STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

ORDER ADOPTING DISTRIBUTED SYSTEM IMPLEMENTATION PLAN GUIDANCE

Issued and Effective: April 20, 2016

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At a session of the Public Service Commission held in the City of Albany on April 20, 2016

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre
Diane X. Burman, concurring

CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

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(Issued and Effective April 20, 2016)

BY THE COMMISSION:

INTRODUCTION

In the Order Adopting Regulatory Policy Framework and Implementation Plan in this proceeding,[1] the Commission described the need to develop a more transactional, distributed electric grid that meets the demands of the modern economy including improvements in system efficiency, resilience, and air emissions reductions. The Track One Order began a transition from the historic model of a unidirectional electric system serving inelastic demand, to a dynamic model of a grid that encompasses both sides of the utility meter and relies increasingly on distributed resources and dynamic load management.

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[1] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order).

To guide this transition of the utility model, the Commission defined a set of functions of the modern utility that are called, collectively, the Distributed System Platform (DSP). DSP functioning combines planning and operations with the enabling of markets.[2] The vehicle by which improved planning and operations will be defined and implemented is the Distributed System Implementation Plan (DSIP), the subject of this Order. The DSIP process, which will include active collaboration among utilities, stakeholders, and Department of Public Service Staff (Staff), is designed to promote this transition in a way that develops balanced and effective plans.

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. In the digital economy, improving the quality and flow of information has led to enormous increases in value and system efficiency across many industries. As the Track One Order states, these efficiencies must be brought to the electric industry to meet the challenges of the modern economy.

In the context of the DSIP, improved information means greater transparency and visibility of electric system planning and operations. Greater transparency to market participants, both of system needs and of operational modes that can meet those needs, will encourage innovation and will support efficient private capital investments. Improved visibility is also critical on the utility-facing side of planning and operations to improve efficiency and resilience.

While planning and operations must become more visible and transparent, ensuring customer privacy, as well as system security and reliability, remain paramount. In an increasingly

[2] Track One Order at 26-30.

technological world, protection of consumer information, privacy, cybersecurity, and physical security are subjects that require constant vigilance, improvement, and adaptation. The deployment of systems that support greater degrees of situational awareness and flexibility simultaneously, ironically offer the opportunity to make our networks more secure and resilient if done correctly, and also potentially more vulnerable, if the appropriate protections are not applied.

In this Order, the Commission requires utilities to make the following three filings in 2016: (1) a plan and associated timeline for a stakeholder engagement process during DSIP filing development (due May 5, 2016); (2) an individual utility Initial DSIP addressing its own system and identifying immediate changes that can be made to effectuate state energy goals and objectives (due June 30, 2016); and, (3) a joint — and as necessary, individual — Supplemental DSIPs by all utilities addressing 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 (due November 1, 2016). The DSIP filings will require utilities to describe and analyze certain specified processes and data related to distribution system planning and distribution grid operations that account for distributed energy resources (DERs). The utility DSIP filings will also address common grid architecture approaches and interfaces that will be necessary, current and planned, advanced metering initiatives, and gathering and sharing of customer data to support robust and liquid retail markets. While commonality of means and methods is required, implementation need not occur simultaneously. Although the DSIP process requires utilities to make filings that will detail certain information (further described below and itemized in

Attachment 1 to this Order.), such as projected investment budgets, the recovery of costs associated with DSIP implementation will be addressed in individual utility rate cases and/or through other proceedings.

BACKGROUND

The Track One Order requires each utility, as a DSP, to file a DSIP. On October 15, 2015, Staff submitted the Staff Proposal Distributed System Implementation Plan Guidance (Guidance Proposal) to provide greater detail with respect to the DSIP filing process and the contents of the DSIP filings.

The Guidance Proposal outlines a two-phase approach to the DSIP filings. The Initial DSIP is intended to be a thorough self-assessment, whereby each utility addresses its own system and notes immediate changes that could be made to effectuate Reforming the Energy Vision (REV) policies and objectives and to conduct a more comprehensive and transparent planning process. The Supplemental DSIP is intended to outline the tools, processes, and protocols that will be developed by utilities, either jointly or under shared standards, to plan and operate a modern grid capable of dynamically managing distribution resources, as well as supporting retail markets that coordinate significant investment in DERs and efficiently manage resources. The Guidance Proposal suggests that the Initial DSIPs be filed by June 30, 2016, and Supplemental DSIP be filed jointly by the utilities on or before September 1, 2016.

The Guidance Proposal provides that a meaningful stakeholder engagement process, including focused technical conferences and discussions, will be a critical component of developing the DSIP filings. Accordingly, it invited commenting parties to explain how best to define and structure the stakeholder engagement process to ensure open and effective communication, as well as to prioritize the subjects and issues to be addressed in the DSIPs. In addition, the Guidance Proposal maintains that the Initial DSIPs and the Supplemental DSIP will be made publicly available and a process for stakeholder comment will be set forth according to public notice.

The Guidance Proposal proposes that the Initial DSIPs address the following three areas:

a) Distribution System Planning:
- Forecasts of demand and energy growth;
- Available resources;
- Delivery infrastructure capital investment plans; and,
- Beneficial locations for DER deployment.

b) Distribution System Operations:
- System operations;
- Volt/VAR optimization; and,
- Interconnection processes.

c) Distribution System Administration:
- System data acquisition and sharing;
- Customer data and engagement;
- Customer data questions for comment; and,
- Advanced metering functionality and communication infrastructure.

In addition, the Guidance Proposal suggests that a discussion of relevant REV demonstration projects should be integrated into the Initial DSIPs.

With respect to the Supplemental DSIP, the Guidance Proposal prompts the utilities to describe the stakeholder engagement process used to develop the information provided therein. The Guidance Proposal also proposes that the Supplemental filing address and analyze the following topics:

- Advanced distribution system planning;
- Advanced distribution grid operations;
- Granularity of pricing;
- New York Independent System Operator, Inc. (NYISO)/DSP roles, responsibilities, and interactions;
- Data access to facilitate markets;
- Market participant rules;
- Settlement procedures;
- Approaches for procuring DERs; and,
- Joint system planning and system operations progress.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rule Making (SAPA Notice) was published in the State Register on November 4, 2015 [SAPA No. 14-M-0101SP14]. The time for submission of comments pursuant to the SAPA Notice expired on December 21, 2015. Moreover, in a Notice Inviting Public Comment on Distributed System Implementation Plan Guidance, issued on October 15, 2015 in this proceeding, the filing of Initial Comments on the Guidance Proposal was invited, by December 7, 2015, with Reply Comments due December 21, 2015. The time to file reply comments was subsequently extended to January 6, 2016.

In response to the notices, a broad spectrum of organizations, institutions, utilities, and DER service providers submitted their views. The commenters are listed with abbreviations in Appendix A; the Initial Comments and Reply Comments received are summarized in Appendices B and C, respectively. Some of the comments were highly detailed and analyzed the issues at length.

Commenters may be categorized into several groupings: the public interest intervenors, consisting of national, regional, and local environmental groups and other public policy advocates; DER providers and organizations, including many trade organizations representing groups and consortiums of DER providers and DER interests; utilities, including New York’s major electric and gas companies; customer representatives, including industrial, commercial, and residential advocates; and, governmental entities. The positions of the parties, however, diverge widely and an extensive variety of alternatives, modifications, and suggestions directed to the Guidance Proposal were presented.

LEGAL AUTHORITY

The Public Service Law grants the Commission the legal authority to prescribe the system planning efforts and filings required by this Order. Section 5(1) grants the Commission jurisdiction over the sale or distribution of electricity. Section 5(2) permits the Commission to “encourage all . . . corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities.” Pursuant to Section 65(1), every electric corporation must safely and adequately “furnish and provide [electric] service, instrumentalities, and facilities.” Section 66(1) extends general supervision to electric corporations having authority to maintain infrastructure “for the purpose of . . . furnishing or transmitting electricity.” Pursuant to Section 66(2), the Commission may “examine or investigate the methods employed by . . . corporations . . . in manufacturing, distributing, and supplying . . . electricity,” as well as “order such reasonable improvements as will best promote the public interest . . . and protect those using . . . electricity.” Moreover, pursuant to Section 66(3) the Commission may prescribe “the efficiency of the electric supply system." Accordingly, the Commission has the jurisdiction over the electric utilities affected by this Order to require them to comply with the requirements outlined herein.

DISTRIBUTED SYSTEM IMPLEMENTATION PLAN PURPOSE

The Track One Order described the goals of the DSIP as the vehicle that "serve[s] as a source of public information regarding DSP plans and objectives, including specific system needs allowing market participants to identify opportunities [as well as to] serve as the template for utilities to develop and articulate an integrated approach to planning, investment, and operations, . . . enabl[ing] the Commission to supervise the implementation of REV in the context of system operations."[3] The Commission continued, "[t]he DSIP will contain (among other things) a proposal for capital and operating expenditures to build and maintain DSP functions, as well as the system information needed by third-parties to plan for effective market participation."[4] The open process offered by the DSIPs is intended to promote utility/stakeholder relations, allow third-parties to provide cost-effective market solutions to identified energy needs, expand the use of DER, and increase energy efficiency measures. Furthermore, making utility data and planning processes more visible to all parties will encourage beneficial DER solutions and investments that will maximize use of the distribution system to meet customer needs. The DSIP process is envisioned to be a multi-year plan, subject to public comment and regular updates. Accordingly, the DSIPs will

[3] Track One Order at 129.

[4] Track One Order at 32.

document utility plans over a five-year period, with updated DSIP filings required every two years.

Current grid design reflects technical, informational, and economic assumptions that date back a full century. Electric distribution systems and bulk electric system have been the two broad infrastructure categories that utility planners and operators have used to plan and operate their systems. Bulk system planners would typically lump distribution customer demands on their bulk substation and assure sufficient resources were available to serve them. Under the traditional design of the system, distribution planners rightfully rely on the bulk system as the source of supply. Therefore, they plan and operate the distribution grid as a one-way delivery system to meet local demands. The conventional wisdom was that demand was largely inelastic and the inherent volatility of electric usage and supply should be largely met by generation control and dispatch. In actuality, customer usage, the distribution and bulk transmission system, and generation are a single ecosystem that is most efficient when it operates as a seamless system of systems.

In the aftermath of Superstorm Sandy, New Yorkers experienced firsthand the effects of prolonged system failure. A distributed, smarter, and more resilient network that contains sufficient local supply resources, whether in isolation or as part of a microgrid, will be a critical component of assuring efficient, reliable power both on “blue sky days” and following major climatic events. The DSIP links the multiple systems that compose the power network so that information and communications can flow in multiple directions and promote efficient and better solutions for customers and system owners and all the while assuring a reliable electric system.

Traditional distribution system planning has relied on deterministic system modeling because, while customer load was variable, it was generally predictable. Now, with better and greater penetration of behind-the-meter DERs, more granular price signals with the advent of smart metering, more animated products/services from third-parties, the net load is likely to be more volatile. The Track One Order describes in detail that due to the increased opportunities for greater degrees of distribution grid management and penetration of resources that increase the responsiveness and dynamic nature of load, a grid design that was designed to serve in an analog world and operated in a command and control environment with largely inelastic demand, and for a unidirectional physical and transactional flow, is increasingly anachronistic and inadequate. As distribution utilities today need to serve load that is much more sensitive and dynamic, and shift toward integrating increasing amounts of DERs into their systems, they will rely upon these resources to complement energy procured from the wholesale market. Therefore, utilities need to contemplate a grid architecture that accounts for all facets of how the industry is changing and the impacts to not only the physical grid design, but how it plans to proactively approach and appropriately manage its responsibilities as a DSP. The Pacific Northwest National Laboratory's Grid Architecture report states, "[t]he use of grid architecture is the difference between being able to actively shape the grid of the future based on sound representation of a multiplicity of structures and the interactions involved, versus passively allowing the grid to evolve in a bottom-up manner and waiting to see what emerges. Grid Architecture provides the discipline to manage the complexity and the risk associated with changing the grid in a manner that significantly reduces the likelihood of unintended consequences.”[5]

Future grid design will reflect the overall electric system’s planning and operational needs. For example, in meeting daily customer energy demands, there are several choices available: 1) the bulk system can dispatch a generator to increase output; 2) the distribution utility can dispatch DERs to increase output; or, 3) customers can reduce their energy consumption, all achieving the same basic goal. In order for this evaluation and decision to be made, however, the distribution system operator, the bulk system operator, the customers and the competitive markets need to be seamlessly coupled to ensure, to the extent possible, the most efficient action is taken. Similarly, maintaining voltages within acceptable limits is paramount to maintaining a reliable electric system at all levels. This is normally done today by varying the levels of reactive power or volt-ampere reactive units (VARs). As a general rule, to reduce losses, VAR resources should be located relatively close to where they are needed. To the extent that a customer with relatively high VAR demands can install equipment at his location to provide VARs, that would lessen the need for them to come from other sources, thereby reducing losses and reducing utility capital expenditures needed to purchase and install VAR equipment at its own facilities.

The utilities should apply modern grid architecture principles when designing the electric grid of the future. System planning and operations will need to evolve to seamlessly interact with and accommodate the nature of these DERs, including operational characteristics such as intermittency and

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[5] J.D. Taft and A. Becker-Dippmann, Pacific Northwest National Laboratory, Grid Architecture, January 2015.

various levels of reliability. Some of the future principles were discussed in the MDPT report, issued on August 17, 2015.[6] This included significant connectivity between different elements tied to the distribution system, similar to what currently exists at the wholesale level. It is important that utilities keep these future principles in mind as they move forward with these initial DSIP filings.

Physical grid architecture should follow nationally standardized paths, to the extent possible, to facilitate the integration of products and services across the varied market models that may be used among the states.[7] Given the widespread range of potential developers, products, and services, the ability to readily exchange information and integrate new innovations is paramount. Therefore, the standardization efforts should seek to incorporate open source or similar principles to promote interoperability. The Supplemental filing should identify the actions to incorporate these fundamentals.

Utilities will need to use scenario based probabilistic modeling to be able to predict how much energy the resources distributed throughout their systems can reliably deliver. Further, as distribution utilities develop the ability to predict the variability of these resources, they can plan and

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[6] Case 14-M-0101, Market Design and Platform Technology Working Groups Final Report (issued August 17, 2015) (MDPT Report).

[7] A delineation of how distribution functions in common grid architecture may be developed in the context of differing market models is provided in Future Electric Utility Regulation, Report No. 2., published by Lawrence Berkeley National Laboratory in October 2015. This is not a definitive discussion and is not adopted here; however it should serve as an input in collaborative development of grid architecture in New York.

operate using smaller reserve margins, thereby improving the overall cost-effectiveness of the system.

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. Finally, the information that the DSIPs will provide is essential to the development of retail markets that accurately and fully price the value of DERs to the grid and electric consumers. Electric utilities today, and into the foreseeable future, will have the fundamental responsibility of assuring safe, reliable, and cost-effective electric service. Thus, the need to provide information to market participants must be accomplished without compromising the reliability and security of the system and consumer privacy.

As the utilities transition to the DSP role, they will also facilitate and coordinate DER integration into grid operations. To perform these functions, the utilities will need tools to observe/monitor and coordinate/control the distribution system. To maintain reliability, operators will need improved situational awareness to both proactively and reactively manage the distribution network. Sensing and control technologies that allow utilities to observe/monitor and coordinate/control a much more dynamic and two-way distribution system will need to be developed. Increased monitoring and observability into distribution networks through advanced systems will enable grid operators to manage the grid and optimize DER value under both normal conditions and outage events. Control systems such as automated voltage control and VAR control provide increased operating flexibility and efficiency. These tools will need to be supported by a secure and scalable communications network.

The processes to accommodate customers and DER providers seeking to interconnect with the utility needs to be streamlined, automated, and integrated with grid optimization planning. Along with identification of new system tools, rules must be put in place incorporating cybersecurity and privacy protection.

The REV initiative continues to stress the goals of more efficient energy use, deeper DER penetration, establishing vibrant markets to transact electric grid services, and adopting innovative and sustainable energy technologies. Transitioning the current electric system is feasible through grid architecture principles that account for the elements needed to support these goals. Each utility, however, is a separate entity and the distribution systems were developed separately in different environments to meet different needs. These differing starting points add a layer of complexity for utilities transitioning from their existing systems to a DSP in a uniform way. Therefore, obtaining our goals requires long-term approaches comprising incremental steps, each one meant to bring New York toward a cleaner, more resilient, and more affordable energy system through the development of dynamic, self-sustaining markets that will eventually set the pace of industry change. As one of those steps, utilities and stakeholders need to assess and better understand the present status of each service territory and determine the starting point, both within the individual utilities and collectively, as a state. The DSIP filings require utilities and stakeholders to collaborate and begin compiling such assessments. Though utilities, market participants, and other stakeholders will develop a deeper understanding of the opportunities to benefit consumers through DER deployment and more intelligent networks as the market matures, the DSIP filings required by this Order are 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.

A) DSIP Filing Process

The Guidance Proposal recommends that the DSIP process for 2016 involve two separate filings: the Initial DSIPs and the Supplemental DSIP. In addition, the Guidance Proposal recommends that the utilities develop a stakeholder engagement process to provide for greater transparency with respect to utility operations and planning, and adequately vet the DSIP topics.

According to the Guidance Proposal, the Initial DSIPs are intended to be a thorough self-assessment addressing each utility’s system and identifying immediate changes that can be made to effectuate REV goals and objectives. The Initial DSIPs, the Guidance Proposal suggests, should focus on information that the utilities currently have, as well as preliminary changes that are necessary to conduct a more comprehensive and thorough planning process. The proposed filing deadline for the Initial DSIPs is June 30, 2016.

After the utilities file their individual Initial DSIPs, the Guidance Proposal recommends that the utilities file a joint Supplemental DSIP. The Guidance Proposal suggests that the utilities should begin collaborating on the Supplemental DSIP, including a stakeholder engagement process, simultaneously with preparation of their Initial DSIPs. The proposed filing deadline for the Supplemental DSIP is September 1, 2016.

The Guidance Proposal asserts that the purpose of the Supplemental DSIP is to provide additional information necessary for long-term planning and coordination, and to expand upon the concepts presented in the Initial DSIPs. In the Supplemental DSIP, utilities would also develop a coordinated approach to DER deployment by defining standardized methodologies, protocols, and tools necessary to plan and operate a modern grid.

Comments

A number of parties support the filing process as proposed, but a number of other suggestions were received. NYC, for example, asserts that the Commission should defer action on the Guidance Proposal and instead proceed with DSIP development on a topic-by-topic basis, pointing to other ongoing proceedings and white papers upon which the Commission has not yet acted.

With respect to the Initial DSIPs, the Joint Utilities recommend that the Guidance Proposal regarding incorporating DERs into the system planning process and for forecasting and identifying beneficial DER locations be deferred to the Supplemental DSIP to allow for the development of a consistent approach between utilities and third-parties. Instead, the utilities would perform an analysis of currently available information related to beneficial locations for DERs to identify near-term initiatives, substation load-shape forecasts, forecasts of DER impacts on peak load, energy and load shapes, and data specific to areas where DERs may provide reliability or operational benefits.

With respect to the Supplemental DSIP, contrary to the Guidance Proposal, the Joint Utilities prioritized and categorized the DSIP topics into three groups. Category One topics include a methodology for determining hosting capacity, the interconnection process, an advanced metering infrastructure (AMI) rollout policy, data access policies for customer and system data, and DER procurement approaches. Category Two topics include demand forecasting, DER forecasting, a methodology for determining energy storage impacts, a system planning methodology, standardizing a load-flow analysis process, cybersecurity, coordinated demand response and DER dispatch tools, market participant rules, and joint system planning and system operations procedures. Category Three topics include improved granular pricing, NYISO/DSP coordination, and settlement procedures. The Joint Utilities recommend that the Category One and Two topics be addressed in the Supplemental DSIP, while Category Three topics be deferred until after the Supplemental DSIP has been filed.

Other suggestions received include condensing the process such that both the Initial and Supplemental DSIPs are due by June 30, 2016, offering a technical conference where each utility is required to present a proposed Initial DSIP and answer questions from Staff and stakeholders, and requiring greater detail in the Initial DSIPs to address the concern that the Supplemental DSIP filing may be too soon after the Initial

DSIP deadline to be effective. In addition, several parties recommend that more guidance be provided to the utilities with respect to the Supplemental DSIP requirements.

Discussion

Staff has reported to the Commission that utilities have been working on establishing baseline information following the issuance of the Guidance Proposal. Therefore, the proposed filing date of June 30, 2016 for the Initial DSIPs gives the utilities sufficient time to finish collecting and analyzing the requested information and accordingly, is adopted. On the other hand, the proposed September 1, 2016 filing date for the Supplemental DSIP does not provide sufficient time for an adequate stakeholder process and, therefore, the utilities are directed to file the Supplemental DSIP by November 1, 2016. Subsequent DSIPs will be required on a biennial basis beginning June 30, 2018. Future DSIP filings are expected to include increased detail, such as developments in markets and technology capabilities as well as lessons learned and improvement opportunities. All DSIP filings, except the stakeholder engagement process, but including the Initial and Supplemental DSIP filings, will be filed with the Secretary to the Commission and subject to Commission action.

It is also expected that stakeholder engagement with Staff, developers, and third-parties will continue into the future. Although the DSIP process requires utilities to make filings detailing certain information (further described below) such as DER deployment plans, energy forecasts, and projected budgets, specific dollar amounts associated with implementation will be addressed in individual utility rate cases and/or through other proceedings unrelated to the deadlines adopted herein for the Initial and Supplemental DSIPs.

The content requirements of both DSIP filings are discussed in detail below. The Joint Utilities' proposal to defer certain requirements to the Supplemental filing, or further into the future, is rejected. As noted in the Guidance Proposal, although not all the information requested may be currently and completely available, it is imperative that the utilities provide the data and information that is presently available. The extent to which certain data and information needs to be further collected and/or analyzed should be addressed through the stakeholder process during development of the Supplemental DSIP filing.

As provided for in the Guidance Proposal, the utilities must develop a coordinated approach to DER deployment by defining standardized methodologies, protocols, and tools. Furthermore, the Supplemental DSIP should identify national standardized approaches. The utilities should coordinate efforts with utilities in other jurisdictions, such as California, to better provide for a national perspective in the Supplemental DSIP filing.

B) Stakeholder Engagement Process

According to the Guidance Proposal, the stakeholder engagement process is a critical component of the DSIP filings and is intended to improve transparency of utility planning and operations. The Guidance Proposal provides that the stakeholder engagement process will involve technical conferences and discussions to vet each proposed subject area. In addition, the Initial DSIPs and the Supplemental DSIP will be filed with the Commission and made publicly available. Once filed, a process for stakeholder comment will be set forth pursuant to public notice.

The Guidance Proposal invited parties to explain how best to define and structure the stakeholder process to ensure and facilitate open and effective communication. Further, the Guidance Proposal specified that comments should prioritize the subjects and issues to be addressed in the stakeholder process, as well as how the process will continue as the utilities develop into functional DSPs, and as technology and markets continue to evolve.

Comments

Though the parties are generally supportive of stakeholder engagement in the DSIP process, many suggestions were made to ensure the most meaningful engagement possible. For example, it was suggested that three periods of stakeholder engagement be created: before, during, and after DSIP development. Technical conferences, working groups, and monthly conferences were suggested for the winter and spring of 2016. It was also suggested that a stakeholder process be implemented following the Initial DSIP filings to create a governing structure for ongoing DSIP evaluation.

Several suggestions were made to require greater utility involvement in the stakeholder process, such as requiring the utilities to: 1) create a public website and/or hire a public expert to help stakeholders better understand the DSIPs; 2) make periodic reports on their DSIP performance and milestones; 3) document stakeholder input; 4) explain how stakeholder input was taken into account in developing both the Initial and Supplemental DSIPs; 5) provide written responses to comments; and, 6) share the background information upon which they base their responses. Another recommendation received was to direct the utilities (or Staff or a consultant) to provide summaries of their DSIP filings and make the summaries available to stakeholders. Coordinating with local governments was also mentioned to ensure efficient public planning and consideration of environmental impacts.

Several parties discussed engaging some form of stakeholder support, such as an independent expert or neutral facilitator. The parties debated whether the utilities should choose such expert or facilitator, as well as what sectors (environmental, consumer, etc.) should be represented in the stakeholder engagement process.

With respect to the Supplemental filing, the Joint Utilities propose to hire a consultant, both retained and compensated by the Joint Utilities, to lead stakeholder engagement efforts. The Joint Utilities state that their stakeholder engagement process will follow their prioritization of the Supplemental DSIP topics (noted above). In addition, the Joint Utilities anticipate that technical conferences will be needed at the outset of the engagement process. The Joint Utilities propose to begin the stakeholder engagement process shortly after the Commission acts on the Guidance Proposal.

Discussion

The stakeholder engagement process will be led by the utilities. Staff has reported to the Commission that the utilities are currently prepared to perform this task as a result of their efforts following the issuance of the Guidance Proposal. To ensure that both the Initial and Supplemental DSIPs are developed with consideration of stakeholder input, the utilities must immediately engage stakeholders. Accordingly, by May 5, 2016, the utilities must define the stakeholder engagement processes and associated timelines that will be used to inform development of their DSIP filings, as well as their plans for continued stakeholder engagement into the future. The utilities should follow this Order in setting priorities on stakeholder engagement in consultation with Staff and other stakeholders. It is further worth noting that this stakeholder engagement is supplemental to and quite different from utility engagement with technology and consumer experience partners and DER developers, which should be occurring naturally during the course of the development of this new business model.

C) Integration of Demonstration Project Results

The Guidance Proposal recommends that utilities discuss their relevant current and near term REV demonstration projects in their DSIPs. Further, the Guidance Proposal specified that the DSIP will reflect ongoing work as issues are resolved, including within demonstration projects.

Comments

In general, the commenting parties support requiring utilities to address their REV demonstration projects in the DSIP filings. It was proposed, however, that the utilities be required to describe how these projects will contribute to the achievement of the various components of their DSIPs. It was debated whether the utilities should be required to propose additional projects. The Joint Utilities also support inclusion of demonstration projects in their DSIPs, but assert that the approval process should be streamlined and the proposal criteria should be broadened to allow projects outside of those outlined in the Track One Order to move forward. The Joint Utilities also suggest that they be allowed to propose new criteria for demonstration projects that go beyond the criteria articulated in the Track One Order.

Discussion

As noted in the Track One Order, demonstration projects are intended to inform decision makers related to developing DSP functionalities, measure customer response to programs and prices associated with REV markets, and determine the most effective implementation of DERs. The Track One Order also outlined a wide range of criteria, including the partnerships between utilities and third-parties and the potential for new revenue stream opportunities for both, deployment of advanced distribution systems, and testing of various rate designs. As demonstration projects, they are intended to test new technologies and approaches to assess value, explore options, and stimulate innovation before committing to full-scale implementation.

Utilities should discuss relevant current and near-term demonstration projects in their DSIPs, including how these projects are informing decisions on how to achieve specific DSP functions, DSP goals, and state energy objectives. Our primary objective is to integrate third-party participation and investment with DSP functionalities. The utility should seek to incorporate positive demonstration results into the DSIPs. New project ideas or proposed changes to existing approved demonstration projects may be discussed in the DSIPs, but will be decided based on the existing process used for demonstrations that is external to the DSIPs. Additionally, the State is establishing a central forum entitled REV Connect. REV Connect will accelerate the ability of technology suppliers, entrepreneurs, and utilities to identify innovative and sustainable market enabling solutions that meet defined needs of consumers, communities, and utilities. The utilities should take advantage of REV Connect in leveraging other demonstration projects for their own use.

D) Content Requirements for DSIP Filings

The achievement of environmentally and economically efficient electric power through self-sustaining markets and market regulation is the ultimate goal of REV. To accomplish that objective, utilities and third-parties must first identify, develop, and integrate the systems and investments required for a truly dynamic and transactive distribution system. As in any market, however, potential investors in DERs or other investments that can enhance the value of the grid require meaningful and timely information on the needs of the system so that they may in turn seek investment opportunities that support customer desires and/or enhance the value of the system. The requirements for what is contained in the DSIPs are focused on addressing these first steps and establishing new processes to promote the elements of REV.

The Initial DSIPs will require the utilities to provide a base level of data, including information related to forecasts, planned investments, and operating systems, and a description of their system planning practices. It is intended that sharing such information will allow third-parties to evaluate where and to what extent their services may be used to enhance the distribution system. These Initial DSIPs will also identify the limitations of current utility operations and the tools that can and should be developed to reliably operate a distribution system with high DER penetration levels.

In addition to system information, customer data collection and sharing is necessary to enable DER suppliers and customers to make investments and effectively participate in DER markets. To contribute to improved data sharing and collection between utilities, authorized third-parties, and customers, the DSIP filing should identify available customer data and common methodologies to collect and share data.

The Supplemental DSIP filing, unlike the Initial DSIPs, is intended to provide common approaches or resolutions necessary to operate in a dynamic environment. Outcomes of the Supplemental Filing would be applied to all distribution utilities, such that developers and third-parties would be able to interact and obtain information in the same manner, regardless of the underlying utility. This will allow consistency in business making decisions and easier entry into all areas of the State. The development of the common planning and operational tools and processes needed going forward must reflect extensive stakeholder engagement to provide the best chance of success. The Supplemental DSIP filing must recognize how the processes to be established will be able to adapt to increases in DER deployment, changes in technologies, and other advancements as the distribution grid continues to evolve. It is expected that the level of utility modernization and DER deployment rates will vary, and that the principles and approaches outlined in the Supplemental filing will not adversely impact appropriate advancement. This balancing between generating new products and service offerings quickly and having them developed and presented under a common, standardized method is a task that will need to be consistently assessed. That said, we recognize the pace of change and adaptation may vary with each company and that the requirement for commonality should not delay implementation by individual companies.

The Supplemental DISP also presents the opportunity for the utilities to collaborate in the development of initiatives that will have the effect of reducing carbon emissions, including de-carbonizing the transportation system. One such opportunity that should be addressed in the Supplemental DSIP is planning for, and enabling increased deployment of, electric vehicle supply equipment (EVSE). The market growth of plug-in electric vehicles (PEV) will be enhanced by the State’s PEV deployment goals resulting in increasing demand and adoption of PEVs and the corresponding need for EVSE will likewise increase.

Coordinated statewide approaches by the utilities will directly contribute to market development and decreases in carbon emissions. In addition to new demand on the system resulting from PEV charging service, issues related to vehicle-grid integration will have direct impact on utility operations and planning. Therefore, it is appropriate for the utilities to include consideration of EVSE deployment as part of the DSIP process.

While PEV and corresponding EVSE market conditions may vary across the state, early planning should identify and address collaborative initiatives that can set the stage for accelerated market growth. The collaborative planning may also be supplemented by individual utility initiatives, consistent with the collaborative planning for the deployment and integration of EVSE in their service territory.

The required engagement plan should also include a description of plans to coordinate and engage with stakeholders including the industry and municipalities in investigating and developing their EVSE deployment approaches or proposals.

The DSIPs required by this Order are the first steps toward ensuring the requisite information on system requirements is available, on a timely basis, to all market participants. The processes necessary to facilitate market entry and to identify future investments that the utilities should make to increase the capacity of the system and integrate increasing levels of distributed resources that can make the grid more efficient, reliable, and resilient are also identified in this Order. The following subsections discuss specific content requirements with regard to distribution system planning and distribution grid operations. All of the content requirements, in a more detailed form, for both the Initial and Supplemental DSIPs are itemized and presented in Attachment 1 to this Order.

1) Distribution System Planning

In the Initial DSIPs, utilities should describe current distribution system planning practices, including forecasting methodologies, and selection and prioritization of projects to address system needs. In addition, the Initial DSIPs should include a base level of system planning data and information that will allow DER providers to make economic decisions regarding best locations for future DER investments. As discussed in more detail below, utilities need to provide in the Initial DSIP filings information including current five year capital investment plans as well as an initial assessment of the capability of the distribution system to accommodate and host DERs, including identification of specific locations within the distribution system that are the highest priority for distribution capacity and operational relief. Additionally, utilities should provide current hosting capacity data and a standard definition of hosting capacity that will serve as the basis for a standard hosting capacity methodology to be developed for filing in the Supplemental DSIP. Granular substation and feeder level data should also be provided, recognizing that, due to the disparate nature of data acquisition system equipment deployment across utilities, the full range of system data is not likely to be available at this time. However, utilities should identify those data gaps and plans to address system data collection and sharing.

a) Forecast of Demand and Energy Growth

Accurately forecasting the demand growth, which contributes to distribution system peaks, is necessary for utility planning and the efficient subsequent adoption of DERs. The Guidance Proposal would require the utilities to include in their Initial DSIP filings annual peak demand, peak day load shape, and energy load forecasts for each of the next five years at the company-wide level; peak demand and load shape forecasts for the next five years at a substation level; identification of the impact of significantly increased DER penetration on the methodology used for regional and system-wide forecasts; an explanation of how the forecasts were derived and why the utility uses that methodology; and, a description of how to ensure accuracy of forecasts as DER penetration levels increase.

Comments

Commenting parties were generally supportive of the Guidance Proposal, but further insist that utilities must explicitly state all underlying assumptions related to growth scenarios and modeling uncertainties. NY-BEST argues that, due to this uncertainty, the DSIPs should place a higher value on “optionality” of DER. NY-BEST further argues that the utilities should build a higher degree of uncertainty into the planning process, and should include an analysis of multiple scenarios incorporating the value of other energy sources (specifically, energy storage). EDF believes utilities should develop multiple DER growth scenarios based on different degrees of DER deployment, and each scenario should take into account the storage capacity and amount of DER deployed. Acadia argues that the utilities should be required to include forecast sensitivities and a comparison of prior forecasts against actual results, as well, to assess their effectiveness in predicting actual results. NYC comments that the utilities should incorporate both utility-related and consumer-driven DER projects into their system planning and forecasting efforts. The Joint Utilities recommended that due to processes still needing to be developed, efforts on forecasting is one topic that should be moved from the Initial DSIP filing to the Supplemental DSIP filing.

Discussion

Initial DSIPs should describe the utilities current forecast methodologies and include granular forecast data. Accurate substation specific forecasts will enable more efficient capital planning by both utilities and DER providers. To the extent that some data for substations and further down the distribution infrastructure is not available for some utilities, those utilities should identify what data is available at the time of filing. The initial DSIP should also describe the utility's plans to expand and provide the data across the service territory, explaining the process for categorizing the information (by location, size, etc.) and making substation level forecasts available to outside stakeholders. The utilities' data processes need to recognize the intention that more granular data and forecasts will be needed in the future to identify beneficial locations for DER.

The utilities should also discuss in the Initial DSIP the impact that significantly increased DER penetration will have on the methodology used for regional and company-wide system forecasts and describe how new DER-related factors will be reflected in load forecasting models. In addition, the utilities should explain how the forecasts were derived (e.g., performing a top-down analysis of a company-wide peak forecast and/or a bottom-up aggregation of substation level peak demand forecasts) and why the utility uses that methodology. The utilities should explain whether the combined use and synchronization of both top-down and bottom-up methodologies could produce increased accuracy of company-wide and substation-specific forecasts cost-effectively. In the stakeholder process, utilities should discuss incorporating DER providers' forecasts into the utility forecasts, which will ultimately result in more robust and accurate forecasting.

With respect to Acadia's comments, the Commission agrees that, in future DSIPs, the utilities should 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. With respect to NYC's comment, though it is critical that the utilities begin incorporating DER adoption in their system planning process, the recent Benefit Cost Analysis Order (BCA Order) has widened the scope of projects that are put through a screening process and, as such, forecasts should follow a stochastic, or probabilistic, methodology rather than a deterministic methodology.[8] This may result in the need for additional tools, systems, or processes to manage the data and arrive at appropriate methodologies. Ultimately, quality forecasts, with data as granular as possible, which take into account demand-drivers as explanatory variables, will lead to more optimal investment decisions by the utilities and DER providers.

b) Available DER Resources

The Guidance Proposal suggests that the utilities describe what resources will be available, both DER and traditional delivery infrastructure, as part of the Initial DSIP filing. The utilities would be required to: (1) describe the process for gathering information from DER providers, other stakeholders, and other available resources to enhance forecasts of expected DER performance and penetrations levels over time; (2) identify the specific expected contribution to peak load, energy reduction, and load shaping for each type of DER resource for the next five years; (3) explain how the utility will

[8] Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

incorporate the impacts on peak load, energy reduction, and load shaping for each DER resource into its planning process; and, (4) describe the details of other procedures and/or programs which it may implement to increase the quantity and value of DER resources.

Comments

SolarCity proposes that the utilities should be required to define specific desired available resources and new tariffs for DER resources, as well as describe the details of other programs and procedures to increase the quantity and value of DERs. EDF proposes that the utilities should define concrete plans for increasing DER deployment for underserved low- and moderate-income (LMI) customers. In response to EDF's proposal, the Joint Utilities assert that it is premature to include such a requirement for DER deployment in LMI communities given the numerous other proceedings in which such issues are being concurrently developed and further note that demonstration projects provide an opportunity to test effective LMI customer participation in DERs.

Discussion

The Guidance Proposal recommendations regarding the provision of information related to available DER resources and how that information will be gathered and reflected in the utilities' planning processes are adopted. The utilities should also describe existing and future plans and programs to increase the quantity and value of DER resources. Utilities should include in their DSIPs any demonstration project results related to data for increasing DER resources, including adoption in LMI communities, to the extent that such data exists at the time the DSIP is filed. The Commission is committed to ensuring that fair and effective access to DER resources and programs remain a central component to REV implementation. In our approval of the

Clean Energy Fund (CEF) Framework, the Commission assigned to New York State Energy Research and Development Authority (NYSERDA), Staff, and the newly-created Clean Energy Advisory Council the responsibility of identifying the barriers to, and opportunities for, DER access by LMI communities.[9] We also established a set-aside in the Community Renewables Order for LMI communities. While the DSIP is not the right forum to develop concepts, we will require utilities in the Supplemental and future DSIPs to provide any information that could support achievement of our LMI access and penetration goals.

The Commission also agrees with SolarCity that procurement programs and pricing methodologies for valuing DER are essential elements of REV. The Commission is addressing these issues through the CEF implementation, Track Two of REV, and specific DER pricing dockets.[10] The role of the DSIPs is to ensure effective implementation of these decisions, but is not the venue for their development. The desired outcome of these proceedings is for market participants to have the requisite information such that they may make investment decisions with a high degree of confidence of their value and, overtime, have the benefit of an increasing liquid market. The DSIP process should facilitate these goals by providing necessary information to market participants. To that end, the utilities shall develop a standard process to effectuate communication between the utilities and DER providers to identify opportunities for DER deployment, and coordinate information regarding the DER providers' upcoming projects and any impacts such projects might have on the utility grid.

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[9] Case 14-M-0094, Clean Energy Fund, Order Authorizing the Clean Energy Fund Framework, (issued January 21, 2016).

[10] See, Case 14-M-0224, Community Choice Aggregation; see also, Case 14-M-0094, Clean Energy Fund.

c) Delivery Infrastructure Capital Investment Plans

The Guidance Proposal recommends the utilities provide the following as part of their Initial DSIPs: (1) identification of current reliability planning criteria; (2) a description of the current capital budgeting process and an explanation of how the process integrates and considers DER installed on the utility's distribution system; (3) five-year historical spending amounts for transmission, substation, and distribution infrastructure, as well as information technologies, communications, and shared services; (4) five-year forecast capital budgets for the same categories as above, as well as details on upgrades required to support DSP capabilities and projects where DER has the potential to impact project needs (including projects which would need to move forward regardless of DERs); and, (5) identification of the driving factors and mitigating techniques considered, included, or rejected (and an explanation of why such techniques were rejected) for areas where there are large changes between the historic, current, and future spending amounts.

Comments

NECHPI notes that discussions on grid modernization and reinforcement investments are critically important. NECHPI also points to how presenting incremental investments in these areas allow stakeholders to evaluate assumptions made by the utilities to enable and support expanded DER. Exelon disagrees that utilities should present capital budgets for stakeholder and market participant review, stating that provision of this data as part of the DSIP process would be redundant with rate cases and other regulatory processes. Replying to Exelon, EDF states that providing this data as part of the Initial DSIP would not be duplicative. IREC notes that utilities should be required to justify their delivery infrastructure capital investment plans in their DSIPs, including details on how their proposed distribution infrastructure upgrades support the improved integration of DER and identify transmission and distribution projects where energy storage, in particular, could impact project needs. The Acadia Center notes that the utilities should be directed to investigate how strategic DER deployment would mitigate aging infrastructure replacement costs. Also, parties debated whether the utilities should be required to include plans for upgrading circuits where hosting capacity is near or at its limit. The Joint Utilities did not comment on the Guidance Proposal's recommendations on infrastructure capital plans.

Discussion

Improving the timing of information flow is critical to the success of REV. It is not efficient, and frequently ineffective, to rely on rate cases as the first venue to raise the potential for non-wire alternatives. By the time a capital project is presented in a rate filing, the need for the project may be imminent and it will often be too late to develop effective and reliable non-wire alternatives. This results in unnecessary litigation in the rate case with an unsatisfactory result.

The Guidance Proposal suggestion to include delivery infrastructure capital investment plans in the Initial DSIPs is adopted. This includes identifying the impact DERs may have in order to defer or eliminate transmission and distribution projects. Exelon's argument that the utilities should not include their capital budgeting information in the DSIP is unpersuasive. While there is some overlap between the data that will be required as part of the Initial DSIP and the data that is provided as part of rate case proceedings, the data presented in the Initial DSIPs will help third-parties develop the business case and value proposition in both areas on the utility system where DER penetration is particularly valuable and elsewhere where future utility plans may impact DER investments. The DSIP process is a better vehicle for examining the company's capital projections and refining the identification of system needs and potential alternatives. The input from the parties in the DSIP process would inform and help utilities refine their capital plans that they file in rate cases.

d) Beneficial Locations for DER Deployment

The Guidance Proposal calls for the utilities to identify locations on their systems where DERs would be most valuable. Specifically, the utilities should include a plan to reveal (spatially and temporally) more granular (further disaggregated zonal) wholesale energy prices. Additionally, the plan should identify specific areas in the utility footprint where DERs would provide benefits to the distribution system. These include areas where there is an impending or foreseeable delivery infrastructure upgrade need where DERs would have a delivery infrastructure avoidance value; where DER may provide reliability or operational benefits; or, where there is no forecast delivery infrastructure need for years to come and hence the infrastructure avoidance value of DERs is likely to be lower or insignificant in the short-term. It should also include a list of specific infrastructure projects by location, and description of the process used to identify the projects where DER solutions should be compared as potential alternatives to traditional grid infrastructure under varying scenarios of DER integration, and describe how the utility will use the BCA Handbook for performing the comparative analysis of substituting DERs to defer infrastructure investments. Further, the filing should describe a proposed process for collaborating with stakeholders to develop and implement ways for various DERs to be substituted for traditional grid-based solutions in order to avoid or reduce utility capital or operating costs.

The Guidance Proposal also noted that the utilities must make operational system data available to enable suppliers to make investments and develop products to meet customer needs and state energy policy objectives. Since the Initial DSIPs are intended to focus on making utility system data available and providing locations where DERs would have system value, Initial DSIP filings should describe the extent to which system data is currently available for sharing with third-parties. In addition, Initial DSIPs should include plans to expand collection of granular system data, the process for making data available to stakeholders, and a discussion of plans to efficiently use technology to increase the availability of granular data.

Comments

Commenting parties support varying levels of information related to optimal locations and levels of DERs. Some parties suggest that the utilities should direct customers and providers to high-value locations, where DERs can interconnect with minimal or no system upgrade requirements. Others argue that the utilities should indicate what level and types of DERs would provide value in each area. Some parties argue that the utilities should go further and also share their analyses and rationale for traditional infrastructure investments and for DERs, including a complete description of the potential for cost-effective DERs, by technology type and customer sector, allowing stakeholders to provide input regarding where the utilities plan to place these assets, as appropriate.

The Joint Utilities recommend that the Commission adopt the four-part screening process for identifying areas for non-wires alternatives that was proposed and rejected in their initial comments to the Staff BCA Whitepaper.[11] They also state that there is an inherent tension between providing as much information as possible as soon as possible to inform DER locational value and the fact that the models and data necessary to support increased DER penetration do not yet exist.

NYC contends that there are many ways in which DERs could provide value to consumers and that the utilities' obligations to provide information should be expansive, not narrowed to areas where DERs would be justified by wholesale energy prices or may provide reliability benefits. NYC further states that all salient information should be disclosed to the marketplace such as, but not limited to, the nature of the expected needs and the ability to rely on alternatives to traditional infrastructure. IREC comments that DSIPs should include details on how utility proposed distribution infrastructure upgrades support the improved integration of DERs.

Regarding system data acquisition and sharing, commenting parties urge that clear and consistent statewide rules regarding system data are needed. NYC notes that neither the Guidance Proposal nor the Track One Order provide any guidance to the utilities with respect to data acquisition and sharing, which could allow each utility to develop different data access rules. Accordingly, parties suggest establishing rules regarding the data to be made available, the manner in which such data will be made available, the frequency of updates

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[11] Case 14-M-0101, Reforming the Energy Vision, Staff White Paper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (filed July 1, 2015).

and releases of the data, and the cost, if any, to be charged for the data.

IREC requests that the Commission require more granular information from utilities to identify specific expected contributions to peak load, energy reductions, and load shaping at the system-wide level and, at least, at the substation level. NRG adds that, to attract DERs to the circuit, the distribution system must incorporate sensors and data acquisition systems that identify which DERs will most effectively optimize the system. This system can then send signals to DER providers about the specific types of functionality and technologies that can best meet system needs, while enhancing customers’ value from owning or leasing DERs.

The Joint Utilities recommend that, rather than providing raw system data, they provide DER providers with insightful information. Since distribution system data is not self-explanatory, it must be considered in the context of the local system design criteria, normal and contingency configurations, distribution assets ratings, circuit routing, potential security concerns, and local knowledge of operational performance. The Joint Utilities believe that, without such insights, the use of raw system data would lead to inefficient distribution planning. The Joint Utilities also believe such insightful information will provide significant value to DER providers. This value will become increasing vital as DER penetration grows and the system becomes more complex and dynamic. By providing information instead of raw data, concerns of data security and data sensitivity can be more readily managed. Finally, the Joint Utilities believe that our guidance should acknowledge the primary obligation of utilities is to provide reliable service, including addressing physical security, cybersecurity, and privacy requirements for recipients prior to providing certain customer and system data.

Discussion

The goal of utilities defining areas with higher value will allow for the development of projects that would likely result in positive BCA analyses. Developers require information on system needs in order to offer innovative solutions. The utilities should provide the information necessary for developers to offer solutions that can improve the efficiency of the system and add value to customers. While the distribution systems are not the same, and recognizing that data and information access is uneven at this point, the utilities should begin to offer as much information as is readily available to begin the process of supporting optimal DER investments.

Initial DSIPs, therefore, should include identification of specific areas in each utility's footprint where there is an impending or foreseeable delivery infrastructure upgrade need and where DERs would potentially provide delivery infrastructure avoidance value or where DERs may provide other reliability or operational benefits. Consistent with the transmission and distribution capital investment plans, the utilities should list specific infrastructure projects by location and indicate the potential for DER to resolve or mitigate forecasted system requirements, including the level of output needed over specific time periods. The utilities should also describe the process used to identify the projects where DER solutions should be compared as potential alternatives to traditional grid infrastructure under varying scenarios of DER integration. In their comments concerning the

Benefit Cost Analysis Framework,[12] the utilities proposed a four step screening process. In the BCA Framework Order,[13] the Commission ordered the utilities to use a broader, more flexible screening process than the one proposed. The utilities should propose such an improved screening process in their Initial DSIP filings, addressing the concerns expressed by the Commission in its BCA Framework Order.

Initial DSIP filings should also explain how the utility expects to maximize the integration of DERs in such beneficial areas to avoid making unnecessary investments. This open process is expected to promote utility/stakeholder relations, enable third-parties to provide cost-effective market solutions to identified energy needs, and drive consumer value related to the regulated distribution system. The utilities should actively collaborate with Energy Service Companies (ESCOs), DER providers, and other stakeholders in developing its plan. Educational efforts should be designed to increase acceptance, improve system utilization, and ease implementation issues. In the process, utilities and providers will gain understanding of the services that customers desire and are likely to utilize, and the DSPs role in enabling third-parties to provide those services.

The stakeholder process should also consider the Joint Utilities’ proposal that they will provide DER providers with insightful information instead of raw system data. Sharing system data with third-parties will ultimately result in innovative decisions for both the third-parties and the

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[12] Case 14-M-0101, supra, Initial Comments of the Joint Utilities to Staff White Paper on Benefit-Cost Analysis (filed August 21, 2015).

[13] Case 14-M-0101, supra, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) (BCA Framework Order).

utilities. Accordingly, barriers to DER entry need to be removed. Addressing the information imbalance that currently exists will help remove such barriers. Today, there is very little information available to DER providers regarding the value of, or cost to, site resources in any particular area of the distribution system, or what type of resources or operational characteristics would have the most value. The system data supplied should bring together the information that DER providers will need to locate resources in areas of the system that will produce the most value. Utilities should work with stakeholders to address the types and level of data to be provided, the methodology and rules for providing system data (including addressing security concerns), and frequency of updates. The Supplemental DSIP process should define the base level of data available to customers, including DER developers, at no cost.

While it is imperative that utilities provide system data and information to DER providers and customers, security concerns relating to the electric transmission and distribution system must also be addressed. Appropriate controls to secure data are needed, and those controls must be consistent with standardized requirements. Utilities should consider increasing and improving cybersecurity protection measures for network monitoring, setting passwords, and expanding remote access. Although distributed resources have the potential to increase system resilience, security protections must be in place to protect the integrity of the grid as the DSP platform continues to incorporate more non-utility assets.

Protecting the grid against breaches has been, and will continue to be, an ongoing effort. Utilities should continue to address security issues through existing working groups and in concert with leading cybersecurity authorities, such as the North American Electric Reliability Corporation (NERC), the National Institute of Standards and Technology (NIST), and other related agencies, to develop rules and protections and to stay informed with respect to evolving cybersecurity threats and available defense measures. In addition, utilities should stay abreast of developing privacy and cybersecurity technology, and incorporate such technology into their systems to maximize protection against cybersecurity threats. The plan and timeline for system data sharing in the Initial and Supplemental DSIPs should reflect these concerns and considerations, while at the same time taking into account stakeholder input.

With respect to the comments submitted by IREC and the Joint Utilities, many of the operating tools and functionalities required to incorporate and rely on large scale DER deployment to promote public policy outcomes, including the requisite algorithms and software solutions to price the marginal value of DER as efficiently as practicable, are either immature or incomplete and should be developed collaboratively. Therefore, utilities should work with the NYISO to develop a methodology for revealing subzonal wholesale Locational Marginal Prices (LMPs). This will serve as the base for developing LMP+D or the market prices to be paid to DER providers based on their location on the system and output over time. The DSIPs should be consistent with the efforts concurrently being discussed in Case 15-E-0751, the Value of DERs Proceeding.

e) <u>Hosting Capacity</u>

Information related to hosting capacity (the amount of DERs that the electric distribution system can reliably accommodate without material utility system upgrades) would play an important role in the development of an integrated and efficient grid. The Guidance Proposal would require utilities to define initial utility activities related to hosting capacity as part of the Initial DSIP filing, and, in the Supplemental DSIP, set forth a standard approach, including how information will be shared with market participants and stakeholders.

Comments

Several parties suggested that hosting capacity be analyzed using a common methodology on a circuit-by-circuit basis. It was debated whether utilities should be required to communicate the results of hosting capacity calculations for all of their circuits and locations, or just those circuits and locations that are experiencing problems or are of high value. The parties also considered whether to require utilities to provide plans to upgrade circuits in their respective service territories nearing their hosting capacity limits.

The Joint Utilities propose that defining a methodology for determining hosting capacity is something that would be analyzed and presented within the Supplemental DSIP. Further, the Joint Utilities propose that the hosting capacity analysis focus on distribution feeder backbone facilities on radial systems, noting that estimating hosting capacity for looped and network designs is much more complicated and capabilities for this analysis need to be developed. The Joint Utilities disagree with SEIA that plans should be defined to upgrade each circuit nearing hosting capacity limit, and instead propose to work with stakeholders to identify optimal means of enabling DER.

Discussion

The understanding of the capacity of the distribution system to safely host DERs is an area where an effective DSP must become particularly proficient. The Commission anticipates that this understanding will grow as utilities gain experience with the various uses of DERs and as both utilities and developers are financially motivated to increase circuit hosting capacity and productivity using better information, pricing, and safe operation techniques to reduce, delay, or eliminate the need for more expensive upgrades. We also expect that, concomitant with these operational changes, control management tools will be developed and implemented to support higher levels of situational awareness and dynamic system management.

In the Initial DSIP, the utilities shall adopt a common definition for hosting capacity and provide known hosting capacity data for all circuits in their service territories, regardless of whether the circuit presents a high- or low-value proposition and the level of remaining hosting capacity on such circuits.[14] The utilities should also specify their approaches for calculating hosting capacity. As part of the Supplemental filing, the utilities should examine the information tools that are either available today or can be made available to increase hosting capacity, both from a planning and operations perspective. The Commission anticipates that as the utilities gain greater understanding of actual, as opposed to perceived hosting capacity, this information will be updated. Accordingly, through the stakeholder processes and Supplemental filing the utilities should develop the common methodologies they will use to determine hosting capability, the system information that will be available to support investment decisions, and the proposed frequency that the DSP will use to update this information as they gain experience or make new investments. At a minimum, the utilities shall establish a hosting capacity map that will be available to DER providers, as

[14] For the purpose of this Order, the circuits refer to both radial and network systems. With respect to network systems, utilities are expected to identify hosting capacity data on a sub-network, granular basis such as at the network transformer level.

well as provide detailed reports describing the issues faced by problematic circuits. The map should also present relevant system information for distribution substations, such as capacity ratings and loading data.

Utilities are also specifically directed to consider emerging technologies that can be used to increase the hosting capacity on a circuit, such as that currently being evaluated in the Avangrid Flexible Interconnect Capacity Solution Demonstration Project, on an even footing with traditional utility infrastructure upgrades.[15] To that end, 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. These demonstrations can include expansion of existing demonstrations or new ones with a view towards gaining better understanding how specific approaches to developing or operating the system can cost-effectively and reliably increase the capacity of individual networks to host and use DERs as an integrated resource to a secure grid. As previously stated, proposals for new demonstration projects not specific to this requirement shall be filed separately using the existing process that is external to the DSIPs.

SEIA’s proposal that the utilities provide a plan to upgrade each circuit where hosting capacity is reaching or has reached its limit is denied. While the Commission supports increased DER penetration as a means to achieve the goals of the REV proceeding, any upgrades to the utilities’ distribution systems that will be included in rate base must, in and of

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[15] See, Case 14-M-0101, Reforming the Energy Vision, Flexible Interconnect Capacity Solution Demonstration Project Implementation Plan (filed January 11, 2016).

themselves, be cost beneficial and useful for system reliability and security. The costs of investments that are only necessary to support market transactions should not be imposed on non-participating consumers. We recognize, however, that many times the determination of need is complex and investments made for one purpose can address multiple needs. Thus, as part of their Supplemental planning process, the utilities should propose approaches they will use when requested by developers to upgrade circuits to increase hosting capacity on particular circuits to support increased DER, as opposed to known system reliability needs and mechanisms that can be applied to support these investments that can benefit both the development of the market and consumers.

f) Probabilistic Modeling and Load Flow Analyses

As utilities shift toward integrating increasing amounts of DERs into their systems, they will be relying upon these resources to complement energy procurements from the wholesale market. The nature of these DERs and associated properties with respect to intermittency and various levels of reliability, however, need to be integrated into the planning process. Therefore, the Guidance Proposal recommends that the utilities identify a process to move from deterministic to a probabilistic modeling approach for distribution system planning. Similarly, the Guidance Proposal recognizes the need for load flow analyses to incorporate the DERs effects on the system.

Comments

NY-BEST recommends that the utilities recognize the high degree of uncertainty with the planning process and suggests utilities’ DSIPs contain analyses of multiple load growth scenarios, appropriately value the “optionality” of DER, and incorporate the flexibility of energy storage. The Joint

Utilities believe that certain planning functions to be contained in the Supplemental DSIP may not be resolved by the time of the filing, but meaningful progress could be made and described in the Supplemental DSIP. The Joint Utilities note that resolution would take additional time due to the extraordinary nature of the issues and limited experience to draw from, including other jurisdictions.

Discussion

Utilities need to recognize and determine a means to maximize the benefits of DER and integrate these benefits into their planning processes. By incorporating approaches to modeling assets with uncertainties in the Supplemental DSIPs, utilities and stakeholders can identify commonalities across the utilities. In addition, utilities and stakeholders will be able to leverage collective knowledge to perform reasonable load flow modeling to be used in utility planning processes. Therefore, the Guidance Proposal recommendation that the Supplemental DSIP discuss these topics is adopted.

As previously discussed, utilities need to recognize the benefits numerous DERs offer as part of the planning and energy procurement process. Probabilistic modeling accounts for, among other things, the intermittency of certain DERs. As various DERs continues to be deployed, the use of new modeling approaches will be necessary to operate in a proficient manner while maintaining the overall reliability of the grid. It is expected that work in this area will continue to progress and that utilities would seek to incorporate methodologies that minimize inefficiencies and overall costs.

2) Distribution Grid Operations

As discussed in more detail below, the Initial DSIPs related to systems operations should include all available system operations information and a detailed plan to supply additional information in the future. Supplemental DSIPs should contain plans to further expand monitoring capabilities for data collection, communications, and information technology systems to support anticipated data and analytical needs as a DSP. They should also include details on distribution infrastructure upgrades to support DSP capabilities. The utilities should engage in a stakeholder process to seek input on the development of standard communication protocols for monitoring and control of DERs. The utilities should also move forward and include in the Initial DSIPs descriptions to implement voltage and VAR control in the near- and long-term, as well as how third-parties can interact and provide voltage and VAR control services. Utilities shall comply with the Track One Order requirements that DER interconnection procedures be streamlined and distribution automation be expanded. Such improvements must be reported in the Initial DSIPs. Supplemental DSIPs should include a proposed interconnection plan, developed through stakeholder engagement, as well as a timeline to implement the proposed improvements.

a) <u>System Operations</u>

The Guidance Proposal notes that utility distribution grid operations will continue to evolve to incorporate increased levels and types of DERs. Furthermore, the utility must incrementally enhance the distribution system into an intelligent, automated, and animated system focusing initially on monitoring, observability, coordination, and control. To that end, the Guidance Proposal lists system operations topics that should be included in the Initial DSIPs, including effects of increased DER penetration on the ability to serve customers, changes to existing policy and processes to ensure that safety and reliability are maintained or improved, visibility and communications protocols to observe and interact with DER providers, operational needs during normal operations and during outage events or periods of system stress, reliability-enhancing protocols, and plans to maintain cybersecurity.

The Supplemental DSIP should include a plan and budget for communications and information technology infrastructure, as well as expand upon the required cybersecurity protections. The Guidance Proposal also recommends the Supplemental Filing address the responsibilities and interaction between the utilities and the NYISO.

Comments

NRG believes that the DSIPs should focus on utility ownership and operation of sensors and analytics that identify system needs and convey that information to competitive DER owners and service providers. NRG, however, indicated that utilities should not maintain exclusive control of the systems that control and operate DERs.

NYPA recommends using its electric power research and development facility to assist the utilities in carrying out REV initiatives. The goals of the facility are to help distribution and transmission operators reduce system strain during peak use, enhance load and distribution network monitoring, improve distribution system planning, and expedite renewable resource integration and deployment of DERs.

CEOC advises that technical conferences should be initiated to investigate scheduling coordination between the NYISO planning process and the DSIP process. However, NYC believes that the NYISO has neither a role in, nor authority over, retail marketplace matters, and is not within the scope of the REV goals, principles, or objectives. NYC contends that though it makes sense to consider interactions between the wholesale and retail markets, that process should be open to all market participants.

The Joint Utilities recommended that coordination with the NYISO focus on demand response procurement and that topics related to the integration of DER markets with NYISO markets should be addressed after the Supplemental Filing. CEOC notes the utilities' DER planning activities should be conducted within a timeframe that allows the information to be incorporated into the NYISO's reliability planning process.

Discussion

Increased automation, monitoring for data collection, control, and standards will be integral to grid operation with increased levels of DERs. As the Guidance Proposal noted, initial activities should be focused on monitoring, observability, coordination, and control. The utilities must first make a thorough evaluation of their existing systems to determine what modifications are needed to ensure such incremental advancement. As time progresses, the complexity of systems used to monitor and control DERs will only increase, as will the necessary standards. In the long-term, the utility must progress to equip the distribution system with adequate monitoring and communication infrastructure. This infrastructure will enable intelligent, rapid, and precise control, deploy automated solutions across the system, and facilitate transactions for grid services via an animated market.

Staff's list of system operations topics produced little controversy. Accordingly, the utilities should include the system operations topics outlined in the Guidance Proposal in their Initial DSIPs. In addition, the utilities should describe their existing programs, tools, and processes to ensure or address cybersecurity, as well as their plans to increase and improve such measures. Reflecting a commitment to protect sensitive data and the integrity of the grid, such future plans should outline an evolving cybersecurity program wherein the utilities incorporate new and improved technologies and information made available by cybersecurity authorities regarding potential threats and available countermeasures. The operational details required to meet this requirement will continue to evolve, and if the information is not available by the Initial DSIP filing deadline, the utilities should provide all available information and a detailed plan to supply this information in the future.

Supplemental DSIPs should contain plans to further expand monitoring capabilities for data, communications, and information technology systems to support anticipated data and analytical needs as a DSP, including an explanation of the basis for the selected approach and forecasted budgets. They should also include details on distribution infrastructure upgrades to support DSP capabilities (e.g., low-cost, high-resolution sensors that enhance system visibility and increase option value, power flow controllers, or solid-state distribution transformers for meshing radial networks or interfacing with microgrids). In order to expand upon this process, utilities should engage in a stakeholder process to seek input on the development of standard communication protocols for monitoring and control of DERs.

With respect to the roles, responsibilities, and interactions between utilities and the NYISO, it is expected that the Supplemental DSIP will begin to define the obligations and actions that will be needed to ensure seamless and reliable operations of a dynamic transmission and distribution grid.

b) Volt/VAR Optimization

The Guidance Proposal suggests that the utilities include in their Initial DSIPs: 1) plans to implement volt/VAR optimization (VVO) in the near-term, and over the long-term; 2) how third-parties can interact and provide VVO services; and, 3) an evaluation and discussion of the costs and benefits of upgrading VVO capabilities, including how new VVO capabilities fit in with the evolving grid.

Comments

EDF notes more direction should be provided to the utilities regarding the development of VVO implementation plans so that stakeholders are able to conduct simple analyses and establish their positions on investment proposals. Specifically, EDF mentions that utilities should provide information on the current state of adoption of VVO in their service territories, as well as be directed to conduct feasibility studies on their respective distribution systems for the implementation of VVO. DVI suggests utilities should also include an evaluation of the comparative costs and benefits of different technology approaches in mapping out their near-term and long-term implementation of VVO, as well as a benefit cost analysis that considers the value of technologies that serve cross-functional purposes. In addition, NY-BEST suggests that the utilities should be required to identify compensation mechanisms for VVO.

Noting that the Guidance Proposal indicated the utilities would continue to be required to operate the grid in a safe and reliable manner, NYC states the DSIPs should require utilities to conduct an analysis to demonstrate that VVO is consistent with each utility’s obligation to provide adequate and reliable service. NYC also points out that the utilities should be required to develop a reasonable set of communication protocols. AEEI noted it should be easy to incorporate new types of devices and services, especially if behind-the-meter activities become part of the clearinghouse for settlement. DVI notes that VVO technology that integrates voltage data from AMI provides greater energy savings and greater voltage stability on primary circuits hosting solar distributed generation.

Discussion

Staff's list of VVO topics produced very little debate. Accordingly, the utilities should move forward and include in the Initial DSIPs descriptions to implement VVO in the near and long term, as well as how third-parties can interact and provide VVO services. The following analyses should also be included in the DSIPs: existing VVO capabilities and technologies currently in use; a benefit cost analysis comparing upgraded VVO capabilities alongside current VVO capabilities; and, a discussion of new VVO capabilities and how they fit in with the evolving grid within the utility's service territory.

c) Interconnection Process

The Track One Order discusses the importance and need to improve the interconnection process to allow for the efficient expansion of DERs while maintaining safe operations. The Guidance Proposal reinforces the requirements contained in the Track One Order and requires a process for interconnecting DERs through an online portal in the Initial DSIPs. The process should include the status of current efforts, future plans, and how this function will be integrated into planning process improvements, and monitored to measure the effectiveness of the interconnection process, as well as plans for optimization of planning by modeling system impacts of DERs, risk assessments, and resiliency.

Comments

Commenting parties suggest that the DSIPs include methods to improve the timeliness of the interconnection process. In particular, SolarCity suggests performance targets and performance reports. Additionally, SolarCity stresses the importance of aligning utility financial interests with the goals of REV and suggests an earnings incentive mechanism (EIM) related to the interconnection process. SEIA states that the DSIP should indicate specific steps utilities should use to reduce time between application and interconnection, and supports the establishment of an EIM. NECHPI asserts that the proposed interconnection EIM metrics are inadequate, arguing that emphasis should instead be placed on instituting a collaborative stakeholder process to establish best practices for interconnection and on updating the state's Standardized Interconnection Requirements. The Joint Utilities suggest that an Interconnection EIM should not be discussed in advance of the Track Two decision. EDF believes that rewarding rapid interconnection of DG should not begin until rules are in place to protect public health and the environment from the emissions associated with these generation sources.

Discussion

In recent months, steps have been taken to facilitate the interconnection of DERs in New York. We have approved revised standard interconnection rules to take effect under all of the utilities' tariffs on April 29, 2016.[16] In partnership with NYSERDA, we have appointed a Staff ombudsman for distribution level interconnection issues to assist both developers and utilities and to identify opportunities for improving the interconnection process. In addition, an interconnection technical working group has been established to assist in resolving technical concerns and developing improved screening tools to determine grid impacts and solutions.

[16] Case 15-E-0557, Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less, Order Modifying Standardized Interconnection Requirements (issued March 18, 2016)

These actions will support the expansion of DERs, but utility engagement will remain essential. Therefore, utilities shall comply with the Track One Order requirements that DER interconnection procedures be streamlined. Such improvements must be reported in the Initial DSIPs. To the extent that the utilities do not have a live, fully functioning online interconnection portal in place by the time of the Initial DSIP, the utilities should supply plans that describe how the portal will be developed. In order to facilitate additional improvements to the interconnection process, prior to the Supplemental DSIP, utilities should engage stakeholders to offer input on improvements that could be made upon the information provided in the Initial DSIPs. Supplemental DSIPs should include a proposed comprehensive plan, developed through stakeholder engagement, as well as a timeline to implement the proposed improvements.

With respect to interconnection-related EIMs, the comments received from parties in the Track Two proceeding and on the Guidance Proposal are abundant and substantial. EIMs will be addressed in the Track Two proceeding.

E) Advanced Metering

Advanced metering offers many benefits to both utilities and customers due to its ability to capture and timely communicate data beyond simple energy usage. Such data includes the instantaneous demand, voltage, and power quality. The increase in granular data enables utilities to improve system design and provides visibility to impacted customers during outage events. Moreover, the use of advance metering will enhance a customer’s ability to manage their bill by providing them better access to disaggregated data, especially when compared to usage information provided on a monthly basis only. Advanced metering also allows for new rate designs and energy management products to be developed, as well as provides the support needed for customers to participate in future markets.

The Guidance Proposal notes that some level of advanced metering functionality is likely required in order to achieve REV objectives; but does not specify the technologies, ownership structures, and deployment strategies necessary to optimize AMI as a tool for achieving REV objectives. Instead, the Guidance Proposal requested that parties submit comments specifying the benefits advanced metering technology provides, including the functionality and required deployment levels to aid the Commission in determining how advance metering would best further REV goals. The Guidance Proposal specifically sought comments on a series of questions related to AMI and the underlying communications infrastructure.

Comments

Commenters generally support the use of AMI. Several parties, however, emphasize that a thorough analysis should be completed to determine the effectiveness of the AMI project. EDF recommends that utilities should not expect to implement AMI infrastructure without a deployment schedule of programs that justify the investments. Before taking action on AMI investments, MI suggests the utilities should be required to provide: (1) detailed proposals; (2) detailed cost estimates and associated delivery rate impact analyses; and, (3) detailed evaluation of customer benefits, including tangible cost savings. The Joint Utilities reasoned the extensive lessons learned on AMI should be leveraged. They also state the customer bill impact and the value resulting from deployment will vary based on the attributes specific to each utility’s service territory, including size, population density, customer demographics, and geography. For this reason, the Joint Utilities recommend that a positive business case should accompany any plan for wide-scale deployment of AMI within a utility’s service territory.

Commenting parties also generally believe the meter should be utility owned and operated. SEIA advises, however, that there is a danger that utility AMI deployment may stifle third-party innovation and that it will be important to create a level playing field relative to metering requirements, data protocols, and data access. SEIA encourages exploring a model where any provider of advanced metering functionality (AMF) receives payment for providing such functionality to the grid.[17] The Joint Utilities conversely note that cybersecurity risks increase with increasing diversity of technologies and ownership models used to collect the required data. IGS believes third-party meter installations would increase capital costs for DER projects and create additional cost recovery risks. IGS also states, to the extent third-parties are permitted to install and own advanced meters, it would be necessary to establish rules that would ensure that ESCOs and DER providers have non-discriminatory access to customer interval data, subject to appropriate customer authorization.

With respect to rate design and compensation, IGS states wide-scale deployment and additional rate design modifications for all customers are necessary to ensure that they receive appropriate price signals and incentives. EDF believes it is important that customer and third-party data access policies be addressed at the same time that AMI deployment plans are considered for funding. MI notes that AMI investments will trigger cost allocation and cost recovery

[17] AMF has the capabilities that AMI offers such as measurement and two-way communication but without prescribing any particular set of enabling technologies.

issues, and accordingly urges that each service class be responsible for its own metering costs.

Discussion

The deployment of AMI or equivalent advanced metering functionality will be an important contribution to enabling utilities to assume the role of the DSP. AMI will provide information that affords customers the opportunity to participate in demand response and energy efficiency programs, as well as innovative rate structures, allowing them to better manage electricity consumption and bills and drive overall system efficiencies. Additionally, AMI will facilitate customer access to value-added products and services provided by third-parties including DER providers and ESCOs.

In their Initial DSIP filings, utilities should include a summary of the most up-to-date AMI rollout plans over the next five years. Any AMI proposals made within DSIP filings, rate cases, or separate petitions, should be accompanied by a detailed business plan that, at a minimum, addresses the following elements: 1) plans and schedules for deployment; 2) new or upgraded data management, communications, billing or other backend systems to support AMI along with associated budgets; 3) proposed innovative rate structures; 4) a benefit-cost analysis consistent with the BCA Order; and, 5) customer rate impact analyses.

AMI plans should also be accompanied by a thorough customer engagement plan and incentives to manage costs and encourage the integration of cost-effective alternative solutions that may be offered by third-parties. Such plans should include a robust customer outreach and education program, both prior to and subsequent to any AMI rollout, designed to increase acceptance, ease implementation, and allow customers to make informed decisions, including participation in innovative pricing programs and other AMI-enabled programs. Utilities should collaborate with companies that specialize in consumer engagement, ESCOs, DER providers, customer representatives, and other technology providers in the development of customer engagement plans.

AMI proposals should include proposed metrics to measure the value associated with the AMI deployment. Metrics should include measurements related to customer engagement and participation in new programs, outage management and other system operations impacts, and environmental benefits.

Finally, with respect to meter ownership, as the Commission recently stated, third-party ownership will be allowed so long as the third-party complies with the utility's standards and is willing to incur any additional costs that is put on the system. Utilities should develop contract requirements for such services that include standards for interoperability, cybersecurity, maintenance, and technology specifications.[18]

F) Customer Data

The Guidance Proposal requests that utilities explain how customers can obtain information regarding their energy usage, including processes now available to customers as well as plans for future capabilities. The Guidance Proposal also requires that utilities explain how third-parties, with customer authorization, can now obtain information regarding customer energy usage and other customer-specific information, as well as utility plans to enhance those capabilities.

[18] Cases 15-E-0050, Proceeding on the Motion of the Commission as to the Rates, Charges and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions (issued March 17, 2016).

The Guidance Proposal invited comment on two specific questions:

- What should the Commission direct, beyond current requirements, in order to improve customer and authorized third-party access to the most granular data in as near real-time as possible; and,
- Specifically, what should the Commission direct in order to enhance Electronic Data Interchange (EDI) to facilitate customer and third-party access to standardized, machine-readable consumption data with industry leading protocols and practices?

To help further establish a record on these issues, Staff led technical conferences on customer data issues on December 16, 2015, and January 20, 2016. Several parties, including the Joint Utilities, noted that the final DSIP Guidance should be informed by these technical conferences.

Comments

Commenting parties agreed that customers, as well as authorized third-parties, should have convenient access to customer data and clear and consistent rules regarding the provision of data. NYC notes that the rules should address what data will be made available, the manner in which data will be made available, and the frequency of updates and releases of data.

Parties agreed that a common method of data exchange should be used, but had different suggestions for such exchange, including using the current EDI and Green Button Connect. The Joint Utilities note that the costs of Green Button Connect for functionalities beyond basic usage information have not yet been assessed.

Parties have differing opinions on charging for customer data. While some parties argue that utilities should be required to provide high-quality, real-time energy consumption data to both customers and third-parties to facilitate development and implementation of information-driven products and services, the Joint Utilities counter that charges for customer data may be appropriate when a utility provides incremental, “value-added” services or when a service is offered that not all customers are likely to take advantage of. Mission:data asserts that full deployment of AMI should include a condition that usage data is made available free of charge since providing that information is necessary to realize the value of AMI.

Discussion

Availability of, and access to, data is critically important to facilitate market transactions for DER providers to offer grid services to utilities. The technical conferences explored the advantages and disadvantages of alternative data exchange standards such as Green Button Connect, which is an existing protocol that enables customers to share their granular energy usage data with vendors they select. To be consistent with the recent Commission Order, each utility with AMI deployment plans must submit in their Initial DSIP a proposed implementation plan, budget, and timeline for implementing Green Button Connect or alternate standard that offers similar functionality.[19] Recognizing that the data exchange standards accommodate a range of datasets and other parameters regarding data delivery, in preparing their filings, utilities should meet with ESCOs and DER vendors to explore how these options should be addressed.

Green Button Connect or similar standard may not be an appropriate tool for utilities without AMI deployment plans. Accordingly, those utilities must identify other tools that could be used to enable customer and authorized third-party

[19] Case 15-E-0050, Supra, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions.

access to customer data, as well as implementation plans, budgets, and timelines, in their Initial DSIPs.

It is expected that EDI will continue to be useful and appropriate to exchange data between ESCOs and utilities, including hourly, interval, and billing quality data on a monthly basis. EDI is not suited, however, to exchanging detailed consumption data between utilities and vendors, or for use by consumers. Further, transmission of interval data on a next-day or real-time basis requires a protocol other than EDI, such as File Transfer Protocol. Accordingly, DSIP filings must include plans to phase-in the ability to provide ESCOs with access to daily, hourly, and eventually, close to real-time access to customer usage information, including budgets and timelines. The comments discussing whether utilities would be allowed to charge for certain customer data will be addressed in the REV Track Two proceeding.

CONCLUSION

The DSIP process is intended to promote development of a modern grid capable of supporting increasing levels of DERs. The information required to be filed with both the Initial and Supplemental DSIPs will ensure that third-parties have the data necessary to provide market solutions to energy needs that are both cost-effective and technologically advanced. In addition, the DSIP process will contribute to the success of REV-related goals, including more efficient energy use, supporting innovative and sustainable energy technologies, as well as increased DER penetration. Though the industry will develop a deeper understanding of the modern electric grid and the opportunities that are available to benefit consumers through DER deployment as the market matures, the DSIP filings required by this Order are the first steps toward establishing a grid capable of supporting increased levels of DER into the future and ultimately achieving statewide energy policy objectives.

<u>The Commission orders</u>:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file their plans and associated timelines for a stakeholder engagement process during development of their Distributed System Implementation Plan filings no later than May 5, 2016, in conformance with the discussion in the body of this Order.

2. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file individual Initial Distributed System Implementation Plans by June 30, 2016, in conformance with the discussion in the body of this Order and Attachment 1.

3. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file a joint Supplemental Distributed System Implementation Plan by November 1, 2016, in conformance with the discussion in the body of this Order and Attachment 1.

4. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation

d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018.

5. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

6. This proceeding is continued.

By the Commission,

(SIGNED)

KATHLEEN H. BURGESS
Secretary

APPENDIX A

LIST OF COMMENTERS ON DSIP GUIDANCE

(Name and Abbreviation)

Public Interest Intervenors

Acadia Center	Acadia
Advanced Energy Economy Institute[1]	AEEI
Clean Energy Organizations Collaborative[2]	CEOC
Environmental Defense Fund	EDF
Interstate Renewable Energy Council, Inc.	IREC

Providers & Organizations

Advanced Energy Management Alliance	AEMA
Dominion Voltage, Inc.	DVI
Energy Storage Association	ESA
Mission:data Coalition	Mission:data
National Energy Marketers Association	NEM
New York Battery and Energy Storage Technology Consortium, Inc.	NY-BEST
Northeast Clean Heat and Power Initiative	NECHPI
Smart Wires, Inc.	Smart Wires
SolarCity Corporation	SolarCity
Solar Energy Industries Association	SEIA

Governmental Entities

City of New York	NYC

[1] Advanced Energy Economy Institute, the charitable and educational organization affiliated with Advanced Energy Economy (AEE), submits comments on behalf of AEE, two state/regional partners (the Alliance For Clean Energy New York (ACE NY) and the New England Clean Energy Council (NECEC)), and their joint and respective member companies.

[2] The Clean Energy Organizations Collaborative includes: Acadia Center, Association for Energy Affordability, Citizens for Local Power, Clean Coalition, Environmental Advocates of New York, Natural Resources Defense Council, The Nature Conservancy, New York League of Conservation Voters, New York Public Interest Research Group, Pace Energy and Climate Center, and Sierra Club.

New York Power Authority	NYPA

Utilities

Exelon Companies[3]	Exelon
IGS Energy, LLC	IGS
Joint Utilities[4]	Joint Utilities
NRG Energy, Inc.	NRG

Customer Representatives

Multiple Intervenors[5]	MI

[3] The Exelon Companies include Exelon Corporation and its subsidiaries: Constellation, NewEnergy, Inc.; Exelon Microgrid LLC; Constellation Energy Nuclear Group, LLC; Nine Mile Point Nuclear Station, LLC; R.E. Ginna Nuclear Power Plant, LLC; Exelon Generation Company, LLC; Baltimore Gas and Electric Company; Commonwealth Edison Company; and, PECO Energy Company.

[4] The Joint Utilities are: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

[5] MI is an unincorporated association of approximately 60 large industrial, commercial, and institutional energy consumers with manufacturing facilities located throughout New York State.

APPENDIX B

ANALYSIS OF DSIP GUIDANCE COMMENTS

SUMMARY OF INITIAL COMMENTS

Public Interest Intervenors

A. Acadia

Acadia recognizes that the DSIP Guidance is a significant step towards utilities considering an array of diverse energy resources and strategies to maximize benefits for New York's energy system. Acadia suggested more specific guidance be provided for forecasting demand and energy growth (targeting energy efficiency as a key system optimization resource in the DSIPs), delivery infrastructure capital investment plans, and beneficial locations for DER deployment.

First, Acadia suggests utilities should be required to include both 50-50 (half of years would fall above the forecast and half below) and 90-10 (one of every ten years would exceed this level) forecasts and winter/summer peak demands with the other required forecasts. Acadia further recommends the utilities be required to provide a comparison of prior company-wide and, where possible, substation-level forecasts against actual results, weather-adjusted as appropriate, for forecasts conducted ten, five, and two years before the latest available actual results and assess their effectiveness in predicting actual results. Acadia also noted that if utilities will be using updated forecasting methods, they should provide company-wide and substation-level five-year forecasts starting five years before the latest available actual results using the new methodology and describe the methodologies used to weather-adjust actual loads to further address forecast accuracy. As a final note, Acadia mentioned that utilities should indicate how their forecasting methodology incorporates changes in other efficiency standards, such as federal product efficiency standards, in their forecasts.

Second, Acadia urges utilities to actively propose in their DSIPs how they intend to deploy and maximize energy efficiency resource acquisition so that New York consumers can benefit from the same degree of economic benefit, cost reduction, and system optimization that consumers in states with leading efficiency investment efforts are enjoying.

Third, Acadia notes that strategic DER deployment can mitigate the impact of variables such as mechanical stress, electrical loading, operating practices, and environmental factors affecting the useful life of distribution infrastructure, lowering replacement and maintenance costs. Therefore, Acadia suggests utilities investigate the impacts of incorporating DER in their asset optimization strategy and identify gaps in their current asset optimization methodology, followed by subsequent public review and input.

Finally, Acadia suggests the Commission adopt a cost-benefit framework that reflects the public interest and is designed or expanded to capture New York's energy policy priorities. Locational and temporal data on prices, costs, and benefits should be included in the utilities' analyses to appropriately identify beneficial locations for DER deployment.

With respect to AMI, Acadia notes that when retail electricity rates reflect time- and location-specific values, it will make economic sense to compensate distributed generation at the same rates. Acadia also notes, AMI may also enable bi-directional rates for distributed generation customers. In addition, Acadia would expect utilities to incorporate sensitivity analyses for a limited set of variables in their cost-benefit analysis for AMI. Finally, Acadia notes AMI should be deployed when and where it is cost-effective.

To improve the chances for effective stakeholder engagement, the DSIP consultation process needs to incorporate the following: (1) creating a fair decision-making process that will encourage stakeholder participation; (2) identifying and overcoming information hurdles stakeholders face in complex energy policy discussions; (3) considering strengthening stakeholder participation through expert support; and, (4) responding to stakeholders that face financial barriers to participation.

B. AEEI

AEEI expects the DSIPs to have an important role to play in how energy efficiency is delivered, however, AEEI remains concerned that there is inadequate support for energy efficiency in the near-term. In addition, AEEI supports coordination among utilities and the use of common tools, processes, protocols, and standards in the Supplemental DSIP. To that end, AEEI supports the Commission holding a technical conference during which each utility is required to present their proposed Initial DSIP and answer questions from Staff and stakeholders. Furthermore, AEEI supports directing utilities to provide summaries of the DSIP filings, directing Staff to prepare these summaries, or hiring an independent consultant to review and analyze the DSIPs and publish a report on their findings. AEEI envisions these summaries being condensed versions of the DSIPs that would contain all the essential elements of the DSIPs so that stakeholders would be able to get a complete picture of the plans. This process should also include regular, periodic reporting from utilities on specific DSIP performance and milestones.

AEEI suggests that DSIPs be reviewed and approved/disapproved once, and the dollars associated with the approved DSIPs then be incorporated into a utility’s rates; but there should not be a second review of the approved DSIPs in the next rate case.

AEEI argues that the Commission should retain a single consultant to determine the potential for reducing load and peak demand through increasing system efficiency in each utility territory on a utility-by-utility basis.

AEEI condones focusing on avoiding large-scale transmission projects, outlining how utilities will work to ensure that DER is properly considered as part of the NYISO planning process, and believes the Commission should also encourage the NYISO to ensure DER is considered before any new transmission infrastructure is constructed.

AEEI is concerned that the phrases “access to data” and “customer engagement” continue to be lumped together, which may complicate the metrics for effective customer engagement in the EIMs. Additionally, the current definition of “consumer engagement” is unclear. AEEI also suggests that the definition of “customer engagement portal” is unclear and therefore, AEEI provides several clarifying distinctions and definitions for Commission consideration.

AEEI suggests the Commission direct the utilities to use the same data exchange standard, as well as a third-party tester to verify consistent implementation (e.g., Green Button and Green Button Connect). AEEI further suggests that the AMF needed to transmit such data be based on FERC, NIST, and the Grid Modernization Proceeding in Massachusetts. Additionally, any alternatives to traditional AMI must provide the fundamental measurement along with two-way communication ability.

AEEI contends an interoperable AMI backbone can enable multiple customer engagement applications, as well as secure, timely data to support participation in near real-time markets. In addition, as business needs evolve beyond those that exist during the early phases of REV market implementation, AMI is able to cost-effectively scale to multiple applications and territories and will allow third-parties providing engagement solutions to better identify those customers with higher benefit potential. AEEI identifies numerous AMI and communication network support systems including a back office information technology system. AEEI also submits that there are variations in ownership models depending on the component (though AEEI believes the meter should be utility owned and operated). The ideal timeframe to deploy the anticipated AMF strategy is eighteen to twenty-four months ahead of the anticipated DER adoption to a geographic portion of the utility territory.

AEEI argues that customer load data must be provided to ESCOs and the NYISO in a way that allows the NYISO to settle ESCOs’ loads in a timely manner based on actual usage instead of the class load shapes of their customers. However, AEEI suggests there are surgical, high-value scenarios that can be justified absent a full-scale deployment of advanced meters, such as Volt-VAR and Integrated Volt-VAR control, DR/DM, energy storage, distributed generation, etc. AEEI emphasizes that the Commission should make it easy to incorporate new types of devices and services, especially if behind-the-meter activities become part of the clearinghouse for settlement.

C. CEOC

CEOC states that they support most of the recommendations provided in the DSIP Guidance. However, they believe Staff should provide more guidance on how the utilities should facilitate the role of market participants in developing DER and what the utilities should do for those customers, sectors, services, and technologies that market participants are not able or willing to serve. They recommended that Staff provide more guidance regarding how the DSIPs will address the role of the utilities and market participants.

CEOC asserts that the DSIPs should include a discussion on how the utilities will achieve the State Energy Plan goals and the high level policy goals of enhanced customer knowledge and tools, market animation, system-wide efficiency, fuel and resource diversity, system reliability and resiliency, and reduction of carbon emissions. For the development of DER, CEOC suggests that Staff require each utility to provide a complete description of the potential for all cost-effective DER, by technology type, and by customer sector, where relevant. They believe the above information will facilitate development of a benchmark against which utility solicitations and the performance of other market mechanisms can be evaluated. The information will also indicate the type and amount of DERs that the utility should implement if the market participants are unable or unwilling to do so. It will also provide the potential for all cost-effective DER that can be used as a basis for setting EIM targets. CEOC notes that the utilities should include in the DSIPs the technical potential of the full universe of DER opportunities and the full economic value of DERs to indicate the cost-effectiveness of DER potential. CEOC understands that as the DER markets are still in formative stages, significant amounts of DER (and in particular, energy efficiency and demand response) will not be implemented by market participants alone and that utilities will have to play a significant role in implementing those DERs that the market does not implement.

While commenting on energy efficiency, CEOC stated that each utility should include estimates of the potential for all cost-effective energy efficiency resources in their DSIPs. They further stated that the estimate of cost-effective efficiency potential should include all of the energy efficiency programs and savings that are currently planned for in each utility’s ETIP, as well as any additional cost-effective efficiency resources that could be implemented beyond those savings levels by the utility and by market participants. They emphasized that the complete estimates of efficiency potential will be important to ensure that the utility stands ready to implement those efficiency resources that market participants do not carry out, and to help in setting a benchmark for the total amount of efficiency resources that should be delivered. They stressed investing in proven programs and techniques to achieve state energy goals rather than on experimental programs.

CEOC stated that the utilities’ transitional energy efficiency targets and projected future potential must be viewed alongside NYSERDA’s Clean Energy Fund efficiency targets. They continue that stronger utility targets, a full projection of each utility’s efficiency potential, and a more detailed description of NYSERDA’s projected efficiency budgets and targets will ensure that New York meets its State Energy Plan goals and does not backslide on existing commitments.

Commenting on demand response, CEOC generally supports the Commission’s findings and recommendations. As with efficiency resources, CEOC asserts that the DSIPs should include the entire universe of potential DR opportunities, based not only on all existing demand response program delivery and implementation practices, but also on all feasible additional practices that can be implemented by the utilities or market actors. They opine that the Initial DSIPs should include all of the relevant demand response programs from the utilities’ most recently approved Dynamic Load Management plans, as well as estimates of the potential for additional demand response programs that would be cost-effective in the context of REV.

With respect to distributed generation, CEOC anticipates bill crediting mechanisms will be the primary vehicle for utilities to promote distributed generation resources. They state that the utilities may be allowed to own or otherwise sponsor distributed generation resources when market participants are unable or unwilling to do so, particularly for low- or moderate-income customers. They emphasize that the utilities should include in their DSIPs the best estimate of the potential for distributed generation resources which will provide useful information to market participants and also help utilities to foster, or reinforce, the market for distributed generation.

On energy storage technologies, CEOC stated that the DSIP should include a detailed forecast of the cost-effective potential for energy storage options for both customer-sited storage and grid-sited storage. They opined that once more information is available regarding the opportunities and the cost-effectiveness of storage technologies, the Commission can decide on the utilities’ role and the market mechanisms that might be used to effectively spur development of storage.

With respect to plug-in electric vehicles, CEOC states that customers with electric vehicles can play an important role if they are provided with appropriate rate structures. CEOC recommends that the DSIPs include a robust load management component to help maximize benefits for utility customers, as well as forecasts on (1) the impact of electric vehicles on future energy and capacity demands, (2) the expected locations of electric vehicle customers and charging stations on the electric grid, and (3) the likely impact that electric vehicles will have on generation, transmission, and distribution needs based on current and alternate rate design for more efficient types of electricity charging (and discharging). They further stated that the DSIPs should include a plan on accelerating the deployment of electric vehicles and related infrastructure.

They expect the utilities to invest in this infrastructure where market actors are likely unable to make such investments and to target areas typically underserved by private, third-party charging service providers, including disadvantaged communities, multifamily buildings, workplaces, and DC fast charging for public access, where needed.

CEOC believes the Commission needs to provide more concrete guidance regarding the specific actions that the utilities should undertake to support the competitive markets for DER. They recommend that the Commission direct utilities to use competitive bidding processes to procure energy efficiency and demand response resources from market participants. They also recommend that the utilities be allowed the flexibility to use separate bidding processes for separate types of DERs or a combined bidding process for all types of DERs together. CEOC suggests that, prior to the beginning of the bidding process, each utility file with the Commission a DER procurement plan, which would provide the utility’s updated best estimate of the amounts and costs of DER available in its service territory as identified in its Initial DSIP, as well as all of the relevant information pertaining to the competitive bidding process, including the proposed solicitations, a description of the evaluation process, and the specific criteria that will be used to select the winning bidders. CEOC proposes that the Commission and other stakeholders get involved in reviewing the DER procurement plans and the RFPs from competitive bidding. CEOC cautions the Commission not to exercise such a degree of authority over the procurement process so as to risk its authority being preempted and further cautions the Commission not to design or approve any market mechanisms that would put the Commission in the role of approving a wholesale rate as just and reasonable. They opine that the DSIPs should include proposals for alternative mechanisms to encourage market development of DERs other than RFP-based competitive bidding.

CEOC agrees with focusing analysis on distribution circuits that have the greatest opportunity for DERs. However, CEOC recommends the Commission require utilities start with a system-wide analysis of DER before moving to a circuit-level analysis. CEOC is concerned that circuit-specific analyses will result in some sections of the service territory receiving too much attention and too many DERs, relative to other sections.

CEOC supports having technical conferences as a means of exchanging ideas, proposals, and recommendations among utilities, the Commission, and stakeholders. CEOC suggests that the Commission issue its findings on the Initial DSIPs prior to the date when the utilities file the Supplemental DSIP because the Commission findings are likely to be very influential in shaping the Supplemental DSIP. The Supplemental DSIP should set forth a means of coordinating procurement or other incentive mechanisms between utilities for those DERs that are most efficiently procured jointly. CEOC encourages stakeholder engagement and DSIP evaluation in light of resource portfolios, BCA, risks, constraint of resources, and state energy policy goals.

CEOC states that the DSIP Guidance is not clear about how or when EIMs would be developed in relation to the DSIP process. They believe that more details should be provided about these processes and how they interact, as both the EIMs and the DSIPs will serve critical functions in moving the state toward achieving REV-related goals. CEOC states that it fully supports identification of areas where transmission-level infrastructure could be deferred/supplemented and opportunities for DER to avoid distribution infrastructure upgrades.

Regarding coordination with NYISO in the DSIP process, CEOC states that the Commission should initiate a technical conference to investigate scheduling coordination between the NYISO planning process and the DSIP process, and should consider altering the DSIP schedule so that the data developed through the DSIPs and the programs proposed therein can be seamlessly taken into account in the NYISO process.

CEOC agrees that data collection and sharing is necessary to achieve REV objectives and suggests maintaining a process in data collection and sharing. Finally, CEOC acknowledges that AMI will play an important role in achieving REV goals by giving customers more control over their energy use and emphasizes that a thorough benefit cost analysis should be done to determine the cost effectiveness of the AMI project.

D. EDF

EDF is concerned that the DSIP Guidance does not provide recommendations on certain key DSIP issues and encourages parties to respond to the questions posed by Staff. EDF believes that parties should have an opportunity to comment on a full draft DSIP Guidance.

EDF supports Staff’s proposal to require utilities to collaboratively prepare and jointly file a Supplemental DSIP, in consultation with a stakeholder process. EDF encourages the Commission to direct the utilities to work more closely with local governments in developing their DSIPs. Specifically, EDF suggests that the DSIP Guidance direct the utilities to provide information to local governments including data pertaining to capital spending projects, upcoming system upgrades, system data, and energy consumption. EDF also suggests that if there are deficiencies in confidentiality or data gathering that the utility be responsible to correct these deficiencies.

EDF agrees with Staff’s requirement that utilities include the following within their DSIPs: detailed delivery infrastructure and capital investment plans, certain system load and DER forecasting for the next five years at the company-wide and substation levels, the impact of significantly increased DER penetration, and a description of how new, DER-related factors are reflected in load forecasting models. EDF believes this information will allow utilities to more accurately forecast the system load and help them manage the system better. EDF also believes that it will encourage utilities to recognize the value of DER penetration and incentivize them to support DER deployment. However, EDF suggests the Commission require the utilities to develop longer term DER development projections.

EDF agrees with Staff’s proposal that utilities identify the most beneficial locations and unbeneficial locations for DER deployment, which will help DER providers make informed decisions for investing in new resources. However, EDF believes that environmental benefits and harms should be factored into the discussion on beneficial locations.

EDF agrees with Staff’s proposal to require utilities to provide system data, on a substation basis, and feeder-level data in areas where DERs are expected to have high value. EDF also agrees that utilities should be required to develop plans to expand the collection and sharing of granular system data.

With respect to improving customer and authorized third-party access to granular data, EDF believes that AMI deployment is critical in order to improve such access to data as near to real-time as possible. EDF notes that Staff’s utility requirement to identify which data fields are to be transmitted is generally consistent with the direction of the Commission framework order and believes it is crucial to set clear and comprehensive expectations with respect to said data access. A failure to address data access issues upfront can lead to unrealized AMI benefits for many years. EDF also recommends that utilities be directed to consider the infrastructure needs and costs for providing high-quality data early on. EDF suggests that the use of the Open Data Access Framework can be used to identify and develop parameters and metrics related to customer data access, which should be addressed in the context of AMI deployment. EDF suggests that Staff recommend customers have access to their electric usage data including consumption, power, and pricing data in fifteen-minute intervals and a machine-readable format. EDF believes that utilities should also be directed to provide high quality data early on to enable third-party innovators and entrepreneurs to expand services such as demand response and energy efficiency solutions.

EDF recommends that providing data access for customers and their authorized third-parties should be based on the emerging industry standards or national standards, such as Green Button Connect, particularly to automate the transfer of data with authorized third-parties. Lastly, EDF suggests Staff recommend that AMI plans submitted by the utilities convey an understanding of the cost of designing and implementing the Green Button Connect functionality.

EDF strongly agrees that utilities should implement VVO and describe near-term and long-term implementation plans. EDF also believes that Staff should provide more direction to the utilities regarding the development of VVO implementation plans to enable stakeholders to conduct simple analyses and establish their own positions on investment proposals. Such Staff direction should include the current state of adoption of VVO, a feasibility study of implementing VVO in order to identify costs and benefits, identification of the priority order in which VVO should be undertaken, and quarterly or annual performance metrics in order to evaluate the progress and success of the VVO enabled operational, environmental, and societal benefits.

EDF believes AMI is the best alternative to meet REV goals such as market animation, customer engagement, and carbon reduction. AMI will provide granular customer data to third-party DER providers and consumers, enabling the DER providers to make investment decisions and develop pricing mechanisms. Customers will be informed of price signals that may cut demand and reduce carbon emissions in the long run. EDF also states that AMI can support demand rates for mass market customers, provided the system, as deployed, has that functionality. AMI can also support demand rates that take into account the system and/or local peak demand.

EDF suggests more emphasis be placed on renewable energy and environmental goals in the DSIP Guidance. EDF believes that the DSIP filings could be an appropriate place to develop new energy efficiency programs to meet REV objectives. Additionally, EDF recommends that ambitious energy efficiency targets should be set as part of the DSIP process. EDF also affirms that the incorporation of state environmental goals should be required within utilities’ DSIPs. EDF agrees with Staff’s proposal to require the utilities to describe how they will evaluate and incorporate the use of energy storage as part of the overall planning process and as part of their solutions to avoid more traditional infrastructure investments.

With utilities playing a central role in achievement of state environmental goals, EDF believes electric utilities need to build their systems and conduct business with customers and third-parties in a manner that makes demand more flexible, thus enabling intermittent renewable resources to play a far larger role in meeting demand. EDF also recommends the Commission direct the utilities to devise multiple DER growth scenarios, based on different degrees of DER deployment, which should be consistent with state decarbonization and renewable energy goals. Each scenario should take into account the storage capacity subject to the type and amount of DER deployed.

EDF supports Staff's proposal to require utilities to discuss REV demonstration projects within their DSIPs. EDF also agrees the utilities should be required to propose additional projects and continually improve, refine, and otherwise drive toward state energy objectives. However, EDF notes more detail is necessary about what utilities must consider when developing demonstration projects and suggests the Commission direct projects toward identified public policy outcomes and require the utilities to develop proposals for projects that would achieve specific DSP functions or goals.

EDF supports requiring utilities to include BCA within their DSIP filings. Because the BCA framework is not finalized, EDF proposes the BCA should take into account all relevant costs and benefits, including social and environmental externalities.

EDF notes that the DSIP Guidance does not mention market development for low-income customers and does not discuss environmental justice impacts of DER development. EDF points out that this omission falls short of the Commission's recommendation that the DSIPs should include plans for increasing DER deployment in underserved markets. Therefore, EDF strongly encourages Staff to include in the DSIP Guidance a requirement that the utilities include concrete plans for increasing DER deployment in underserved markets. EDF also suggests the Commission direct utilities to take into account the potential for harmful emission concentrations from certain DERs in those sections of the DSIPs that relate to identifying beneficial locations for DER deployment.

EDF suggests the DSIPs should include separate descriptions of how well the interconnection processes are working with respect to different types of distributed generation. EDF further suggests that information about the efficiency and emissions of any distributed generation DER should be gathered as part of any application process established for interconnection. EDF also suggests regulations pertaining to DG emissions should be adopted by the Commission and/or DEC in conjunction with REV, including the expected DEC Part 222 rule.

E. IREC

IREC makes suggestions with respect to integration of demonstration project results in the DSIP filings, the contents of the Initial DSIPs, Supplemental DSIP, and stakeholder engagement.

Though IREC supports requiring utilities to address their REV demonstration projects in their DSIPs, it suggests that the Commission also require utilities to describe how these projects will contribute to the achievement of the various components of their DSIPs.

IREC makes several suggestions with respect to the contents of utilities' Initial DSIPs. IREC suggests adding a hosting capacity section and implementing integrated system planning in the Initial DSIPs. IREC suggests the hosting capacity section should include the following: (1) a description of the utility's current knowledge of the hosting capacities of feeders and/or line sections on its system, and the utility's plan for determining the hosting capacities of all feeders on the system; (2) a description of the utility's methodology used to determine hosting capacities, and whether/how this methodology will change in order to ensure consistency across the utilities; (3) a description of the utility's process for updating hosting capacity information in a timely manner; (4) a method for effectively sharing hosting capacity information with stakeholders, to be made available upon the submission of the Initial DSIPs; and, (5) specific information on how the utility will use hosting capacity information, as well as other system data, to streamline the interconnection process and propose a timeline for adopting any proposed changes to the interconnection process.

With respect to forecast of demand and energy growth and available resources, IREC suggests: (1) requiring utilities to identify specific expected contribution to peak load, energy reduction, and load shaping at the system-wide level and at least at the substation level; (2) a separate requirement be added for utilities to include at least two DER growth scenarios, explain their methodologies and assumptions for developing those scenarios, and explain how those scenarios are incorporated into their various forecasts; and, (3) requiring utilities to explain how they will incorporate their DER growth forecasts into their planning processes.

IREC agrees that utilities should be required to justify their delivery infrastructure capital investment plans in their DSIPs, and further suggests: (1) the utilities be required to include details on how their proposed distribution infrastructure upgrades support the improved integration of DER; (2) the Commission clarify that transmission and distribution projects, where DER could impact project needs, include both transmission and distribution upgrades that could be deferred or eliminated by DER and those that are required to accommodate higher penetrations of DER; and, (3) the Commission encourage utilities to identify transmission and distribution projects where energy storage, in particular, could impact project needs. With respect to utility identification of beneficial locations for DER deployment, IREC suggests that initial efforts should focus equally on sharing information regarding locations where infrastructure upgrades would be unnecessary or minimal, in order to encourage DER deployment in low-cost areas of the grid as well as high-value areas. As discussed above, IREC also emphasizes that determining hosting capacity is an objective, analytical process, which will serve not just to help utilities to determine high-value and low-cost location, but also to identify the infrastructure investments necessary for accommodating DER. IREC further suggests the Commission incorporate a specific requirement for utilities to direct energy storage projects to high-value areas of the grid and where energy storage could be deployed to enable greater amounts of other DER to be utilized.

IREC suggests the Commission require utilities to articulate how they expect the changes instigated by their DSIPs to affect or require changes to their interconnection processes and outline the steps necessary to make those changes. IREC suggests that the Commission require the utilities to describe the barriers and challenges associated with the current interconnection process. From utilities' perspective, IREC believes these challenges and barriers could include, but are not limited to incomplete or erroneous applications; applicants lacking information about the interconnection process and their options; and application queues that are clogged, for example due to "fishing" applications or unresponsive applications. In addition, IREC suggest the utilities provide supporting data regarding the current process, including the number of applications received, associated processing times, how many applications were able to receive expedited treatment, how many required a more detailed study, and the average costs of interconnection broken out by project size. IREC further suggests that utilities explain how the data they gather and share, in particular the hosting capacity data, will affect the interconnection process; and indicate how their interconnection processes accommodate, or will accommodate, interconnection of energy storage.

With respect to system data acquisition and sharing, IREC recommends that utilities work with stakeholders to develop a process for the acquisition and sharing of feeder-level data, with the ultimate goal of providing data on all feeders through their service territories, and a timeline for achieving this goal. IREC further suggests the Commission require utilities to provide system data in an online, publicly available map, unless a utility proposes and justifies another method for sharing the information. Finally, IREC suggests utilities discuss how all relevant investments will affect the availability of more granular system data, not just how AMI can increase the availability of such data.

IREC also makes suggestions for the Supplemental DSIP. IREC supports allowing utilities additional time to develop a joint Supplemental DSIP and making determination of hosting capacity a specific topic the Supplemental DSIP must address. Regarding interconnection, IREC suggests that the Supplemental DSIP should not just address an “automated interconnection process,” but rather the development of a consistent, streamlined process across the state in the near-term, which may involve increasing automation over time. In addition, IREC recommends the utilities describe the steps they plan to take to streamline and improve DER interconnection, as well as associated timelines, including, but not limited to, their plans for automation.

Finally, IREC comments on stakeholder engagement. IREC suggests utilities should explain how stakeholder input was taken into account in developing both the Initial and the

Supplemental DSIPs. IREC further recommends holding three technical conferences before the utilities file their Initial DSIPs on the following subjects: (1) current utility distribution system planning; (2) utility progress to date in identifying high-value and low-cost areas for DER on their systems and how utilities expect to address these issues in their DSIPs; and, (3) current interconnection process, anticipated modifications, and ways in which the changes associated with DSIPs will affect interconnection going forward. In addition, IREC suggests one technical conference between the Initial DSIPs and the Supplemental DSIP on hosting capacity methodology. After both filing deadlines, IREC also suggests that the utilities be required to give overview webinars on their Initial DSIPs (separately) and on the Supplemental DSIP (jointly) to provide parties some additional insight into the DSIPs and opportunities to ask questions. IREC believes that stakeholders should have the opportunity to provide written comments on the Initial and Supplemental DSIPs, as well. IREC encourages the utilities and the Commission to contribute to a meaningful and transparent stakeholder engagement throughout DSIP development.

Providers/Trade Organizations

A. AEMA

AEMA supports Staff’s approach in the DSIP Guidance and its emphasis on uniformity to help market participants contribute to the change process and engage stakeholders.

With respect to the stakeholder engagement process, AEMA suggests a collaborative investigation and evaluation of alternatives early in the process. AEMA asserts that developing the system-wide platform characteristics and standards that will best facilitate the growth of new product and service markets will require such collaboration among utilities and market participants. Specifically, AEMA suggests the DSIP Guidance encourage the utilities to formally and transparently seek out third-parties to inform expected performance and penetration levels, as well as to gather key information on business models, technologies, and obstacles to implementation. Providing customers and providers with access to data is also recommended as a collaborative effort to be specified in the DSIP Guidance.

Concerning AMI, AEMA asserts that access to relatively small intervals of energy consumption data (at least fifteen-minute increments) is critical for many emerging information-driven products and services, such as home energy management and demand response. Further, AEMA sees AMI for the mass market as a utility function, to overcome the higher cost of custom meter installation for small businesses and residences; it is simply too expensive for the vast majority of consumers to install individual smart meters.

AEMA encourages Staff to consider various DER procurement approaches (e.g., tariffs, RFPs, auctions) with emphasis on selecting those that: (1) best enable price discovery; (2) provide the greatest certainty that resources will be delivered; (3) stimulate the highest interest from DER providers and thus, ensure lowest cost outcomes for ratepayers; and, (4) enable clear performance standards to ensure successful capital deferral.

B. DVI

DVI supports the Staff requirement that the Initial DSIPs include a section on VVO that describes plans to implement VVO in the near- and long-term, how third-parties can interact and provide VVO services, evaluates and discusses the costs and benefits of upgrading VVO capabilities, and discuss new VVO capabilities and how they fit in with the evolving grid in a utility’s service territory.

However, DVI also mentions the causal relationship between VVO’s benefits and the technology approach that a utility might adopt. DVI states the technology approach to VVO has critical importance to the level of potential energy savings and the kWh benefit to customers’ bills. Conservation Voltage Control relies on modeling that is limited to operational data on distribution primary circuits and without more granular voltage data on secondary circuits down to the customer meter, distribution planning and operations must be based on assumptions from historical conditions, not real-time information. Modern adaptive control using AMI allows near total automatic response to the typical dynamic secondary circuit environment, allowing safe, reliable delivery of energy to the customer at lower voltage settings with sustainable energy savings.

DVI suggests utilities’ DSIPs also include an evaluation of the comparative costs and benefits of different technology approaches in mapping out their near-term and long-term implementation of VVO, an assessment of which technology approach might best correlate with their DER planning and hosting capacity needs, and a costs and benefits analysis that considers the value of technologies that serve cross-functional purposes, or that can serve as a driver or foundation for future technology applications as the electric system evolves.

DVI states VVO technology that would integrate voltage data from AMI provides greater energy savings and voltage stability on primary circuits hosting solar DG and that these benefits could help build a business case that would support further or expedited deployment of AMI that is ultimately required for the integrated DER model envisioned by this proceeding. DVI finally comments because VVO would be a distribution efficiency program that does not require any change in customer behavior or initial investment by customers, it serves the public policy interest in expanding access to energy efficiency benefits to low-income customers.

C. ESA

ESA and NY-BEST made previous recommendations on the BCA Whitepaper that a more rigorous analysis and resulting framework is needed to identify benefit or avoided-cost values, other than energy and capacity, for storage technologies and applications. These previous recommendations should be considered and amended to the DSIP development process according to ESA. NY-BEST and ESA note that accounting for uncertainty in demand forecasting, load shape, and general system planning assumptions is an important component of DSIP development.

ESA urges the Commission to ensure that the state renewable energy goal of reaching 50% renewable energy by 2030 be addressed and integrated in the development of the DSIPs.

The level of control the utilities have on the DSIP Guidance and implementation plans are a major concern for ESA. To put parties on equal footing and to ensure sufficient data and analysis is publicly provided, ESA recommends that working groups should be implemented to give DER providers a greater or more formal role in the implementation process and the opportunity to comment on the utilities' initial plans for the distribution system planning process. They encourage the Commission to require utilities to submit an interim, longer-term plan sometime between now and 2020, similar to the requirements of many other states that utilities submit up to twenty-year integrated resource plans every two to three years.

ESA cautions that there will be a need for more granular guidance beyond having the utilities define how to evaluate and incorporate the use of energy storage in the overall planning process, such as more detailed DER penetration targets, and suggests these be developed or established by the Commission as part of the DSIP Guidance.

ESA believes that too much flexibility is given to utilities in proposing optimal locations for DER alternatives to traditional grid assets in distribution system planning. ESA recommends that utilities provide detailed information on proposed infrastructure planning for both DERs and traditional grid assets. In cases where utilities see a preference for traditional infrastructure, the DER community should be given the opportunity to see publicly the rationale made and have the opportunity to rebut.

D. Mission:data

Mission:data asserts that the plummeting cost of computing power, in conjunction with the availability of free usage data to consumers as enabled by AMI, is facilitating the development and deployment of individualized energy efficiency and other DER strategies. With respect to energy efficiency and demand response, the data-enabled tools being developed for a national market are emerging as the most powerful, cost-effective means for consumers to manage and reduce energy use.

According to Mission:data's expectations, use of real-time meters, inexpensive data storage, and computing power are the levers needed to scale individualized energy management strategies for buildings. It envisions that significant opportunities exist now for the commercial and residential sectors. These opportunities are enabled by granular, real-time data and are an order of magnitude larger than the savings that many customer engagement strategies are attaining today. Mission:data urges Commission adoption of an affirmative policy requiring utility submissions to provide consumers convenient access to their own information in standard electronic formats and the ability to easily and electronically share that information with service providers of their choice. Full deployment of AMI should include the condition that the usage data generated is made available to consumers and their authorized third-parties, free of charge and part of basic utility service, arguing that providing information to consumers is central to realizing the value of advanced meters.

Mission:data envisions three methods by which advanced meter data can empower customers: (1) customer data be made available through a user web portal which would also allow customers to select the vendor of their choice and authorize the ongoing transfer of meter data in an electronic format to that vendor; (2) customers be able to authorize a third-party to receive usage and cost information, and the third-party be able to present this authorization to the utility to receive the data electronically; and, (3) usage information be received in real-time from the smart meter by an in-home device or Internet gateway. Mission:data expects that use of real-time data can unlock a host of new applications and services. Functional requirements should, as a minimum, allow customer access to their data in real-time or near real-time.

Mission:data argues that a significant advantage of utility-scale advanced meter deployments is that pricing is more attractive than if ordered for individual projects or in smaller lots, also noting that substantial variability in infrastructure capabilities, and/or data formats used, makes it more expensive to develop end-user applications, reduce adoption costs for consumers, and achieve the scale necessary to significantly affect overall energy consumption.

Turning to the question posed by the Commission regarding direction it should consider, beyond current requirements, in order to improve customer and authorized third-party access to the most granular data in as near real-time as possible, Mission:data (1)advocates that: consumers should have an affirmative right to access the best available information about their own energy use, both interval usage data provided to the customer via DSP systems; and real-time usage information available at the premise. (2) Consumers should be able to share their energy information with trusted service providers of their choosing, following a simple and electronic authorization process; and, (3) data access should be provided as part of basic utility service and implementation should be included in the rate base.

Mission:data also points out that DSPs enable the development of applications that can accurately predict for consumers the financial consequences of their energy management decisions. This requires consistent and systematic use of widely adopted national standards and protocols to enable New York to harness tools developed for a national market.

Mission:data believes it would be premature to declare any data access method too expensive at this stage because of recent developments: large utility vendors recently began offering Green Button Connect software, so implementation costs are likely to be less than those incurred by early adopter states. Furthermore, a growing range of new data-driven applications assure greater savings opportunities for consumers. The Commission should establish in DSIP guidance that cost estimates for data access include at least two components. First, DSP’s should provide information sufficient to establish the cost of providing consumers with secure and authorized web service deployment. Second, DSP’s should provide information establishing the cost of energy information delivery based on the specific information model implemented. We believe this information will allow for any cost-benefit assessments to determine which costs are attributable to data security and authorization (which are likely to be consistent regardless of the data standard employed) and which costs are attributable to the specific data standard and information delivery mechanism.

Mission:data believes that the Commission should set minimum requirements for specific authorization processes because a data access system with poor, clumsy or inconvenient authorization methods will not be used by consumers. Customer authorization is a key leverage point in meeting the state's policy objectives, because authorization to share usage data is typically the beginning of a customer's use of DERs. Concerning authentication and authorization processes, Mission:data cites cases where the processes are successfully employed. Utility DSPs should be able to handle data release authentication and authorization whether it begins at the utility's website or with a vendor's website. Mission:data encourages the Commission to require at a minimum, the DSPs to implement the ESPI/GBC authorization processes. They believe there are other methods that can and should be sanctioned that provide flexibility to different customers while assuring the DSP that the authorization is not fraudulent. We also encourage the Commission to require the DSPs to implement several flexible authorization mechanisms in order to reach all customers with whatever tools and technologies are available to them.

Mission:data notes that energy management tools are most effective when savings are expressed in terms of dollars saved rather than kilowatts or therms, which are opaque to consumers. Mission:data advocates that DSPs be required to provide detailed billing and tariff information to consumers and third-parties in a standardized, machine readable format at no charge to all customers and their third-parties. Customer engagement through utility bills is much more likely to take place if software can be used to interpret their bills, thereby ensuring that energy management tools provide consumers with accurate estimates of the dollar savings likely to result from recommended actions. Mission:data notes UCA-IUG OpenADE Task Force has already developed a tariff schema for this purpose.

Finally, Mission:data offers some insight into the question posed by the Commission on EDI. Simply put, EDI protocols were developed decades ago for other purposes and are very dated. ESPI/Green Button Connect was developed by the industry in 2010-12 and uses eXtensible Markup Language (“XML”), a modern standard used almost everywhere on the internet today. Since EDI was not designed for exchanging interval electricity data and the NIST’s Priority Action Plan for smart grid standards requires a new set of standards (which led to ESPI/GBC), it should not be used. Mission:data strongly urges the Commission to require the DSPs to provide consumption data to customers and authorized third-parties using ESPI/GBC. This requirement does not preclude the continued use of EDI in existing applications. Artificially adapting EDI to support consumption data is counter-productive because the recipients of that consumption data, the entrepreneurs and innovators making DER solutions, do not use EDI. Further, the use of EDI introduces security risks through the file transfer process it employs and use of personally identifiable information.

E. NEM

First, NEM recommends that ESCOs and other third-party providers be actively engaged as partners in the delivery system planning process. NEM is concerned that the proposed DSIP process is still too similar to the traditional utility monopoly infrastructure planning process, wherein the utilities are tasked with identifying system needs and tend to decide, independently, what resources should be called upon to meet those needs. NEM suggests that using such a process here would lead to decisions made in favor of utility-provided solutions and fail to advance the REV goals of strong DER participation and increased consumer engagement in energy usage decisions. NEM suggests implementing an open stakeholder process during all DSP planning phases.

Second, NEM suggests that ESCOs and other third-party providers should be provided with quality customer energy data in a more timely fashion. NEM urges that utilities should not be able to withhold such customer information because without it, ESCOs will be inhibited from designing and providing more innovative products that are more responsive to demonstrated customer needs. NEM suggests creating and implementing a streamlined mechanism by which ESCOs can obtain data from all of their customers (with customer authorization), without having to make multiple requests for each individual customer’s data from the utilities. ESCOs and utilities should also be able to continue to use their existing EDI infrastructure to share data.

Finally, NEM urges that the costs of metering upgrades should not be unfairly shifted to customers and function as an anti-competitive barrier to ESCO participation in the marketplace or to consumer shopping. As and when these metering upgrades are implemented, utilities should be required to provide ESCOs with metering data in as close to real-time as possible in order to realize the full benefits of AMI for consumers. NEM is concerned that, should utilities deploy AMR and ESCOs and other competitive DER providers deploy AMI to individual customers, it would become uneconomic for ESCOs to serve those customers, particularly mass market customers, and it would create an anti-competitive barrier to consumer shopping. ESCOs and other competitive DER providers may wish to provide metering to specific customers that offers increased functionality to support differentiated product offerings, and ESCOs should be permitted, but not required, to do so.

F. NY-BEST

NY-BEST supports the Commission's efforts to transform New York's electric industry with the objective of creating market-based, sustainable products and services that drive an increasingly efficient, clean, reliable, and customer-oriented industry. It also supports the State Energy Plan goals to generate 50% of the state's electricity from renewable sources by 2030 and to reduce greenhouse gas emissions by 40% by 2030 and 80% by 2050. However, NY-BEST expressed concerns with respect to the requirement that utilities evaluate and incorporate energy storage in their DSIPs. NY-BEST suggests that Staff add specific analysis requirements to conduct this evaluation in the final DSIP Guidance and to prepare more detailed evaluation guidance. NY-BEST recommends creation of a working group to prepare this more detailed evaluation guidance.

NY-BEST is also concerned that the DSIP Guidance does not contain any direct links to state renewable energy goals. NY-BEST recommends that the DSIP Guidance include interim five-year renewable targets for each utility and that utilities be required to include renewable integration in their five-year DSIP plans. In addition, NY-BEST recommends that the DSIP Guidance be amended to require utilities to present longer-term plans that intersect with 2030 state renewable targets. While NY-BEST supports the requirement for a five-year plan, they believe it is insufficient to secure investments and investors or provide DER providers with a sense of the long-term market. NY-BEST recognizes that long-term plans are subject to change, but urges that having this framework upfront is key to the success of the five-year DSIP.

NY-BEST believes it is important to recognize that the utilities’ ability to accurately forecast load growth currently faces several challenges and recommends that the DSIP Guidance recognize these challenges and place a higher value on optionality of DERs. NY-BEST more specifically recommends that the DSIP Guidance build this higher degree of uncertainty into the planning process, require utilities to include an analysis of multiple scenarios, and incorporate an optionality value of such resources as energy storage. NY-Best believes it is important to recognize that energy storage, with its ability to be incrementally and rapidly deployed, offers a high degree of value when faced with load growth uncertainty combined with an aging electric system.

NY-BEST notes the DSIP Guidance skews the decision-making process about beneficial DER locations in favor of the utilities, with only limited information being shared regarding their analysis in support of these decisions. NY-BEST recommends that utilities be required to share information and data, as well as their analysis and conclusions, for those projects where they determined that traditional investments are preferred over DER options. NY-BEST believes that sharing this information will enhance the transparency of the decision-making process and provide an opportunity for industry rebuttal. Moreover, NY-BEST encourages Staff to require utilities to perform full circuit mapping of their distribution systems and share this information with market participants.

NY-BEST supports the inclusion of VVO in the DSIPs and suggests that, in addition to requiring utilities to incorporate plans to implement VVO in their DSIPs, utilities also be required to identify compensation mechanisms for VVO.

Additionally, NY-BEST notes that limited guidance is provided to the utilities with respect to the Supplemental DSIP and some of the most important decisions are covered in that filing. NY-BEST recommends that the Commission build on the work of the Market Design and Platform Technology Working Group and create a working group of utilities and DER stakeholders to develop additional guidance for utilities on their Supplemental DSIP in the first quarter of 2016.

G. NECHPI

NECHPI requests that the Commission mandate a range of foundational work necessary for successful development of meaningful DSIPs. NECHPI recommends the following: (1) development of ten-year state integrated energy resource reports and ten-year state and utility integrated resource plans by resource (to the circuit level for utilities), updated every two years; (2) consideration of a preferred-resource loading order to avoid discriminatory behavior against CHP; and, (3) mandating common methodologies which all utilities should be required to use, such as a common BCA framework, circuit-level hosting capacity analysis, locational net benefit methodology, circuit capabilities analysis (the EPRI BCA Framework, in particular).

NECHPI suggests the Commission mandate utilities to use the California Distributed Resource Plan Proceeding and Filed Proposed Utility Distributed-Resource Plans (“DRPs”) as roadmaps for the systematic and cost-effective development of their DSIPs. NECHPI notes that the DSIP Guidance does not include many of the elements contained in the proposed California DRPs and recommends that their form, organization, and proposed subject areas be followed in the DSIPs.

NECHPI recommends that the Commission mandate utilities to develop specific strategies and plans to overcome DER barriers and what appears to be a lack of engagement with and commitment to REV objectives. NECHPI posits that without mandated tasks and timelines, the utilities would be reluctant to implement REV-related initiatives.

NECHPI suggests the Commission require specific DER implementation plans by resource on a yearly basis to combat the belief that utilities have three to five years before serious distributed-resource planning will be needed. NECHPI cautions that waiting to implement such distributed-resource planning can hinder accomplishing program goals and objectives.

It should be noted that NECHPI included a comprehensive discussion on the California Public Utilities Commission's rulemaking and orders on distributed resources planning, as well as distribution-system voltage issues researched by the California Energy Commission.

H. SolarCity

SolarCity recommends that the DSIP Guidance be modified to accelerate the rate of change assumed in the REV initiatives already established by the Commission. SolarCity notes that a number of REV goals were not adequately addressed and that the DSIP Guidance needs to reflect expected changes and outcomes for which utilities will be accountable.
SolarCity suggests that the MDPT report captures key themes and suggests next steps in the REV process that need to be implemented. SolarCity points out that the MDPT report outlines recommendations for near- and mid-term DSP market design and platform technology issues, which it suggests will facilitate near- and mid-term implementation of the DSP market. Therefore, SolarCity requests further regulatory consideration in the context of the DSIP Guidance to secure fulfillment of the REV objectives in the near future.

SolarCity commends Staff's proposal for each utility to present innovative approaches, and expected outcomes, to address REV objectives within their DSIP. SolarCity suggests, however, that the proposal is insufficient in two regards: (1) it emphasizes novelty over improvement; and, (2) it does not recognize that innovation, as a process, is as an integral part of DSP providers' responsibilities. Thus, it is crucial to design into DSP provider activities an iterative process for gathering lessons learned and innovative ideas from the global industry, and leveraging them to make ongoing improvements to the DSIPs.

Regarding interconnection, SolarCity agrees with Staff that interconnection process improvements are critical. SolarCity believes that significant, and often unjustified, interconnection delays have been routinely observed on larger, commercial projects and these delays threaten the success of the Commission's community DG program. SolarCity suggests a few ways to combat delays: (1) require the utilities to offer a service for a one-time payment to leverage its relationships to obtain all necessary municipal and environmental permits on a timely or expedited basis; (2) give utilities a performance target to meet every year; and, (3) grant the utility a pre-determined incremental percentage above and beyond the allowable return on equity if targets are exceeded. SolarCity suggests that a reasonable benchmark be established for interconnection best practices and could create an incentive without undergoing wholesale ratemaking changes. SolarCity urges that guidelines be provided as soon as possible to create an interconnection performance report, noting that transparent interconnection process performance reporting will allow for meaningful assessment of utility and developer timelines and actions.

SolarCity requests that the DSIP Guidance outline a list of specific grid needs that could be supported through market mechanisms. Utilities should be directed to describe proposals for specific sets of market mechanisms to meet each need. SolarCity recommends the following market mechanisms: (1) proposed implementation timeline and evaluation criteria; (2) a list of technologies that are envisioned to participate in the market; (3) proposed definitions of products and services transacted in the market, including geographic scope; (4) proposed market rules; (5) proposed role of the DSP provider in market operations; and, (6) proposed communications protocols and infrastructure to support the market. SolarCity also recommends that the language in the DSIP Guidance regarding cybersecurity specify, in greater detail, the cybersecurity concerns to which the utilities should respond.

SolarCity suggests that the existing guidance regarding VVO should be expanded to require consideration of smart inverters and energy storage, including third-party-owned and behind-the-meter equipment. SolarCity also suggests a target timeline be established to define the standards for enabling smart inverter capabilities, the scope of capabilities desired, and to enable those capabilities in the field. SolarCity recommends that VVO be on the list of grid needs for which utilities propose relevant market mechanisms.

SolarCity recommends that utilities be directed to describe their vision for customer engagement in various proposed DSP markets and other activities. Utilities should also be required to describe how third-parties will be enabled to provide and enhance customer engagement. SolarCity also suggests utilities should be required to propose programs that will promote customer education and encourage desired behaviors.

SolarCity is concerned about the timing of the Supplemental DSIP filing in relation to the Initial DSIPs. SolarCity is concerned that, without more structured guidance, the utilities might not be able to jointly achieve a consensus by the deadline for the Supplemental DSIP filing. SolarCity is also concerned that asking for a joint filing will not adequately support the degree of innovation and transformation that will be required to fully achieve REV objectives. In other words, SolarCity is concerned that seeking a joint response will represent the lowest common denominator, rather than the best combination of innovative concepts.

Accordingly, SolarCity recommends that Staff direct the utilities to file more comprehensive initial filings, including the content which was proposed to be delayed until the Supplemental DSIP filing and specific near-term implementations of DSP markets. The proposals should link grid needs, available solutions, market mechanisms, and supporting communications infrastructure. Following the initial filings, SolarCity recommends that Staff begin a stakeholder process or convene a working group to drive development of a standardized guidance for Initial DSIP implementation. SolarCity suggests that the creation of a dispute resolution mechanism and/or governing structure for ongoing monitoring and evolution of the DSP be added to the DSIP Guidance. SolarCity further suggests the Commission set a date on which more detailed guidance will be available for the supplemental stage and provide for the creation of a dispute resolution mechanism and/or governing structure for on-going monitoring and evolution of the DSP.

SolarCity recommends that the guidance related to available resources define each of the specific desired available resources, and describe the details of other procedures/programs that may be implemented to increase the quantity and value of DER resources and define new tariffs. In the context of enabling a distribution-level market, enhanced ROEs could be designed to 1) grow DER asset base up to a point where a market is more attainable and liquid, 2) ensure that DERs are effectively utilized, and 3) foster higher asset utilization rates.

Regarding organizational structure, SolarCity believes the separation of the core regulated utility function and the DSP operations should be discussed and how a level playing field will be ensured.

I. SEIA

SEIA supports the Commission as it sets forth to achieve REV goals and objectives and remains committed to working with all stakeholders to ensure that this process leads to plans that are in the best interests of customers. SEIA comments on five sections of the DSIP Guidance including: (1) the recommended two-phase approach to the DSIP filings; (2) the stakeholder engagement process; (3) delivery infrastructure capital investment plans; (4) distribution grid operations relating to the interconnection process; and, (5) and AMF and communication.

Regarding the recommended two-phase approach to the DSIP filings, SEIA recognizes the first DSIPs will only be a preliminary step toward achievement of REV goals, however, asserts that the schedule as laid out in the DSIP Guidance can be compressed and improved through re-organization of tasks. SEIA believes that time is of the essence on Commission review of utility DSIPs. SEIA notes the inclusion of issues identified in the platform technology and planning sections of the MDPT report will be addressed in the first set of DSIPs while the DSIP Guidance does not address a number of the business model and rate design issues that were raised in the MDPT report. SEIA asserts these other issues will need to be addressed in additional proceedings for the REV market to reach full force. Since this process will take time, there is an increased urgency to move quickly to evaluate the DSIPs so the other issues can be addressed and the market can continue to grow. SEIA believes the Supplemental DSIP can be submitted to the Commission by June 30, 2016 rather than September 1, 2016. SEIA suggests that the final product will be improved by increasing the transparency of the process throughout by providing opportunities for stakeholder input and requiring at least one interim report from the utilities.

SEIA agrees that a consistent statewide approach will benefit consumers by allowing DER providers to treat New York as a single market opportunity, rather than a balkanized utility-by-utility market that requires customized products for different areas of the state. However, SEIA recognizes that there are substantive differences in service territories, pointing to grid architectures, existing technical sophistication of the grid, and planning and operational practices of the various utilities across the state.

SEIA proposes a different approach to the DSIP filing process. SEIA suggests the utilities meet first to discuss assumptions, planning and capital budgeting approaches, and technical solutions needed to address DSIP requirements. These discussions should also include approaches for designing a stakeholder engagement process. The intent of this meeting is to begin the DSIP process with an understanding of the similarities, differences, and resources available throughout the state. SEIA also believes this will prevent delay if there are substantial differences in approaches that, under the Staff schedule, may not surface until after the Initial DSIPs are filed. SEIA recommends each utility assign a team to meet jointly with the other utilities to continue the process of understanding and balancing their differences. SEIA is therefore proposing that the utilities prepare an interim report on or around February 15, 2016 and hold monthly open stakeholder workshops, commencing in early 2016, to document and discuss their initial findings. SEIA maintains that this will allow Staff and stakeholders to monitor progress during the development of implementation plans.

With respect to the stakeholder engagement process, SEIA believes a number of REV outcomes will be improved through active stakeholder participation in the initial design of the DSIPs and implementation plans. SEIA suggests that, during the DSIP development process, the Commission should provide a designated expert to serve as a common resource for stakeholders. SEIA also recommends that a well-structured and interactive process for stakeholder input in the ongoing distribution planning process should be a requirement of every DSIP. Use of common models and approaches should be encouraged. Furthermore, each utility should then invite stakeholders to participate in distribution planning presentations.

SEIA believes that determining hosting capacity is necessary and suggests each utility be required to include a plan for upgrading each circuit or area network where hosting capacity is near its perceived limit. SEIA points out that DERs are likely to have more delivery infrastructure avoidance value that is also easier to quantify in these areas. SEIA notes that this demonstrates that utilities should go beyond providing information on the current state of the grid and should also provide concrete steps that the utility will take to move forward with REV implementation.

SEIA suggests the DSIPs indicate the specific steps and relevant metrics each utility will use to reduce the amount of time between application and interconnection, improve transparency of the interconnection process, and reduce costs by improving efficiencies in the process. This would allow the interconnection process to be measured within the EIM framework that the Commission establishes.

SEIA believes that the need for foundational grid modernization investment is critical and recommends that the

Commission propose a more modest approach to mass deployment of AMF given competing needs for other foundational grid investments. SEIA advocates incentivizing DER providers to supply AMF to active market participants and states many third-party providers are developing business models and technology platforms that will enable them to make these deployments for their customers. In areas that have been identified as high value target areas for deployment of DER, SEIA states it may be appropriate for AMF to be installed in all customer premises.

SEIA cautions there is a danger that utility AMI deployment may stifle third-party innovation and it will be important to create a level playing field relative to metering requirements, data protocols, and data access. In order to promote an even playing field, SEIA states there must be some equivalency in cost recovery for metering and communication investments. SEIA prompts the Commission to explore a model where any provider of AMF receives payment for providing such functionality to the grid.

Governmental Entities

A. NYC

NYC stresses statewide uniformity, clear guidance, and a level playing field when developing REV initiatives. NYC argues that input should be sought from all sectors of the marketplace to inform REV, the DSP process, and the evolving nature of the retail marketplace. Accordingly, NYC suggests the Commission defer consideration of the DSIP Guidance and consider proceeding with DSIP development on a phased, topic-by-topic basis as the information and issue development for each topic are completed. Furthermore, as the basis for the DSIP Guidance are whitepapers upon which the Commission has not acted, it is inappropriate to rely on them for DSIP filings.

NYC contends the proposed BCA framework does not properly value externalities and the inclusion of the BCA framework in DSIPs may lead to improperly capturing the value of renewable resources and energy efficiency measures. Similarly, the Track Two Whitepaper and associated comments leaves several key questions either unanswered or enmeshed in stakeholder debate. NYC further argues that relying on the findings of the MDPT report would be inappropriate as it does not identify the necessary architecture of the DSP or retail marketplace, provide a description of the AMF needed for the retail marketplace, or provide detailed guidance to the utilities. Lastly, the DSIP Guidance seeks, primarily, utility input on basic factual information that should have been compiled for use in developing the DSIP Guidance in order for interested parties and prospective market participants to evaluate it for accuracy and completeness.

Therefore, NYC suggests the Commission convert the DSIP Guidance into a set of information requests and give the utilities a period of forty-five or sixty days to provide detailed responses and to provide for an opportunity to review the responses and posit clarifying questions, possibly resulting in a hearing or other process that involves real-time interactions and the development of an appropriate record.

NYC agrees that there is great potential for DER to supplant or supplement capital investments or operations and maintenance expenses by utilities, however, overreliance on this premise ignores the many reasons consumers may choose DER. As such, NYC argues there should be broader guidance as to how the utilities should incorporate both utility-related and consumer-driven DER projects into their system planning and future forecasts. NYC suggests either the MDPT Working Group or the working groups instituted during Track One of this proceeding be reestablished and tasked to develop joint recommendations on this topic.

Clear and consistent rules regarding the provision of granular data are needed. In addition, it is important that the same data sharing rules apply statewide. Neither the DSIP Guidance nor the Track One Order provide any guidance to the utilities on the subject, which would allow utilities to develop different data access rules. As such, the DSIP Guidance should specify the data to be made available, the manner in which such data will be made available, the frequency of data updates and releases, and the cost, if any, to be charged for the data. Similar concerns surround how that data will be disseminated. As these issues are still in development, it is not appropriate for the utilities, but rather the Commission through a technical conference, collaborative discussion, or other process in which there can be real-time discussions of the issues, to be the arbiter of these issues and decide which viewpoints to include in the DSIPs to ensure statewide clarity and uniformity.

NYC argues there are many other ways in which DER could provide value to consumers and the utilities' obligations to provide information should be expansive, not narrowed to areas where DER would be justified by wholesale energy prices or may provide reliability benefits. Additionally, all salient information should be disclosed to the marketplace such as, but not limited to, the nature of the expected needs and the ability to rely on alternatives to traditional infrastructure.

NYC suggests that in comparing traditional utility investments to DER investments, the total value provided by each should be considered. The traditional investment would ensure that reliable electric service to an area is maintained, but the DER investment may provide the same reliable electric service, plus possibly environmental and/or societal benefits. Also, NYC submits that though adjustments to communications protocols over time may be appropriate, a reasonable set of communication protocols should be developed and in place at the inception of the marketplace.

NYC suggests it should be confirmed that VVO is an appropriate alternative to investments in infrastructure or DER and that VVO is cost-effective across customer classes. An analysis should be performed to demonstrate that VVO is consistent with each utility’s obligation to provide adequate and reliable service. In addition, the utilities should establish a baseline as to their current VVO capabilities; since it is difficult to assess the merits of upgrading the capabilities without knowing the starting point or the effectiveness of the capabilities that are already in place.

According to NYC, AMI should become a part of basic utility service and available to all consumers. If it is not, inequities could arise in that all consumers would not be able to access the same products and services. Similarly, REV pertains to the utilities’ distribution systems, DER at the distribution level, and the retail marketplace. The NYISO has no role and no authority over retail matters and is not within the scope of the REV goals, principles, or objectives. NYC contends that though it makes sense to consider interactions between the wholesale and retail markets, that process should be open to all market participants. Therefore, NYC recommends that these topics be addressed through a process in which all interested parties are given the same opportunity to provide input. That input once tested, should form the basis of specific guidance to be used to develop DSIPs.

B. NYPA

NYPA supports the Commission’s efforts in developing the utilities’ DSIPs and believes that the information components required by the proposed DSIP Guidance will provide stakeholders with a better understanding of utility plans for DSP implementation and inform stakeholders of opportunities to benefit the grid and consumers through DER deployment and more intelligent networks. Specifically, NYPA supports a stakeholder engagement process that includes focused technical conferences and discussions to allow each subject area to be appropriately vetted as the Initial and Supplemental DSIPs are developed, in addition to the opportunity to comment on the filed DSIPs. NYPA argues that stakeholders may bring to the table a wide range of expertise and ideas that will improve the DSIPs. NYPA believes that this level of stakeholder engagement should extend beyond the development of the Initial and Supplemental DSIPs, as ongoing discourse in the development of future DSIPs will be beneficial in the development of DSP mechanisms and the REV markets.

NYPA suggests using NYPA’s Advanced Grid Innovation Laboratory for Energy (AGILe), an electric power research and development facility, to assist the utilities. AGILe aims to help distribution and transmission operators find ways to reduce system strain during peak use, enhance load and distribution network monitoring, improve distribution system planning, and expedite renewable resource integration and deployment of DERs. To allow development of the most efficient and effective peak reduction programs, NYPA argues it would be beneficial for the utilities to also identify and categorize those networks that have peaks coincident (or near coincident), both time-of-day and season, with the New York Control Area or the utility’s system peak in their Initial DSIPs. This could potentially identify those distribution networks where peak load reduction efforts may yield the greatest benefits by simultaneously addressing network and bulk power peaks.

Utilities

A. Exelon

Exelon supports many critical elements of the proposed DSIP Guidance, including the assignment of the DSP provider role to the existing New York utilities, the requirement to develop utility-specific DSIPs to increase transparency and facilitate competition and integration of distributed resources, and the requirement to explore cross-utility DSIP coordination plans. Exelon supports the use of DSIPs as a way to move REV forward in a measured manner. Exelon advocates for a realistic and reasoned implementation timetable for REV, including engaging stakeholders in the process (with the exception of any requirement that utilities present capital budgets for review by stakeholder and market participants). This advice is based on experience implementing smart grid and smart meter projects in other jurisdictions

The initial DSIPs should be a roadmap, starting with a realistic assessment of existing technology maturity and industry experience implementing major advanced grid distribution level automation, communications and control technologies before moving to substantive planning. Exelon recognizes the value in Staff's two-phase approach for DSIPs that provides better coordination among utilities. A system-wide approach, where feasible and practical, has advantages. A prudent approach may be using these initial DSIP filings to identify those areas where coordination among utilities is feasible in the near- or medium-term, or conversely where coordination is not optimal or feasible given operational requirements. This first cross-utility DSIP alignment plan should focus on identifying the appropriate approach to alignment. Achieving alignment beyond low-hanging fruit will probably need to be a longer, multi-phased process. Moreover, State-wide coordination requires a multi-phase and longer-term process.

Exelon argues that the stakeholder process is an appropriate forum for ensuring that greenhouse gas reductions are treated adequately. Exelon supports the engagement of stakeholders in the process of developing the DSIP framework, but neither at the expense of the overall REV initiative nor in duplication of its ongoing, multiple workstreams. Any requirement that utilities present capital budgets for review by stakeholders and market participants is problematic. Such a requirement would be duplicative of 1) existing adjudicatory processes for the purpose of determining the just and reasonableness of these proposed capital investments and 2) the proposed BCA process. As a result, this additional process will be redundant, inefficient, and costly, making it extremely difficult for utilities to develop baseline capital plans for reliability and other core utility functions, already subject to regulatory and competitive review. Additionally, it introduces potential physical and cybersecurity issues, as well as FERC jurisdictional issues regarding transmission operations and related information.

Exelon agrees with Staff that operating the distribution grid in a safe and reliable manner is paramount, and that the operational details required to meet this obligation will continue to evolve.

Exelon is sensitive to privacy risks and asserts that it is unclear what level of data granularity is required and what useful information about individual customers/small groups of customers can be extracted from very granular data.

Exelon asserts that deployment of universal AMI systems is essential to achieving the REV vision, is uniquely a utility function, and that utilities should be assured cost recovery with these investments. The initial DSIPs shouldn't necessarily be specifying the technologies and standards necessary to maintain the level of reliability, but rather developing the methodologies for how to obtain and make that information, once determined, accessible to stakeholders. In short, there are many and changing variables that may affect distribution system operations from one day to the next; much more analysis is needed to determine the impacts. Complex issues that involve deeming potential savings from deferred distribution investment and maintenance are beyond the scope of the initial DSIPs.

Regarding customer data, Exelon agrees that the privacy risks require careful analysis. Customer choice and innovation require that appropriately licensed and authorized market participants have access to accurate and timely data. Utilities, for their part, should be compensated for any systems needed to make data available.

Exelon stated the deployment of universal AMI systems is essential to achieving the REV vision; utilities should be assured of cost recovery to encourage them to move forward with these investments. Exelon supports the Commission's decision to establish the utility as the owner and operator of the DSP platform. Exelon disagrees, however, that AMI ownership structures should be in question, as that is similarly uniquely a utility function. Exelon's experience with AMI has generally validated the projected benefits of AMI in terms of reduced metering costs, improved accuracy and customer responsiveness, and improved outage analysis and response. Exelon opposes the suggestion in the DSIP Guidance for non-utility revenue metering.

B. IGS

IGS supports many of Staff's proposals, such as focusing on the information each utility presently possesses and initial changes needed for a comprehensive and transparent planning process, Staff’s attention to the role of AMI to provide ESCOs and DER providers access to interval data and system data, and the need to modify existing rate designs to incentivize REV-related goals. IGS suggests Staff placed insufficient emphasis on establishing neutral DSPs and recommends that the Commission reject Staff’s recommendation that the utilities include additional utility-owned REV demonstration projects in their DSIPs. Instead, utilities should identify in their Initial DSIPs how they will functionally separate DSP functions from standard utility operations and utility-owned DER operations. The Commission should reaffirm its commitment to developing a competitively neutral DSP and REV market supported by third-party investment, rather than through demonstration projects and ratebase.

IGS suggests that the Commission focus on three key principles related to advanced meter deployment and the achievement of REV goals: (1) advanced meters must have the capability of recording and transferring granular customer interval usage and power production data to a meter data management system; (2) the owner/operator of the meter data management system must transfer granular interval usage and power production data to ESCOs and DER providers through EDI transactions, subject to an appropriate and easy-to-implement authorization process; and, (3) utilities must adjust ESCOs’ NYISO settlement statement to reflect actual customer usage.

IGS argues that with the installation of advanced metering, utilities should identify whether each customer has an advanced meter, the type of meter (if there are differences), and provide the option for third-parties to choose between summarized and non-summarized interval data. Utilities should also allow third-parties to request specific summarized and non-summarized interval customer usage information (for both existing and potential customers). After receiving the request, the utility should place the requested information on either a File Transfer Protocol site or Secure File Transfer Protocol site.

IGS recommends that the utilities implement and own advanced meters. Requiring third-parties to install meters would create several potential pitfalls and coordination challenges. It would likely lead to a deployment of several different types of metering technologies, some of which may not integrate well with ESCO and DER providers IT systems. Requiring third-parties to install meters would also add additional capital costs for DER projects and create additional risk of cost recovery. To the extent that the Commission permits third-parties to install and own advanced meters, it would be necessary to establish rules that would ensure that ESCOs and DER providers have non-discriminatory access to customer interval data, subject to appropriate customer authorization.

Regarding the data collected by AMI, IGS believes the data should always be owned by the customer. The owner of the meter and meter data management system is a custodian of the data. ESCOs and DER providers should be granted access and use of customer data subject to appropriate and easy to implement customer authorization procedures. ESCOs and DER providers should be able to obtain authorization to access interval data through terms and conditions contained in contracts for REV-related products and services.

C. Joint Utilities

The Joint Utilities generally endorse the Initial DSIP filing objectives, and are broadly supportive of the specific requirements of the DSIP Guidance, however they offer a number of specific comments. The Joint Utilities organize their comments into three sections: comments regarding the Initial DSIPs, comments regarding the Supplemental DSIP filing, and comments regarding Advanced Metering Infrastructure (AMI).

With respect to the Initial DSIP, the Joint Utilities submitted comments regarding: (1) REV Demonstration Projects; (2) distribution system planning; (3) the interconnection process; (4) customer data and customer engagement; and, (5) system data. The Joint Utilities propose that the process for approval of demonstration projects should be streamlined and broadened to explicitly allow utilities to propose project criteria outside of those articulated by the Commission as part of its Track One Order. Furthermore, the Joint Utilities request that the Commission approve the cost recovery mechanism as proposed in their comments on the Track Two Whitepaper.

The Joint Utilities recommend that the proposals regarding incorporating DER into the system planning process and forecasting and identifying beneficial DER locations be deferred to the Supplemental DSIP to allow for the development of a consistent approach for coordination between utilities and third-parties. Instead, the Joint Utilities propose that, as part of the Initial DSIP, the utilities will identify what information is available on incorporating DER today, identify gaps and potential security concerns and identify near-term plans for individual utility enhancements and their alignment with on-going efforts in Supplemental DSIP development. To the extent possible, the Initial DSIPs will provide substation forecasts of DER impacts on peak load, energy, and load shapes, as well as provide data for specific areas where DER may provide reliability or operational benefits. The Joint Utilities further request that the DSIP Guidance adopt the four-part process for identifying Non-Wire Alternative areas as proposed in their Initial Comments to the BCA Whitepaper. This screening process would provide clarity to developers and utilities by identifying the specific traditional transmission and distribution investments that have the potential to be deferred or replaced by NWAs.

The Joint Utilities anticipate that the Commission will adopt changes to the interconnection process prior to the filing of the Initial DSIPs, however, they support further improvements to the interconnection process, including increased automation of certain aspects. The Joint Utilities propose to work with Staff and stakeholders in a collaborative process on the five most important enhancements to the interconnection process: (1) improving the screening process; (2) clarifying the SIR process; (3) identifying and incorporating industry best practices; (4) improving the cost and timeliness estimates of utility interconnection reviews; and, (5) improving cost estimates for necessary system upgrades. The Joint Utilities propose that the final DSIP Guidance include which steps of the interconnection process are reasonable to automate.

Regarding the Supplemental DSIP, the Joint Utilities submitted comments regarding: (1) topics to be addressed in the Supplemental DSIP; (2) prioritization of Supplemental DSIP topics; (3) the proposed stakeholder engagement process; and, (4) other topics to be addressed in the Supplemental DSIP. The Joint Utilities propose to assign the topics, which Staff designated for the Supplemental DSIP into three categories of descending priority. Category 1 would consist of those topics that advance REV at a reasonable cost by providing value to customers or develop capabilities necessary for DSP operation, and have an appropriate timeframe where implementation plans can be presented as part of the Supplemental DSIP and significant progress can be made in the first two years thereafter. Category 2 would consist of topics, which require more time and stakeholder engagement than would be feasible for filing contemporaneous to the Supplemental DSIP, and would likely not be fully achieved, although substantial progress would be anticipated, during the first two years thereafter. For items in Category 2, progress made will be presented in the Supplemental DSIP filing along with a plan that addresses future efforts. Category 3 would consist of topics, which cannot be addressed in the Supplemental DSIP because they require the development and testing of additional enabling technologies and new business practices prior to implementation. The Joint Utilities request that Category 1 and 2 topics be addressed as part of the Supplemental DSIP, but that Category 3 topics instead be deferred for consideration until after the Supplemental DSIP filing.

According to the Joint Utilities, Category 1 topics include: (1) a methodology for determining hosting capacity; (2) improving the interconnection process; (3) determining an appropriate AMI rollout policy; (4) determining data access policies for customer and system data; and, (5) determining appropriate DER procurement approaches. The Joint Utilities propose that Category 2 topics include: (1) demand forecasting; (2) DER forecasting; (3) a methodology for determining energy storage impacts; (4) a probabilistic system planning methodology; (5) standardizing a load flow analysis process; (6) handling cybersecurity issues; (7) developing coordinated demand response and DER dispatch tools; (8) creating a standard set of DSP market participant rules; and, (9) joint system planning and system operations procedures among utilities. The Joint Utilities propose that Category 3 topics include: (1) improved granular pricing; (2) coordination with the NYISO regarding roles and responsibilities of the NYISO and distribution utilities, other types of DER dispatch outside of demand response, and coordination between the NYISO and distribution utilities at the interface between systems; and, (3) procedures for settlement of DER assets in the DSP markets.

The Joint Utilities note that an efficient and effective stakeholder engagement process used to discuss the Supplemental DSIP topics will result in better solutions. To that end, the Joint Utilities propose to retain a consultant to design/conduct the stakeholder engagement process, who would lead technical conferences, distribute material to educate stakeholders, frame key issues to ensure the stakeholder engagement process is as effective as possible. The Joint Utilities further suggest that, although the consultant would be retained and compensated by the utilities, the consultant should be independent from the utilities and responsive to all stakeholders. The Joint Utilities further request that the stakeholder process conform to its proposed prioritization of topics to be considered in the Supplemental DSIP.

The Joint Utilities offer a number of other proposals related to topics to be addressed in the Supplemental DSIP. Regarding determination of hosting capacity, the Joint Utilities propose that the Supplemental DSIP be focused on determining hosting capacity at the distribution circuit level for radial systems only. The Joint Utilities note that while determining hosting capacity on radial systems is relatively straightforward, similar determinations on looped or network systems are significantly more complicated and capabilities do not currently exist to perform these calculations.

The Joint Utilities propose a stakeholder engagement process to address identifying system and customer data which has the greatest value, the costs of gathering such data, what analyses should be performed on the data, and how data would be communicated to customers and third-parties. The Joint Utilities also stated distribution system data is not self-explanatory and must be considered in the context such as the local system design criteria, potential security concerns, and local knowledge of operational performance. Without such context, the use of raw system data would lead to inefficient distribution planning.

The Joint Utilities note that they have been working to develop a coordinated cybersecurity policy among its member utilities, and request that cybersecurity and customer data privacy concerns be addressed by the final DSIP Guidance prior to requiring the utilities to communicate certain sensitive system and customer data to customers and third-parties. The Joint Utilities further note that they plan to engage stakeholders on cybersecurity issues focusing on desired outcomes and their associated costs instead of on the technical details of how such cybersecurity would be achieved.

Regarding AMI, the Joint Utilities are supportive of using AMI as the preferred technology to meet the needs of the future DSP markets; however the customer bill impact associated with AMI and the value derived from deployment will vary based on the attributes specific to each utility’s service territory including size, population density, customer demographics, and geography. For this reason, the Joint Utilities recommend that a positive business case should accompany any plan for wide-scale deployment of AMI within utility’s service territory. The Joint Utilities note that collection and analysis of data, either through AMI or other distribution sensors, at the grid edge is critical for DSP operations, and that AMI is a proven means of providing data on customer load, outages, end-point voltage readings, and contribution of DERs to the distribution system. The Joint Utilities further note that AMI has the known capability to support grid modernization, and will allow customers to participate in dynamic pricing offerings, while providing operational efficiencies versus traditional metering. The Joint Utilities are unaware of any other single technology which can mimic the capabilities of an AMI system, nor one that would allow customers to participate in dynamic pricing programs or mass market demand-based rate designs. Furthermore, the Joint Utilities note that cybersecurity risks increase with increasing diversity of technologies and ownership models used to collect the required data.

C. NRG

NRG shares the Commission’s REV vision. To achieve the REV goal, NRG submits that the REV process should focus on ensuring that (1) each utility’s financial incentives align with a vibrant market for DERs, (2) that each utility’s role as a DSP is implemented in an impartial manner and that utilities’ are held accountable for their role as DSPs, and (3) that the DSIPs adequately take into account the perspectives and interests of customers and DER providers. NRG emphasizes that the stakeholder process must be continued in the long-term to ensure that the REV marketplace rules and structures remain responsive to the needs of the platform users and to ensure that utilities are held accountable in their role as DSPs.

NRG also believes it is important that the utilities are limited to their traditional delivery role and the core monopoly functions of platform administration. If utilities are allowed to provide competitive services, other competitive suppliers will be deterred from investing private capital and entering the market, significantly delaying development of the REV marketplace. Accordingly, NRG suggests the Commission require that DSIPs clearly indicate how the utilities will create a neutral platform that will encourage third-party DER providers and customers to invest sufficient capital to realize the full potential of infrastructure deferral, grid operational support, and customer value.

NRG agrees with Staff that vigorous stakeholder engagement is necessary for developing the DSIPs. Stakeholders, including customers, DER suppliers, aggregators, and others, are the third-parties who will need to bring forth their capital and innovation to make REV a success. DSIPs must to be responsive to the needs of that customer base, and should be broad and flexible, reflecting the many ways that third-parties will want to interact with the DSP and the REV marketplace.

NRG suggests a series of monthly stakeholder sessions starting in January 2016 and facilitated by a neutral party. While the utilities should be primary presenters, they should not act as the facilitator. A third-party facilitator will ensure that there is a sufficient opportunity for all parties to prepare and present their views, to ask questions, and to offer suggestions to inform the preparation of the DSIPs. Sessions early in the year can inform both the Initial DSIPs and the Supplemental DSIP, and mid-year/summer sessions can focus more directly on the Supplemental DSIP.

In addition to the DSIP issues introduced by Staff, NRG suggests several areas where the DSIP proposals should be expanded or modified, and which should be included in stakeholder discussions as DSIPs are prepared. According to NRG, it appears that the DSIP framework envisions DERs as providing energy and little more. DSIPs should address not just simple hosting capability, but should go further and identify the specific challenges and solutions specific circuits face and the type or functionality of DERs that would best address those challenges and improve circuit efficiency or performance.

NRG adds identifying the type of DER or DER functionality that would best address particular circuit needs is insufficient to attract those DERs to the circuit. Appropriate operational information and price signals will require significantly more data about system needs, and how DERs can meet those needs, than is currently provided by the AMI technologies discussed in the DSIP Guidance. To enable such communication between DERs and the grid, the distribution system must incorporate sensors and data acquisition systems that identify which DERs will most effectively optimize the system. The system can then send signals to DER deployers and service providers about the specific types of functionality and technologies that can best meet system needs while enhancing customers’ value from owning or leasing DERs.

Accordingly, NRG explains the DSIPs should not envision exclusive utility ownership and control of the system(s) that control and operate DERs. Instead, the DSIPs should focus on utility ownership and operation of sensors and analytics that identify system needs and convey that information to competitive DER owners and service providers. NRG suggests this will encourage competitive DER providers to use non-utility capital and optimization capabilities, whether alone or in conjunction with the DSP or utility, to design, select, develop, operate, and optimize a variety of DERs. Utility investments should focus on gathering and sending the signals regarding the type of DER and needed functionality to the competitive side of the marketplace, but not necessarily on systems to control and operate those DERs.

NRG suggests the Commission consider establishing a framework for an ongoing stakeholder process and debate of changes to the market rules that would exist separate from the utilities. NRG notes it is critical to have a neutral facilitator to ensure that schedules and agendas are administered fairly and to bring about a high level of confidence in all parties as REV develops. Likely in the early days of REV, this stakeholder group would be active, but would meet less frequently as the rules are completed and the market becomes well-established.

Customer Representatives

A. MI

MI is concerned that the DSIP Guidance assumes large investments in AMI that have yet to be justified. Before taking action on AMI investments, MI suggests the Commission should require (1) detailed proposals, (2) detailed cost estimates of what is being postponed and associated delivery rate impact analyses, and (3) detailed quantifications of the purported benefits to customers, including tangible cost savings.

MI also notes that possible AMI investments trigger significant cost allocation and cost recovery issues which have yet to be decided or addressed in the DSIP Guidance. For example, all or most large non-residential customers have already paid for their own advanced meters and it would be highly inequitable to impose on such customers the costs of supplying other service classes with advanced meters. MI urges that each service class should be responsible for its own metering costs.

APPENDIX C

ANALYSIS OF DSIP GUIDANCE COMMENTS

SUMMARY OF REPLY COMMENTS

Public Interest Intervenors

A. Acadia

Acadia is concerned that the DSIP Guidance needs a more specific set of stakeholder engagement requirements. Acadia suggests the stakeholder process continue beyond development of the Initial and Supplemental DSIPs, into the approval and implementation phase. Acadia is generally supportive of engaging a third-party expert to facilitate the stakeholder process but cautions against a consulting firm hired by and reporting to the utilities. Acadia instead recommends that any such third-party expert report to the Commission.

To meet the target of fifty percent renewables by 2030, Acadia recommends the Commission require greater cost-effective energy efficiency investment while the DSIP process unfolds because the Clean Energy Fund and the Energy Efficiency Transition Implementation Plan offer inadequate support for energy efficiency and it is unclear when DSIP implementation will have a material impact on energy efficiency deployment.

Acadia recommends drawing on lessons learned with other projects in other jurisdictions, such as National Grid’s DemandLink pilot in Rhode Island and Central Maine Power’s (a subsidiary of Iberdrola, a parent company of NYSEG and RG&G) Boothbay Smart Grid Reliability pilot.

Acadia disagrees with the Joint Utilities’ prioritization and organization of the Supplemental DSIP topics into three categories. The first category consists of near-term activities, category two contains activities that require more time and stakeholder engagement, and category three reflects activities that cannot be addressed in the Supplemental DSIP.

Specifically, Acadia is concerned that a number of crucial topics appear in categories two and three, namely, demand forecasting and coordination with the NYISO. Instead, Acadia recommends the utilities adopt a comprehensive approach to the topics in categories two and three, as well as provide a timeline and target deliverables in the Supplemental DSIPs.

Lastly, Acadia notes the DSIP Guidance needs more detail and direction. Acadia points out that the DSIP Guidance relies on draft documents (the BCA Whitepaper and the Track Two Whitepaper) and should instead lay out the details referenced in those documents explicitly within the Guidance.

B. AEEI

Noting that, in the initial comments, parties interpreted the role of the DSIPs in different ways, AEEI suggests more clarity is needed from the Commission on how the DSIPs will fit into the overall implementation path for REV. Specifically, more clarity is needed on the DSIP timeline after the filing of the Supplemental DSIP in September 2016 and on the timing of Commission decisions that will approve implementation of the DSIPs.

With respect to stakeholder engagement, AEEI recommends the Commission make experts available to support meaningful engagement by a wide range of stakeholders. AEEI suggests Acadia's idea to create a fund through which stakeholders could retain expert support and the Joint Utilities' suggestion of using a third-party expert should both be considered.

AEEI suggests considering ways to accelerate the Supplemental DSIP timeline. AEEI also notes the utilities should still make progress toward their Earnings Impact Mechanisms and include detail on these areas in the DSIPs.

AEEI disagrees with the Joint Utilities that, rather than providing raw system data, utilities would provide DER providers with "insightful information, resulting from and in context with utility planning processes, regarding locations of system needs and the ability of the system to host distributed generation." The Joint Utilities' suggestion does not give DER providers enough information. AEEI also disagrees with the Joint Utilities' suggestion to adopt the four-part screening process proposed in the Joint Utilities' Initial Comments to the BCA Whitepaper because it is too narrow in scope to serve as the general foundation for BCA in REV.

C. CEOC

With respect to the DSIP process and timeline, CEOC recommends that the information requested in the DSIP Guidance, supplemented by potential estimates for varying types of DERs, be provided by the utilities and vetted by stakeholders in technical conferences during the winter and spring of 2016. CEOC is concerned that the Joint Utilities assert the data necessary to support increased DER penetration does not yet exist. CEOC urges utilities to use the best data available and not to delay initial DER procurements. CEOC also notes the utilities' DER planning activities should be conducted within a timeframe that allows the information to be incorporated into the NYISO's reliability planning process.

CEOC continues to recommend, at least in the near-term, that DER be procured using a RFP-based competitive procurement process, rather than an auction process. CEOC further recommends that, before using an auction process, the utilities be required to test such processes using pilot programs. If the pilot programs are found to be successful, then auctions could be considered. Regardless, CEOC suggests auctions not be used to procure DERs unless the following conditions have been met: (1) the commodity being sold is very narrowly drawn; (2) the commodity being sold has a sufficient number of competitive producers; (3) the auction is conducted by an independent third-party with no financial stake in the outcome; and, (4) the auction process is overseen by the Commission and is supported with monitoring protocols.

With respect to AMI, CEOC recommends that the DSIP Guidance should describe the components of an AMI business plan and how AMI will facilitate customer billing management and achievement of REV goals. CEOC suggests AMI proposals be made and considered within or concurrent with the DSIP process and that technical conferences precede AMI proposals. CEOC also mentions ongoing stakeholder engagement through an AMI Collaborative.

CEOC also suggests any AMI proposals be accompanied by an assessment of cost-effectiveness, using consistent valuations and methodologies statewide. Specifically, CEOC recommends that any DSIPs including proposals for AMI contain the following: (1) projected rate and bill impacts on low-income customers and proposals for ensuring residential and low-income customers have access to programs using AMI data; (2) environmental and DER-related benefits, such as a description of the REV-related products/services that will be enabled by the proposed AMI project, identification of environmental and DER-related benefits, and the extent to which identified benefits could be achieved with an AMI alternative or a partial AMI deployment; (3) customer engagement and education plans; and, (4) procedures for giving customers near-real-time access to their individual customer data and for giving third-party providers near-real-time access to both individual and aggregate customer data.

With respect to stakeholder engagement, CEOC agrees with AEEI’s suggestions to create three periods of stakeholder engagement (before, during, and after DSIP development) and to engage some form of stakeholder support, such as independent experts. CEOC disagrees, however, with the Joint Utilities' recommendation to engage stakeholder representatives chosen by the utilities. If stakeholder representatives are used, they should include individuals from the environmental and consumer sectors in proportion to the utilities' representation.

CEOC disagrees with the Joint Utilities' proposal to limit data access for vendors and other providers. CEOC supports NYC's recommendation that the Commission solicit information from market participants as to the data they need and determine what information be made available to them. CEOC also agrees with NY-BEST and ESA that the utilities should share detailed information on proposed infrastructure planning.

D. EDF

EDF agrees with AEEI's proposal for three periods of stakeholder engagement (before, during, and after DSIP development). EDF also agrees that some form of stakeholder support may be necessary, such as hiring independent experts. EDF disagrees, however, with Exelon's contention that allowing stakeholders to review capital budgets would be redundant with existing adjudicatory processes and the proposed BCA process. EDF strongly disagrees with the Joint Utilities' suggestion to engage stakeholder representatives chosen by the utilities. If stakeholder representatives are used, they should include individuals from the environmental and consumer sectors and the utilities should not be permitted to choose representatives.

EDF disagrees with the Joint Utilities' proposal to limit data access for vendors and other providers. EDF supports NYC's recommendation that the Commission solicit information from market participants as to the data they need and determine what information be made available to them. EDF also agrees with NY-BEST and ESA that the utilities should share detailed information on proposed infrastructure planning.

The Joint Utilities prioritized and organized the Supplemental DSIP topics into three categories. The first category consists of near-term activities, category two contains activities that require more time and stakeholder engagement, and category three reflects activities that cannot be addressed in the Supplemental DSIP. EDF notes AMI is included in category one, while granular pricing and DER procurement approaches are contained in category three. EDF argues the utilities should not expect to implement AMI infrastructure first, and then delay the implementation of the programs that justify AMI infrastructure investment. EDF suggests DSIP plans that involve AMI deployment include the schedule for deployment of the programs that justify investment in AMI as close in time as possible to AMI implementation.

E. IREC

IREC urges the Commission not to shift certain requirements from the Initial DSIPs to the Supplemental DSIP. Instead, utilities should be encouraged to explain the information they have, report on current status, provide insight into their methodologies and assumptions, identify gaps, and set timelines for improvement.

The Joint Utilities prioritized and organized the Supplemental DSIP topics into three categories. The first category consists of near-term activities, category two contains activities that require more time and stakeholder engagement, and category three reflects activities that cannot be addressed in the Supplemental DSIP. IREC suggests that the Commission require utilities to include all relevant, available information on the DSIP Guidance topics, regardless of category, and that the Commission set firm timelines for all three categories.

IREC reiterates the importance of firm timelines for gathering the information and conducting the analyses discussed in the DSIP Guidance, especially with respect to hosting capacity. IREC urges the Commission to set such timelines.

IREC supports including logical “next steps” requirements in the DSIP Guidance. To be meaningful, these additional “next steps” should be accompanied by firm timelines. IREC also recommends that utilities be required to explain how the actions and information in their DSIPs will help meet other New York State energy goals.

With respect to hosting capacity, IREC urges the Commission to require utilities to share hosting capacity and other system information for all locations. IREC urges the Commission to set forth a plan for utilities to analyze their entire systems, not just beneficial areas of their grids. IREC further recommends the Commission consider what information stakeholders should receive regarding system capacity and system data, as well as how to best present that information. IREC suggests such information be made available to stakeholders on June 30, 2016.

IREC supports the inclusion of demand and DER forecasting methodologies, as well as multiple long-term DER growth scenarios, in both the Initial and Supplemental DSIPs.

IREC supports prioritizing interconnection in the utilities’ category one topics. IREC suggests the Commission require utilities to describe to describe the challenges and obstacles associated with the current interconnection process in both the Initial and Supplemental DSIPs, especially with respect to projects above 50 kW.

IREC notes the following suggestions for stakeholder engagement from the Initial Comments and urges the Commission to consider them: (1) requiring utilities to document stakeholder input and provide written responses to comments; (2) requiring utilities to share the background information and studies upon which they base their determination; (3) creating a public website and/or hiring a public expert to help stakeholders better understand the information presented in the DSIPs; and , (4) coordinating with local governments to ensure efficient public planning and consideration of environmental impacts.

With respect to AMI, IREC asks the Commission to require the utilities to articulate how the AMI data will be shared and analyzed in order to meet REV goals and objectives and to establish timelines for any proposed AMI rollout effort.

Providers & Organizations

A. Smart Wires

Smart Wires requests that the Commission allow technology experts access to distribution network data and provide mechanisms for these third-parties to earn revenue so that New York ratepayers can benefit from new, cost-effective technologies on the system. (Smart Wires references the NYISO’s mechanism whereby third-parties invest in the transmission system and suggests a similar mechanism can be used here.)

Utilities

A. Joint Utilities

The Joint Utilities urge that demonstration projects are a valuable tool in REV development, enabling them to test and learn how to perform in their new DSP roles while delivering benefits to customers and third-parties. The Joint Utilities do not think, however, the utilities need to document the benefits from demonstration projects in their DSIPs because the projects already have their own established regulatory track, filings, review, and approvals.

While the Joint Utilities support development of a portal to give customers access to customer-related data, they urge that it is premature to set a timeline for such development. The Joint Utilities support ongoing technical conferences on customer data access. The Joint Utilities support use of a data transfer mechanism that reflects stakeholder discussions but in particular, notes that the costs of Green Button Connect (mentioned by several parties' Initial Comments) for functionalities beyond basic usage information have not yet been assessed. In response to several parties' suggestion that granular customer usage data should be a basic utility service, the Joint Utilities assert that charges may be merited when a utility provides incremental, "value-added" services or when a service is offered that not all customer are likely to take advantage of.

The Joint Utilities reiterate that they support giving DER providers "insightful" system information because providing raw system data would not be useful but rather, would likely create confusion and create potential security concerns.

With respect to hosting capacity, the Joint Utilities disagree with several parties' comments suggesting utilities outline detailed plans for system upgrades. Instead, the Joint Utilities propose to work with stakeholders to identify optimal means for enabling DERs.

The Joint Utilities posit that it is too premature include a requirement that utilities develop plans for increasing DER deployment in underserved markets; more research is required. Furthermore, the utilities' demonstration projects provide an opportunity to test low-to-moderate income customer participation in DER.

The Joint Utilities argue that it is not constructive to comment further on specific EIMs in the DSIP proceeding, in advance of the Track Two decision. The alignment of DSIP filings with EIMs can be addressed once policy guidance is issued for both Track Two and DSIP.

<u>APPENDIX D</u>

State Environmental Quality Review Act

FINDINGS STATEMENT

April 20, 2016

Prepared in accordance with Article 8 - State Environmental Quality Review Act (SEQRA) of the Environmental Conservation Law and 6 NYCRR Part 617, the New York State Public Service Commission (Commission), as Lead Agency, makes the following findings.

Name of Action:	Reforming the Energy Vision (Case 14-M-0101) Order Adopting Distributed System Implementation Plan Guidance
SEQRA Classification:	Unlisted Action
Location:	New York State/Statewide
Date of Final Generic Environmental Impact Statement:	February 6, 2015.
FGEIS available at:	http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101

I. Purpose and Description of the Action

The regulatory initiative launched in this proceeding, Reforming the Energy Vision (REV), aims to reorient both the electric industry and the ratemaking paradigm toward a consumer centered approach that harnesses technology and markets. Distributed energy resources will become integrated into the planning and operation of electric distribution systems, to achieve optimal system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system. The direction taken by the

Commission in this proceeding is consistent with the terms of the 2014 Draft State Energy Plan [Shaping the Future of Energy, New York State Energy Planning Board, 2014] that calls for the use of markets and reformed regulatory techniques to achieve increased system efficiency, carbon reductions, and customer empowerment.

In the attached order, the Commission provides guidance and requires utilities to make the following three filings in 2016: (1) a plan and associated timeline for a stakeholder engagement process during Distributed System Implementation Plan (DSIP) filing development; (2) an individual Initial DSIP addressing each utility's system and identifying immediate changes that can be made to effectuate State energy goals and objectives; and, (3) a joint Supplemental DSIP addressing 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.

II. Facts and Conclusions in the EIS Relied Upon to Support the Decision

In developing this findings statement, the Commission has reviewed and considered the "Final Generic Environmental Impact Statement in Case 14-M-0101 - Reforming the Energy Vision and Case 14-M-0094 - Clean Energy Fund" issued on February 6, 2015 (FGEIS). The following findings are based on the facts and conclusions set forth in the FGEIS.

A. Public Needs and Benefits

The FGEIS indicates that REV is designed to rethink the regulatory structure of the electricity distribution system, and establish an improved paradigm, supported by regulatory oversight, to accomplish the goals of active customer decision-making and involvement, increased distributed generation, deployment of real-time responsive technology and the use of distributed system platforms to reduce adverse air emissions and to increase system efficiency.

B. Potential Impacts

Chapter 5 of the FGEIS describes the expected environmental impacts of the action. The adoption of guidance and the preparation of Distributed System Implementation Plans (DSIPs) will not of itself create any environmental impacts. If the plans are ultimately implemented, it is expected that the DSIPs will enable a greater and more efficient deployment of Distributed Energy Resources (DER), so in that aspect the creation of the DSIPs will induce growth.

C. Mitigation

Chapters 5 and 6 of the FGEIS identify mitigation measures that could address the potential adverse impacts of the action. The provision of guidance and the preparation of Distributed System Implementation Plans (DSIPs) is not identified as something that would trigger mitigation measures.

D. Cumulative Impacts and Climate Change

In aggregate, the clean energy technologies and resources promoted by REV create one common long-term, indirect effect: reducing the use of energy generated from fossil fuels. The environmental impact of a reduction in the use of fossil fuel based energy generation on the human environment is generally positive, but will occur over a long time horizon [FGEIS 5-48].

III. Conclusion

The REV program is anticipated to yield overall positive environmental impacts, primarily by reducing the State’s use of, and dependence on, fossil fuels, among other benefits. In conjunction with other State and Federal policies and initiatives, REV is designed to reduce the adverse economic, social and environmental impacts of fossil fuel energy resources by increasing the use of clean energy resources and technologies FGEIS ES-10].

CERTIFICATION TO APPROVE:

Having considered the Draft and Final Generic Environmental Impact Statement, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6 NYCRR 617.11, this Statement of Findings certifies that:

1. The requirements of 6 NYCRR Part 617 have been met; and

2. Consistent with social, economic and other essential considerations from among the reasonable alternatives available, the action is one that avoids or minimizes adverse environmental impacts to the maximum extent practicable, and that adverse environmental impacts will be avoided or minimized to the maximum extent practicable by incorporating as conditions to the decision those mitigative measures that were identified as practicable; and

3. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

Name of Lead Agency:
New York State Public Service Commission

Address of Lead Agency
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DISTRIBUTED SYSTEM IMPLEMENTATION PLAN GUIDANCE

A. DSIP Filing Process

The Commission requires utilities to make the following three filings in 2016 related to Distributed System Implementation Plan (DSIP), with the second and third filing subject to Commission action. Subsequent DSIPs, which will also be subject to Commission action, will be required on a biennial basis beginning June 30, 2018. Future filings are expected to include increased detail, such as developments in markets and technology capabilities as well as lessons learned and improvement opportunities.

i. a plan and associated timeline for a stakeholder engagement process during DSIP filing development (May 5, 2016);

ii. an individual utility Initial DSIP addressing its own system and identifying immediate changes that can be made to effectuate state energy goals and objectives (June 30, 2016); and,

iii. a joint and necessary, individual Supplemental DSIP by all utilities addressing 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 (November 1, 2016).

B. Stakeholder Engagement Process

The stakeholder engagement process will be led by the utilities. To ensure that both the Initial and Supplemental DSIPs are developed with consideration of stakeholder input, the utilities must immediately engage stakeholders. Accordingly, by May 5, the utilities should define the stakeholder engagement processes and associated timelines that will be used to inform development of their DSIP filings, as well as their plans for continued stakeholder engagement into the future. The utilities should follow this guidance document in setting priorities on stakeholder engagement in consultation with Staff and other stakeholders. It is further worth noting that this stakeholder engagement is supplemental and is quite different from utility engagement with DER developers, which should be occurring naturally during the course of the development of this new business model.

C. Integration of Demonstration Project Results

Utilities should discuss relevant current and near-term demonstration projects in their DSIPs, including how these projects are informing decisions on how to achieve specific DSP functions, DSP goals, and state energy objectives. The utility should seek to incorporate positive demonstration results into the DSIPs. New project ideas or proposed changes to existing approved demonstration projects may be discussed in the DSIP, but will be decided based on the existing process used for demonstrations that is external to the DSIPs.

D. Content Requirements for DSIP Filings

The requirements for what is contained in the DSIPs is focused on addressing the steps identified in the Order and establishing new processes to promote the elements of REV. The DSIPs will be presented using a two-phased approach. The first phase will require the utilities to provide a base level of data, including information related to forecasts, planned investments, and operating systems, and a description of their system planning practices in an Initial DSIP filing. These Initial DSIPs will identify the limitations of current utility operations and the tools that can and should be developed to reliably operate a distribution system with high DER penetration levels. The Initial DSIPs shall also include other information as directed by Commission orders, including but not limited to the requirements in Appendix C of the January 20, 2016, Order in Case 14-M-0101 (Benefit Cost Analysis Framework).

The Supplemental DSIP filing, unlike the Initial DSIPs, is intended to provide common approaches or resolutions necessary to operate in a dynamic environment. The Supplemental DSIP filing must recognize how the processes to be established will be able to adapt to increases in DER deployment, changes in technologies, and other advancements as the distribution grid continues to evolve. This includes the need to address standardization and interoperability of grid architecture. The Supplemental DSIP should also address the development of an engagement plan for increased deployment of electric vehicle supply equipment (EVSE). The utilities should coordinate to directly contribute to EV market development and the resulting decreases in carbon emissions. The following sections detail the requirements to be included within the Initial DSIPs and the Supplemental DSIP filings.

INITIAL DSIPs

1. Distribution System Planning
    a. Forecast of Demand & Energy Growth
        i. Describe the utilities current forecast methodologies and include granular 8760 hour forecast data in kW or kWh.
        ii. To the extent that some data for substations and further down the distribution infrastructure is not available for some utilities,
            1. those utilities should identify what data is available at the time of filing and
            2. the utility’s plans to expand and provide the data across the service territory,
            3. explaining the process for categorizing the information and making substation level forecasts available to outside stakeholders. The utilities’ data processes need to recognize the intention that more granular data and forecasts will be needed in the future to identify beneficial locations for DER.
        iii. Discuss the impact that significantly increased DER penetration will have on the methodology used for regional and company-wide system forecasts and describe how new DER-related factors will be reflected in load forecasting models.
        iv. Explain how the forecasts were derived (top-down analysis of a company-wide peak forecast and/or a bottom-up aggregation of substation level peak demand forecasts) and why the utility uses that methodology.

v. Explain whether the combined use and synchronization of both top-down and bottom-up methodologies could produce increased accuracy of company-wide and substation-specific forecasts cost effectively.

vi. In the stakeholder process, utilities should discuss incorporating DER providers’ forecasts into the utility forecasts, which will ultimately result in more robust and accurate forecasting.

b. <u>Available DER Resources</u>

i. Describe existing and future plans and programs to increase the quantity and value of DER resources.

ii. Include in their DSIPs any demonstration project results related to data for increasing DER resources, including adoption in LMI communities, to the extent that such data exists at the time the DSIP is filed.

c. <u>Delivery Infrastructure Capital Investment Plans</u>

i. The Guidance Proposal requirement is adopted. This includes identifying the impact DER may have in order to defer or eliminate transmission and distribution projects.

1. Identify the current reliability planning criteria.
2. Describe the current capital budgeting process for investment in delivery infrastructure.
3. Explain how the planning and budgeting process integrates consideration of DER resources.

4. Provide historical spending amounts over the past five years for transmission, substations, and distribution infrastructure.
5. Provide capital budgets for a forward five-year period, broken down into transmission, substations, and distribution categories.
   a. Include detailed project listings for each grouping, similar to those provided in annual filings and rate cases.
6. Present historical spending over the past five years for information technologies, communications, and shared services.
7. Provide the forecasted budgets, including an explanation of the basis for the selected approach, for developing monitoring, communications, and information technology systems to support anticipated data and analytical needs as a DSP.
   a. Include details on distribution infrastructure upgrades to support DSP capabilities (e.g., low-cost, high-resolution sensors that enhance system visibility and increase option value, power flow controllers, or solid-state distribution transformers for meshing radial networks or interfacing with microgrids).
8. Identify all transmission and distribution projects (categorically) with a focus on highlighting where DER, future or existing,

has the potential to impact the project needs.

a. Identify all projects within this grouping that will need to move forward regardless of DER deployment, due to other operational limitations and describe any limiting factors and their implications.

9. For areas with large budgetary changes from current spending:

a. Identify the driving factors/projects behind the increase or decrease.

b. Identify what mitigating techniques, such as extending overall implementation timeframe or limiting the number of areas for installation or use of DERs, were considered, possibly included, or rejected for each of the drivers. Indicate why those rejected were not appropriate.

d. Beneficial Locations for DER Deployment

i. Provide the information necessary for developers to offer solutions that can improve the efficiency of the system and add value to customers. The utilities should begin to offer as much information as is readily available to begin the process of supporting optimal DER investments.

ii. Include identification of specific areas in each utility's service territory where there is an impending or foreseeable delivery infrastructure upgrade need and where DERs would potentially provide delivery infrastructure avoidance value or where DER may provide other reliability or operational benefits.

iii. Consistent with the transmission and distribution capital investment plans, the utilities should list specific infrastructure projects by location, and

1. indicate the potential for DER to resolve or mitigate forecasted system requirements, including the level of output needed over specific time periods and
2. describe the process used to identify the projects where DER solutions should be compared as potential alternatives to traditional grid infrastructure under varying scenarios of DER integration.
    a. Propose an improved screening process in their Initial DSIP filings. The process should be a broader, more flexible screening process than the one proposed in their comments concerning the Benefit Cost Analysis Framework.
3. Explain how the utility expects to maximize the integration of DER in such beneficial areas to avoid making unnecessary investments.

e. Hosting Capacity

i. Adopt a common definition of hosting capacity.

ii. Provide known hosting capacity data for all circuits in their service territories, regardless of whether the circuit presents a high- or low-value proposition and the level of remaining hosting capacity on such circuits.

iii. Specify their approaches for calculating hosting capacity.

2. Distribution Grid Operations

a. System Operations

i. Specify the expected or potential near-term effects of increased DER penetration on the ability to serve customers, with specific reference to each type of DER and its grid interface.

ii. Describe the changes to existing policy and processes that will be required in order to ensure that safety and reliability are maintained or improved at the same time that DER penetration is encouraged, expanded, and integrated into system operations.

iii. Describe the visibility and communications protocols to observe/interact with DER providers that will be implemented in the next several years while continuing safe and reliable system operation.

iv. Identify and distinguish operational needs during normal operations and during outage events or other periods of system stress (e.g., low voltage condition, near thermal limitations, etc.) and plans to implement reliability-enhancing protocols like fault location, isolation, and service restoration.

v. Specify plans to ensure cybersecurity.

vi. Describe existing programs, tools, and processes to ensure or address cybersecurity, as well as plans to increase and improve such measures.

vii. If the information is not available by the Initial DSIP filing deadline, the utilities should provide all available information and a detailed plan to supply this information in the future.

b. Volt/VAR Optimization (VVO)

i. Describe plans to implement VVO in the near-term, and over the long-term and how third-parties can interact and provide VVO services.

ii. Evaluate and discuss the costs and benefits of upgrading VVO capabilities.

1. Discuss new VVO capabilities and how they fit in with the evolving grid within the utility’s service territory.

iii. The following analyses should also be included in the DSIPs:

1. existing VVO capabilities and technologies currently in use;
2. a benefit cost analysis comparing upgraded VVO capabilities alongside current VVO capabilities; and
3. a discussion of new VVO capabilities and how they fit in with the evolving grid within the utility’s service territory.

c. Interconnection Process

i. Comply with the Track One Order requirements that DER interconnection procedures be streamlined.

ii. To the extent that the utilities do have not a live fully functioning online customer interconnection portal in place by the time of the Initial DSIP the utilities should supply plans that describe how the portal will be developed.

iii. Engage stakeholders to offer input on improvements that could be made upon the information provided in the Initial DSIPs.

E. Advanced Metering

i. Include a summary of the most up to date AMI rollout plans over the next five years.

ii. Any AMI proposals, made within DSIP filings, rate cases, or separate petitions, should be accompanied by a detailed business plan that, at a minimum, addresses the following elements:

1. plans and schedules for deployment;
2. new or upgraded data management, communications, billing or other backend systems to support AMI along with associated budgets;
3. proposed innovative rate structures;
4. a benefit-cost analysis consistent with the BCA Order; and,
5. customer rate impact analyses.

iii. Plans should also be accompanied by a thorough customer engagement plan and incentives to manage costs and encourage the integration of cost effective alternative solutions that may be offered by third-parties.

1. Such plans should include a robust customer outreach and education program, both prior to and subsequent to any AMI rollout,

designed to increase acceptance, ease implementation and allow customers to make informed decisions, including participation in innovative pricing programs and other AMI enabled programs.

iv. Include proposed metrics to measure the value associated with the AMI deployment.

1. Metrics should include measurements related to customer engagement and participation in new programs, outage management and other system operations impacts, and environmental benefits.

v. Third-party ownership will be allowed so long as the third-party complies with the utility's standards and is willing to incur any additional costs that is put on the system. Utilities should develop contract requirements for such services that include standards for interoperability, cybersecurity, maintenance, and technology specifications.

F. Customer Data

i. Each utility with AMI deployment plans must submit a proposed implementation plan, budget, and timeline for implementing Green Button Connect or alternate standard that offers similar functionality.

ii. Utilities without AMI deployment plans must identify other tools that could be used to enable customer and authorized third-party access to customer data, as well as implementation plans, budgets, and timelines.

iii. Include plans to phase in the ability to provide ESCOs with access to daily, hourly, and eventually, close to real-time access to customer usage information, including budgets and timelines.

SUPPLEMENTAL DSIP

1. Distribution System Planning
    a. Forecast of Demand & Energy Growth
        i. In future DSIPs the utilities should 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.
        ii. Forecasts should follow a stochastic, or probabilistic, methodology rather than a deterministic methodology.
    b. Available DER Resources
        i. The Commission adopts the Guidance Proposal regarding available DER resources without modification.
            1. Describe the process for gathering information from DER providers, other stakeholders, and other available resources in order to enhance forecasts of expected DER performance and penetrations levels over time;
            2. for each type of DER resource, identify the specific expected contribution in kW or kWh per hour to peak load, energy reduction and load shaping in the next five years. Assumptions used should be described clearly;
            3. for each type of DER resource, explain how the utility will incorporate expected peak load, energy reduction and load shaping in its planning process; and,

4. describe the details of other procedures/programs that may be implemented to increase the quantity and value of DER resources.

ii. Provide any information that could support achievement of our LMI access and penetration goals.

iii. Develop a standard process to effectuate communication between the utilities and DER providers to identify opportunities for DER deployment, and coordinate information regarding the DER providers' upcoming projects and any impacts such projects might have on the utility grid.

d. Beneficial Locations for DER Deployment

The utilities should actively collaborate with ESCOs, DER providers, and other stakeholders in developing its plan. Educational efforts should be designed to increase acceptance, improve system utilization, and ease implementation issues.

i. Propose a plan and timeline for consistent statewide system data sharing

1. A stakeholder process should consider the Joint Utilities proposal that they will provide DER providers with insightful information instead of raw system data.

2. Work with stakeholders to address the types and level of data to be provided, the methodology and rules for providing system data, including addressing security concerns and frequency of updates.

3. Define the base level of data available to customers, including DER developers, at no cost.
4. Identify any refined or atypical data services that the utilities can perform beyond the base level that may be the subject of fees.

ii. Security concerns, relating to the electric transmission and distribution system, must also be addressed.

1. Appropriate controls to secure data are needed and those controls must be consistent with standardized requirements.
2. Consider increasing and improving protection measures for network monitoring, setting passwords, and expanding remote access.
3. Continue to address security issues through existing working groups and in concert with leading cybersecurity authorities, such as NERC, NIST, and other related agencies, to develop rules and protections.
4. The plan and timeline for system data sharing in the Initial and Supplemental DSIPs should reflect the following concerns and considerations, while at the same time taking into account stakeholder input.
    a. to stay informed with respect to evolving cybersecurity threats and available defense measures.
    b. In addition, utilities shall stay abreast of developing privacy and cybersecurity technology and

incorporate such technology into their systems to continually offer improved protection against cybersecurity threats.

5. Work with the NYISO to develop a methodology for revealing subzonal wholesale LMPs

iii. Present the methodology for unbundled zonal hourly or sub-hourly prices in accordance with the efforts concurrently being discussed in Case 15-E-0751, "Value of D Proceeding".

e. <u>Hosting Capacity</u>

i. Include a timeline and standard methodology for calculating and improving circuit-level hosting capacity data.

ii. Examine the information tools that are either available today or can be made available to increase hosting capacity, both from a planning and operations perspective.

iii. Develop the common methodologies they will use to determine hosting capacity, the system information that will be available to support investment decisions, and the proposed frequency that the DSP will use to update this information as they gain experience or make new investments.

iv. Establish a hosting capacity map that will be available to DER providers as well as provide detailed reports describing the issues faced by problematic circuits. The map should also present relevant system information for distribution substations, such as capacity ratings and loading data.

v. Establish a database that will include substation level data on hosting capacity, capacity ratings, and actual and forecasted 8760 loads.

vi. Consider emerging technologies that can be used to increase the hosting capacity on a circuit on an even footing with traditional utility infrastructure upgrades.

vii. 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.

viii. Propose approaches they will use when requested by developers to upgrade circuits to increase hosting capacity on particular circuits to support increased DER as opposed to known system reliability needs and mechanisms that can be applied to support these investments that can benefit both the development of the market and customers.

f. Probabilistic Modeling and Load Flow Analyses

i. Determine a means to maximize the benefits of DER and integrate these benefits into their planning processes.

ii. Discuss Guidance Proposal recommendations

a. Plan and process to move from deterministic to a probabilistic modeling approach.

b. Process for Performing Load Flow Analyses.

c. As various DER continue to be deployed, the use of new modeling approaches will be necessary to operate in a proficient manner while maintaining the overall reliability of the grid.

iii. Incorporate methodologies that minimize inefficiencies and overall costs.

2. Distribution Grid Operations

a. System Operations

i. Outline an evolving cybersecurity program wherein the utilities incorporate new and improved technologies and information made available by cybersecurity authorities regarding potential threats and available countermeasures

ii. Plans to further expand monitoring capabilities for data, communications, and information technology systems to support anticipated data and analytical needs as a DSP, including an explanation of the basis for the selected approach and forecasted budgets.

iii. Details on distribution infrastructure upgrades to support DSP capabilities (low-cost, high-resolution sensors that enhance system visibility and increase option value, power flow controllers, or solid-state distribution transformers for meshing radial networks or interfacing with microgrids).

iv. Engage in a stakeholder process to seek input on the development of standard communication protocols for monitoring and control of DER.

v. With respect to the roles, responsibilities, and interactions between utilities and the NYISO, it is expected that the Supplemental DSIP will begin to define the obligations and actions that will be needed to ensure seamless and reliable operations of a dynamic transmission and distribution grid.

c. Interconnection Process

i. Include a proposed comprehensive plan, developed through stakeholder engagement, as well as a timeline to implement the proposed improvements.

F. Customer Data

i. Include plans to phase in the ability to provide ESCOs with access to daily, hourly, and eventually, close to real-time access to customer usage information, including budgets and timelines.

Commissioner Diane X. Burman concurring:

As reflected in my comments made at the April 20, 2016 session, I concur on this item.