilities should conduct periodic risk assessments. The utilities will define the scope (organization level, mission/business process level, or information system level) and frequency of the assessment. Information system-level risk assessments should consider the effectiveness of the security and privacy controls in place when determining the overall risk to utility operations.

16. System and Services Acquisition

Utilities will integrate security requirements into the system and services acquisition lifecycle. Utilities will consider that funding/resources can prohibit the immediate inclusion of specific security requirements for all investments, including, but not limited to acquisition of DER through procurement mechanisms such as tariffs and NWA. Therefore, the utilities allow for a process to prioritize security investment needs.

17. System and Communications Protection

The utility will implement a process to protect information and information systems, data residing in these systems, and communications among these systems as well as systems external to the utility (*e.g.*, DER providers and customers). This process should build upon the utilities configuration management process to:

- Identity and prevent vulnerable system configurations;
- Build upon security considerations in the enterprise architecture to apply defense in depth strategies (*e.g.*, boundary protections);
- Consider a process to identify when and where encryption is required based on system sensitivity and importance; and
- Consider the use of network monitoring technologies.

18. System and Information Integrity

Each utility will identify a process or procedure to identify and monitor information system errors and flaws, based on system sensitivity and importance. Each utility will determine and prioritize specific areas of concern and address them according to the company's business concerns. The process will build upon the patch/configuration management and security considerations in enterprise architecture[154] to address:

- Unauthorized system changes;
- Timely installation of patches and firmware when technically feasible; and
- Protections on information system entry and exits point (*e.g.*, web servers, firewalls) to address spam and malicious code.

D. Privacy Controls

Addressing privacy requires the Joint Utilities to use a common language to describe privacy requirements and protections needed. The following privacy guidelines are the basis for a common vocabulary to facilitate a better understanding, and communication about privacy risks and the effective implementation of privacy principles. These control families are rooted in both the NIST Privacy catalog and the Generally Accepted Privacy Principles ("GAPP").

[154] Enterprise architecture is a well-defined practice that helps to incorporate and govern IT resources from a strategy and business-driven perspective.

1. *Authority & Purpose*

The utilities define, document, communicate, and assign accountability for its privacy policies and procedures.

2. *Accountability, Audit, & Risk Management*

The utilities will monitor compliance with privacy policies and procedures and have procedures to address privacy related inquiries, complaints, and disputes.

3. *Data Quality & Integrity*

The utilities will maintain accurate, complete, and relevant personal information for the purposes identified in the privacy notice.

4. *Data Minimization & Retention*

The utilities will collect personal information only for the purposes identified in the privacy notice.

5. *Use, Retention and Disposal*

The utilities will limit the use of personal information to the purposes identified in the notice and for which the individual has provided implicit or explicit consent. The utilities will retain personal information for only as long as necessary to fulfill the stated purposes or as required by law or regulations and thereafter appropriately disposes of such information.

6. *Individual Participation & Redress - Choice and Consent*

The utilities describe the choices available to the customers and obtains implicit or explicit consent with respect to the collection, use, and disclosure of personal information. The utility will provide customers with access to their personal information for review and update.

7. *Security*

The utilities have technical, physical, and administrative controls in place to protect personally identifiable information (“PII”) that is collected or maintained by the utility against loss, unauthorized access, or disclosure, so that planning and response to privacy incidents comply with New York State law.

8. *Information Sharing with Third Parties*

The utilities will work so that any data shared with third parties is in alignment with the Privacy Notice. The utilities will evaluate any new instances of data sharing, prior to sharing that data, to confirm alignment with the privacy notice.

9. *Transparency*

The utilities provide notice about its privacy policies and procedures and identifies the purposes for which personal information is collected, used, retained, and disclosed.

10. *Use Limitation*

The utilities disclose personal information to third parties only for the purposes identified in the privacy notice and with the implicit or explicit consent of the customer.

11. Additional security control considerations – control families

SP 800-53 is a master catalog of security controls providing guidance for threat and risk considerations. Network monitoring, passwords, and remote access are addressed in the following control families.

Network and information system monitoring spans multiple families within the Joint Utilities' Cybersecurity and Privacy Framework. Information system monitoring capability is achieved through a variety of tools and techniques enabling a quick response to problems within the grid and networks. Utilities must consider network monitoring from multiple angles (*e.g.*, AMI, Wide Area Network ("WAN"). The distribution networks require enhanced situational awareness as the diversity of distribution automation increases and DER resources proliferate the system. Intrusion detection and Intrusion Prevention Systems, are critical for real-time threat detection inside the utility's networks, while advanced grid management services, such as FLISR aims to minimize interruptions in services and improve network reliability. The utilities will also consider the implementation of a Security Information and Event Management ("SIEM") system, which provides the capability to view relevant data about an enterprise's security with the aim of spotting anomalous activity or events. This near real-time analysis enables a faster response to potential threats.

a. Identification and Authentication ("I&A") control family

The IA control family provides guidance for the use and management of passwords. An effective password management practice should consider the disparate requirements for users and system/service accounts. Should a utility chose passwords as an authenticator, the following should also be a consideration:

- Password complexity requirements;
- Password history requirements (*e.g.*, when changing a password you cannot use the last three that were chosen); and
- Password lifetime requirements (how often the password should change, *e.g.*, every 90 days).

b. Access Control ("AC") control family

The AC control family provides guidance on remote access considerations. Expanding connectivity demands require utilities to continually address remote access in a way that safeguards data and introduces minimal solution management challenges. When considering remote access solutions utilities should consider:

- All the threats, vulnerabilities, and security controls associated with a particular remote access solution;
- Access authorizations (permissions, least privilege);
- Sensitivity and importance of the information accessed;
- Roles and responsibility for remote access users; and
- Remote administration requirements of devices (*e.g.*, more stringent identification and authentication requirements, identifying those components that can be remotely administered).

E. Commitment to Information Sharing and Threat Intelligence Awareness

The importance of situational awareness on security threats remains paramount to the protection of the electric grid. Collaboration with cybersecurity authorities and working groups provide vital information for the development and implementation of protections that are in alignment with best practices. The Joint Utilities will continue to address security issues though participation in working groups and subscriptions. The following list of working groups and leading cybersecurity authorities is not meant to be exhaustive or mandatory, but exhibits the Joint Utilities' capability to address emerging cybersecurity and privacy concerns. The Joint Utilities agree that participation in additional working groups is both encouraged and beneficial. The Joint Utilities further recognize the need to adjust or cease participation based on the needs of the utility at the time. The Joint Utilities should continue to facilitate independent intelligence exchange to suit their needs over and beyond working group participation. The following is a representative list of Joint Utilities working group participation, and does not suggest that each utility participates in each group.

1. 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. The E-ISAC gathers and analyzes security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity subsector, across interdependent sectors, and with government partners. [155]

2. EEI

The EEI represents all United States investor-owned electric companies. EEI provides public policy leadership, strategic business intelligence, essential conferences, and forums.[156]

3. 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.[157]

4. EPRI

EPRI conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public.[158]

5. 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

[155] *See* https://www.esisac.com/#about
[156] *See* http://www.eei.org/about/mission/Pages/default.aspx
[157] *See* http://www.electricitysubsector.org/ESCCBrochure.pdf
[158] *See* http://www.epri.com/About-Us/Pages/Our-Business.aspx

Emergency Response Teams ("CERTs") to share control systems-related security incidents and mitigation measures. The ICS CERT provides a current information resource to help industry understand and prepare for ongoing and emerging control systems cybersecurity issues, vulnerabilities, and mitigation strategies to include Control Systems Vulnerabilities and Attack Paths.[159]

6. 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.[160]

7. The United States Computer Emergency Readiness Team ("US-CERT")

The US-CERT leads efforts to improve the nation's cybersecurity posture, coordinate cyber information sharing, and proactively manage cyber risks to the nation while protecting the constitutional rights of Americans.[161]

F. Risk Management and the Risk Assessment

As the Joint Utilities seek to continually deliver reliable and secure services, the risk assessment becomes the primary tool to determine the appropriateness and timing of implementing specific technologies. When considering a new technology or change in infrastructure, the risk assessment will identify:

- Threats. This process becomes particularity important as DER penetration increases and will allow utilities to identify specific threat scenarios. These scenarios can be both cyber and physical. Once these scenarios are understood, and the ongoing information made available through the utility participation in working groups, risk decisions can be made as to the incorporation of new or improved technologies.
- Vulnerabilities (both internal and external). This requires the utility to identify weakness in its organization and/or information system that can be exploited by an identified threat. As with threats, it is important to note the emergence of vulnerabilities as the business model and operational environment changes in support of REV.
- Impact. The utility will work to define/quantify the damage to utility assets and operations should a threat successfully exploit a vulnerability (*e.g.*, brown out, black out, loss of PII).
- Probability. The utility will work to identify the likelihood and/or frequency that an event will occur. Likelihood determinations consider threat assumptions and tangible threat data (*e.g.*, historical data on cyber-attacks).

[159] *See* https://ics-cert.us-cert.gov/
[160] *See* https://www.infragard.org/
[161] *See* https://www.us-cert.gov/

These steps consider new threats and vulnerabilities to guide the adjustment of existing controls and the selection of new controls in the consideration of new technology implementations. Any successful control implementation or adoption of new technology must also consider people and process. People must be properly trained and processes must be properly documented.

When evaluating the risk associated with data sharing, the risk assessment is intended to determine the cybersecurity posture of the third party. The risk assessment will also help to identify and prioritize the risks to better understand the impact and probability to help safeguard data. Based on rigor and sensitivity this assessment can include the following items:

- A cybersecurity questionnaire intended to gauge the cybersecurity posture of the organization and its alignment of control implementation with industry standards.
- Supporting documentation as evidence to the information provided in the questionnaire. This evidence is intended to validate the effectiveness of the controls in place, and identify any weaknesses. This evidence can include:
    - ISO certification letters;
    - Payment Card Industry ("PCI") Data Security Standard Reports on Compliance;
    - The American Institute of Certified Public Accountants ("AICPA");
    - Service Organization Controls ("SOC") 2 reports; and
    - Reports on controls at a service organization relevant to security, availability, processing integrity, confidentiality, or privacy.

Based on a review of this evidence, the utility has the option to request detailed corrective action plans to address any of the identified weaknesses. Contractual language will reflect the requirement to protect/secure utility data and may also include requirements/controls to address any identified weaknesses noted the utility's assessment. Contractual language may also include a "right-to-audit-clause" so that the utility may consistently monitor the security posture of the third party.

At the completion of the risk assessment, a risk recommendation is rendered. The utility reserves the right to deny any request for data should the risk should risk be deemed too high. Should the utility choose operate in the presence of any risks identified by the cyber review, the utility must make a formal acceptance of the risk.

1. Classifying System Data Security Risks

The provision of system data will need to be evaluated through the lens of system safety and reliability. As discussed in the individual utilities' initial DSIP filings Cybersecurity and Privacy Strategy Framework, each utility will adopt a formal risk management program that identifies, acts on, and mitigates risks.[162] The individual utilities' risk management program will be applied to the sharing of specific system data elements that are determined to be sensitive information.

[162] The referenced framework was included in the Initial DSIP filings of Con Edison, O&R, and National Grid, and was also referenced by Central Hudson.

Sensitive information will be determined through a data classification process at each utility. For example, data classifications ranked from the lowest to the highest level of sensitivity may be created. Data requests for information classified as sensitive received from qualified third parties will be screened against these data classifications to determine the appropriate risk program review for the request.

To classify system data, questions that will be considered by the utility may include

- How would distributed grid operations, facilities, and assets be affected if the system data inadvertently reaches an unintended audience?
- Could the use of the system data in combination with other requested information or publicly available information result in negative impact to the distributed grid operations, facilities, and assets? If so, to what extent?
- Does the information contain personally identifiable information such as biographical data, contact information, names, addresses, and telephone numbers?
- Does the information reveal discrete information about specific customers?
- Does the information contain business confidential information such as contract pricing data or forecast data which could hamper competitive markets if released?
- Would the release of information violate contract terms?
- Could the information result in compromise to a system, data file, application, or other business function if inappropriately shared?
- How could someone intent on causing harm to distributed grid assets, key facilities, and systems use the information to his or her advantage?
- Could this information be used to harm others?
- Would release of information result in vulnerabilities to the operation of the electric distribution system?

Data classifications under which system data elements are placed will include a range of classification from non-sensitive to restricted information. For example, the data categories may include:[163]

- Publicly Available. Public data or information lawfully, properly, and regularly disclosed generally or broadly to the public requiring little or no restrictions in producing, processing, handling, storing, transmitting, distributing, replicating, or destroying information. This is typically regarded as information in the public domain. Disclosure will not adversely impact the distribution system operation or key distribution system facilities or assets.
- Company. Data or information regarding critical assets, key facilities, and systems maintaining the reliability and security of the distribution system requires precautions and protective measures in its access, production, processing, sharing, handling, storage, transmission, distribution, replication, or destruction of information. Inadvertent or

[163] Adapted from NERC, *Security Guidelines for the Electric Sector: Protecting Sensitive Information*. Available as of September 6, 2016 at http://www.nerc.com/docs/cip/sgwg/Protecting%20Sensitive%20Information%20Guideline%20Draft%20Revision%208-30-11%20v04.pdf.

unauthorized disclosure or modification will adversely impact the distribution grid or key distribution system facilities or assets, and

- Restricted. Data or information regarding critical assets, key facilities, and systems maintaining the reliability and security of the distribution system requires secure restrictions and protective measures in its access, production, processing, sharing, handling, storage, transmission and distribution, replication, and destruction procedures. Inadvertent or unauthorized disclosure or modification may severely impact the distribution system or key distribution system facilities or assets.

Using the example of the three classifications above, the strictest controls would apply to the restricted information classification, which would include information for which access should be limited to only those with a business need to know. Restricted information would be subject to risk management program procedures for the appropriate means of data storage, retrieval, transmission, and reception, whether the data lies within a physical boundary or not. Results of such a risk review will inform the utility decision to honor or deny third-party data requests for information. Public data may require little or no controls to protect; however, specific standards, such as user registration, could be required for the sharing of company data.

IT system standard tools and architecture will be utilized to assist in protection of data. Examples might include encryption approaches and user identification policies based on the data category accessed. Other tools include IT infrastructure such as firewalls and network access. For example, utilities may choose to eliminate live linkages between critical monitoring equipment and other networks, or between customer billing applications and other networks as a means of protecting such sensitive information from an unauthorized back-door.

Another important aspect related to system data security is the issue of oversight on the use of system data after it is shared with the data requesting entity. The Joint Utilities expect that a detailed deliberation on the legal and financial safeguards will be needed to avoid liability issues that may arise if the requesting entity releases data or misuses data, potentially leading to system issues. Thus, the Joint Utilities require an understanding of the intended the context of the data request, to mitigate situations arising from potential misuse.

G. Summary of Next Steps

The Joint Utilities understand the Commission is concerned with the ability to maintain up-to-date security and privacy practices with industry standards. Each of the utilities is committed to maintaining an active cyber and privacy management program and already participates in industry working groups to this point. Each utility intends to continue their participation in the New York State Security Working Group, which meets quarterly. In addition, the Joint Utilities agree to share among each other information learned and advancements in security technology with each other on a schedule aligned with the quarterly New York State Security Working Group quarterly meetings.

The Joint Utilities have agreed that working group participation provides the mechanism to stay informed to evolving cybersecurity threats and available defense measures. Additionally, Joint Utilities' cyber and privacy representatives will remain active with relevant stakeholder engagement sessions and with internal system data and customer data exchanges and discussions.

VIII. Conclusion

Through both the Initial DSIP filings and this Supplemental DSIP filing the utilities are positioned to make significant progress in developing the processes and operational capabilities necessary to transition to their role as DSPs and support DER integration and other REV objectives. Their plans have benefited from the input of stakeholders, who participated in frequent meetings and activities on a broad range of topics.

The Joint Utilities are committed to continued stakeholder engagement, which will promote ongoing information sharing and the refinement of utility plans in future DSIP filings. The Joint Utilities also commit to further collaboration as a group, including continued development of common standards, protocols, and processes that will support statewide markets and allow for greater convergence of capabilities over time.

The utilities' plans reflect a phased approach to developing DSP capabilities that allows for iteration and the incorporation of lessons learned from the many demonstration projects currently underway and developments in related proceedings. Specific investments plans will be part of upcoming rate requests, which will further clarify the pace, timing and scope of DSP development. Subsequent DSIP filings will build on the near-term actions implemented as a result of this plan and reflect ongoing stakeholder discussions.

APPENDICES

Appendix A: Stakeholder Engagement Summary

A. Overview

The Distributed System Implementation Plan (DSIP) Order envisions the Initial DSIPs and the jointly-filed Supplemental DSIP as coordinated vehicles by which "improved future planning and operations will be defined and implemented."[164] The Joint Utilities filed a plan for stakeholder engagement on May 5, 2016,[165] which described the framework used to ensure parties had multiple opportunities to participate and provide input. For the Initial DSIPs, each utility convened at least one workshop to share details on the utility's specific Initial DSIP filing. Additionally, the Joint Utilities held an informational forum on February 29 focused on system planning. For the Supplemental DSIP, the Joint Utilities developed and are implementing a multi-tiered approach to stakeholder engagement that offers several different forums for learning about the utilities' efforts and discussing technical details. As part of this approach, the Joint Utilities maintain and regularly update a website dedicated to their stakeholder engagement efforts for the Supplemental DSIP, including notifications of upcoming meetings and materials from past stakeholder engagement meetings.[166] The Joint Utilities also monitor an associated email address created for stakeholders to provide additional feedback or ask questions regarding the engagement process or material.

1. Supplemental DSIP Engagement Structure: Multi-tiered Approach

The Advisory Group ("AG") is comprised of approximately 20 organizations that are representative of the breadth of stakeholder sectors engaged in the REV Proceeding. In addition to the Joint Utilities, the Advisory Group includes representation from New York State Department of Public Service Staff ("Staff"), DER providers, software and hardware vendors, the New York Power Authority ("NYPA"), the New York Independent System Operator ("NYISO"), Independent Power Producers of New York ("IPPNY"), environmental advocates, and organizations representing large and small commercial and residential customers. The AG guides the Joint Utilities on the priorities and sequence of topics for stakeholder discussions and provides overall feedback to the Joint Utilities on topics relevant to DSIP development. The topics outlined in the DSIP Guidance Order were organized into three categories—distribution system planning, grid operations and market operations—with corresponding Engagement Groups ("EG") assigned to each category.[167] With meetings held from May through September, the EGs were intended to foster shared understanding on the technical details and strive toward common ground through discussion and feedback. EGs were open to participation by all stakeholders through in-person and virtual meetings. Presentation material from the meetings and the meeting schedules can be found on the Joint Utilities' website.

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164 REV Proceeding, DSIP Guidance Order, p. 2.

165 REV Proceeding, Stakeholder Engagement Plan.

166 http://www.jointutilitiesofny.org/

167 The intention of splitting the topics into EGs was to reflect dominant themes for the category and balance workload across the groups. The categorization did not predetermine the placement of topics in the Supplemental DSIP.

Stakeholder engagement conferences were also held June through September via webinar and were open to all stakeholders. The Joint Utilities used these webinars to share updates on the various topics in development for the Supplemental DSIP and to solicit additional feedback from stakeholders.

a. Participating Organizations

Over 100 organizations participated in one or more efforts within the stakeholder engagement process. Content reflected within the Supplemental DSIP filing regarding stakeholder input does not, however, represent the unanimous agreement by all participants, but rather the views of one or more parties who offered their perspectives during the engagement process.

- Acadia Center
- Advanced Microgrid Solutions
- AES Corporation
- Albany Capital District EV Drivers
- Alliance for Energy Affordability
- Association for Energy Affordability
- Atlas Public Policy
- BlueRock Energy
- Bloom Energy
- Booz Allen Hamilton
- Borrego Solar Systems
- Bright Power
- BYD Motors
- CALM Energy
- Capital District Clean Communities
- ChargePoint
- Citizens for Local Power
- CLEAResult
- Climate Action Associates
- Comverge
- Cypress Creek Renewables
- Department of State Utility Intervention Unit
- Digital Energy Corp
- Direct Energy
- DNV GL
- DWGP
- EarthKind Energy
- E Cubed
- Edison Electric Institute
- Electric Power Research Institute
- Electron Storage, Inc.
- EnerNOC
- Enervee
- Enbala Power Networks
- EnergyHub
- ENRGISTX Inc.
- Energy Technology Savings, Inc.
- Environmental Defense Fund
- EV-Box North America, Inc.
- EV Connect, Inc.
- EVgo Services Institute
- Exelon, a Constellation Company
- FirstFuel
- General Electric
- General MicroGrids
- General Motors
- GreenLots
- Honeywell
- ICF
- IPLAN Access
- International Brotherhood of Electrical Workers
- Interstate Renewable Energy Council
- KODA Consulting
- Landis+Gyr
- Lime Energy
- Lockheed Martin
- Long Island Power Authority
- M&W Group
- More Than Smart
- Miller Bros
- Mission:Data
- MJ Bradley & Associates
- Natural Resources Defense Council
- Navigant Consulting
- Newport Consulting Group
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York Power Authority
- New York State Department of Public Service
- New York State Energy Research and Development Authority

- New York State Office of General Services
- NRG Energy
- New York State Smartgrid Consortium
- NYC Department of Transportation
- NYC Mayor's Office of Sustainability
- OATI
- O'Brien and Gere
- Opower
- Opus One Solutions
- Oracle
- PACE Energy & Climate Center
- Pacific Northwest National Laboratory
- PathStone
- Peak Power Inc.
- PECO Energy Company
- Platform Power Corp
- Plug in America
- PSEG Long Island
- Read and Laniado, LLP
- Related Companies
- Renewable Energy Systems Ltd
- RPI Center for Future Energy Systems
- Schneider Electric
- ScottMadden, Inc.
- Siemens PTI
- Sierra Club
- Smarter Grid Solutions
- SmartWatt Energy, Inc.
- SolarCity
- StrateGain
- Sunnova
- SunPower
- Sunrun
- Sunverge
- Sustainable Energy Economics
- Tesla
- The Alliance Risk Group
- The Mosaic Company
- Totem Power
- Urban Green Council
- Verde Energy USA
- Westchester County
- Willdan
- World Team Now

b. Ground Rules

All AG and EG stakeholder meetings operated under ground rules based on the Chatham House Rule and commercial confidentiality. The ground rules are as follows:

- All stakeholder engagement (AG and EG) meetings, webinars and information exchange are designed solely to provide an open forum or means for the expression of various points of view in compliance with antitrust laws.
- Under no circumstances shall stakeholder engagement activities be used as a means for competing companies to reach any understanding, expressed or implied, which tends to restrict competition, or in any way, to impair the ability of participating members to exercise independent business judgment regarding matters affecting competition or regulatory positions.
- Proprietary information shall not be disclosed by any participant during any stakeholder engagement meeting or its subgroups. In addition, no information of a secret or proprietary nature shall be made available to stakeholder engagement members.
- All proprietary information which may nonetheless be publicly disclosed by any participant during any stakeholder engagement meeting or its subgroups shall be deemed to have been disclosed on a non-confidential basis, without any restrictions on use by anyone, except that no valid copyright or patent right shall be deemed to have been waived by such disclosure.
- AG discussions will be open forums without attribution and no public documents by the AG will be produced unless publication is agreed upon by the group.

B. Advisory Group

The AG met monthly between April and November in support of the filing. Meetings were scheduled with a 2:1 ratio between New York City and Albany to accommodate the travel schedules of the members. It is anticipated that the AG will continue to meet on an ongoing basis beyond December in support of future DSIP filings. Membership will be reviewed on an annual basis and potentially rotated to ensure representation across the breadth of stakeholders. Meeting summaries are available on the Joint Utilities website.[168]

Purpose
The AG is an open forum for stakeholders who are actively engaged in the REV process and have an interest in advising the development of the DSIP filings and providing guidance on the stakeholder engagement process.
Objectives
• The AG advises the Joint Utilities on the sequence and priorities of topics that EGs should discuss in order to achieve greater shared understanding of issues covered in the DSIP filings, and to build toward common ground through iterative discussion and feedback. • The AG also provides input on EG members, discussion scope, and any output documents that would advance greater shared understanding. • It is anticipated that the AG will continue after the Supplemental DSIP filing to support productive stakeholder engagement for future DSIP filings.

Member Organizations of the Advisory Group	
Type of Organization	**Organization**
Joint Utilities	Central Hudson
Large Customer	City of New York Mayor’s Office of Sustainability
Joint Utilities	Con Edison / O&R
Joint Utilities	Con Edison / O&R
Large Customer	Couch White, LLP
Small Customers & Consumer Groups	Dept. of State Utility Intervention Unit (UIU)
Marketers	Direct Energy
DER Provider	EnerNOC
Environmental	Environmental Defense Fund (EDF)
IPPNY	Exelon, a Constellation Company
Joint Utilities	National Grid
Environmental	Natural Resource Defense Council (NRDC)
DER Provider	New York Battery & Energy Storage Technology Consortium (NY-BEST)
Wholesale market	New York Independent System Operator (NYISO)

168 http://jointutilitiesofny.org/joint-utilities-of-ny-advisory-group/

State/Public power	New York Power Authority (NYPA)
NYSERDA	New York State Energy Research and Development Authority (NYSERDA)
NY DPS	New York State Department of Public Service (NY DPS)
DER Provider	NRG Energy
Joint Utilities	NYSEG/RG&E
DER Provider	SolarCity
Facilitator	ICF

C. Engagement Groups

The Joint Utilities engaged stakeholders in a series of EG meetings on most of the topics outlined in the DSIP Guidance Order. EG meetings took place in NYC and Albany every two weeks. In many cases, groups also held a webinar-based meeting in between the in-person meetings to give additional opportunities to share background information or for parties to make presentations. To accommodate a broader range of stakeholders, webinar and call-in capabilities were available for in-person stakeholder meetings.

The goal of the EGs was to exchange information and ideas, facilitate the Joint Utilities' understanding of stakeholder needs, facilitate stakeholder understanding of utility functions, and identify areas of convergence and differences.

The Joint Utilities appreciate the stakeholder participation across the Engagement Groups, both virtually and in-person. Stakeholders presented informative topical material and provided constructive and insightful feedback to the Joint Utilities throughout the process. The summaries of input provided here do not necessarily imply consensus among stakeholders, but rather highlight feedback received during the engagement effort, much of which is reflected in the Joint Utilities' plans presented in the Supplemental DSIP.

1. *Distribution System Planning Engagement Group*

Purpose
The Distribution System Planning Engagement Group is an open forum for stakeholders who are actively engaged in the REV process and the DSIP. The purpose of the EG is to explore common ground in approaches regarding the evolution in planning the distribution system in New York as Distributed Energy Resource (DER) penetration increases and as the market evolves, in order meet customers' needs and public policy goals. Topics covered in the EG include suitability criteria for non-wires alternatives and hosting capacity.

Topic Description - Non-Wires Alternatives (NWA) Suitability Criteria
NWA suitability criteria address processes intended to identify projects where DER solutions should be considered as potential alternatives to traditional grid infrastructure. The goals of these criteria are to ensure that developers get the best projects with the greatest chance for success; provide developers with greater clarity, certainty and long term visibility to the market; and avoid misallocation of time and resources for market participants.
NWA Suitability Criteria Charter

• Determine a set of appropriate criteria for project applicability including risk and design standards.
• Discuss which types of needs (*e.g.*, load relief, reliability) can best be met through NWA solutions, and which may present less opportunity for DER-led solutions.
    o Understand the what and why of grid needs
    o Describe how these factors, project characteristics and timelines to completion affect NWA suitability
• Explore the dimensions of projects, including traditional and alternative cost and fit parameters, and whether there are threshold levels that indicate NWA suitability.

Topic Description – Hosting Capacity
Hosting capacity is the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades. Discussions on hosting capacity within the stakeholder engagement group will include a timeline and standard methodology for calculating and improving circuit-level hosting capacity data. The group will also examine the information tools available or that can be made available to increase hosting capacity (*e.g.*, storage).
Hosting Capacity Charter
• Discuss methodological approaches and data inputs for determining hosting capacity, and which are appropriate for which systems in New York. • Describe how these answers differ for radial and network systems. • Discuss the potential evolution of methodology in terms of modeling and data requirements, the outputs that can be derived from the analysis, and the uses of those outputs. • Review different models and approaches to calculate and publish hosting capacity. • Discuss potential solutions to increasing hosting capacity (*e.g.*, storage). • Develop timeline to implement.

Meeting Schedule and Topics				
Date	**Location**	**Topic**	**Subtopic**	**Stakeholder Presentations**
May 20, 2016	Virtual	Kick-off meeting		
June 2, 2016	Albany	NWA Suitability Criteria	Understanding grid needs and suitability criteria; Begin deep dive discussions	
June 8, 2016	Virtual	NWA Suitability Criteria	Recap of June 2nd meeting; Continue deep dive discussion	• Acadia Center • EnerNOC
June 16, 2016	NYC	NWA Suitability Criteria	Continue deep dive discussion; Begin gap analysis on screens; Discuss BCA.	• Acadia Center • Advanced Microgrid Solutions • Enbala • Schneider Electric • SolarCity
June 23, 2016	Virtual	NWA Suitability Criteria		
June 30, 2016	NYC	NWA Suitability Criteria	Summarize key messages, common ground achieved, gaps narrowed.	• Advanced Microgrid Solutions
July 14, 2016	NYC	Hosting Capacity	Kick-off	• Borrego Solar • EPRI • IREC
July 21, 2016	Virtual	Hosting Capacity		
July 28, 2016	Albany	Hosting Capacity	Increasing Hosting Capacity	• EPRI • IREC
August 4, 2016	Virtual	Hosting Capacity	Increasing Hosting Capacity	• Advanced Microgrid Solutions • NY-BEST • Smarter Grid Solutions
August 11, 2016	NYC	Hosting Capacity	Wrap up	• Enbala

a. NWA Suitability Criteria

The following organizations participated in one or more engagement group meetings on NWA Suitability Criteria either in person or virtually:

- Acadia Center
- Advanced Microgrid Solutions
- Booz Allen Hamilton
- Borrego Solar Systems
- Cypress Creek Renewables
- Enbala Power Networks
- Environmental Defense Fund
- Exelon, a Constellation company
- Direct Energy
- ICF
- Interstate Renewable Energy Council
- Natural Resources Defense Council
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York Power Authority
- New York State Energy Research and Development Authority
- New York State Department of Public Service
- NRG Energy
- NYC Mayor's Office of Sustainability
- Opus One Solutions
- PACE Energy & Climate Center
- Schneider Electric
- SolarCity

i. *Key Input from Stakeholder Engagement*

- There was agreement between stakeholders and utilities that projects can be categorized as suitable for NWA and those not suitable for NWA.
- Well-designed NWA suitability criteria can be valuable to stakeholders and utilities and provide an efficient way to engage NWA.
- Stakeholders and utilities agreed that NWA suitability can be guided by criteria related to the type of work, the timeline of the need and the size of the solution. Load relief projects and some subset of reliability / resiliency projects are likely to provide the best early opportunities for NWAs to compete.
- Stakeholders requested more specification on the principles and contents of the NWA suitability criteria to be provided by each utility and how these criteria will be incorporated into utilities' planning process, which aims to identify the greatest opportunities for soliciting feasible NWA solutions as alternatives to traditional investment.
- Stakeholders suggested planning on the distribution system can evolve to explicitly consider infrastructure projects needed to meet other requirements, such as public policy and other goals not tied to the current planning design criteria. To the extent that these become planning guidelines, they can be incorporated as NWA suitability categories.

b. Hosting Capacity

The following organizations participated in one or more engagement group meetings on Hosting Capacity either in person or virtually:

- Acadia Center
- Advanced Microgrid Solutions
- Booz Allen Hamilton
- Borrego Solar Systems
- CLEAResult
- Cypress Creek Renewables
- Enbala Power Networks
- Electric Power Research Institute

- Environmental Defense Fund
- Green Charge Networks
- ICF
- Interstate Renewable Energy Council
- Long Island Power Authority
- Miller Bros
- Natural Resources Defense Council
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York Power Authority
- New York State Department of Public Service
- New York State Energy Research and Development Authority
- NRG Energy
- NYC Mayor's Office of Sustainability
- Opus One Solutions
- PACE Energy & Climate Center
- PSEG LI
- Schneider Electric
- Siemens PTI
- Smarter Grid Solutions

i. *Key Input from Stakeholder Engagement*

- Stakeholders sought to gain insight into the timeframes and data requirements for the development of each of the four stages of hosting capacity analysis. The Joint Utilities worked with stakeholders to provide insight into each of the stages in the hosting capacity roadmap.
- Stakeholders and utilities agreed it would be beneficial to determine a consistent approach in New York for hosting capacity analysis.
- Stakeholders reviewed the relative merits of a streamlined approach vs. other approaches to hosting capacity analysis and discussed the relative computational and scalability of various approaches.
- Stakeholders expressed a desire for the Joint Utilities to provide additional data outputs and a greater degree of alignment in the methodologies that utilities used in their development of the red zone indicator maps.
- Stakeholders expressed a desire for the inclusion and implementation of innovative approaches for the increase of hosting capacity and described the merits of several technologies.
- Stakeholders expressed an interest in exploring the impacts of reconfiguration and protection mechanisms of the circuits on hosting capacity analysis and how or when these impacts would be reflected in utilities' modeling tools.
- Stakeholders outlined several additional types of data that could expand upon the data currently provided.
- Stakeholders expressed an interest in leveraging hosting capacity analysis in the context of interconnection and urged the Joint Utilities to explore use cases for this analysis that could enhance and further expedite the interconnection process.

2. Distribution Grid Operations

Purpose

The Distribution Grid Operations Engagement Group is an open forum for stakeholders who are actively engaged in the REV process and the Distributed System Implementation Plan (DSIP) filings to provide input to, and exchange ideas with, the Joint Utilities on topics related to grid operations, as identified by the Advisory Group.

Topic Description – System Data

System data includes grid information such as power consumption, power quality, and reliability at various granularities (system-wide, substation, feeder, etc.). The data is used to generate insightful information that is used by the utilities to support the planning and operation of the distribution system. Insightful information derived from system data would also enable DER providers to make investment and operational decisions that would be beneficial to the overall system, thereby increasing societal benefits. The utilities would provide the information necessary for developers to offer solutions that can improve the efficiency of the system and add value for customers.

- Discuss the type of system data that the stakeholders would require to make investment decisions on the New York grid.
  - Identify the highest value information for DER providers to make effective decisions.
  - Identify the granularity of the information required for specific planning and analysis purposes.
  - Identify the frequency of the information required.
- Discuss methods for overcoming limitations related to security and confidentiality.
- Discuss the process for providing value added information to stakeholders.

Topic Description – Monitoring and Control

Monitoring of the distribution assets and DERs in the distribution system is essential for maintaining the reliability of the grid. As DER have considerable impact on the operation of the distribution grid, the need for advanced monitoring capability increases with the penetration of distributed energy resources. The topic focuses on the needed expansion and improvement in visibility and communication protocols to interact with and observe DER providers.

Control at the distribution level refers to signaling and mobilization of distribution assets to satisfy system operational goals in real-time. The ability to control distribution system assets is vital to the reliable and efficient operation of the distribution grid. The term “control” signifies the utility having complete discretion over operation of the asset, whereas, the term “dispatch” indicates that the utility sends control signals to the asset owner who has discretion over operation of the asset. The term “dispatch” is used for signals sent to DER providers.

Monitoring and Control Charter

- Determine the monitoring requirement for DER.
- Explore the impact of DERs on real-time operations of the grid that include scheduling, operation and dispatch.
- Explore potential control signals to align NYISO and DSP generation or needs for load reduction.
- Discuss standards and protocols for DER aggregation.
- Discuss DER response to emergency and contingency events.

NYISO/DSP Interaction and Coordination Charter
• Describe the extent to which retail and wholesale operations are currently coordinated within existing programs. • Explore the evolution in assumptions necessary to align NYISO and DSP operations. • Determine whether further analysis of DER is necessary for more accurate estimation of DER contribution to serving grid needs for planning and operations. • Explore the visibility required for DER on the distribution system for NYISO to accurately reflect and align their forecasts.

Meeting Schedule and Topics

Date	Location	Topic	Subtopic	Stakeholder Presentations
May 23, 2016	Virtual	Kick-off meeting		
June 2, 2016	Albany	System Data	Types of information most useful to stakeholders	
June 16, 2016	NYC	System Data	Providing useful information (what and how)	• Environmental Defense Fund • NRG Energy • SolarCity
June 30, 2016	NYC	System Data	Addressing security concerns	• NRG Energy
July 14, 2016	NYC	Monitoring & Control	Monitoring and control requirements for DERs; Impact of DERs on real-time operations of the grid; DER response to emergency and contingency events	• SolarCity
July 28, 2016	NYC	Monitoring & Control	Impact of DERs on real-time operations of the grid; Control signals to align NYISO and DSP generations or needs for load reduction; standards and protocols for DER aggregation	• EnergyHub • Enbala • NYISO • PACE • Schneider Electric
August 25, 2016	Albany	ISO/DSP Interaction & Coordination	Current and future coordination between NYISO and DSP; Explore future analysis and visibility of DER	• CAISO

a. System Data

The following organizations participated in one or more engagement group meetings on System Data either in person or virtually:

- Acadia Center
- Advanced Microgrid Solutions
- City of New York Mayor's Office of Sustainability
- Cypress Creek Renewables
- EnergyHub
- EnerNOC
- Environmental Defense Fund
- Exelon, a Constellation Company
- ICF
- Natural Resources Defense Council
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York Power Authority
- NRG Energy
- New York State Department of Public Service
- New York State Energy Research and Development Authority
- PACE Energy & Climate Center
- SolarCity

i. *Key Input from Stakeholder Engagement*

- Stakeholders and utilities agreed that enhancing the transparency of modeling or planning methodologies may reduce the need for specific data requests.
- While stakeholders and utilities agreed that utilities are and should be the distribution system planners, a few stakeholders expressed some concern that utilities may not provide enough detailed information to enable DER Providers to do their own planning and assessments.
- Stakeholders and utilities agreed that the definition of "value-added data" should be refined and made consistent across contexts (*e.g.*, system data, customer data, etc.).
- Stakeholders requested that data be formatted for ease of access and that the format be standardized across utilities.
- Stakeholders and utilities agreed that what is considered "value-added data" now may evolve over time.
- A few stakeholders requested frequent and up-to-date information at the most granular levels possible to support integration of possible DER solutions.
- Stakeholders requested joint development (DER providers and Joint Utilities) of a working list of currently available data, data requested but not yet available, and associated plans and priorities to make data available.
- Stakeholders requested a portal for access to data.

b. Monitoring & Control

The following organizations participated in one or more engagement group meetings on Monitoring & Control either in person or virtually:

- Acadia Center
- Electric Power Research Institute
- Enbala Power Networks
- Ener-Group
- Environmental Defense Fund
- Engineers and Surveyors Institute
- Exelon
- ICF
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York Power Authority
- New York State Department of Public Service
- New York State Energy Research and Development Authority
- PACE Energy & Climate Center
- PA Consulting Group
- RSP Systems
- Schneider Electric
- Siemens PTI
- Smarter Grid Solutions

i. Key Input from Stakeholder Engagement

- Stakeholders advise utilities to design rules flexible to integrate a broad range of technologies, including emerging technologies.
- Stakeholders advise the Joint Utilities to adopt communication protocols and channels with lower investment costs for DERs. An example would be wireless cloud based protocols.
- Stakeholders advise the Joint Utilities to provide clarity on the policy instruments and implementation timeline for Monitoring and Control standards.
- Stakeholders advise Monitoring and Control rules should be able to accommodate the aggregation of resources.

c. NYISO/DSP Interaction and Coordination

The following organizations participated in one or more engagement group meetings on ISO/DSP Interaction & Coordination either in person or virtually:

- Acadia Center
- CAISO
- Direct Energy
- Environmental Defense Fund
- ICF
- Natural Resources Defense Council
- Navigant
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York State Department of Public Service
- New York State Energy Research and Development Authority
- NRG Energy
- PACE Energy & Climate Center
- Siemens PTI
- Schneider Electric
- SunPower

i. Key Input from Stakeholder Engagement

- Stakeholders wanted to ensure that DER resources are not inhibited by additional coordination functions and have the ability to participate in multiple markets.
- There was general agreement for collaboration with NYISO and their DER roadmap.
- Stakeholders requested NYISO and DSPs provide informational sessions describing the current degree in coordination of functions in areas outside of operations only.

3. Market Operations

Purpose
The Market Operations Engagement Group is an open forum for stakeholders who are actively engaged in the REV process and the Distributed System Implementation Plan. The purpose of this EG is to explore the Joint Utilities' approaches for facilitating market mechanisms that effectively support and encourage the adoption of Distributed Energy Resources while meeting customers' needs and complying with the DSIP Guidance Order.

Topic Description – Granular Pricing
The distribution-level marginal prices that reflect the value of a specific DER, or portfolio of DERs, to the distribution system at a given location and point in time. Granular prices will likely be unbundled, *i.e.*, there will be separate prices for energy, capacity, reliability and other services offered by DERs. Utilities will work with NYSIO to develop a methodology for revealing subzonal wholesale LMPS, on either an hourly or sub-hourly basis. *Note: this definition is pending the outcomes of Case 15-E-0751, "Value of D" Proceeding.*
Granular Pricing Charter

• Discuss NYISO initiative for revealing subzonal LMPs.
• Background
    o Explore stakeholder's views on:
    o What locational naming convention might be provided to easily identify the price point?
    o Ways to make pricing data accessible and available.
• Discuss price variability expectations.
• Explore and discuss timing of current initiative and criteria and considerations for moving forward.

Topic Description – Customer Data
Customer Data may identify the person, entity or location to which it applies. Customer information may include usage data, account/profile data, end-use and other qualitative data, and results from customer-specific analyses. Customer usage data is a subset of customer information and contains a customer's usage or production of energy. This usage data can be aggregated by various groupings for use by authorized third parties, or used for the benefit of public needs.
Customer Data Charter

• Collection Frequency, Reporting Frequency and Availability of Usage Data
    o Discuss how often usage data might be collected by the utility, and how often it would be made available to customers/authorized agents, and at what quality level.
    o Discuss customer data platform-related sensitivities (*e.g.,* AMI versus non-AMI systems).

- Aggregation of Usage Data
    - o Discuss standardized aggregated data offerings (*e.g.*, rate class, kW, kWh, circuit, tax district, zip code).
    - o Discuss utility sided aggregated data system automation efforts and reporting methods.
    - o Discuss standards for anonymizing aggregated data to protect individual customer privacy (*e.g.*, 15/15 rule).
- Additional Data Needs
    - o Explore and identify additional useful customer information beyond usage data.
    - o The Commission-approved Track 2 Order defined Basic Data as "the usage for each applicable rate element, including usage bands specified in the applicable tariff. This is the level of data necessary to render, reconstruct and understand the customer's bill."
    - o *Note: pricing for basic and value-added data is a Track Two matter*

Topic Description – DER Sourcing

Market actions taken by the utility to increase the amount of installed DER on its system. This may be done to address specific system deficiencies (*i.e.*, Non-Wires Alternatives), and/or to secure the environmental or other attributes of DERs. The chief mechanisms for DER Sourcing are Pricing (*e.g.*, Net Energy Metering tariffs, TOU pricing), Programs (*e.g.*, distribution-level Demand Response tariffs) and Procurement (*e.g.*, bilateral contracts, RFPs/RFIs/RFOs).

DER Sourcing Charter

- Describe and discuss the existing approaches the Joint Utilities may use to support adoption of DER:
    - o Pricing approaches, such as Net Energy Metering and Time of Use pricing;
    - o Program approaches, such as distribution-level Demand Response tariffs and Energy Efficiency Transition Implementation Plans; and
    - o Procurement approaches using structured solicitations.
- Discuss potential refinement of the Procurement approaches to improve efficiency and effectiveness and the potential for common implementation by the Joint Utilities.
- Describe and discuss dependencies with other REV and REV-related proceedings.

Topic Description – Electric Vehicle Supply Equipment (EVSE)

Planning for and developing an engagement plan for the increased deployment of EVSE on utilities' distribution system which supports the State's deployment and market growth goals for PEVs with the intent of reduced carbon emissions. Planning for deployment of EVSE is responsive to expected growth in PEVs as well as represents an opportunity to address the distribution planning and operational issues of vehicle-grid integration. Early planning should identify and address collaborative initiatives that set the stage for accelerated market growth of PEVs.

Electric Vehicle Supply Equipment (EVSE) Charter

- Describe and discuss current or planned areas of Joint Utilities collaboration on EVSE issues:
    - o REV and other demonstration projects;
    - o Customer outreach and education efforts; and
    - o Involvement or coordination with EV-related state and local partnerships, programs and initiatives.
- Discuss the opportunity for the Joint Utilities to contribute to a coordinated collaborative effort around the broader EV market issues in New York.
- Discuss various forecasting methodology and tools related to EV adoption, and explore Joint Utilities input into a shared view for New York State, considering transportation sector impacts as

well as state and federal requirements. • Discuss potential principles for utility facilitation of EV infrastructure.

Meeting Schedule and Topics				
Date	**Location**	**Topic**	**Subtopic**	**Stakeholder Presentations**
June 28, 2016		Kick-off Meeting		
June 28, 2016	Albany	Granular Pricing		• NYISO
July 13, 2016	NYC	Customer Data	Data Collection; Reporting Frequency; Availability of Usage Data	• EnerNOC • Mission:DATA • Urban Green & NRDC
July 13, 2016	NYC	DER Sourcing	Existing NWA plans; challenges and lessons learned	
July 19, 2016	Virtual	Customer Data	Recap July 13th meeting	• Advanced Microgrid Solutions • SolarCity
July 26, 2016	Albany	Customer Data	Aggregation of Usage Data	
July 26, 2016	Albany	DER Sourcing	Dependencies with other REV and Related Proceedings	
August 9, 2016	NYC	Customer Data	Additional Data Needs	
August 9, 2016	NYC	DER Sourcing	Potential Refinements to NWA Procurement Approach	
August 16, 2016	NYC	EVSE	Current State; Opportunities for Utility Collaboration	• M.J. Bradley & Associates • NYSERDA
August 30, 2016	Albany	EVSE	Principles for Utility Involvement	
September 12, 2016	Albany	EVSE	Forecasting Methodologies	

a. Granular Pricing

As agreed upon in the Advisory Group, the initial stakeholder engagement meeting invitation was extended to members of the AG, with broader group discussion and input provided at a later engagement conference session. The following organizations participated in the June 28th meeting:

- Direct Energy
- Exelon, a Constellation Company
- ICF
- Natural Resource Defense Council
- New York Battery Storage Technology Consortium
- New York Independent System Operator
- New York Power Authority
- New York State Department of Public Service
- SolarCity

i. *Key Input from Stakeholder Engagement*

As outlined in the *Granular Pricing* section of the Supplemental DSIP, the Joint Utilities and NYISO met with stakeholders of the Advisory Group on June 28th at NYISO to discuss the NYISO initiative for revealing subzonal LMPs.

b. Customer Data

The following organizations participated in one or more engagement group meetings on Customer Data either in person or virtually:

- Association for Energy Affordability
- Booz Allen Hamilton
- Bright Power
- Direct Energy
- EnergyHub
- EnerNOC
- Enervee
- Environmental Defense Fund
- ICF
- Mission:Data
- Natural Resources Defense Council
- New York Independent System Operator
- New York Power Authority
- New York State Department of Public Service
- New York State Energy Research and Development Authority
- New York State Utility Intervention Unit
- NYC Mayor's Office of Sustainability
- PACE Energy & Climate Center
- PSEG LI
- Siemens PTI
- Schneider Electric
- SolarCity
- Urban Green Council

i. *Key Input from Stakeholder Engagement*

- Stakeholders presented several use cases for aggregated data.
- Stakeholders expressed support for expanded data access and delivery capabilities that may be delivered via Green Button Connect[169], and required about their associated implementation schedules.

[169] http://energy.gov/data/green-button

- Stakeholders commented that current authorization and enrollment processes are unnecessarily complicated and require information that often seems obscure to customers. There was interest in and support for an enrollment process that would support a positive customer experience through open authorization and a guided setup/enrollment process that keeps customers informed about what services and programs they are signing up for or authorizing third party access to.
- Stakeholders within the customer and system data engagement groups noted that the Standard aggregated data set would likely be useful or necessary to include in NWA solicitations. Stakeholders also noted that DER providers may eventually be able to obtain data access authorizations from individual customers in a given area and create their own aggregations.
- Utility tariffs should be available in a machine-readable format, for ease of access and updating, to support reconstructing a customer's bill. The utilities should closely monitor efforts to develop national standards.
- Stakeholders would find it valuable if utilities made whole-building aggregated usage data available state-wide, with support for automated request and uploading to Energy Star Portfolio Manager.[170]
- Some stakeholders strongly urged the Joint Utilities against adopting the 15/15 standard on the grounds that it is overly-restrictive and will prevent many entities, particularly small building owners, from complying with existing laws.
- There was concern regarding the Joint Utilities proposal that third parties would have to pay for aggregated data, even when used for the purpose of complying with existing laws and/or supporting public interest projects.
- Stakeholders requested easy access to customer meter data with low latency (*i.e.*, 15 minute, 5 minute, less than 5 minutes, real-time) and higher granularity (*e.g.*, 5 minute, real-time streaming).

c. DER Sourcing

The following organizations participated in one or more engagement group meetings on DER Sourcing either in person or virtually:

[170] https://www.energystar.gov/buildings/facility-owners-and-managers/existing-buildings/use-portfolio-manager

- ❖ Acadia Center
- ❖ Advanced Microgrid Solutions
- ❖ Bloom Energy
- ❖ Booz Allen Hamilton
- ❖ Comverge
- ❖ Demand Energy
- ❖ EnergyHub
- ❖ EnerNOC
- ❖ Exelon, a Constellation Company
- ❖ Honeywell
- ❖ ICF
- ❖ Natural Resources Defense Council
- ❖ New York Battery Storage Technology Consortium
- ❖ New York Independent System Operator
- ❖ New York Power Authority
- ❖ New York State Department of Public Service
- ❖ New York State Energy Research and Development Authority
- ❖ NYC Mayor's Office of Sustainability
- ❖ PACE Energy & Climate Center
- ❖ Schneider Electric
- ❖ SolarCity

i. *Key Input from Stakeholder Engagement*

- ➢ Stakeholders suggested the procurement process should be as streamlined and transparent as possible.
- ➢ Recent NWA procurement RFPs contained detailed demographic information that was very helpful from a developer perspective.
- ➢ The Joint Utilities should provide a single "portal" where NWA opportunities would be posted, in addition to the existing practice of using the individual utility websites.
- ➢ The rules for DER participation in multiple programs (*e.g.*, wholesale and distribution-level demand response) should be clarified, since some DERs may require multiple revenue streams to be financially viable.
- ➢ Stakeholders suggested the Joint Utilities should standardize commercial and operational performance standards.
- ➢ Stakeholders requested more granularity regarding the expected trajectory and pace of long-term market development.
- ➢ Stakeholders expressed interest in gaining more insight into the utilities' evolving process for identification and solicitation of NWA opportunities.
- ➢ Stakeholders supported the Joint Utilities' proposed refinements to the NWA procurement process (in particular, the proposed bidder pre-qualification process as implemented in the recent Con Edison BQDM demand response auction), and offered numerous additional suggestions.
- ➢ Stakeholders believe the utility should include the cost of the "traditional solution" in the NWA opportunity solicitation.
- ➢ Stakeholders expressed a need for considering longer-term (*i.e.*, 10-15 year) NWA contracts.
- ➢ Some stakeholders stated that an open enrollment tariff mechanism could be used to incent DER development over a long period, to the benefit of both DER developers and utilities.
- ➢ Bilateral contracts could provide flexibility for developers to offer and the utility to procure non-standard products and services without having to wait for "open windows" or provide a solution for a specific location.

d. Electric Vehicle Supply Equipment (EVSE)

The following organizations participated in one or more engagement group meetings on EVSE either in person or virtually:

- Albany Capital District EV Drivers
- Acadia Center
- Atlas Public Policy
- Capital District Clean Communities
- ChargePoint
- Climate Action Associates
- Direct Energy
- Edison Electric Institute
- Electric Power Research Institute
- EnergyHub
- Environmental Defense Fund
- EV-Box North America, Inc.
- EV Connect, Inc.
- EVgo Services Institute
- Exelon, a Constellation Company
- General Electric
- General Motors
- GreenLots
- ICF
- International Brotherhood of Electrical Workers
- MJ Bradley & Associates
- Natural Resources Defense Council
- Navigant Consulting
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York Power Authority
- New York State Department of Public Service
- New York State Energy Research and Development Authority
- NRG Energy
- NYC Department of Transportation
- NYC Mayor's Office of Sustainability
- PACE Energy & Climate Center
- Plug in America
- Sierra Club
- SolarCity
- SunPower
- Tesla
- Verde Energy USA

i. *Key Input from Stakeholder Engagement*

- It is critical that the Joint Utilities collaborate not only among the Joint Utilities, but with a broad base of stakeholders since many aspects of the EV industry are outside the realm of traditional utility business and operations. Thus, continued engagement with industry stakeholders, automakers, EV dealerships, EV infrastructure providers, EV driver groups, government and other utilities is imperative.
- Stakeholders suggested the Joint Utilities collaborate and work with stakeholders to support solicitation of EV funding opportunities from the federal government, DOE loan programs, and the Volkswagen EPA settlement.
- EVSE technology is changing rapidly to the point that current technology may be obsolete in several years. For this reason, stakeholders recommend that the Joint Utilities remain technology-agnostic when considering EVSE investments.
- Stakeholders suggested utilities should consider siting facilities in underutilized or low-income areas.
- Utilities should consider the full range of benefits in their BCA of EV projects. Conducting a BCA based on current EV penetration levels is flawed and projections of future EV adoption are critical.
- Some stakeholders offered additional principles regarding customer choice, innovation and competitive markets.

- The ideal balance between utility and third-party ownership is an open question, and one that will likely be influenced by outcomes from California. Some stakeholders suggested that the utilities should leverage their access to large amounts of capital to invest in public charging stations.
- Some stakeholders noted that creating a separate matter number for EV activities might unnecessarily restrict their scope if created under the REV docket. Other stakeholders commented that there are still ample opportunities for projects to show value under the REV process, and that this is consistent with the utilities' current engagement in the DSIP and other REV elements.
- Stakeholders generally supported the goals and substance of the Joint Utilities' proposed EV Readiness Framework, but sought clarity on the timelines for creating the Readiness Framework and for implementing the actions (particularly investments) that the individual utilities may identify within the Framework.

D. Stakeholder Engagement Conferences

The Joint Utilities hosted engagement conferences via webinar between June and September, which were open to participation by all stakeholders. As proposed by the AG, the intent of the larger engagement sessions was to provide an additional opportunity for input from a broader audience than the smaller, more focused Engagement Groups. Presentations were assimilated from the discussions within the engagement groups followed by a question and answer session, co-led by a stakeholder and utility representative. The Q&A sessions incorporated questions submitted in advance and during the webinar.

A follow-up survey was distributed after the stakeholder engagement webinars in August and September to solicit additional feedback or suggestions regarding the topics and the engagement process in general. Stakeholders were also provided the opportunity to directly email the Joint Utilities at info@jointutilitiesofny.org with further comments or questions.

The presentation material, recordings, and summaries of the Q&A sessions are available on the website for review.

Date	Topics Covered
June 29, 2016	Overview of the stakeholder engagement process
July 27, 2016	• Suitability Criteria of Non-Wires Alternatives • System Data
August 18, 2016	• Hosting Capacity • Monitoring and Control • Customer Data
September 15, 2016	• Demand and DER Forecasting • Cybersecurity and Privacy

September 23, 2016	• DER Sourcing • Granular Pricing

1. June Stakeholder Engagement Process Webinar

The first stakeholder outreach webinar on June 29, 2016 was intended to provide an overview of the stakeholder engagement efforts the Joint Utilities of New York planned to help inform the filing of the Supplemental DSIP, as well as provide additional opportunities for involvement in the ongoing effort. In attendance were 60 participants representing 42 stakeholder organizations, not including representatives from the Joint Utilities:

- Advanced Energy Economy
- Advanced Microgrid Solutions
- BlueRock Energy
- BNMC
- Borrego Solar Systems, Inc.
- CALM Energy, Inc.
- CLEAResult
- Competitive Energy Consulting Inc.
- Comverge
- County of Westchester
- DWGP
- EarthKind Energy
- EnergyHub
- EnerNOC
- ENRGISTX Inc.
- Environmental Defense Fund
- ICF
- Landis+Gyr
- Lawrence Berkeley National Lab
- Lime Energy
- Lockheed Martin Energy
- M&W Group
- More Than Smart
- Navigant
- New York Independent System Operator
- New York State Smart Grid Consortium
- Natural Resources Defense Council
- NY State Department of Public Service
- NYC Mayor's Office of Sustainability
- New York Power Authority
- Opower
- PathStone
- Peak Power LLC
- PECO
- Siemens PTI
- Sierra Club
- SmartWatt Energy, Inc.
- SolarCity
- Sunnova
- Sunrun
- Sunverge
- Tesla
- The Mosaic Company

2. July Stakeholder Engagement Conference

The July stakeholder engagement conference was held via webinar on July 27, 2016 and focused on Suitability Criteria for Non-Wires Alternatives and System Data. In attendance were 54 participants representing 39 stakeholder organizations, not including representatives from the Joint Utilities:

- Booz Allen Hamilton
- CALM Energy
- Citizens for Local Power
- CLEAResult
- Comverge
- Electric Power Research Institute
- Electron Storage, Inc.
- Enbala Power Networks
- Energy Technology Savings, Inc.
- Environmental Advocates of New York
- FirstFuel
- ICF

- Interstate Renewable Energy Council
- IPLAN Access
- Kevala, Inc.
- KODA Consulting, Inc.
- Newport
- New York Battery & Energy Storage Technology Consortium
- New York Independent System Operator
- New York State Department of Public Service
- New York State Dept. of State Utility Intervention Unit
- New York State Energy Research and Development Authority
- NRG Energy
- O'Brien and Gere
- PACE Energy and Climate Center
- Peak Power Inc.
- Platform Power Corp
- PSEG Long Island
- Related Companies
- Renewable Energy Systems Ltd
- S&C
- Siemens PTI
- Smarter Grid Solutions
- SunPower
- Sunverge
- Sustainable Energy Economics
- Totem Power
- Westchester County
- World Team Now

3. August Stakeholder Engagement Conference

The August stakeholder engagement conference webinar was held August 18, 2016 and focused on customer data, monitoring & control, and hosting capacity. In attendance were 49 participants representing 47 stakeholder organizations, not including representatives from the Joint Utilities:

- Acadia Center
- Advanced Microgrid Solutions
- AES Corporation
- Alliance for an Energy Efficient Economy
- Association for Energy Affordability
- Bloom Energy
- BlueRock Energy
- BYD Motors
- CLEAResult
- Climate Action Associates LLC
- Comverge, Inc
- County of Westchester
- Cypress Creek Renewables
- E Cubed LLC, NECHPI, and Joint Supporters
- EarthKind Energy
- Enbala Power Networks
- Energy Storage Association
- Energy Technology Savings, Inc.
- Environmental Defense Fund
- Electric Power Research Institute
- EV Connect Inc.
- EV - Box
- General MicroGrids
- Greenlots
- ICF
- Institute for Policy Integrity
- Interstate Renewable Energy Council
- Koda Consulting, Inc.
- Lockheed Martin
- Navigant
- New York Power Authority
- New York Independent System Operator
- New York State Department of Public Service
- New York State Energy Research and Development Authority
- New York State Smartgrid Consortium
- NRG Energy
- NYC Mayor's Office of Sustainability
- Oracle
- Pacific Northwest National Laboratory
- PSEG Long Island
- Read and Laniado, LLP
- Related Companies

- Schneider Electric
- ScottMadden, Inc.
- Siemens
- Smarter Grid Solutions
- SolarCity
- SunPower
- The Alliance Risk Group
- The Mosaic Company
- Totem Power
- Verde Energy USA

4. September Stakeholder Engagement Conference #1

The first September stakeholder engagement conference webinar, held on September 15, 2016 focused on Demand and DER Forecasting and Cybersecurity and Privacy. In attendance were 45 participants representing 33 stakeholder organizations, not including representatives from the Joint Utilities:

- Acadia Center
- Bloom Energy
- BRIDGE Energy Group
- CLEAResult
- Comverge, Inc.
- Couch White, LLP
- Digital Energy Corp
- DNV GL
- E Cubed LLC, NECHPI, and Joint Supporters
- Electric Power Research Institute
- Energy Technology Savings, Inc.
- ICF
- Interstate Renewable Energy Council
- KODA Consulting, Inc.
- Landis + Gyr
- Lockheed Martin
- Long Island Power Authority
- Navigant
- New York Independent System Operator
- New York State Department of Public Service
- New York State Office of General Services
- OATI
- Oracle
- Pace Energy and Climate Center
- PSEG LI
- Read and Laniado, LLP
- RPI Center for Future Energy Systems
- Schneider Electric
- Siemens PTI
- StrateGain
- Totem Power
- Utility Intervention Unit
- Willdan

5. September Stakeholder Engagement Conference #2

The second September stakeholder engagement conference webinar, held on September 23rd, focused on Granular Pricing and DER Sourcing. In attendance were 87 participants representing 54 stakeholder organizations, not including representatives from the Joint Utilities:

- A. Page & Associates LLC
- Acadia Center
- Association for Energy Affordability
- Bloom Energy
- BRIDGE Energy Group
- CALM Energy Inc.
- Clean Coalition
- Climate Action Associates LLC.
- Comverge, Inc.
- Cypress Creek Renewables
- Digital Energy Corp
- Direct Energy
- E Cubed LLC
- EarthKind Energy
- Electric Power Research Institute
- Empire Advocates
- Enbala Power Networks
- Energy Technology Savings, Inc.
- EnergyHub
- Environmental Defense Fund

- Exponent, Inc.
- FuelCell Energy
- General MicroGrids
- ICF
- Interstate Renewable Energy Council
- Kisensum
- KODA Consulting, Inc.
- Landis + Gyr
- Lockheed Martin
- Long Island Power Authority
- Natural Resources Defense Council
- Navigant
- New York Independent System Operator
- New York Power Authority
- New York State Energy Research and Development Authority
- New York State Department of Public Service
- New York State Office of General Services
- NRG Energy
- NYC Mayor’s Office of Sustainability
- OATI
- Pace Energy and Climate Center
- PSEG LI
- Related Companies
- Renewable New York, LLC
- Rensselaer Polytechnic Institute
- RPI Center for Future Energy Systems
- Schneider Electric
- Siemens PTI
- SolarCity
- Stone Mattheis Xenopoulos & Brew, PC for Nucor Steel Auburn, Inc.
- StrateGain
- Tesla
- The Alliance Risk Group
- Totem Power
- TRC Solutions
- Xcel Energy

Appendix B: Con Edison Hosting Capacity Demonstration Project Proposal

Con Edison is working to increase hosting capacity to accommodate the increasing amount of applications for DG by identifying the necessary technology to adapt the grid from unidirectional to bidirectional power flows. These efforts align with the priorities of stakeholders and the Commission that have emerged through the Track One Order.[171] Communicating hosting capacity data to the developer community provides value by sending economic signals to developers to more efficiently site DG resources, enabling greater penetration of clean sources of energy.

Con Edison has piloted several advanced technologies with third party partners that can increase hosting capacity by permitting DG interconnection in areas where export was not permitted (*i.e.,* network systems), increasing the maximum nameplate capacity of an interconnection application, or maximizing the output of an installed unit while maintaining network reliability. Early results of these pilots have indicated that those technologies allow the network grid to adapt to reverse power flows, allow interconnection on isolated spot networks, and lower the expense to DG customers that would require a DTT solution to interconnect. Furthermore, DG developers indicate that creating cost certainty early in the interconnection process may benefit developer business cases during the critical customer acquisition or project planning phases. Ultimately, early cost certainty may lead to greater DER penetration through more projects being funded and progressing to completion.

Specifically, Con Edison will propose a demonstration project[172] to offer three solutions to address various types of DG interconnected to different system configurations, summarized below:

Proposed Solution	Generator Type	Interconnection Point
(A) Phase comparison anti-islanding	Synchronous generation, typically CHP	Typically interconnected to high-tension voltage levels (> 4kV)
(B) Communication-aided control	Inverter-based exporting generation like PV	Isolated spot networks
(C) Enhanced network protector relays and algorithms	Inverter-based exporting generation like PV	Distributed mesh grid or spot networks with a reach

171 REV Proceeding, Track One Order.
172 Con Edison proposes this demonstration project in response to the requirement in the DSIP Order stating "[U]tilities shall propose individual demonstration projects that provide them the opportunity to use alternate approaches to increasing hosting capacity and facilitate greater DER penetration on their networks." REV Proceeding, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), p. 45.

Con Edison has partnered with General Electric (solution A) and Electronic Technology Inc. ("ETI") (solutions B and C) to deliver these technology solutions. Con Edison will propose to offer these technologies at simplified upfront prices, which will include engineering study costs, field work, and materials for the export-enabling technology as a value-added service or platform service revenues ("PSR") to be approved by the Commission. By setting upfront pricing for the export-enabling technologies, the following benefits will accrue:

> Customer: A more transparent interconnection process because the early interconnection solution increases the chances of project completion and lowers costs for interconnections that would have otherwise required a DTT solution;
>
> Third Party Partners: Field validation of advanced technology;
>
> Developer Community: A more streamlined interconnection process due to fewer iterations of cost estimating, and increased cost certainty for project financing due to fixed upfront costs of interconnection early in the project lifespan;
>
> System: Increased hosting capacity to accommodate additional DG with existing infrastructure, which may lead to increased clean sources of energy and lower risk associated with integrating DG into the system; and
>
> Utility: Increased experience with advanced technology and PSR split with ratepayers for the value-added service provided as the DSP.

Con Edison proposes to test the following hypotheses to confirm the value of the project to the different parties:

- The export-enabling solutions will continue to provide service in a safe, reliable, and economic manner;
- Offering upfront pricing of advanced technology will provide greater cost certainty and will be more attractive to developers and interconnecting customers;
- Customer satisfaction will increase relative to the prior process;
- The cost of interconnection will be less variable; and
- The value-added service will result in PSR that will be split between the utility as the DSP and the ratepayers.

The demonstration project will run for three years. A detailed demonstration proposal filing, to be made in the REV docket in the first quarter of 2017, will include specific pricing and both technical and market response metrics currently under development.

Appendix C: Orange & Rockland Hosting Capacity Demonstration Project Proposal

Increasing hosting capacity to accommodate the increasing applications for DG has emerged as an early priority in the Track One Order.[173] Communicating hosting capacity values to the developer community is essential to send economic signals to developers to enable greater penetration of clean sources of energy.

O&R will propose a Variable Export Demonstration Project in response to the requirement in the DSIP Order stating, "as part of the Supplemental DSIP, utilities shall propose individual demonstration projects that provide them the opportunity to use alternate approaches to increasing hosting capacity and facilitate greater DER penetration on their networks."[174] The demonstration project is proposed to begin in 2017, and will run for two years. In parallel to this demonstration project, O&R is working with the other electric utilities of New York to determine the algorithm and presentation format of hosting capacity. Practical experience gleaned from this project will provide test cases for the use of advanced inverter functionality coupled with supporting technology to limit DG export to the system from reaching a level that would require significant upgrades to the local distribution system. It will also explore the customer appetite for such technology and arrangements as an alternative to incurring significant system upgrade costs to interconnect.

O&R will propose focusing on both technology improvements and the development of a value proposition to increase hosting capacity on the system by utilizing advanced technologies to increase hosting capacity on circuits. This will maximize the size and export capability of DG interconnection applicants and provide an alternative to incurring significant system upgrade costs to interconnect. For select DG applications 300 kW to 2 MW in size facing significant distribution system upgrade costs to interconnect, O&R is proposing to demonstrate advanced inverter functionality paired with supporting technology to maximize the proposed DG project's ability to export without negatively impacting reliability and distribution system performance. To date, O&R has been working with Smarter Grid Solutions ("SGS") as a partner to offer these technologies and solution to DG developers as part of this demonstration. SGS delivers products and services that enable utilities and developers to integrate DER and provides Active Network Management ("ANM") products, planning tools, and a range of consultancy and engineering services. SGS ANM enables automated, real-time generation management for O&R that controls for the feeder-level constraints that could dictate hosting capacity. In contrast to the majority of ANM deployments to date, this REV demonstration project proposes to use the SGS product, *ANM Element*, as a stand-alone deployment located at the point of common coupling. This makes it faster and easier to deploy and customize, allowing the REV demonstration project to proceed quickly.

173 REV Proceeding, Track One Order.

174 Case 14-M-0101, REV Proceeding, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), p. 45.

In addition to the solution described above, O&R is also developing a component of the demonstration project for mid-sized DG projects (50-300 kW) facing significant distribution system upgrade costs in order to interconnect. O&R is exploring partnership with a third-party to leverage advanced inverter functionality and supporting technology, potentially paired with energy storage, to maximize a DG project's size and ability to export without incurring significant system upgrade costs in order to interconnect. This will be done by leveraging technology to match the DG system's export with a customer's real-time load plus hosting capacity available on the circuit segment.

This demonstration will test two hypotheses. First, O&R will explore if interconnecting a DG system with the use of advanced inverter functionalities coupled with supporting technology, such as behind-the-meter storage, will allow customers to interconnect a larger DG system than otherwise would be possible. Second, O&R will also test if inverter technology paired with a tailored curtailment algorithm can maximize a DG system's ability to export back to the grid up to, but not above, a level that would negatively impact operating parameters, thus avoiding costly upgrades for developers.

The proposed demonstration project will provide value to all parties involved. The participating customers will maximize the size and level of export available for their DG systems with a significantly reduced cost to interconnect. The technology vendors will benefit through greater revenues associated with higher sales and a field validation of their nascent technology. DG developers will benefit from optimized revenue potential, significantly reduced interconnection costs, a streamlined interconnection process, and greater cost certainty for projects. Financing costs for developers will likely be lower due to the increase cost certainty. Finally, O&R will benefit by gaining experience with advanced technologies to interconnect DG, in determining and increasing local hosting capacity, and expanding monitoring and control capabilities.

As O&R gains experience with the performance of advanced inverter functionality paired with supporting technology, as well as with additional energy storage technologies on the system, similar solutions will be offered more widely as alternatives to significant infrastructure upgrades for applicable customers. These solutions would likely contain eligibility criteria and requirements developed through experience gained on this demonstration project. These offerings will also be guided by collective industry lessons on these technologies' ability to increase hosting capacity on circuits.

This demonstration project is proposed concurrently with the Supplemental DSIP and the formal demonstration proposal is planned for filing in late 2016. With this demonstration project, the desired outcome is a less expensive, and potentially faster, interconnection process that enables increased amounts of successful DG interconnection applications. This will be achieved by reducing the costs to interconnect in certain situations and locations.

Appendix D: NYSEG Hosting Capacity Demonstration Project Status & Lessons Learned

Executive Summary

The Flexible Interconnect Capacity Solution (FICS) demonstration project tests a new model for interconnecting Distributed Energy Resources (DERs) to the distribution grid using Active Network Management (ANM) rather than firm capacity. ANM technology allows the utility to manage DER within grid constraints (e.g., voltage, overloads, etc.) using real-time sensing and controls, avoiding more expensive upgrades. This model provides the potential to save on interconnection costs with minimal curtailment on DER, aiding economic viability. In addition, ANM provides the potential for greater penetration of DER.

Two proposed DERs in the New York State Electric and Gas Corporation (NYSEG) service territory have been targeted as the demonstration sites for the initial FICS scope. Using ANM, a portion of the interconnection costs for each DER will be deferred by managing network constraints identified in NYSEG's interconnection analysis. The DERs include a 2 MW solar photovoltaic (PV) farm and a 450 kW farm waste generator.

At the end of Q2 2016, agreements were provided to each of the two demonstration sites. The solar photovoltaic site developer has signed the agreement, but the farm waste generator site developer agreement is still pending. Also, the development of the PV site is delayed pending environmental permitting. The permitting survey should be completed in Q2 2017, with potential remediation to follow.

During Q3 2016, the project team advanced technical implementation of the ANM platform for the 2 MW PV farm project. The building and configuration phase of the platform progressed with the construction and configuration of the ANM platform and applications, and with the completion of Factory Acceptance Tests (FAT) against approved test specifications.

Subsequent to the successful completion of FAT for the PV project, plans for 4Q 2016 include:

- Ship servers and production panels to NYSEG
- Install and configure servers and panels at NYSEG
- Commission system at NYSEG
- Perform Site Acceptance Tests (SAT) and integration testing with NYSEG meters and controllers. Field devices will be commissioned later when the site is ready.
- Screen additional interconnection requests for applicability of ANM.

The following report provides a progress update on the tasks, milestones, checkpoints, and lessons learned to date.

A. Demonstration Highlights since the Previous Quarter

Activity and results during Q3 2016 include:

- Completed construction and configuration of the ANM platform and applications for the PV farm.
- Completion of Factory Acceptance Tests (FAT) for the PV farm against approved test specifications.

B. Activity Overview

1. FICS DER #1

On June 28, the 2 MW PV farm developer executed a FICS agreement with NYSEG. On July 21, NYSEG was informed that the 2 MW PV farm project was on hold for up to nine months due to environmental permitting and the necessary evaluations. As the agreement has been executed for this project, NYSEG has continued to progress the project factory acceptance test (FAT) and a modified site acceptance test (SAT) in preparation for resumed field activities.

2. FICS DER #2

On June 29, NYSEG issued a proposed FICS agreement for a 450 kW farm waste generator. NYSEG offered three options to interconnect the generator:

1. Do not participate in FICS and upgrade the Aurora substation transformer bank;
2. Participate in FICS, with the generator managed by ANM to address the thermal capacity constraint at the Aurora substation transformer bank. Install new distribution line regulation to prevent high-voltage conditions; or
3. Participate in FICS, with the generator managed by ANM to address the thermal and voltage constraints.

To date, the customer has not executed the agreement and so, NYSEG has deferred construction, configuration, and testing the ANM platform for this project pending execution of the FICS agreement.

3. Other Activity

In light of the project delays and deferrals noted above, NYSEG is preparing to screen additional interconnection requests for applicability of ANM. A change order has been drafted by Smarter Grid Solutions (SGS) to provide expertise in screening and planning of DER projects for flexible interconnection. Priorities during this activity will include:

- Evaluate and prioritize potential FICS DER;
- Capture the current processes for DER interconnection screenings and work with the planning team to make suggestions for “manual” FICS screenings;
- Suggest improvements for automating interconnection screenings;

- Document and disseminate flexible interconnection screening techniques and strategies to help with the DER interconnection demand, including presentations and workshops as necessary; and
- Utilize findings for a possible NYSERDA funding proposal.

C. Work Plan

1. Updated Work Plan

Activity	**Q3 2016**	**Q4 2016**	**Q1 2017**	**Q2 2017**	**Q3 2017**	**Q4 2017**
Factory Acceptance Test (Site 1)						
Site Acceptance Test (Site 1)						
Construction (Site 1)						
Operation (Site 1)						
Agreement Execution (Site 2)						
Acceptance Tests (Site 2)[175]						
Construction (Site 2) [176]						
Operation (Site 2) [177]						

2. Next Quarter Planned Activities

In Q4 2016, the project team aims to complete the following tasks:

- Ship DER #1 servers and production panels to NYSEG
- Install and configure DER #1 servers and panels at NYSEG
- Commission DER #1 system at NYSEG
- Perform DER #1 Site Acceptance Tests (SAT) and integration testing with NYSEG meters and controllers. Field devices will be commissioned later when the site is ready.
- Screen additional interconnection requests for applicability of ANM

[175] * Assumes agreement execution 4Q2016
[176] * Assumes agreement execution 4Q2016
[177] * Assumes agreement execution 4Q2016

D. Conclusion / Lessons Learned

To date, over 700 interconnection applications have been evaluated to arrive at the candidate projects described above. As expected, many of the applications do not have grid constraints and many others have steady-state or flicker constraints that would not be resolved by ANM. However, this review of applications has resulted in the additional observations noted below.

- The portability of solar PV development poses challenges. Developers can choose alternative sites where firm capacity is available.
- Additional FICS candidate selection is inhibited by the large number of queued projects. Feeder DG capacity is already consumed by projects in queue, although some may ultimately be cancelled.
- Applications are concentrated among a few developers with substantial PV capacity cleared for interconnection.

Appendix E: Cybersecurity and Privacy Framework

Cyber Security & Privacy Strategy Framework

1. Executive Summary

The NY Reforming the Energy Vision (REV) Cybersecurity and Privacy Framework ("Framework") focuses on ensuring that adequate attention is given to cybersecurity and customer privacy challenges to address new and emerging threats introduced by the NY Reforming the Energy Vision (REV) order. This Framework provides a common language for understanding and managing cybersecurity risk. The Framework enables all NYS utilities to align their cybersecurity activities while considering individual utility business requirements, risk tolerances, and resources.

The Framework enables NYS utilities regardless of size, degree of cybersecurity risk, or cybersecurity sophistication to apply the principles and best practices of risk management to improving the security and resilience of critical infrastructure.

The Framework incorporates cybersecurity best practices and industry standards that are consistent with leading cybersecurity authorities, such as NERC, NIST, and other related agencies, that will help NYS utilities identify, implement, and improve cybersecurity practices. (See appendix 3.1). It creates a common language for addressing cybersecurity and privacy threats ("threats") to the NYS utility sector. The proposed framework is designed to evolve with changes in cybersecurity threats, processes, and technologies. This Framework envisions effective cybersecurity as a dynamic and evolving response to threats. As a result, NYS utilities that adopt this Framework would be better positioned to comply with future cybersecurity and privacy regulations.

The Framework consists of six main parts:

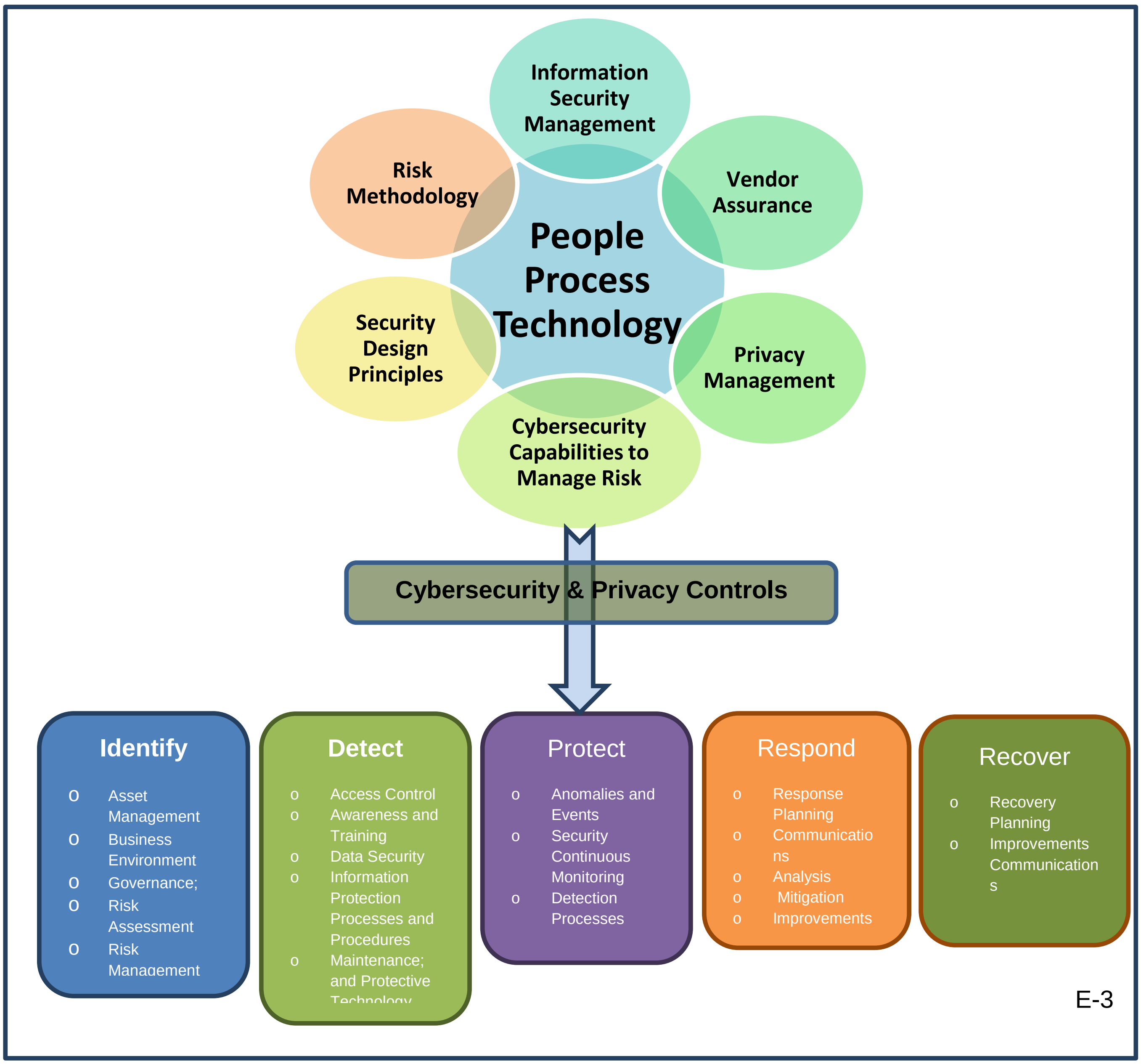
1. **Information Security Management***:* This component provides for a set of cybersecurity policies and standards that would help govern each NYS utility to design, implement and maintain a coherent set of policies, processes, and systems to manage cyber related risks to its information assets , thus ensuring acceptable risk levels to the NYS REV objectives set aside in the vision;
2. **Risk Methodology***:* This component provides for a standardized approach to identifying assets, vulnerabilities, and threats and their impacts to provide a good assessment of cyber risk to a utility;
3. **Security Design Principles:** Security design principles (sometimes referred to as guiding principles or design principles) are fundamental security objectives that should be met during the development of any security architecture, and applied when the corresponding security controls are implemented
4. **Cybersecurity Capabilities to Manage Risk:** This component provides the necessary procedures, controls, and technologies within the organization to eliminate, reduce, or mitigate risk. This component will specifically identify the cybersecurity activities within the functional categories of: Identify, Protect, Detect, Respond, and Recover (see figure below).
5. **Privacy Management***:* This component provides for a privacy framework that is embedded within the overall strategic vision to protect company information as well as customers' privacy and comply with legal and regulatory requirements;

6. **Vendor Assurance**: This component provides procedures and policies for protecting against threats that can be introduced through the supply chain and to ensure an assurance program exists to continually monitor on a regular basis.

The Framework is meant to be initial guidance to NYS Utilities and their third party contractors and business partners that will be participating in the REV initiative and will be expanded to include further guidance of the minimum control objectives expected for participation that will be released as part of the NYS Order Adopting Distributed System Implementation Plan (NYS DSIP) Guidance Supplemental filing due on November 1, 2016.

2. The Framework

The Framework is focused on people, processes and technology as being the foundation for a comprehensive cybersecurity and privacy governance program. This enables every NYS utility to provide a consistent approach in establishing cybersecurity and privacy objectives, managing risks, and implementing relevant cybersecurity capabilities and controls.



2.1 Information Security Management

Each participating utility shall adopt a formal cybersecurity program and plan based on an accepted industry recognized framework to insure Confidentiality, Integrity, and Availability (CIA) of systems, information, and assets. This component will position each utility to comply with the NYS DSIP. Information Security Management is based on ISO/IEC 27001, which is an industry known standard providing requirements for an information security management system (ISMS) and is noted as an informative reference within the NIST Cybersecurity Framework.

Information Security Management requires that all businesses and operating companies within the regulated NYS utilities, including third party contractors and business partners, develop cybersecurity policies and standards that will properly mitigate the risks identified by each NYS utility as part of implementing a risk management strategy (described in more detail in Section 2.2 below). These cyber policies and standards exist to protect assets in use and to govern REV related projects and activities. Third party contractors and business partners must work with each NY Utility to ensure that they have adequate information security management practices, which is discussed in more detail in Section 2.6 below.

During the course of NY REV Grid modernization effort, any existing information security management policies or standards should be periodically reviewed, amended, and appropriately communicated to ensure the relevance and accuracy to any business or functional change via a risk-based approach.

2.2 Risk Methodology

Each participating NYS utility organization shall adopt a formal risk management program that identifies, acts on, and mitigates risks based on an industry approved risk methodology framework (approved list of frameworks in Appendix 3.1). Such a framework must include a standardized approach to Governance, Risk, and Compliance and define an organization-wide methodology to manage cybersecurity risk. Risk-informed policies, processes, and procedures are defined, implemented as intended, and periodically reviewed. Consistent methods should be implemented to respond effectively to any change in risk to the respective utility. These methods must be in place to develop and refine the policies and standards mentioned above, and protect information based on data privacy, confidentiality, integrity, availability and critical infrastructure considerations in accordance with the law, regulations and internal data classification standards.

The risk management program shall incorporate and address risks related to each NYS Utility's REV program and each of the individual REV projects. As a result, the respective NYS Utility must have a process in place to identify threats and vulnerabilities, implement controls to mitigate risks, and manage residual risk accordingly to meet the respective utilities risk appetite for the REV program and individual projects. Finally, the NYS Utilities will need to align compliance objectives with regulatory, legal and statutory obligations and requirements and provide assurance and attestation of their effectiveness.

2.3 Security Design Principles

The foundation of any desired security architecture is a set of design principles intended to serve as a guidance when choosing the relevant cybersecurity controls (Section 2.5.1) that are leveraged to promote an adaptable architecture necessary to deliver a competitive advantage to the NYS utilities and their customers. These principles are based on the industry standard ISF (Information Security Forum) General Information Security Principles and they are:

1. **Balance Risk with Business value**: Security controls should be commensurate with the value of the information assets and vulnerability risk.
2. **Strive for simplicity:** Simplicity of security controls should result in better understanding and management of security controls, and the prompt resolution of security related issues.
3. **Obscurity is not Security:** The term “security through obscurity” is used to refer to the idea that a less well-known, less common, and thus less inviting target appears more secure statistically, even if it is not more secure technically. In many cases, it is not more secure, and it is often just a matter of time before attention is focused on that environment.
4. **Enforce Least Privilege:** Only the minimum possible privileges should be granted to a user, technology or a process for accessing an information asset.
5. **Promote Privacy:** Solutions should support privacy through prudent data collection, access and consent.
6. **Need to Know:** Access should be provided only to information that is necessary to perform a relevant business function
7. **Ensure Accountability and Traceability:** Information security accountability and responsibility must be clearly defined and acknowledged. Accountability must be enforced through traceability.
8. **Enable Continuous Protection of Information:** Information protection at all times is required to guarantee the Confidentiality, Integrity & Availability of information.
9. **Security is integral to System Design:** Security must be addressed at all stages of the solution life cycle .The security requirements of a system or application should be considered as part of its overall requirements (and not as an afterthought).
10. **Perform Defense in Depth:** This principle guides the selection of controls to ensure resilience against multiple vectors of attack, and to reduce the probability of a single-point of failure in the security of the architecture.

2.4 Cyber Security Capabilities to Manage Risk

The Framework will help deliver capabilities to manage threats and risks. Any of the industry recognized standards and best practices noted in Section 3.1 below may be utilized by each NYS Utility to identify and implement the detailed cybersecurity capabilities. For the purposes of the framework, the following capabilities, which are based on the NIST Cybersecurity Framework, are Identify, Protect, Detect, Respond, and Recover and will enable the participating NYS Utilities to define policies, procedures, controls, and technology to address risks and threats.

- **Identify**: Develop the organizational understanding to manage cybersecurity risk to systems, assets, data, and capabilities. The activities in the Identify Function are foundational for effective use of the Framework. Understanding the business context, the resources that support critical functions, and the related cybersecurity risks, enables each utility to focus and prioritize its efforts, consistent with its risk management strategy and business needs. Examples include: Asset Management; Business Environment; Governance; Risk Assessment; and Risk Management Strategy.
- **Protect**: Develop and implement the appropriate safeguards to ensure delivery of critical infrastructure services. The Protect Function supports the ability to limit or contain the impact of a potential cybersecurity event. Examples include: Access Control; Awareness and Training; Data Security; Information Protection Processes and Procedures; Maintenance; and Protective Technology.
- **Detect**: Develop and implement the appropriate activities to identify the occurrence of a cybersecurity event. The Detect Function enables timely discovery of cybersecurity events. Examples include: Anomalies and Events; Security Continuous Monitoring; and Detection Processes.
- **Respond**: Develop and implement the appropriate activities to take action regarding a detected cybersecurity event. The Respond Function supports the ability to contain the impact of a potential cybersecurity event. Examples include: Response Planning; Communications; Analysis; Mitigation; and Improvements.
- **Recover**: Develop and implement the appropriate activities to maintain plans for resilience and to restore any capabilities or services that were impaired due to a cybersecurity event. The Recover Function supports timely recovery to normal operations to reduce the impact from a cybersecurity event. Examples include: Recovery Planning; Improvements; and Communications.

2.4.1 Cybersecurity & Privacy Controls

Cybersecurity and privacy controls provides a comprehensive range of countermeasures for the NYS Utility and its information systems to avoid, counteract, or minimize loss or unavailability due to threats acting on vulnerabilities. The controls should be designed, in combination, to be preventative, detective, or corrective that creates a layered security approach and protects the confidentiality, integrity, and/or availability of information. They involve aspects of policy, oversight, supervision, manual processes, actions by individuals, or automated mechanisms implemented by information systems/devices that fall under an overarching governance program. This program will have similarities amongst the NYS Utilities, but will also include differences, as it will be based on each utility's individual risk management process and implemented security and privacy controls. Each NYS Utility will describe their individual program in further detail within their individual NYS DSIP and DSIP Supplemental Filings.

Though this Framework is not meant to delve into specific control activities, as it is intended to allow flexibility for each NYS Utility and their third party contractors and business partners, it is important to recognize that a control environment should address certain general control topics. Any of the industry recognized standards and best practices noted in Section 3.1 below may be utilized by each NYS Utility to identify and implement the detailed control activities; however, for purposes of this Framework, the NIST Special Publication 800-53 Rev 4 Security and Privacy Controls for Federal Information Systems and Organizations ("NIST SP 800-53") guidance shall be leveraged to identify those control topics or "family" as noted in the table below. This serves to assist the NYS Utilities in providing greater flexibility and agility to defend against an ever changing threat landscape, along with the ability to implement a structured approach to tailor any provisions required to specific missions/business functions, environments of operation, and/or technologies based on the level of risk that is acceptable to the specific utility.

ID	Family	ID	Family
Security Control			
AC	Access Control	MP	Media Protection
AT	Awareness and Training	PE	Physical and Environmental Protection
AU	Audit and Accountability	PL	Planning
CA	Security Assessment and Authorization	PS	Personnel Security
CM	Configuration Management	RA	Risk Assessment
CP	Contingency Planning	SA	System and Services Acquisition
IA	Identification and Authentication	SC	System and Communications Protection
IR	Incident Response	SI	System and Information Integrity
MA	Maintenance	PM	Program Management
Privacy Control			
AP	Authority and Purpose	IP	Individual Participation and Redress
AR	Accountability, Audit, and Risk Management	SE	Security
DI	Data Quality and Integrity	TR	Transparency
DM	Data Minimization and Retention	UL	Use Limitation

Each NYS Utility and their third parties and business partners must design their REV security and privacy programs to address each of the above control family topics, regardless of which security and privacy standards or best practices are selected for implementation.

Additional guidance on security and privacy controls will be developed as part of the NYS DSIP Supplement filing due November 1, 2016. This will allow for each of the NYS Utilities to begin the process of implementing this Framework and leveraging lessons learned in continuing to enhance it.

2.5 Privacy Management

Each NYS Utility shall have a governance structure in place that shall be responsible for ensuring data privacy compliance aligned with the NYS DSIP, NYS General Business Law § 899-aa(2), and an industry recognized framework(see Section 3.1) . This function also draws on resources from the utility's legal department to create a partnership to ensure that the people, processes, and technology are considered and embedded as part of an integrated approach to privacy compliance. Every NYS Utility shall ensure a designated data privacy team shall be responsible for developing a Data Privacy Strategy and deliver a Data Privacy Governance Program, which is fully aligned with the companies NYS REV effort.

In support of achieving the goals of the NYS REV initiative, each NYS Utility must develop and maintain their Data Privacy Governance Program with key personnel and committees at various levels of the organization that set, direct, and implement a privacy governance strategy that consists of a privacy risk methodology that identifies each NYS Utility's privacy threats and vulnerabilities, implement controls to mitigate risks, and manage residual risk accordingly to meet the respective utilities risk appetite. The Data Privacy Program will provide clear accountabilities through policy and supporting initiatives for delivering the company's key administrative, technical, and physical privacy and information security safeguards.

Similar to the information security principles noted in Section 2.3 above, the NYS Utility's Data Privacy Program should also consist of design principles to ensure credibility and promote continued customer confidence and goodwill. These principles are based on the Generally Accepted Privacy Principles (GAPP) that ensure the efficient and systematic control of collection, processing and disposition of personal information based on internationally recognized best practice. They are:

a. **Management**: The entity defines, documents, communicates, and assigns accountability for its privacy policies and procedures.
b. **Notice**: The entity provides notice about its privacy policies and procedures and identifies the purposes for which personal information is collected, used, retained, and disclosed.
c. **Choice and Consent**: The entity describes the choices available to the individual and obtains implicit or explicit consent with respect to the collection, use, and disclosure of personal information.
d. **Collection**: The entity collects personal information only for the purposes identified in the notice.
e. **Use, Retention and Disposal**: The entity limits the use of personal information to the purposes identified in the notice and for which the individual has provided implicit or explicit consent. The entity retains personal information for only as long as necessary to fulfill the stated purposes or as required by law or regulations and thereafter appropriately disposes of such information.
f. **Access**: The entity provides individuals with access to their personal information for review and update.
g. **Disclosure to third parties**: The entity discloses personal information to third parties only for the purposes identified in the notice and with the implicit or explicit consent of the individual.
h. **Security for Privacy**: The entity protects personal information against unauthorized access (both physical and logical).
i. **Quality**: The entity maintains accurate, complete and relevant personal information for the purposes identified in the notice.
j. **Monitoring and Enforcement**: The entity monitors compliance with its privacy policies and procedures and has procedures to address privacy related inquiries, complaints and disputes.

2.6 Vendor Assurance

Each NYS utility should protect against supply chain threats to information systems and assets as part of their information security strategy. Utilities should implement a standardized process for identifying, assessing, and mitigating security risks that can be introduced at the supply chain level. Individuals involved in the acquisition process should be educated on identifying and intercepting such risks. Examples of supply chain threat agents may include: foreign intelligence services, cyber criminals, insider threats, and industrial espionage.

Supply chain risk management should be developed as a multi-departmental engagement with respective responsibilities. The engagement should integrate strategies and goals on the corporate level, guidance and procedures on the business level, and policy implementations and constraints on the information systems level.

A comprehensive strategy for protecting against supply chain risks should include at a minimum:

- Performing due diligence and risk assessment of potential new vendors
- Validation of vendor security controls to ensure the design and operating effectiveness to mitigate the risks identified appropriately by the respective NYS utility.
- Periodic monitoring of the vendor contract and to ensure compliance to the NYS utility agreed terms and conditions
- Enforcing policy and procedure compliance
- Ensuring the protection of customer information at rest and in motion
- Providing methods for allowing customer opt-in prior to releasing any customer information unrelated to the normal delivery of energy
- Appropriate security terms within legal agreements with third parties that ensure that they have proper security and privacy controls to protect NY Utilities' customer information

3. APPENDIX

Industry Standards and Best Practices

Cybersecurity Industry Standards and Guidelines leveraged to inform development of Cybersecurity and Privacy Joint Utility Framework

- NIST Cybersecurity Framework
- NISTIR 7628: Guidelines for Smart Grid Security
- NIST SP 800-53: Security and Privacy Controls for Federal Information Systems and Organizations
- NIST SP 800-30: Guide for Conducting Risk Assessments
- NIST SP 800-161: Supply Chain Risk Management Practices for Federal Information Systems and Organizations
- NIST 800-144: Guidelines on Security and Privacy in Public Cloud Computing
- NIST IR 8062: Privacy Risk Management for Federal Information Systems
- Fair Information Practice Principles (FIPPs)
- Electric Sector Cybersecurity Capability Maturity Model (ES-C2M2)
- DOE DataGuard Energy Data Privacy Program
- AICPA Generally Accepted Privacy Principles
- ISO/IEC 27001 Information Security Management
- ISO/IEC 27002 Code of Practice for Information Security Controls
- ISO/IEC 27005 Information Security Risk Management
- ISO/IEC 27018 Code of Practice for Protection of PII in Public Cloud
- ISO/IEC 29100 Privacy Framework
- ISO/IEC 29101 Privacy Architecture Framework
- ISO/IEC 29134 Privacy Impact Assessment
- DOE voluntary code of conduct
- Information Security Forum General Information Security Practices

Definitions

- **Access Control**: Access to assets and associated facilities is limited to authorized users, processes, or devices, and to authorized activities and transactions.
- **Analysis**: Analysis is conducted to ensure adequate response and support recovery activities.
- **Anomalies and Events**: Anomalous activity is detected in a timely manner and the potential impact of events is understood.
- **Asset Management**: The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.
- **Availability:** is generally considered the next most critical security requirement, although the time latency associated with availability can vary.
- **Awareness and Training**: The organization's personnel and partners are provided cybersecurity awareness education and are adequately trained to perform their

information security-related duties and responsibilities consistent with related policies, procedures, and agreements.

- **Business Environment**: The organization's mission, objectives, stakeholders, and activities are understood and prioritized; this information is used to inform cybersecurity roles, responsibilities, and risk management decisions.
- **Communications (Recover)**: Restoration activities are coordinated with internal and external parties, such as coordinating centers, Internet Service Providers, owners of attacking systems, victims, other CSIRTs, and vendors.
- **Communications (Respond)**: Response activities are coordinated with internal and external stakeholders, as appropriate, to include external support from law enforcement agencies.
- **Confidentiality**: is generally the least critical for actual power system operations, although this is changing for some parts of the power system, as customer information is more easily available in cyber form: Privacy of customer information is the most important =general corporate information, such as human resources, internal decision-making, etc.
- **Cybersecurity**: is the protection required to ensure confidentiality, integrity and availability of the electronic information communication system.
- **Data Security**: Information and records (data) are managed consistent with the organization's risk strategy to protect the confidentiality, integrity, and availability of information.
- **Detection Processes**: Detection processes and procedures are maintained and tested to ensure timely and adequate awareness of anomalous events.
- **Governance**: The policies, procedures, and processes to manage and monitor the organization's regulatory, legal, risk, environmental, and operational requirements are understood and inform the management of cybersecurity risk.
- **Integrity**: is generally considered the most critical security requirement for power system operations, and includes assurance that:
    - Data has not been modified without authorization
    - Source of data is authenticated
    - Timestamp associated with the data is known and authenticated
    - Quality of data is known and authenticated
- **Improvements (Recover)**: Recovery planning and processes are improved by incorporating lessons learned into future activities.
- **Improvements (Respond)**: Organizational response activities are improved by incorporating lessons learned from current and previous detection/response activities.
- **Information Protection Processes and Procedures**: Security policies (that address purpose, scope, roles, responsibilities, management commitment, and coordination among organizational entities), processes, and procedures are maintained and used to manage protection of information systems and assets
- **Maintenance**: Maintenance and repairs of industrial control and information system components is performed consistent with policies and procedures.
- **Mitigation**: Activities are performed to prevent expansion of an event, mitigate its effects, and eradicate the incident.

- **Personal information**: Information that is about, or can be related to, an identifiable individual that a NYS Utility has a relationship with.
- **Privacy**: The rights and obligations of individuals and organizations with respect to the collection, use, retention, disclosure and disposal of personal information.
- **Protective Technology**: Technical security solutions are managed to ensure the security and resilience of systems and assets, consistent with related policies, procedures, and agreements
- **Recovery Planning**: Recovery processes and procedures are executed and maintained to ensure timely restoration of systems or assets affected by cybersecurity events.
- **Response Planning**: Response processes and procedures are executed and maintained, to ensure timely response to detected cybersecurity events.
- **Risk Assessment**: The organization understands the cybersecurity risk to organizational operations (including mission, functions, image, or reputation), organizational assets, and individuals.
- **Risk Management Strategy**: The organization's priorities, constraints, risk tolerances, and assumptions are established and used to support operational risk decisions.
- **Security Continuous Monitoring**: The information system and assets are monitored at discrete intervals to identify cybersecurity events and verify the effectiveness of protective measures.

REV DPS Orders

- Add links of all the orders that are relevant to the REV initiative (need to provide proper references)
- The NYS Order Adopting Distributed System Implementation Plan Guidance.
- Reference to the orders specific to NYS REV: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument
- PSC Order 13-M-0178 Security for the Protection of Personally Identifiable Customer Information:http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B28CDF9EB-8661-491C-B2C2-E6E527297EE0%7D