BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service	Case 19-E- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service	Case 19-G- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service	Case 19-E- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service	Case 19-G- ____

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DIRECT TESTIMONY OF REFORMING THE ENERGY VISION PANEL

Christian J. Bilcheck
Scott M. Bochenek
Brian A. Conroy
David M. Conroy
Michael J. DeAngelo
Rita I. King
James L. Mader
Sean K. Sullivan
Marc P. Webster

May 20, 2019

DIRECT TESTIMONY OF REFORMING THE ENERGY VISION PANEL

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DIRECT TESTIMONY OF REFORMING THE ENERGY VISION PANEL

I. INTRODUCTION

Q. Please state the names of the members on this Reforming the Energy Vision Panel ("Panel").

A. We are Christian J. Bilcheck, Scott M. Bochenek, Brian A. Conroy, David M. Conroy, Michael J. DeAngelo, Rita I. King, James L. Mader, Sean K. Sullivan, and Marc P. Webster.

Q. Mr. Bilcheck, please state your title and business address.

A. I am the Vice President of Asset Management and Planning. My business address is 100 Marsh Hill Road, Orange, Connecticut 06477.

Q. Please summarize your work experience and educational background.

A. In my current role, I have responsibility for Avangrid Networks, Inc. ("Avangrid") transmission, distribution, and integrated system planning, including Non-Wires Alternatives ("NWAs"), Investment Planning and Asset Management. I have over 32 years of experience in the electric utility industry, primarily in grid operations and planning. I have a BS in Electrical Engineering and an MBA. My Curriculum Vitae ("CV") is set forth in Exhibit __ (REV-1).

Q. Have you previously testified in other proceedings before the New York State Public Service Commission (the "Commission") or any other state or federal regulatory agency?

A. I have not previously testified before the Commission. I have, however, testified before state regulatory commissions in Connecticut (e.g., Department of Public Utility Control Docket No. 08-01-01 - Review of Peaking Generation Projects; Public Utilities Regulatory Authority ("PURA") Docket No. 17-12-03 - Investigation into Distribution System Planning of the Electric Distribution Companies) and in Maine (Maine Public

Utilities Commission ("Maine Commission") Docket No. 2018-194 - Commission Initiated Investigation into Rates and Revenue Requirements Pertaining to Central Maine Power Company).

Q. Mr. Bochenek, please state your title and business address.

A. I am the Manager, Smart Grid Programs. My business address is 18 Link Drive, Binghamton, New York 13904.

Q. Please summarize your work experience and educational background.

A. In my current role, I am responsible for assessing trends, developing strategies, and developing pilot projects related to distributed energy resources ("DERs") with a significant focus on electric transportation. I have worked for the Companies for over 15 years in various roles including Supervisor of Customer Billing and Manager of Energy Efficiency Programs. I have an AA in Liberal Arts from Cayuga Community College, a BA in Human Development from Binghamton University, an MBA from Strathclyde University, and an MBA from Comillas Pontifical University. My CV is set forth in Exhibit __ (REV-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. No.

Q. Mr. Brian Conroy, please state your title and business address.

A. I am the Director of Network Projects and Initiatives. My business address is 162 Canco Road, Portland, Maine 04103.

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Q. Please summarize your work experience and educational background.

A. In my current role, I am responsible for Smart Grids Planning, particularly the Distributed System Platform ("DSP") technology platform. I have worked for the Company for 33 years in various innovation, planning, operations, and engineering roles including Director of Electric Systems Engineering and Manager of the Energy Control Center. My CV is set forth in Exhibit __ (REV-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. I have not testified before this Commission, but I have testified before the Connecticut PURA for their Investigation into Distribution Planning under Docket No. 17-12-03. I have also testified before the Maine Commission under rate case Dockets 2018-00194 and 2013-00168, and before the Maine State Legislature's Joint Energy, Utilities and Technology Committee for geomagnetic disturbances, electromagnetic pulses, and microgrids.

Q. Mr. David Conroy, please state your title and business address.

A. I am the Director of Electric System Planning. My business address is 162 Canco Road, Portland, Maine 04103.

Q. Please summarize your work experience and educational background.

A. I am responsible for leading and coordinating the 2018 New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E" and together with NYSEG, the "Companies") Distributed System Implementation Plan ("DSIP") effort and filing, as well as representing the Companies on the Northeast Power Coordinating Council Reliability Coordinating Committee. I have over 40 years of experience in the electric utility business. I have a BS in Electrical Engineering from Cornell University and an MBA from the University of Southern Maine. My CV is set forth in Exhibit __ (REV-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. Yes. I testified before the Commission in the Rochester Area Reliability Project Article VII proceeding, Case 11-T-0534. In addition, I have testified before the Maine Commission for the Maine Power Reliability Program and several other Certificate of Public Convenience and Necessity cases, as well as the Maine Commission's Investigation into Transmission Planning Standards and Criteria, and before the Federal Energy Regulatory Commission ("FERC") in the Bucksport Complaint proceeding.

Q. Mr. DeAngelo, please state your title and business address.

A. I am the Program Manager – Non-Wires Alternatives. My business address is 18 Link Drive, Binghamton, New York 13903.

Q. Please summarize your work experience and educational background.

A. In my current role, I manage Avangrid Network's NWA and Non-Pipe Alternatives ("NPA") programs in New York and in Maine. I have over 11 years of experience in the power generation and electric and gas utility industries. I have a BS in Business Economics and Marketing and an MBA. My CV is set forth in Exhibit __ (REV-1).

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Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. I have not previously testified before the Commission. I have, however, testified before the Maine Commission in Docket No. 2016-00049 - Investigation into the Designation of Non-Transmission Alternative Coordinator.

Q. Ms. King, please state your title and business address.

A. I am the Senior Director, Smart Grids Innovation and Planning. My business address is 180 Marsh Hill Road, Orange, Connecticut 06477.

Q. Please summarize your work experience and educational background.

A. In my current role, I have enterprise level responsibilities to design, implement, execute and promote Avangrid innovation processes, demonstration projects, distribution system platform planning, and culture. I have over 25 years of electric industry experience in a wide range of areas, including customer service, economic development, and project & process management. I have a BS in Electrical Engineering and an MS in Marketing. My CV is set forth in Exhibit __ (REV-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. I have not previously testified before the Commission. I have, however, testified before regulatory commissions in Connecticut.

Q. Mr. Mader, please state your title and business address.

A. I am the Manager of Programs and Projects, Smart Grids Innovation. My business address is 180 Marsh Hill Road, Orange, Connecticut 06477.

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Q. Please summarize your work experience and educational background.

A. In my current role, I help develop and implement innovative technologies in the areas of energy storage and microgrids. I have worked in multiple engineering disciplines throughout my 27 years in the utility industry including Substation Engineering, Protection and Control Engineering, Transmission Engineering and Distribution design. I received a BS in Electrical Engineering Technology from Northeastern University in 1991 and I am a certified Project Management Professional. My CV is set forth in Exhibit __ (REV-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. I have not previously testified before the Commission, but I have testified before the Connecticut PURA.

Q. Mr. Sullivan, please state your title and business address.

A. I am the Interim Director – Smart Grids. My business address is 1387 Dryden Road, Ithaca, New York 14850.

Q. Please summarize your work experience and educational background.

A. In my current role, I am the Interim Program Director for NYSEG's Energy Smart Community ("ESC") Program located within Tompkins County, including Ithaca, New York. My education includes an MBA and a BS in Geology. My CV is set forth in Exhibit __ (REV-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. No.

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Q. Mr. Webster, please state your title and business address.

A. I am the Manager – Project Portfolio for the Companies. My business address is 18 Link Drive, Binghamton, New York, 13902.

Q. Please summarize your work experience and educational background.

A. I have worked for NYSEG and RG&E for 25 years. I started as a Principal Analyst – Gas Pricing in 2004 and progressed through the Companies in various positions. I have managed the retail access programs at NYSEG and RG&E, the NYSEG Back Office Billing department, the Customer Satisfaction and Appeals department, and the large interval electric metering (MV90) department. Prior to my employment at NYSEG and RG&E, I worked for seven years as an analyst with the Baltimore Gas & Electric Company. My CV is set forth in Exhibit __ (REV-1). I hold a BA in Economics and an MA in Economics, both from the University of Delaware.

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. Yes. I have testified on several occasions before the Commission, including in Cases 15-E-0283 et al., the Companies' most recent rate proceeding (the "2015 Rate Case"). I also submitted testimony in support of NYSEG's gas rate filing in Case 01-G-1668 and rebuttal testimony for NYSEG's electric rate filing in Case 05-E-1222. In addition, I have testified before regulatory commissions in Maine and New Hampshire.

Q. What is the purpose of the Panel's testimony?

A. The purpose of our testimony is to support the Companies' Reforming the Energy Vision ("REV") and REV-related initiatives, including the Companies' development of the DSP, enabling deployment of energy storage and electric vehicles ("EV") technologies, and implementing NWA and NPA solutions. Specifically, we discuss: 1) the Companies' investment in advanced metering infrastructure ("AMI") and how it is foundational to REV and the Companies' DSP implementation; 2) the Companies becoming the DSP provider and the actions to develop the DSP that are presented in the 2018 DSIP; 3) the Companies' experience with the ESC and stakeholder engagement and how this experience informs current REV initiatives; 4) the Companies' major REV initiatives, including projects related to energy storage, NWA, NPA, EVs, and energy efficiency; and 5) additional resources necessary to implement the Companies' REV and REV-related initiatives.

Q. Please discuss the Companies' perspective regarding New York State's REV and REV-related initiatives.

A. These initiatives align well with the Companies' overall strategy and will allow the Companies to integrate clean energy resources, provide customers with greater control over their energy usage and total energy bills, and provide market participants with information to make informed investment decisions. The Companies endeavor to be a leader in the energy sector as the industry transitions toward a new paradigm enabled by innovation and advances in clean energy, power delivery, and information technologies.

II. IDENTIFICATION AND SUMMARY OF EXHIBITS

Q. Is this Panel sponsoring any exhibits?

A. Yes. This Panel sponsors the following exhibits:

1) Exhibit __ (REV-1) provides the CVs of the witnesses testifying on this Panel; and

2) Exhibit __ (REV-2) provides an index of the Panel's workpapers. Copies of the workpapers will be provided to the New York State Department of Public Service Staff ("Staff").

III. BACKGROUND OF REV AND CURRENT NYSEG/RG&E REV INITIATIVES

Q. Please provide a brief overview of the initial phases of the REV Proceeding.

A. The Commission initiated the REV Proceeding with its Order Instituting Proceeding, issued on April 25, 2014, in Case 14-M-0101. On February 26, 2015, the Commission issued an Order Adopting a Regulatory Policy Framework and Implementation Plan ("Track One Order"), which, among other things, ordered the utilities to: 1) identify potential NWAs; 2) file DSIPs to plan their transition from their traditional role as a delivery utility to their new role as a DSP provider; and 3) implement demonstration projects to test new technologies, business models, and utility revenue streams.

Q. What major actions has the Commission taken since it issued the Track One Order?

A. The Commission has issued several additional orders in the REV Proceeding, including: 1) the Order Establishing the Benefit Cost Analysis Framework, issued January 21, 2016 ("BCA Framework Order"); 2) the Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, issued May 19, 2016 ("Track Two Order"); and 3) the Order on Distributed System Implementation Plan Filings, issued March 9, 2017 ("DSIP Order"). The Commission has also issued orders in other REV-related proceedings that are relevant to this Panel's testimony, including the December 13, 2018, Order Establishing Energy Storage Goal and Deployment Policy issued in Case 18-E-0130 ("Energy Storage Order"), and the December 13, 2018, Order Adopting

Accelerated Energy Efficiency Targets issued in Case 18-M-0084 ("Energy Efficiency Order").

Q. Please provide an overview of the BCA Framework Order.

A. The BCA Framework Order provides standard criteria and guidelines for electric benefit cost analyses ("BCAs"), which are used for NWAs, Demand Response programs, Energy Efficiency programs, and other projects that might require an analysis of relative costs and benefits. The BCA Framework Order does not impose specific requirements on utilities regarding the calculation of costs and benefits; rather, it provides guidance on categories of costs and benefits to be considered in a BCA. The BCA Framework Order also directed each utility to file biennially for Staff review a BCA Handbook setting forth that utility's specific procedures when conducting a BCA.

Q. Please briefly summarize the Track Two Order.

A. In the Track Two Order, the Commission created the opportunity for new utility shareholder incentives, called Earning Adjustment Mechanisms ("EAMs"), designed to align the utility business model with New York State's energy policy goals.

The Commission also created the opportunity for Platform Service Revenues ("PSRs"). PSRs are new revenue streams for utilities designed to allow the utilities to potentially receive revenue from market transactions that occur on their platforms that link customers to DERs and DER providers.

Q. Please summarize the DSIP Order.

A. In the DSIP Order, the Commission discussed the initial DSIPs, filed individually by the utilities on June 30, 2016, and the shared Joint Utilities of New York ("JU") Supplemental DSIP filed on November 1, 2016. The Commission also required utilities to submit additional filings relating to: 1) the improved provision of hosting capacity data; 2) the development of interconnection web-based portals; 3) screening criteria to determine if utilities should pursue NWAs; and 4) the provision of aggregated customer data. The DSIP Order also required that each utility install at least two energy storage projects prior to the end of 2018.

Q. What role does the JU have in REV?

A. The JU was formed in response to the Commission's DSIP Order to coordinate electric utility responses and actions, where appropriate, associated with various REV and REV-related proceedings. As an example, the JU, in coordination with Staff and stakeholders, helped develop certain DSP aspects that create a consistent model for engaging with developers, resulting in a more efficient market. The Companies' coordination with the JU has also informed their utility-specific DSIP filings. The JU continues its collaborative work today.

Q. Please describe the Energy Storage Order.

A. In its Energy Storage Order, the Commission established a goal of installing 1,500 megawatts ("MW") of energy storage by 2025 and up to 3,000 MW by 2030. The Commission also adopted a comprehensive strategy to address barriers impeding energy storage technologies from competing in the energy marketplace. In adopting these strategies, the Commission noted its intent to accelerate the market learning curve, drive down costs, and speed the deployment of the highest-value energy storage projects that provide maximum benefit to New Yorkers and the electric grid.

Q. Please summarize the Energy Efficiency Order.

A. In its Energy Efficiency Order, the Commission established a Statewide goal of 185 trillion British thermal units ("TBtu") of customer-level energy reduction by 2025. That level represents nearly 1/3 of the total greenhouse gas ("GHG") emission reductions needed to achieve the State's 40% GHG reduction target by 2030. The Commission also identified a comprehensive set of actions to meet that target, with emphasis on increased energy savings through innovative utility efficiency programs. The Order also adopts an incremental target of 31 TBtu of customer level energy reduction by the State's utilities. This goal is inclusive of a subsidiary annual 3% reduction in electricity sales by 2025 and 5 TBtu of savings from the installation of heat pumps, which will help reduce emissions from the heating and cooling of buildings.

Q. Did the Companies address REV as part of the 2015 Rate Case?

A. Yes. REV was in its early stages at the time, and the Companies' Joint Proposal for a three-year rate plan ("2016 Rate Plan") adopted by the Commission's Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal issued on June 15, 2016 in Cases 15-E-0283 et al. ("2016 Rate Order") established the ESC to serve as a test-bed for implementing and deploying REV initiatives in NYSEG's Ithaca region. Under the 2016 Rate Order, the Companies also pursued NWA projects.

Q. How do the Companies currently recover REV and REV-related costs?

A. Under the 2016 Rate Order, to the extent REV and REV-related costs are not included in base rates, capitalized or separately addressed for cost recovery, the Companies defer REV and REV-related incremental costs and fees, including regulatory, consulting, and legal costs, and these deferrals are eligible for recovery in their Rate Adjustment

Mechanism ("RAM"). The Companies propose to continue the current accounting treatment for REV and REV-related costs. This accounting treatment is further addressed in the testimony of the Companies' Revenue Requirements Panel.

Q. Please discuss the Companies' recent REV-related activities.

A. The Companies, both on their own and collaboratively with the JU, have engaged stakeholders in many areas related to REV, including but not limited to: 1) the development of two individual DSIPs in 2016 and 2018 and one Supplemental DSIP in 2016 (discussed in Section V of our testimony); 2) the establishment of the ESC (discussed in Section VI of our testimony); 3) the implementation of NWAs (discussed in Section VII.A of our testimony); 4) the implementation of energy storage projects (discussed in Section VII.B of our testimony); 5) the implementation of the EV DC Fast Charger incentive (discussed in Section VII.C of our testimony); and 6) the implementation of several demonstration projects to test and advance REV principles (discussed in Section V of our testimony).

Q. Have the Companies progressed in implementing their DSIPs?

A. Yes. The Companies have expanded their NWA Suitability Criteria and have initiated additional NWA solicitations since 2016, as discussed in Section VII.A of our testimony. The Companies also jointly developed a Hosting Capacity methodology with the JU and the Electric Power Research Institute, and have developed a web-based portal for DER developers. Further, the Companies have improved their Standardized Interconnection Requirements and Interconnection Process for developers based on stakeholder feedback. These improvements included adding a web-based interconnection portal and automating the interconnection application process. In addition, the Companies have progressed with data analytics efforts and System Automation projects, and have conducted preparatory work to implement AMI on a system-wide basis.

IV. ADVANCED METERING INFRASTRUCTURE IS FOUNDATIONAL TO REV AND THE COMPANIES' DSIP IMPLEMENTATION

Q. What is AMI and why is its deployment foundational for REV and DSIP implementation?

A. AMI includes smart meters, a supporting telecommunications network, Information Technology infrastructure, including Head End System and Meter Data Management System, and applications to process data. Because AMI provides key access to customer information and additional operations data, it is foundational to REV, customer enablement, and DSIP implementation. AMI is also foundational for the Companies in fulfilling their role as the DSP. AMI is similarly critical to the implementation and long-term success of several interrelated REV initiatives, such as energy storage, EVs, energy efficiency and calculating the value of DER.

The Companies' Advanced Metering Infrastructure Panel provides additional details concerning the Companies' AMI proposal and why AMI should be deployed throughout the NYSEG and RG&E service areas.

Q. Could the Companies fully implement their 2018 DSIP without AMI?

A. No; some of the initiatives discussed in the next section of our testimony would not be possible and others would be more costly.

V. 2018 DISTRIBUTED SYSTEM IMPLEMENTATION PLAN AND DISTRIBUTED SYSTEM PLATFORM

Q. Can the Panel please briefly describe the Companies' 2018 DSIP?

A. The Companies filed their 2018 DSIP on July 31, 2018, in Case 14-M-0101. The 2018 DSIP can be accessed via the Commission's Document and Matter Management system. The 2018 DSIP presents the Companies' current capabilities and plan to become the DSP for the Companies' customers and DER operators.[1] It includes a five-year roadmap for investments in key systems, technologies, and projects to modernize the grid and enable DER integration and market development. Specifically, these investments will facilitate the following core DSP functions: 1) integrated system planning; 2) distributed grid operations; and 3) market services. The DSIP also presents the integrated set of technologies and systems needed to enable the Companies, as the DSP, to maintain safe, reliable, and efficient operations while fully supporting the ability to connect and integrate a large number of DERs (the "Technology Platform").

Q. Does the Companies' DSIP approach align with the Commission's REV goals and objectives, including enabling the DSP?

A. Yes. The Companies' continuing efforts to modernize the electric grid, integrate DER and provide customers with the information to take control of their own energy usage is fully aligned with REV principles. The Companies' integrated set of planned implementation projects enhance the Companies' ability to facilitate, integrate, and leverage DER for the benefit of the electric delivery system and customers.

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[1] DER is used to describe a wide variety of distributed energy resources, including end-use energy efficiency, demand response, distributed storage, and distributed generation (e.g., solar, wind, combined heat and power). DER is principally located on customer premises but may also be located on distribution system facilities. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (Feb. 26, 2015).

Q. How is the remainder of this section of your testimony organized?

A. The remainder of this section: 1) summarizes each DSP core function; 2) describes the Companies' Technology Platform; 3) identifies the incremental resources needed to implement the Companies' 2018 DSIP; and 4) discusses the Companies' innovation process supporting the DSP function.

A. <u>Integrated System Planning</u>

Q. How is Integrated System Planning important to REV?

A. Integrated System Planning is one of the Companies' three core DSP functions or pillars. The Companies have an Integrated System Planning group, which focuses on: 1) maintaining a safe, reliable, resilient network by investing in distribution facilities and NWAs, and connecting new DER; 2) delivering value to customers over the long-term by enabling efficient investment decisions by the Companies and DER developers; 3) identifying areas that can accommodate different levels of DER penetration at low cost; 4) communicating system information and insights to DER developers to inform their investment decisions; and 5) providing system information and insights to other Company functions to support their respective DSP responsibilities.

Q. How will the group's work support REV's objectives?

A. As presented in the Integrated Planning Roadmap (Figure VI-3 on page 39 of the Companies' 2018 DSIP), the Companies are focusing on improving their models and the quality of data inputs to those models. This includes leveraging more granular customer usage, DER production, and operational performance data as they become available to perform more accurate and reliable planning forecasts and studies, which will allow the

Companies to identify and provide the most efficient solutions to address the needs of the network, including DER and NWAs.

Q. Please expand on what the Companies plan to accomplish in the next five years with respect to Integrated System Planning.

A. The Companies anticipate deploying foundational tools to support more advanced planning and data management. For example, the Grid Model Enhancement Project ("GMEP") begins in 2019 and will be vital to develop more accurate and granular planning and operating models. The Companies will also continue to develop their DER database, which will provide more granular DER connection and technical information for planning and operations modeling. In addition, the deployment of AMI and distribution automation will provide real-time information on customer and distribution circuit demand and flow patterns to inform the distribution planning process.

Q. What resources are required for the Companies to achieve the enhanced Integrated System Planning capabilities the Panel previously identified?

A. In addition to AMI implementation (more fully described by the AMI Panel), the Companies will have capital and operation and maintenance ("O&M") expenses and require incremental human resources. We discuss these requirements in Section V.E below. Specifically, investments in GMEP and Enhanced DER Monitoring and Control ("M&C"), Load and DER Forecasting, NWA BCA Tool, Hosting Capacity, Innovative Projects, and Interconnection Services projects are required to achieve the REV objectives for Integrated System Planning.

B. <u>Grid Operations</u>

Q. What role does Grid Operations serve as a core DSP pillar?

A. Grid Operations is the core DSP function that monitors and operates the distribution grid to provide safe, reliable, and resilient distribution service. Integration of various types of DER dispersed throughout the grid presents various challenges that the operators in the Companies' Energy Control Center ("ECC") must overcome to take advantage of DER attributes while maintaining quality of service to customers. Grid Operations relies on: 1) an up-to-date inventory of all DER and distribution assets and their capabilities; 2) near real-time data regarding customer usage and power flows throughout the distribution grid; and 3) systems and technology that respond automatically to mitigate potential issues and notify the Companies' grid operators to take actions to resolve an issue.

Q. Has the ESC contributed to the development and testing of the Grid Operations function?

A. Yes. As noted in the 2018 DSIP filing, and as we discuss later in our testimony, the Companies have automated 15 distribution circuits and 4 substations for the ESC project, upgrading line and substation equipment with the latest intelligent distribution assets to provide real-time data to allow for remote monitoring and control from the ECC. The Companies will apply lessons learned from this project as they continue to upgrade the distribution network system-wide to integrate more DER.

Q. What capabilities are necessary to allow Grid Operations to operate with a high penetration of DER assets?

A. As set forth in the 2018 DSIP, the Companies need four sets of capabilities to perform Grid Operations while also accommodating high penetration of DERs: 1) Measurement, Monitoring, and Control; 2) Grid Optimization; 3) DER Management; and 4) New York Independent System Operator ("NYISO") Coordination.

Q. What resources do the Companies need to achieve these Grid Operations capabilities and requirements?

A. Grid Operations requires the capital and operational projects and incremental resources identified in Section V.E below; specifically, investments in Grid Optimization and Innovative Projects are central to achieving the REV objectives for Grid Operations.

C. <u>Market Services</u>

Q. How is the Market Services function important to REV?

A. Market Services is the core DSP function, or pillar, which serves as a platform for customers, DER developers and other third-party product and service providers to transact with the DSP and with each other. With this pillar, the Companies seek to enable the market by promoting engagement by customers to help them consider DER as a resource to manage their energy usage, including their potential to produce and store energy.

Q. Are the Companies recommending additional retail customer Market Services?

A. Yes.

Q. What resources do the Companies need to achieve the Market Services capabilities and requirements?

A. For the Market Services core function, the Companies require the capital and operational projects and incremental resources identified in Section V.E below; specifically, investments in the Data Sharing, Portal, Interconnection Services, Market Services, Hosting Capacity, and Community Distributed Generation Billing projects.

D. Technology Platform

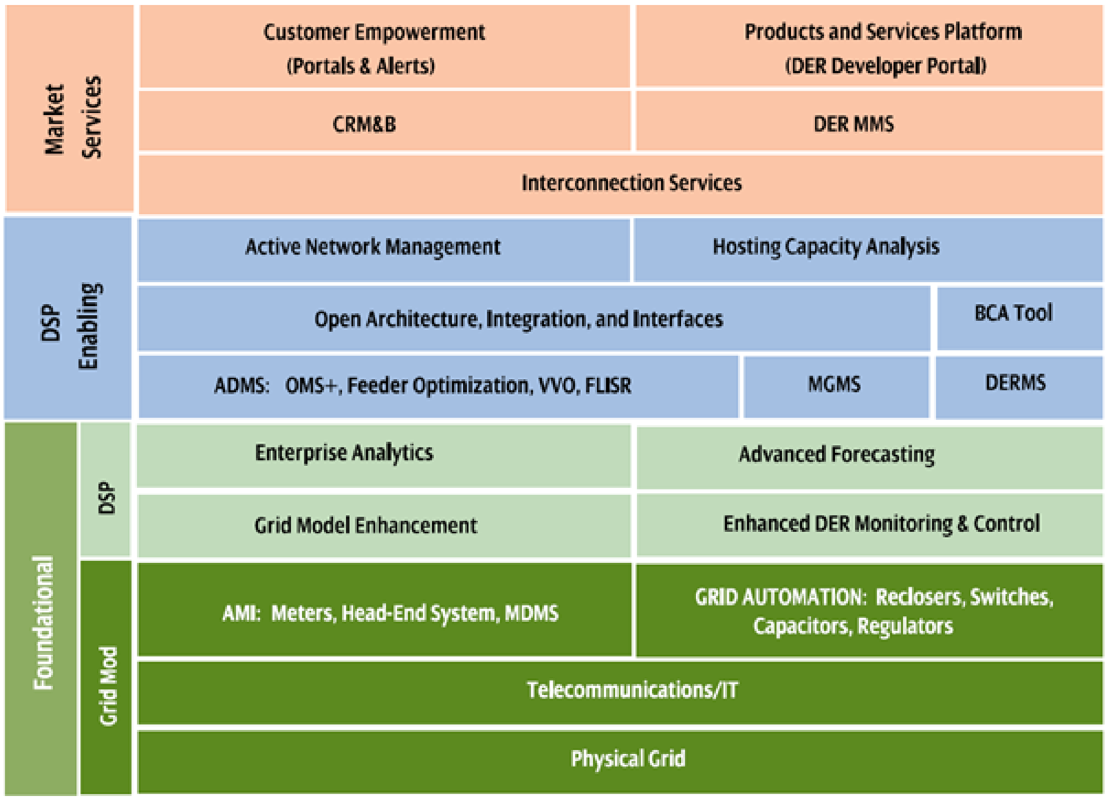
Q. Turning next to the "Technology Platform" component of the Companies' DSP strategy, please briefly describe the nature of the platform.

A. As discussed earlier, the Companies' Technology Platform is the integrated set of technologies and systems that enable the Companies, as the DSP, to maintain safe, reliable, and efficient operations while fully supporting the ability to connect and integrate many DERs.

Q. What are some of the specific technologies and systems that make up the Companies' Technology Platform?

A. The technologies and projects that make up the Companies' Technology Platform fall into the following four major categories: 1) Foundational; 2) DSP Enabling; 3) Market Services; and 4) Energy Storage. The Foundational technologies include AMI, Grid Automation, Enterprise Analytics, Advanced Forecasting, Grid Model Enhancement, and Enhanced DER M&C. The DSP Enabling technologies include an Advanced Distribution Management System ("ADMS"), DER Management System ("DERMS"), Hosting Capacity Analysis, and Active Network Management. The Market Services technologies include Interconnection Services, a DER Market Management System, and a Products and Services Platform. The figure below illustrates how these three categories of component technologies build upon each other to create the Companies' Technology Platform. Some of the technologies identified as part of the Technology Platform will not enter service within the five-year DSIP implementation plan because of their reliance on other technologies being implemented (e.g., AMI), a need for greater DER penetration, or immaturity of the specific technology.

Figure 1: Technology Platform



Q. Please elaborate further on each technology's function.

A. A detailed description of each of the Foundational, DSP Enabling, and Market Services projects are set forth in greater detail on pages 71-82 of the Companies' 2018 DSIP. The Companies' plans regarding energy storage are discussed later in our testimony.

Q. Why do the Companies include energy storage in the Companies' Technology Platform?

A. The Companies believe energy storage is a transformative technology that can provide multiple benefits to the electric system and customers. As we discuss in Section VII.B of our testimony, energy storage will be integral to the Companies' ability to serve load and manage the distribution grid as levels of intermittent DER penetration increase. Furthermore, the Companies believe that, under certain conditions, utilities can deliver the best value to customers by owning and operating energy storage.

E. <u>Five-Year Distributed System Implementation Plan</u>

1. Capital Requirements

Q. Please describe the Companies' five-year DSIP.

A. The Companies' five-year DSIP is the collection of programs, projects, and expenditures that facilitate the Companies' development into the DSP.

Q. How does the Technology Platform fit into that DSIP?

A. The Companies' Technology Platform is the subset of the projects in the DSIP that requires adoption or development of a new technology that is fundamental to the Companies' operation as a DSP.

Q. What are the capital requirements reflected in the Companies' DSIP?

A. A detailed breakdown of the five-year REV capital requirements by project is set forth in Table 1 below. These planned expenditures represent a significant acceleration of capital spending on overall system automation.

<u>Table 1: REV Capital Requirements Summary Table</u>

Project	OpCo	Tech Platform	2019	2020	2021	2022	2023	REV Implementation Category
Advanced Metering Infrastructure (AMI)	NYSEG	Yes	Included in AMI Panel Testimony					Foundational
	RG&E	Yes	Included in AMI Panel Testimony					
Electric Vehicles	NYSEG	No	$ -	$ 4,716,560	$ 5,616,560	$ 5,616,560	$ -	Electric Vehicles
	RG&E	No	$ -	$ 2,156,240	$ 2,516,240	$ 2,516,240	$ -	
Energy Efficiency	NYSEG	No	Included in Energy Efficiency Panel Testimony					Energy Efficiency
	RG&E	No	Included in Energy Efficiency Panel Testimony					
Energy Storage	NYSEG	Yes	$ 1,100,000	$ 16,800,000	$ 14,300,000	$ -	$ -	Energy Storage
	RG&E	Yes	$ 300,000	$ 2,300,000	$ 10,800,000	$ 3,500,000	$ -	
Enterprise Analytics	NYSEG	Yes	$ 1,840,288	$ 1,219,918	$ 1,842,279	$ 975,230	$ -	Foundational
	RG&E	Yes	$ 1,096,880	$ 642,061	$ 919,144	$ 492,090	$ -	
Grid Model Enhancement	NYSEG	Yes	$ 305,460	$ -	$ -	$ -	$ -	Foundational
	RG&E	Yes	$ 163,140	$ -	$ -	$ -	$ -	
Grid Optimization	NYSEG	Yes	$ 1,807,830	$ 1,700,000	$ 1,700,000	$ 3,000,000	$ 3,000,000	Grid Operations
	RG&E	Yes	$ 1,489,830	$ 1,400,000	$ 1,400,000	$ 1,000,000	$ 1,000,000	
Hosting Capacity	NYSEG	Yes	$ -	$ -	$ 151,139	$ -	$ -	Integrated Planning and Market Services
	RG&E	Yes	$ -	$ -	$ 151,139	$ -	$ -	
Innovative Projects	NYSEG	Yes	$ 106,121	$ 7,500	$ -	$ -	$ -	Integrated Planning and Grid Operations
	RG&E	Yes	$ 35,374	$ 2,500	$ -	$ -	$ -	
Interconnection Services	NYSEG	Yes	$ -	$ 478,125	$ -	$ -	$ -	Integrated Planning and Market Services
	RG&E	Yes	$ -	$ 84,375	$ -	$ -	$ -	
Line Automation	NYSEG	Yes	$ 32,064,512	$ 34,840,044	$ 36,889,603	$ 36,889,603	$ 43,359,494	Foundational
	RG&E	Yes	$ 2,515,532	$ -	$ -	$ -	$ -	
Market Services	NYSEG	Yes	$ -	$ 37,500	$ -	$ -	$ -	Market Services
	RG&E	Yes	$ -	$ 12,500	$ -	$ -	$ -	
NWA	NYSEG	No	$ 3,925,985	$ 1,328,240	$ 846,263	$ 864,680	$ 883,499	NWA
	RG&E	No	$ 2,661,975	$ -	$ -	$ -	$ -	
NWA BCA Tool	NYSEG	Yes	$ 44,495	$ -	$ -	$ -	$ -	Integrated Planning
	RG&E	Yes	$ 44,495	$ -	$ -	$ -	$ -	
NWA Support	NYSEG	No	$ 634,500	$ 512,500	$ 512,500	$ 512,500	$ 512,500	NWA
	RG&E	No	$ 418,553	$ 296,553	$ 296,553	$ 296,553	$ 296,553	
Substation Automation	NYSEG	Yes	$ 10,194,620	$ 10,915,851	$ 11,609,085	$ 11,841,267	$ 12,023,192	Foundational
	RG&E	Yes	$ 3,398,207	$ 3,638,617	$ 3,869,695	$ 3,947,089	$ 4,007,731	
			$ 64,147,797	$ 83,089,084	$ 93,420,200	$ 71,451,812	$ 65,082,969	

2. O&M Requirements

Q. What are the O&M requirements of the Companies' DSIP?

A. A detailed breakdown of the five-year O&M requirements by project is set forth in Table 2 below, and includes the following projects: AMI; Community Distributed Generation Billing; Data Sharing Portal; EVs; Energy Efficiency; Energy Smart Community; Energy Storage; Energy Storage Pilot Projects; Grid Model Enhancement; Innovation Process Support; Innovative Projects (e.g., Flexible Interconnect Capacity System, Enhanced M&C, Smart Grid-Smart Inverter); Interconnection Services; Load and DER Forecasting; Line Automation; and Market Services. Internal labor costs are not included in these O&M requirements.

Table 2: REV O&M Requirements Summary Table

Project	OpCo	Tech Platform	2020	2021	2022	2023	REV Implementation Category
Advanced Metering Infrastructure (AMI)	NYSEG	Yes	Included in AMI Panel Testimony				Foundational
	RG&E	Yes	Included in AMI Panel Testimony				
Community Distributed Generation Billing	NYSEG	No	$ 894,348	$ 1,034,037	$ 1,088,549	$ 281,081	Market Services
	RG&E	No	$ 319,410	$ 438,656	$ 545,126	$ 144,799	
Data Sharing Portal	NYSEG	No	$ 175,000	$ -	$ -	$ -	Market Services
	RG&E	No	$ 175,000	$ -	$ -	$ -	
Electric Vehicles	NYSEG	No	$ 1,044,017	$ 1,338,829	$ 1,449,460	$ 373,062	Electric Vehicles
	RG&E	No	$ 447,436	$ 573,784	$ 621,197	$ 159,884	
Energy Efficiency	NYSEG	No	Included in Energy Efficiency Panel Testimony				Energy Efficiency
	RG&E	No	Included in Energy Efficiency Panel Testimony				
Energy Smart Community (ESC)	NYSEG	No	$ 2,511,009	$ 2,416,755	$ 2,544,817	$ 2,589,977	Energy Smart Community
	RG&E	No	$ -	$ -	$ -	$ -	
Energy Storage	NYSEG	Yes	$ -	$ -	$ 644,000	$ 656,880	Energy Storage
	RG&E	Yes	$ -	$ -	$ 180,000	$ 343,600	
Energy Storage Pilot Projects	NYSEG	No	$ 137,366	$ 146,321	$ 214,544	$ 219,975	Energy Storage
	RG&E	No	$ 168,730	$ 172,105	$ 175,547	$ 179,058	
Grid Model Enhancement	NYSEG	Yes	$ 6,600,000	$ 6,600,000	$ 6,600,000	$ 6,600,000	Foundational
	RG&E	Yes	$ 3,400,000	$ 3,400,000	$ 3,400,000	$ 3,400,000	
Innovation Support	NYSEG	No	$ 344,000	$ 350,880	$ 357,898	$ 365,056	REV Innovation Support
	RG&E	No	$ 171,333	$ 174,760	$ 178,311	$ 181,820	
Innovative Projects	NYSEG	Yes	$ 230,660	$ 413,721	$ 133,043	$ 83,627	Integrated Planning and Grid Operations
	RG&E	Yes	$ 112,077	$ 173,216	$ 79,778	$ 63,430	
Interconnection Services	NYSEG	Yes	$ 42,500	$ -	$ -	$ -	Integrated Planning and Market Services
	RG&E	Yes	$ 7,500	$ -	$ -	$ -	
Load and DER Forecasting	NYSEG	Yes	$ 112,500	$ 131,250	$ 125,000	$ 31,250	Integrated Planning
	RG&E	Yes	$ 75,000	$ 43,750	$ 25,000	$ 6,250	
Line Automation	NYSEG	Yes	$ -	$ 553,500	$ 583,500	$ 664,500	Foundational
	RG&E	Yes	$ -	$ 184,500	$ 194,500	$ 221,500	
Market Services	NYSEG	Yes	$ 73,883	$ -	$ -	$ -	Market Services
	RG&E	Yes	$ 24,628	$ -	$ -	$ -	
			$ 17,066,397	$ 18,146,064	$ 19,140,270	$ 16,565,747	

3. Human Resources

Q. What are the incremental human resource requirements of the Companies' DSIP?

A. A detailed breakdown of the five-year human resources requirements to support the Companies' DSIP is set forth in Table 3. The human resources identified in Table 3 are new employees incremental to the Companies' employee levels at the end of the Test Year (i.e., the 12 months ending December 31, 2018).

Table 3: REV Incremental Human Resources Requirements Summary Table

Resource Type	OpCo	2019	2020	2021	2022	2023
Master Data Specialist	NYSEG					
	RG&E		1.0			
Operations Engineers	NYSEG	4.0			3.0	
	RG&E	3.0			2.0	
Smart Grids Analyst (Energy Storage)	NYSEG	0.5				
	RG&E	0.5				
EV Program Implementation Manager	NYSEG	0.7				
	RG&E	0.3				
EV Program Implementation Analyst	NYSEG	0.7				
	RG&E	0.3				
EV Program Planning Analyst	NYSEG	0.7				
	RG&E	0.3				
Project Manager (Energy Storage)	NYSEG		0.5			
	RG&E		0.5			
Owners Engineer (Energy Storage)	NYSEG		0.5			
	RG&E		0.5			
Engineer (Energy Storage)	NYSEG		0.5			
	RG&E		0.5			
Change Management Project Manager	NYSEG		0.5			
	RG&E		0.5			
Data Portal Project Manager & Administrator	NYSEG		1.0			
	RG&E					
Automation Project Engineer	NYSEG	1.0				
	RG&E					
Lead Analyst (Forecasting)	NYSEG			1.0		
	RG&E					
Energy Control Systems Analyst (ADMS)	NYSEG					
	RG&E				7.5	
Lead Analyst (NWA)	NYSEG	1.0				
	RG&E					
Engineer (NWA)	NYSEG	1.0				
	RG&E					
Supervisor (NWA)	NYSEG	1.0				
	RG&E					
		15.0	6.0	1.0	12.5	0.0

Q. Are the dollars associated with these resources accounted for in Table 2 above?

A. No. The O&M dollars shown in Table 2 exclude internal labor. Incremental labor costs are included in revenue requirements as part of the labor category.

F. NYSEG and RG&E Innovation Process

Q. Do the Companies have an Innovation Process that is an important aspect of the Companies' becoming the DSP?

A. Yes. NYSEG and RG&E embrace innovation as a core corporate value. The Companies seek to innovate to improve reliability, increase efficiency, reduce environmental impacts, and provide new affordable services to customers. Innovation directly applies to the Companies' efforts to serve as the DSP and allows new ways to plan, design, build, maintain and operate their assets. Innovation also enables the Companies to provide more granular information and engage their customers to enable better informed choices. Innovation has been vital to the Companies' REV Innovation Portfolio, which includes REV demonstration projects that are formally reviewed and accepted by the Commission, projects that the Companies are pursuing as part of the ESC, and individual pilot projects that are identified as part of the innovation cycle process. Lessons learned within the REV Innovation Portfolio will inform the design of the Companies' Technology Platform and one or more of the three core DSP functions as they are brought to scale.

Q. Have the Companies implemented any REV demonstration projects within the Innovation Portfolio since the 2015 Rate Case?

A. Yes. The Companies are currently implementing or have completed implementation of six REV demonstration projects since the 2015 Rate Case. Completed projects include Community Energy Coordination and the Energy Marketplace. Projects currently being developed and implemented include the Flexible Interconnect Capacity Solution, Behind the Meter Battery Storage, Integrated EV and Battery Storage, and Smart Home Rate.

Q. What have the Companies learned from these demonstration projects?

A. These projects have helped to identify and build understanding of technology along with customer and market needs related to various DERs. Furthermore, these projects have helped inform and develop current program plans in several areas including energy efficiency and demand response programs, interactions with DER service providers, distribution system management, customer engagement, and energy storage. Quarterly reports with more detailed lessons learned are submitted to the Commission.

Q. Will the Companies continue to identify and propose new demonstration projects?

A. Yes. Demonstration projects are valuable to test new business models, new ways of creating value for customers, new ways of creating value for stakeholders, new ways of creating value for the market, and new ways of managing the utility grid. The Companies will continue to leverage demonstration projects as a flexible process for developing newly identified opportunities that have not been previously defined in project plans.

Q. What other programs contribute to the Companies' innovation portfolio?

A. The New York State Energy Research and Development Authority ("NYSERDA") has coordinated an initiative called REV Connect that encourages partnerships between New York's utilities and other companies to accelerate innovation and the development of new business models. The REV Connect online portal provides vendors and solution providers with a single place to review the Companies' postings on areas of interest. The postings draw proposals from the market using a one-page submission. NYSERDA helps to shape, improve and structure proposals before forwarding specific proposals to the appropriate utility.

Q. What are REV Connect innovation sprints?

A. REV Connect innovation sprints focus attention on timely and specific utility needs. For each innovation sprint, solution providers are invited to submit ideas within a specific theme and timeframe. Qualified proposals receive feedback and may be invited to an in-person meeting to pursue innovative partnerships.

Q. Have the Companies pursued any market partnerships as a result of REV Connect?

A. Yes. The Companies participated in each of the three 2018 REV Connect sprints for clean heating and cooling, efficiency, and electrifying transportation. NYSEG is moving forward to design and implement an EV DC Fast Charger pilot project coming out of the electrifying transportation sprint. Specifically, Tompkins County has identified electrification of transportation as a priority to meet its aggressive clean energy goals and has demonstrated high community engagement, making it a natural partner. This pilot project will install DC fast charging stations within the City of Ithaca and Tompkins County as part of the ESC. The DC Fast Charger pilot is discussed in more detail later in our testimony.

Q. Are there other areas of innovation the Companies are interested in advancing through their innovation efforts and REV Connect innovation sprints in the near future?

A. Through the 2019 innovation sprints, the Companies seek to develop a mutually beneficial Smart Cities partnership that may include energy service providers, researchers, municipalities, and others to develop a Smart Cities roadmap. Outcomes from the roadmap may include smart street lighting, smart transportation, smart buildings, DERs, data analytics, customer engagement tools and others. Also, NYSEG sought to increase innovative solutions for its upcoming Request for Information to address natural gas reliability, demand, and/or supply in the Tompkins County region. In addition, the Companies anticipate participating in the second 2019 REV Connect innovation sprint which may be related to energy storage. Finally, the Companies will be seeking innovative solutions to leverage the ESC platform, discussed later in our testimony, to enable customers to drive adoption and engagement and optimize platform operations.

Q. What is the incremental funding requirement for Innovation Process Support, including REV Connect?

A. Incremental funding to transition and institutionalize the REV Connect effort is estimated to cost approximately $164,000 in the Rate Year (escalated at 2%) and has been included in Table 2 in Section V.E above. If the JU elects not to move forward with the shared REV Connect online portal and joint innovation sprints, the Companies would need to re-assess this estimate, including the need to hire one full-time equivalent ("FTE") to support the Companies' innovation process. In addition, the Companies require one additional FTE for REV Change Management efforts. Estimates for these efforts are also included in Table 2 in Section V.E above.

VI. ENERGY SMART COMMUNITY AND STAKEHOLDER ENGAGEMENT

Q. What is the purpose of this section of the testimony?

A. This section discusses the status of and lessons learned from NYSEG's ESC program, including how it supports REV and advances the Companies' ability to serve as the DSP.

We also discuss the Companies' stakeholder engagement initiatives used to advance REV initiatives.

A. <u>Energy Smart Community Program</u>

Q. What is the ESC Program?

A. As discussed in the Companies' 2018 DSIP filing, the ESC serves as an innovation ecosystem platform to test multiple concepts simultaneously in an integrated way. The ESC supports testing the application of new grid technologies such as AMI, and how more granular energy usage and system data can create value for customers, the network, and third-parties. The ESC's integrated project approach has accelerated the Companies' learning process, particularly when they are testing technologies and business models that cut across Integrated Planning, Grid Operations, and Market Services functions.

Q. How have the Companies benefited from the ESC?

A. The ESC has enabled the Companies to develop their DSP capabilities by deploying foundational grid optimization technologies (such as AMI), testing integrated planning tools, and offering products and services platforms that have enabled customers to gain greater control over their energy use, and overall energy bills. As a result, both the Companies and customers have benefited from the ESC.

Q. What are the major lessons learned from the ESC?

A. The Companies confirmed that the foundational technology of AMI is desired by customers, enables DSP capabilities, and is a mature technology to deploy. These conclusions are supported by the following ESC statistics and facts:

- An electric AMI meter no-fee opt out rate of 1.3%;

- 11.7% of customers with an AMI meter are using the Energy Manager, with 22% of such customers actively using the site;
- An excellent electric meter read rate of 99.6%;
- AMI interval usage data is being collected which can be leveraged for analyses related to market research and segmentation, time varying rates, DER adoption forecasting, and customer load profiles; and
- Integration into the ADMS to support outage management.

The Companies also confirmed that an integrated Technology Platform is needed to fulfill their future role as the DSP. In particular, the Companies determined that field surveys and corresponding transfers to the GIS confirmed the need for quality asset and system data to enable accurate real-time power flow modeling, system planning, and DER adoption forecasting. Additionally, lessons learned from the ESC substation and line automation activities were used to inform New York automation deployment.

Q. Did the Companies learn any other lessons?

A. Yes. The Companies learned that customer perceptions of the local utility can improve with effective stakeholder engagement and communications. This conclusion is based on a comparison of surveys from 2016 and 2018 of Tompkins County residents which showed:

- 68% of customers in the upgrade area were aware of the ESC;
- 10% increase in customers who perceive NYSEG as committed to developing renewable energy;
- 10% increase in customers who perceive that NYSEG is collaborating with communities;

- 12% increase in customers who believe that NYSEG is committed to becoming the Utility of the Future; and
- 10% increase in customers who perceive NYSEG as innovative.

Q. Does it appear that NYSEG is considered a "trusted energy advisor" within the ESC?

A. Yes, based on the following: an excellent response to the NYSEG Smart Solutions Marketplace with 1066 transactions, 2003 energy efficiency products sold and 151 demand response enrollees; and a Smart Energy Consumer Collaborative Award for the Smart Partner Program for low- and moderate-income customer energy efficiency.

Q. Do the Companies plan to continue the ESC as a launch pad for future projects?

A. Yes. The Companies request that the Commission authorize the continuation of the ESC. As the launch pad for future technology and processes, the Companies have built integrated grid platforms and integrated customer platforms. The Companies plan to continue the ESC for several reasons, including those related to the three core DSP functions: integrated system planning; grid operations; and market services.

Q. How will the ESC be used in the future for integrated system planning and grid operations purposes?

A. In the near term, the Companies will continue to evaluate, through the ESC, the operational benefits of the grid platforms of AMI, system automation and the advanced functions of ADMS. The Companies will leverage AMI and system data to test integrated distribution planning and load forecasting models to more accurately forecast DER integration and system impacts. The Companies are also working with their ESC AMI provider to test distributed intelligence applications.

Q. In what manner will the ESC be used in the future for market services purposes?

A. With the deployment of the Energy Manager Platform, the Companies will continue to evaluate customer use of AMI data for greater control over their energy costs and the ability to share data with third-parties through Green Button Connect. ESC marketplace and AMI interval data can also be used to test innovative energy efficiency products and services, demand response programs, test customer acceptance of clean heating and cooling technologies, and test the offering of customized products and services informed through data analytics. Additionally, the Companies plan on testing customer use and acceptance of the ESC innovative rate design and conducting further market research.

Q. Are there any other short-term reasons for continuing the ESC?

A. Yes. In 2019, NYSEG launched a DC Fast Charger pilot and a Deadline Differentiated vehicle charging pilot within the ESC.

Q. Are there other long-term reasons for continuing the ESC?

A. In order to leverage the ESC launch pad of established automated grid and integrated customer platforms within the ESC, the Companies anticipate early trials or deployment of DSP-related investments within the ESC. These trials may include, but are not limited to: advanced integrated system planning and load forecasting tools; advanced ADMS functions for monitoring, control and dispatch of DERs; use case testing for data analytics; advanced system automation and resiliency; energy storage; EV supply equipment; NWA trials; multi-function telecommunications network; grid model enhancement and data quality; AMI network resiliency; and innovative demand response and energy efficiency programs and smart cities initiatives.

Q. What are the O&M requirements needed to support the Companies' planned ESC activities?

A. The annual O&M requirements are comparable to what was included in the current rate plan and are estimated at about $2.5 million in the Rate Year. Future years would be subject to inflationary increases and are summarized in Table 4 below. These costs are also included in Table 2 in Section V.E above.

Table 4: O&M Requirements for Planned ESC Activities
($000)

2020	2021	2022	2023
$2,511	$2,417	$2,545	$2,590

Q. What are the capital requirements needed to support the Companies' planned ESC activities?

A. Capital costs for the ESC will continue to be developed and will be submitted as part of the Companies' next update to the five-year Capital Investment Plan ("CIP").

B. Stakeholder Engagement

Q. What stakeholder engagement activities have the Companies planned and implemented surrounding the REV initiatives?

A. The Companies believe that involving stakeholders is important to informing policies and practices, and shaping their approaches. Multiple opportunities were undertaken to involve key stakeholders, particularly in the development of the Companies' DSIPs in 2016 and 2018. For example, on June 20, 2016, the Companies hosted a DSIP Forum in Geneva, New York. More than two dozen interested parties attended to learn about the components of the filing and provide feedback. Presentations included a DSIP overview, grid operations, system planning, market enablement and provision of customer data, DSP technology projects, AMI, the ESC, NWA processes, interconnection improvements, and provision of system data. Three webinars were also conducted with solar developer stakeholders in mid-June 2016. Based on the success of the 2016 forum, the Companies hosted another session regarding their 2018 DSIP filing using a similar format. In addition, a video of the session was posted on the Companies' websites for those unable to attend and to expand the Companies' reach to other stakeholders. This forum was held on June 20, 2018 in Auburn, New York, with more than 70 participants attending from a wide range of interest areas including engineering firms, sustainability coalitions, academic institutions, clean energy companies, consulting firms, solar organizations, elected officials, architectural firms, the New York Power Authority ("NYPA"), electrical contractors, advocacy groups, innovation companies, and a county planning department. Topics included grid operations, AMI, Integrated System Planning (energy storage, forecasting, planning and hosting capacity, NWAs), DSP technology projects (market enablement), innovation & demonstration projects (e.g., EVs, the ESC), and information sharing (customer data and interconnections). The various forums and meetings provided an opportunity for participants to learn the key elements of the Companies' DSIP filings, ask questions, and offer suggestions to provide clarification and/or enhancements to the filing.

In addition to that, the Companies have coordinated with the JU on many stakeholder engagement meetings since 2016, both topical (for instance, hosting capacity) and general (including the November 2017 panel sessions hosted by Staff).

Q. Please summarize the feedback you received on the DSIP and how the stakeholder engagement sessions specifically guided the Companies' policies and practices.

A. Participants indicated that they appreciated the information and the opportunity to provide feedback, as well as the chance to meet directly with the Companies' subject matter experts. Feedback which was used to refine and shape the DSIP filing included:

- Specific timeframe for the initiatives (more quantification and detailed schedule);
- Size of DERs;
- Third-party control of projects versus utility control;
- Security protections;
- Marketing of AMI;
- Readying the grid for electrification;
- Use of innovative rates;
- Need for circuit-level information; more data/transparency on areas of constraint/hosting capacity;
- DSIP in relation to state goals;
- Vision of where the ESC will be in 5-10 years; and
- Utility partnership regarding conservation.

Q. What other REV-related outreach efforts have the Companies undertaken?

A. In addition to stakeholder engagement on the Companies' DSIP filings, NYSEG and RG&E conducted outreach on a number of project-specific initiatives including EVs, energy storage projects, NWAs, and the ESC. The Companies have also been involved in an NPA project in which there has been considerable stakeholder engagement, including two technical conferences. Plans are in process for robust outreach and engagement for AMI which is discussed in the Advanced Metering Infrastructure Panel's testimony.

Q. What "lessons learned" have come from stakeholder engagement efforts in the ESC?

A. Community outreach and stakeholder engagement are critical for ESC and full-scale deployment of AMI and customer platforms because they help: 1) improve the community's trust in the utility and its brand; 2) minimize AMI opt-outs; and 3) improve customer engagement in the utility's products and services platforms.

Q. What specific critical success factors did the Companies learn from stakeholder engagement in the ESC?

A. The Companies learned the following will result in successful stakeholder engagement:

- A full-time trusted community liaison is required to effectively identify and engage key community leaders and influencers. Value is gained through early identification of emerging issues and concerns and associated mitigation actions and enhancing the utility brand in the community through building trust.
- A well-developed and planned Community Outreach and Stakeholder Engagement Strategy & Plan is recommended for full-scale deployment. A resource library and enhanced website is also recommended.
- A straight-forward, transparent and simple public communications approach is recommended for full-scale deployment. Simplicity and clear articulation of benefits to residents and communities are keys to success.

- Careful monitoring and mitigation are required to properly manage smart meter opt-outs. A key lesson learned is that opt-out campaigns not based upon scientific research can quickly manifest and sway public opinion.
- Stakeholders, such as the Cornell Cooperative Extension, provide valuable expertise. They are well known and respected within Ithaca and Tompkins County and have staff members with knowledge and passion for energy issues. Careful consideration and planning are required for determining the applicability for Statewide AMI deployment.

Q. Do the Companies plan to implement similar outreach activities for any new, future REV projects and initiatives?

A. Yes. Stakeholder engagement and proactive outreach are important to the Companies. NYSEG and RG&E will plan and implement appropriate outreach activities for any new project to ensure awareness and provide a mechanism to receive feedback.

VII. MAJOR COMPANY REV INITIATIVES

A. Non-Wire Alternatives and Non-Pipe Alternatives

1. Background

Q. What are the Companies' approaches and objectives for NWA and NPA projects?

A. The Companies' approach to NWA and NPA projects reflect the guidance received from the Commission and involves reviewing traditional electric and gas infrastructure improvements and determining whether there may be economic alternatives to traditional infrastructure investments. Overall objectives for NWA and NPA projects are to build a portfolio of projects which are cost-effective for customers, provide reliable alternatives to traditional capital investment projects, and at the same time provide the Companies with cost recovery, while they comply with regulatory directives and provide a basis to learn from and work cooperatively with other utilities and stakeholders.

Q. How do the Companies identify potential NWA projects?

A. The Companies established NWA Suitability Criteria to determine which traditional wires solutions may be deferred or avoided via NWA. The Companies also established an annual process where the NWA Suitability Criteria are applied to the full list of electric transmission level and electric distribution level projects that are included in the Companies' five-year CIP.

Q. How are potential DER Developers informed of NWA opportunities?

A. Potential NWA opportunities are published on the Companies' websites and are available through links to the REV Connect and the JU websites.

Q. Please describe the Companies' NWA Suitability Criteria.

A. The Companies' NWA Suitability Criteria are used to evaluate traditional infrastructure projects based on project type or need, timeline, and cost. These Suitability Criteria have proven effective in identifying potential NWA projects. As such, they remain unchanged from the Suitability Criteria first described in the JU's May 2017 filing in Cases 14-M-0101 and 16-M-0411 which described how utility planning procedures would apply the NWA Suitability Criteria. The Companies' specific NWA Suitability Criteria are shown in Table 5 below.

Table 5: NYSEG/RG&E NWA Suitability Criteria

Criteria	Potential Elements Addressed
Project Type Suitability	• Load Relief projects that do not involve a customer contribution or have a specific customer in-service date that is sooner than the timeline suitability criteria of 36 months. • Reliability projects and/or a combination of reliability and load relief projects.
Timeline Suitability	• Minimum of 36 months to time of need.
Cost Suitability	• Projects with construction cost greater than $1,000,000.

Q. How do the Companies prioritize the identified NWA opportunities?

A. Once the list of potential NWA projects has been developed, the potential NWA projects are prioritized by time of need. The Companies then plan a tentative schedule for procuring NWA solutions, focusing first on the near-term, high priority projects.

Q. How do the Companies procure NWA solutions?

A. The Companies procure NWA solutions through a competitive bidding process with third-party DER developers utilizing a request for proposals ("RFP").

Q. How do the Companies engage the DER marketplace?

A. When the Companies issue an NWA RFP, the RFP is mass e-mailed to the Companies' NWA distribution list, posted to the Companies' applicable website, linked to the JU and REV Connect websites, and filed with the Commission under Case 14-M-0101.

Q. How do the Companies evaluate whether a potential NWA solution is cost-effective?

A. The Companies utilize the Societal Cost Test ("SCT") as defined in the Companies' BCA Handbook to determine if an NWA solution is cost-effective.

Q. Do the Companies plan NWA projects to defer or to eliminate traditional wires solutions?

A. Yes. The Companies plan to defer traditional wires solutions via NWA solutions.

Q. How is the deferral value of a traditional wires solution used in the BCA process?

A. For each NWA project, the Companies calculate an NWA deferral value associated with deferring the traditional wires solution for a defined number of years. That deferral value is used as a benefit to the NWA solution in the BCA.

Q. How do the Companies calculate an NWA project's deferral value?

A. The Companies calculate the revenue requirement for the traditional solution based upon the project's expected in-service date, and again based upon the deferred in-service date associated with installing an NWA solution for a pre-defined number of years. The difference between the net present values of the revenue requirements for the two projected in-service dates is known as the "deferral value."

2. Current Projects

Q. What NWA projects were included in the 2016 Rate Plan?

A. The NYSEG Java NWA project and the RG&E Station 43 NWA project were included. These NWA projects were the Companies' pilot projects for which information was filed on May 1, 2015 in response to the Track One Order.

Q. Are the Companies working on additional NWA projects?

A. Yes. The Companies are currently actively working on the NYSEG Stillwater NWA, NYSEG New Gardenville NWA, and RG&E Station 51 NWA projects.

Q. How do the Companies identify potential NPA projects?

A. The Companies are in the process of developing an approach similar to the NWA approach described earlier to address when and how potential NPA solutions to traditional long-term system reinforcement projects should be evaluated.

Q. What current NPA projects are the Companies developing?

A. The Companies are currently working on the NYSEG Lansing NPA project to potentially defer the construction of the NYSEG Lansing/Freeville Reinforcement Gas Pipeline Project.

Q. Can you provide some background on the Lansing NPA project?

A. In its Order issued November 16, 2017, in Case 17-G-0432, the Commission directed NYSEG to issue an RFP for NPA proposals that address gas reliability and supply issues identified by NYSEG in its petition associated with the Lansing area.

3. Planned Projects

Q. Have the Companies identified additional NWA projects?

A. The Companies are currently in the process of identifying additional potential NWA projects by applying the Suitability Criteria to the T&D projects included in the most recently filed CIP. The Companies undertake this analysis annually and publish the results on their websites.

4. *Capital / O&M Requirements*

Q. How do the Companies currently recover costs associated with NWA projects?

A. All NWA costs, including those incurred for NWA costs not ultimately linked to a specific project, are capitalized and included in the Companies' rate base as intangible assets, and are amortized over the time frame that the traditional infrastructure solution would have been depreciated. In addition, until such time as the NWA investments are fully reflected as part of rate base in delivery rates, the Companies have been authorized to defer the revenue requirement impact of the NWA investment (typically return of and return on investment) for potential collection through the RAM.

Q. Do the Companies propose as part of these rate cases to alter the current cost recovery in place for NWA?

A. Generally, no. As noted above, there are cost recovery mechanisms already in place to address all NWA costs, including those directly related to projects put into place as well as general NWA activities not associated with a specific project. These general costs could be associated with: 1) the application of the NWA Suitability Criteria to the CIP; 2) NWA program management activities; 3) NWA stakeholder engagement activities; and 4) NWA review activities for projects which do not ultimately result in an NWA project. Specifically, in this case, these general costs are proposed to be included in the intangible asset balance and be amortized over a 20-year period.

Q. How do the Companies treat the payment of interconnection costs associated with NWA projects?

A. The costs of completing the interconnection studies associated with NWA projects are borne by the developer and should be included in a developer's NWA proposal(s). In recent NWA RFPs, the Companies directed developers to exclude the costs associated with the physical interconnection of the NWA resource on the Companies' side of the point of interconnection for purposes of performing an "apples-to-apples" comparison among proposals. Because interconnection costs vary, different vendors are likely to estimate such costs differently.

To the extent that the Companies pay for system upgrade costs associated with interconnecting an NWA project(s), these costs would be included in the project's BCA. As noted above for all NWA costs, the Companies will treat the interconnection costs as an intangible capital asset and recover the costs through the mechanism currently in place and proposed to continue.

Q. What is the Companies' current cost recovery and earnings opportunity for NPA projects?

A. The Companies currently do not have a specific cost recovery or earnings mechanism in place for NPA projects.

Q. Do the Companies propose a cost recovery and earnings mechanism for NPA projects?

A. Yes. The Companies propose to treat NPA costs in the same manner that NWA costs are treated with respect to cost recovery and earnings mechanisms.

Q. Will there be any O&M costs associated with NWA or NPA projects?

A. No. The Companies have treated and propose to continue to treat all costs associated with NWA and NPA projects as intangible capital.

5. NWA Incentive Mechanism

Q. Do the Companies currently have an NWA or NPA incentive mechanism in place?

A. No.

Q. Do the Companies propose an NWA or NPA incentive mechanism?

A. Yes. The Companies propose both an NWA and an NPA incentive mechanism, similar to the mechanisms approved for Niagara Mohawk Power Corporation d/b/a National Grid in Cases 17-E-0238 et al. The proposed mechanisms would provide the Companies with incentives when the present value of the net benefits achieved by an NWA or NPA project exceeds the present value of the net costs of an NWA or NPA project.

Q. What is the amount of incentive the Companies propose?

A. The Companies propose an incentive equal to 50% of the net present value of the net benefits over costs as identified through the application of a forecasted BCA, to be adjusted to the "as-built" or actual value of the net benefits if different than forecast.

Q. Please briefly describe how the Companies' proposed NWA/NPA incentive mechanism would operate.

A. For each NWA and NPA project,[2] the Companies will prepare an SCT BCA, based on the BCA Handbook,[3] which will include the value of deferring the traditional solutions project for a specific number of years,[4] as a benefit to the NWA/NPA project. With the inclusion of the other appropriate benefits and costs for the project, a resultant BCA over one (1.00) indicates the NWA/NPA project is cost-effective when compared to the traditional solution and that it should proceed.

The Companies will contract for the construction of the NWA/NPA project, assign a preliminary incentive equal to 50% of the amount of net project benefits in excess of the net project costs, make appropriate regulatory filings and complete the project. Upon completion of the NWA/NPA project,[5] the Companies will complete a second "as-built" BCA, utilizing actual costs and any other adjustments to costs or

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[2] NWA/NPA "project" may mean a single project or a portfolio of projects proposed to be completed to satisfy a single NWA/NPA need.

[3] The BCA will consider all of the benefit and cost categories in the BCA Order and will utilize the Companies' BCA Handbook.

[4] The NWA/NPA deferral timeframe varies on a project-by-project basis.

[5] Completion of the NWA/NPA project is assumed to occur when the final project is deemed in-service.

benefits which are identified for the "as-built" project. The original preliminary incentive amount will be adjusted if necessary, once again based on 50% of the excess net project benefits compared to the net project costs, and this new incentive amount will be recovered through the cost recovery method described further in this testimony.[6]

Q. Why do the Companies propose to establish a "forecasted" or preliminary incentive amount and a later adjustment based on the "as-built" or actual costs and benefits?

A. The Companies will prepare the forecasted BCA for all proposed projects as part of the NWA/NPA procurement process. Establishing the forecasted incentive amount at this time allows the Companies to file regulatory documents establishing the parameters of the NWA/NPA project with appropriate response time should Staff or the Commission issue directives which might impact the ultimate NWA/NPA project configuration and/or the final incentive amount. Producing an "as-built" BCA based on actual costs and other potential revisions to the project provides a mechanism to better understand the final project terms and allows the Companies and customers to be made whole with regard to payment of an appropriate incentive based on the actual project attributes.

Q. What do the Companies propose for incentives related to projects which must be increased in size from the original NWA or NPA project procurement?

A. Should additional NWA or NPA resources be needed to achieve the initially proposed deferral of a traditional infrastructure project, or to increase the duration of the deferral, the Companies will initiate the procurement of incremental resources as required. As long as it is cost-effective to procure the additional resources to continue the deferral,

[6] If appropriate, the Companies would file amended regulatory filings adjusting the incentive amounts from the original estimated incentive to the "as-built" project incentive.

the Companies will be able to recover the expenditures incurred in obtaining the additional resources, including carrying charges. However, the Companies' "as-built" incentive will not reflect either the costs or the benefits associated with the additional resources.

Q. How do the Companies propose to treat NWA/NPA costs and incentives for projects which require additional resources for effective deferral of the traditional solution, but for which the Companies determine that acquiring additional resources is technically or operationally infeasible?

A. In the case where additional resources are needed but cannot be cost effectively purchased, the Companies will plan to implement a traditional infrastructure solution. Recovery of any incremental costs incurred to this point as well as any incentives related to that project will be halted without requiring a refund of the amounts already collected at that time, except that it should be noted that any obligations made as part of a contracted NWA or NPA project will be resolved as per the associated contract for services, and if not cancellable without cost or penalty, will be recovered in the same manner as general NWA or NPA costs are recovered.

Q. How do the Companies propose to recover the NWA/NPA shareholder incentive amounts?

A. The Companies propose that the NWA/NPA incentives be deferred and recovered through the RAM (to the extent the RAM mechanism is triggered) or be addressed in the Companies' next rate case filing. The deferral of the incentive would occur after the NWA incentive calculations are finalized.

Q. Do the Companies propose different incentives for NWA and NPA projects based on size?

A. No. In keeping with the Companies' current and effective suitability criteria, projects which meet the suitability criteria, including the criteria that the traditional solution is estimated to cost $1,000,000 or more, will be considered for NWA application. The Companies plan to apply the incentives to all successful NWA and NPA projects, regardless of size.

Q. Why do the Companies propose incentive mechanisms for both NWA and NPA projects?

A. The Companies propose similar cost recovery and incentive mechanisms for NWA and NPA projects because the types of projects the Companies have encountered to date function similarly. That is, the NWA or NPA projects are planned to defer a specific infrastructure project which is within the Companies' control. Therefore, there is a parallel between the NWA and the NPA cost recovery and incentive mechanisms.

B. <u>Energy Storage</u>

Q. Does the Commission have any policy or directives related to Energy Storage?

A. Yes. The Commission recently set energy storage targets in the Energy Storage Order, establishing a goal for the installation of 3,000 MW of energy storage in New York by 2030, with the deployment of 1,500 MW by 2025. The Commission also established energy storage procurement targets for the Companies to establish dispatch rights for a minimum of 10 MW of energy storage each. The Energy Storage Order also discusses the current uncertainties related to energy storage in the areas of technology maturity, wholesale market rules, permitting, and cost-efficient economics.

Q. What progress have NYSEG and RG&E made in implementing aspects of the Energy Storage Order?

A. The Companies are analyzing the various topics identified within the Energy Storage Order and have been coordinating with the multiple corresponding JU working groups. Most recently, on February 11, 2019, in compliance with the Energy Storage Order, the Companies filed their implementation plans for a competitive procurement of at least 10 MW per Company, the Companies also filed amendments to their tariffs in compliance with Ordering Clause No. 3 of the Order on May 2, 2019, and completed the inclusion of interconnection upgrade costs in NWA RFPs.

Q. How do the Companies propose to recover the costs associated with the Energy Storage Order?

A. Any associated tariff amendments to effectuate cost recovery for the direct competitive procurement will be filed as directed by the Energy Storage Order. In addition, the Companies propose to create an intangible capital asset equivalent to all of the energy storage project costs. Examples of these costs include, but are not limited to, internal and/or external labor costs, outside services specific to the payments made to third-parties for storage procurement solutions, and/or system upgrade costs associated with interconnecting the projects associated with the Energy Storage Order. Similar to the NWA interim recovery described earlier, the Companies will defer the revenue requirement impact of the costs associated with the Energy Storage Order and established as intangible capital assets, and this deferral would be eligible for recovery through the RAM.

Q. Would the Companies ultimately earn a return on the costs treated as intangible capital assets?

A. Yes. The Companies propose to treat the storage procurement costs as an intangible capital asset that will ultimately be included in rate base. The Companies propose to depreciate/amortize the intangible capital asset over the life of the procurement contract, which is expected not to exceed seven years.

Q. Are the Companies proposing energy storage projects in this case?

A. Yes. We identify the specific projects and associated cost forecasts below. The Companies believe energy storage is a transformative technology that can provide multiple benefits to the electric system and customers. Energy storage enables the operation of intermittent renewable resources, supports the distribution system, and can help New York meet its GHG emission targets. The Companies envision energy storage as a critical tool to help facilitate system and customer solutions. The Companies' proposed investments will support the Commission's goals for energy storage deployment by supporting the development of the storage market in New York, adding new storage use cases to the portfolio, which will allow the Companies to gain additional knowledge and insight into the operation of medium- to large-sized energy storage installations connected to the distribution system to benefit all customers.

Q. Do the Companies have experience with installing energy storage systems?

A. Yes. The Companies have recently completed four energy storage projects, two in NYSEG's territory and two in RG&E's territory totaling 2.8 MW and up to 11.4 megawatt hours ("MWh") of battery storage. Each of these four projects demonstrates unique use cases to help the Companies better understand the impact of smaller scale energy storage projects on customers, both in-front of the meter and behind-the-meter. Through these deployments, the Companies have found that projects connected at a substation reduce the development timeframe and help decrease costs related to permitting, siting, site acquisition, and interconnection.

Q. What is the overall energy storage capacity the Companies are proposing?

A. The Companies propose developing four additional projects, two in NYSEG's territory and two in RG&E's territory providing a total of approximately 12 MW of capacity for load relief and up to 105 MWh of available energy. All four projects will be interconnected at various intermediate voltage class level (12.47 kV - 4.8 kV) distribution substation locations.

Q. Please describe the first energy storage project proposed for NYSEG.

A. The first project proposed for the NYSEG territory is a 5 MW, 70 MWh lead acid battery storage system ("BSS"), along with a synchronous condenser, located at NYSEG's Java substation.

Q. Please describe the Java substation.

A. The Java substation is an electric substation located in the eastern portion of the Lancaster Division. The area served by the Java substation is near the end of the NYSEG service territory and is bordered to the south and east by RG&E's service territory. Currently, the station is comprised of one 34.5-4.8 kV, 5 MVA transformer serving approximately 1,694 residential and small commercial customers via two 4.8 kV distribution circuits.

Q. Why does NYSEG propose to own and operate this BSS at the Java substation?

A. In February 2016, a multi-need NWA RFP solicitation was issued to address three primary needs at the Java substation and defer a planned wires solution. The first need is to reduce the loading on the Java 5 MVA Station transformer below its normal rating (i.e., the "Overload Need"). The second need is to establish sufficient quantities of DER to address reliability and power quality issues that exist on the Java 280 circuit. The third need is to provide a back-up supply for customers served by the Java substation following the contingency ("N-1") loss of either the sole 34.5KV supply or the Java substation transformer (i.e., the "Back-Up Need") which would otherwise lead to an outage of all customers served from the substation. Multiple proposals were received and after comprehensive reviews, including a BCA, a developer was selected to provide the Java NWA solution. However, after lengthy contract negotiations and discussions, it was mutually agreed between NYSEG and the developer that moving forward with the Back-Up Need component of the selected NWA solution warranted utility ownership and operation. This is due to both the liability, and the technical and operational complexities in operating the BSS as an electrical "island" or microgrid, acting as the sole temporary electrical supply to all Java customers following the N-1 event until normal supply is restored. NYSEG will therefore split the original NWA into two specific projects where the Overload Need NWA solution will be developed, owned and operated by the third-party developer and the Back-Up Need NWA solution will be owned and operated by NYSEG and developed in partnership between NYSEG and a developer. This Back-Up Need NWA solution is the BSS and synchronous condenser project NYSEG proposes in this rate case filing.

Q. Please describe the second energy storage project proposed for NYSEG.

A. The second project proposed for the NYSEG territory is a 2 MW, 8 MWh BSS, located at Wales Center substation. This BSS is expected to be Lithium-ion technology.

Q. Please describe the Wales Center substation.

A. The Wales Center substation is an electric substation located in the eastern portion of the Lancaster Division. The area served by the Wales Center substation is near the end of the NYSEG service territory and is bordered to the south and east by RG&E's service territory. Currently, this substation is comprised of one 34.5-4.8 kV, 5 MVA transformer serving approximately 1,773 residential and small commercial customers via two 4.8 kV distribution circuits.

Q. Why does NYSEG propose owning and operating this BSS at Wales Center substation?

A. First, the Wales Center substation transformer has an Overload Need. It is rated 5 MVA (nameplate) and has experienced heavy loading in recent years, exceeding its nameplate rating in four of the last eight years, while approaching its critical eight hour emergency rating of 5.5 MVA. Also, there is potential significant penetration (nearly 3 MW) of intermittent DER (existing and in-queue solar and wind),[7] especially when considering the characteristics of Wales Center substation as a smaller load-serving substation. This large amount of potential intermittent DER introduces future concerns with providing quality of supply to customers (e.g., voltage flicker and regulation) as well as the ability of Wales Center substation to host additional DER cost-effectively. NYSEG believes that utility ownership and operation of this BSS at Wales Center substation is in the best

[7] As of April 2019, 144 KW solar and 100 KW wind connected and 2,580 KW solar in queue (values are nameplate ratings).

interest of key stakeholders (e.g., utility, customers, DER developers and the State) to maximize the value of a BSS to achieve multiple uses and benefits while making advancements in meeting the State's energy storage goals. In this case, the BSS is proposed to: 1) address an Overload Need that would otherwise require a distribution wires or other NWA solution; 2) be effectively integrated into a distribution system with a large amount of intermittent DER to help assure the continued delivery of a reliable and quality supply to customers served by Wales Center substation; and 3) provide an opportunity for NYSEG to learn how and if it can operate a BSS to increase the amount of interconnected DER while providing other grid services.

Q. Please describe the first energy storage project proposed for RG&E.

A. The first project proposed for the RG&E territory is a 2 MW, 12 MWh battery storage system located at Station 91. This BSS is expected to be Lithium-ion technology.

Q. Please describe the attributes of Station 91.

A. Station 91 is an electric substation located in the east section of Rochester. Currently, the station is comprised of two 34.5-4.16 kV, 7 MVA transformers serving approximately 1,503 mainly residential customers via six 4.16 kV distribution circuits.

Q. Why does RG&E propose owning and operating this BSS at Station 91?

A. Both Station 91 transformers are well below their nameplate ratings under normal conditions when they are both in-service and supplying customer load. However, an emerging issue in RG&E and one that is more prevalent in NYSEG is the ability of a substation to operate within its ratings, mainly during peak load days, following the contingent (N-1) loss of one of the substation transformers. This risk exists today at Station 91. When this N-1 caused overload occurs, RG&E typically dispatches emergency crews to the substation to assess the severity of the overload and take actions to address the abnormal condition, in addition to the emergency response necessary to respond to the N-1 contingency event. These actions may include manually deploying supplemental cooling to the overloaded transformer until the other transformer is restored to normal operation or installing an emergency mobile transformer. Consequences of these N-1 overloads range from the shortening of transformer life, risk of transformer failure, and operating actions that result in the intentional outage of customers, often referred to as load shedding. RG&E proposes to integrate a BSS into the operation of Station 91 to mitigate the risk of substation transformer overloads from N-1 events, learn how to leverage any extra capacity of the BSS on any given day to provide other grid services while operating the distribution system more efficiently, and to make advancements in meeting the State's energy storage goals.

Q. Please describe the second energy storage project proposed for RG&E.

A. The second project proposed for the RG&E territory is a 3 MW, 15 MWh battery storage system located at Station 142. This BSS is also expected to be of the Lithium-ion technology.

Q. Can the Panel please briefly describe Station 142?

A. Station 142 is an electric substation located in Canandaigua, New York. Currently, the Station is comprised of two 34.5-12.47 kV, (#1 is 14 MVA and #2 is 22.4 MVA) transformers serving approximately 3,164 residential and small commercial customers via four 12.47 kV distribution circuits.

Q. Why does RG&E propose to own and operate this BSS at Station 142?

A. Station 142 is forecasted to have unacceptable N-1 overload exposure, with the same issues and risks as described for Station 91 above, projected to exist in the 10-year planning horizon; earlier or later depending upon load growth assumptions. Station 142 also has a relatively high penetration of solar photovoltaic ("PV") interconnected (> 4 MW), with over 3 MW connected on a circuit near the station. This makes it a potential location for coordinating the generation with peak load periods. Integration, ownership and operation of a BSS by RG&E at Station 142 provides the opportunity to: 1) address the N-1 issue; 2) operate the grid more efficiently by time-shifting close proximity solar production to daily peak load hours; and 3) learn how and if RG&E can operate a BSS to increase the amount of interconnected DER while providing other grid services.

Q. Please explain how each of these BSS proposals support the State's energy storage deployment goals.

A. The proposed projects will provide key lessons about grid benefits through the various opportunities discussed earlier in each of the projects for NYSEG and RG&E and enable the Companies to broaden their expertise for future energy storage deployments. These projects will advance the deployment of energy storage in New York while utility-scale battery storage is still in the early stages of development.

Q. Can the Panel elaborate further on why the Companies are best suited to own these particular energy storage projects?

A. The Companies propose these projects to solve multiple substation issues that will require significant integration into utility operations and processes while ensuring a safe and reliable distribution system. The REV Track One Order permits utility ownership for storage integrated into the distribution system. In reaching this decision, the Commission recognized the usefulness of energy storage as a distribution system asset meeting key system needs. These proposed energy storage solutions are more conducive to utility ownership (versus NWA or the upcoming ESS competitive procurement) due to the complex nature of the solution required and the multiple grid benefits being provided. Additionally, connecting battery storage at distribution substations can accelerate project development, reduce overall implementation costs, and provide benefits to a larger number of customers.

Q. What is the proposed capital and O&M expenditure for these energy storage projects?

A. Table 6 summarizes the expenditures by proposed battery storage project.

Table 6: Battery Storage Cost Estimates

Company	Division	Substation	Projected In Service Date	Power (MW) / Energy (MWh)	Estimated Capital Cost ($M)	Estimated O&M Cost ($M)
NYSEG	Lancaster	Java	2021	5 / 70	26.8	0.54
NYSEG	Lancaster	Wales Center	2021	2 / 8	5.4	0.11
RG&E	Rochester	Station 91	2022	2 /12	7.8	0.16
RG&E	Canandaigua	Station 142	2021	3 / 15	9.1	0.18
Total				12 / 105	49.1	0.98

Q. May the proposed energy storage projects be modified in the future?

A. Yes. The Companies will conduct a more detailed review before final site and project selection. Both NYSEG and RG&E plan to pursue the proposed opportunities at the selected locations or at an alternate location if the Companies determine an alternate location to be more suitable.

Q. How do the Companies propose recovery for the energy storage projects?

A. The Companies propose to recover all development and implementation costs of these battery storage systems as Company-owned assets. Any potential revenues received by the Companies, such as wholesale market revenues, will be deferred for consideration in the RAM or for disposition in the next rate case.

Q. Are there incremental resource needs in order to manage the Companies' energy storage efforts?

A. Yes. The Companies require an additional four FTEs for program support and administration of energy storage related activity.

C. <u>Electric Vehicle Program</u>

Q. Do the Companies propose an EV Program?

A. Yes. NYSEG and RG&E support electrification of the transportation sector as a key solution for the de-carbonization of New York's economy. This type of program may place downward pressure on the electricity rates paid by all customers to the extent that vehicle charging occurs during off-peak hours. Additionally, the Companies recognize and support New York's ambitious EV targets and the programs that are supporting those targets. New York adopted California's Zero Emission Vehicle mandate which will require upwards of 682,000 zero emission vehicles on the road by 2025.

Q. How many EVs currently are in New York and in the Companies' service areas?

A. As of September 2018, there were 31,721 EVs in New York with an estimated 16% or 5,000 of those within the NYSEG and RG&E service areas.

Q. What is the projected growth for EVs in New York and in the Companies' service areas?

A. As noted above, New York adopted a Zero Emission Vehicle mandate. Compliance with this mandate will require approximately 15% of vehicle sales to be zero emission by 2025, which will amount to approximately 682,000 registered EVs. Using the current EV distribution of 16% within the NYSEG and RG&E service areas, the Companies anticipate there will be 109,000 total EV registrations within NYSEG and RG&E service areas by 2025.

Q. Do the Companies foresee any major barriers to grow the EV market in New York, including in your service areas?

A. Yes. The Companies recognize several barriers to growth. Some of these barriers are squarely in the control of automobile companies, such as having a variety of EV choices to meet driver needs. Other barriers can be addressed by utility investment and activity. These barriers include insufficient access to EV charging infrastructure along with customer awareness of EVs.

Q. Are the Companies currently implementing any EV projects?

A. Yes. The Companies are currently implementing three EV projects. The first is the DC Fast Charger pilot project where the Companies utilized New York's REV Connect process to inform a scalable model for public DC fast charging. The Companies are partnering with Greenlots and NYPA to design and deploy a DC fast charger co-investment model. NYSEG, NYPA, and Greenlots will collaborate on site analysis and site-host recruitment. NYSEG will pay for and own the electrical infrastructure up to the charger and NYPA will pay for and own the charger hardware and pay for and perform the installation. Greenlots will help with construction design and will provide the software to operate the chargers. The site-host will provide the physical space for the chargers.

The second project is the Smart Home Rate REV demonstration project where the Companies are partnering with Cornell University to design and implement deadline differentiated charging. Residential customers will choose the time that they require their

EV to be charged and the EV charging system will choose when to charge in order to optimize cost and system constraints while still meeting the customer's deadline.

The third project is the Integrate EV and Battery Storage REV demonstration project. The Companies have installed two DC fast chargers and five Level 2 chargers at the RG&E Operations Center. This location is intended to demonstrate how battery storage can be integrated with EV chargers to manage cost impacts while optimizing the value of the battery system.

Q. What do the Companies hope to achieve through the EV Program?

A. The EV Program will have three elements that will each focus on a specific outcome to help advance the EV market in New York: 1) Charging Infrastructure, where the Companies will expand the EV charging infrastructure in the NYSEG and RG&E service areas; 2) EV Load Integration, where the Companies will integrate new EV load into the grid in a way that improves the overall efficiency of the system; and 3) Customer Engagement, where the Companies will increase customer awareness of EVs and improve customer comfort with EVs as an alternative to internal combustion engine vehicles.

Q. How many charging ports will be needed in New York and the Companies' service areas to achieve New York's goals?

A. To support 682,000 EVs by 2025, 24,000 Level 2 chargers and 1,400 DC fast chargers will be needed in New York based on analysis using the EVI Pro-Lite tool provided by the National Renewable Energy Laboratory. To support the anticipated 109,000 EVs within the NYSEG and RG&E service territories, the Companies will need approximately 4,000 Level 2 chargers and over 225 DC fast chargers.

Q. Do you anticipate electrification of other types of vehicles other than passenger vehicles?

A. Yes. We anticipate that many transit agencies in New York State will electrify their fleets over the next 20 years and several transit agencies within NYSEG's and RG&E's service areas have committed to some initial level of electric bus adoption. We also anticipate EV growth in medium- and heavy-duty fleets across the State, but do not yet have a good estimate of when this growth will occur.

Q. What will be included in the Charging Infrastructure element of the EV Program?

A. The program will incentivize the installation of three types of EV charging infrastructure: Level 2 chargers; DC fast chargers; and transit bus chargers. Installation of these chargers will be incentivized through utility make-ready investments, where the Companies will pay for all costs related to provisioning new service, including utility interconnection and upgrades, and the installation of electrical infrastructure up to the EV chargers. Third parties will make the remaining investment in the charging hardware, including installation costs, and they will be the owners and operators of those chargers. The Companies anticipate owning and operating DC fast chargers in certain geographic areas that may not be attractive for third-party investment.

Q. What are the objectives of the Charging Infrastructure element?

A. The Charging Infrastructure element aims to support the installation of 2,310 Level 2 chargers, 136 DC fast chargers, and up to 28 transit bus chargers by the end of 2022.

Q. What types of chargers will be included as part of the 2,310 Level 2 chargers?

A. Level 2 chargers provide a charging solution for EVs that will be parked for several hours as a typical EV takes around eight hours to fully charge on a Level 2 charger. Level 2 chargers included in this program will be non-residential installations, such as municipal parking lots, parking garages, retail locations, restaurants, parks, multi-family apartment complexes, workplace parking lots, and light duty fleets. The program will remain flexible to the demands in the marketplace with no specific funding allocated for each possible type of charger installation.

Q. What types of chargers will be included as part of the 136 DC fast chargers?

A. The program will support up to 122 DC fast chargers through make-ready investments and Company ownership of up to 14 DC fast chargers. DC fast chargers provide charging solutions for drivers that are traveling long distances over interstates, drivers without access to home charging, and drivers in need of charging their vehicle as quickly as possible. A typical EV will take around one hour to charge 80% using a DC fast charger, although newer vehicles and DC fast chargers are expected to deliver faster charging rates. DC fast chargers included in this program will have a minimum of 50 kW charging capacity and will be publicly accessible and separately metered from other electrical loads with an allowable 10 kW of ancillary site load.

Q. Will recipients of DC fast charger make-ready incentives also be eligible for the DC fast charger incentives as approved in the February 7, 2019 Order Establishing Framework for Direct Current Fast Charging Infrastructure Program issued in Case 18-E-0138 (“DCFC Order”)?

A. Yes. The DC fast charger make-ready incentives are intended to address and help alleviate the high capital cost associated with constructing new DC fast chargers whereas the incentives approved as part of the DCFC Order are specifically intended to address the ongoing electricity delivery cost for DC fast chargers at a time where charger utilization is expected to be relatively low.

Q. What types of chargers will be included as part of the 28 transit bus chargers?

A. Transit bus chargers will be DC fast chargers that are installed at bus depots and are meant to recharge electric transit buses. Specifically, within NYSEG and RG&E service areas, the Regional Transit Service ("RTS") in Monroe County and Tompkins Consolidated Area Transit ("TCAT") in Tompkins County have near term plans for adopting electric transit buses. We anticipate as many as 28 electric transit buses through 2022. A typical electric bus charger has a capacity of approximately 150 kW. Due to the concentrated nature of bus depots the addition of multiple high-power bus chargers may require significant infrastructure upgrades. The Companies will collaborate closely with RTS and TCAT in order to best meet their needs and support their plans through a make-ready investment model. Transit bus make-ready will focus on on-site and upstream electric infrastructure upgrades up to and including the service transformer.

Q. What will be included in the EV Load Integration element of the EV Program?

A. The EV Load Integration element of the EV Program will develop and implement the Smart Charging Program. The Smart Charging Program will influence the time customers charge their EVs through three distinct strategies: Behavioral; Demand Response; and Load Optimization.

Q. What will be included in the Behavioral strategy?

A. The Behavioral strategy will include three stages of customer incentives with each level building upon the previous level. The Stage 1 incentive will encourage enrollment in the EV rate and will include a survey regarding travel and charging behavior. The Stage 2 incentive will include an agreement to collect data from home chargers either through integration with the chargers directly or through an add-on amp meter. The Stage 3 incentive will act as an additional reward for customers who have demonstrated sustained off-peak charging.

Q. What will be included in the Demand Response strategy?

A. The Demand Response strategy will enroll residential Level 1 and Level 2 EV chargers into the existing NYSEG and RG&E demand response programs. Participants will receive both enrollment incentives and performance incentives when they respond to an event.

Q. What will be included in the Load Optimization strategy?

A. The Load Optimization strategy will include continued execution of the Smart Home Rate REV demonstration project, the Integrated EV and Battery Storage REV demonstration project, along with assessment and possible development of additional EV load control pilot projects.

Q. What are the objectives of the EV Load Integration element of the EV Program?

A. The objectives of the EV Load Integration element include enrolling at least: 30% of EV households and fleets in Stage 1 of the Smart Charging Program; 12% in Stage 2; 10% in Stage 3, and 6% in Demand Response.

Q. What will be included in the Customer Engagement element of the EV Program?

A. The Customer Engagement element will include multiple communications strategies designed to increase customer awareness and improve customer comfort with EVs as an alternative to internal combustion engine vehicles. Strategies include providing enhanced web tools and content, engaging with customers through social media, communicating about EVs through newsletters, email, paid media including radio, search, and digital advertising, along with participation in various community based EV events.

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Q. What is the total EV Program budget?

A. The total program cost will be $29 million, comprised of $23 million of capital expenditures and $6 million in O&M expense.

Q. How do the Companies propose to recover the capital expenditures associated with the EV Program?

A. The charging infrastructure element of this program will include installation of electrical infrastructure to provide service to new EV chargers and ownership of certain DC fast chargers. The Companies will own all electrical infrastructure funded through this program and all investments will be treated as capital expenditures and are part of the Companies' capital expenditures plan.

Q. Are there incremental resource needs in order to manage the EV Program?

A. Yes. The Companies require three additional FTEs for project management and administration of the EV Program related activity.

D. <u>Energy Efficiency</u>

Q. How is Energy Efficiency related to REV?

A. Per the Track One Order, the definition of DER includes Energy Efficiency. Energy Efficiency programs benefit customers and are foundational to New York State's clean energy strategy.

Q. What are the Companies' current plans for Energy Efficiency?

A. Please see the testimony of the Energy Efficiency and Earnings Adjustment Mechanism Panel for a detailed discussion. As that Panel testifies, the Companies have supported and continue to support Energy Efficiency Programs that support REV and the State's Energy Efficiency goals.

VIII. SUMMARY AND CONCLUSION

Q. Please summarize this Panel's testimony.

A. The REV Panel testimony addresses: 1) how REV is necessary to meet State Energy Objectives; 2) how REV is impacting the Companies' businesses and how it will add value to customers and DER Operators; and 3) the additional resources the Companies need to continue to implement REV and REV-related goals and initiatives.

Q. Does this conclude your testimony at this time?

A. Yes.