Initial Distributed System Implementation Plan

Orange and Rockland Utilities, Inc.

Case No. 14-M-0101

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ORANGE AND ROCKLAND UTILITIES, INC.

Initial Distributed System Implementation Plan

Introduction

On February 26, 2015, the New York Public Service Commission ("PSC" or "Commission") issued its Order Adopting Regulatory Policy Framework and Implementation Plan ("Track One Order")[1] in its Reforming the Energy Vision ("REV") proceeding which details the regulatory framework and implementation plan required to promote the REV initiative. The Track One Order requires each utility, as a Distributed System Platform ("DSP") Provider, to file a Distributed System Implementation Plan ("DSIP"). This Initial DSIP filing is intended to be a thorough "self-assessment" of Orange and Rockland Utilities, Inc.'s ("O&R" or "Company") distribution system and describes immediate opportunities that will further contribute to reaching REV policies and goals. It will serve as a source of public information regarding the Company's DSP plans and objectives and the template for an integrated approach to planning, investment, and operations. The DSIP is envisioned as a multi-year plan filed with the Commission that will document the Company's plans over a five year period, with a formal DSIP filing occurring every two years. Pursuant to the Commission's Order Adopting Distributed System Implementation Plan Guidance ("DSIP Guidance Order")[2] issued April 20, 2016, following the submission of this Initial DSIP filing, the Company will jointly file with the Joint Utilities of New York ("JU") a Supplemental DSIP ("SDSIP") on November 1, 2016. The SDSIP is to outline the utilities' plans specifying the tools, processes, and protocols required for issues that require further discussion and collaboration, and a coordinated approach for deployment. Some of these topics include suitability criteria for distributed energy resources ("DER") consideration, probabilistic planning, system and customer data sharing standards, further development of hosting capacity, which will be explored through stakeholder engagement.

New York State's REV initiative aligns with O&R's continuing efforts to modernize and strengthen the electrical distribution system and provide customers with the information and opportunities to take more control of their own energy usage. The Company is supportive of the Commission's efforts through REV and is working collaboratively with stakeholders, Staff, and the Commission, to lead this effort and further REV goals within its service territory. Some aspects of REV, such as integrated system planning, technology enhancements, energy efficiency ("EE"), and customer engagement, are already an integral part of the Company's approach to planning, building, and managing the electric distribution system. O&R is also working to develop plans to meet some of the additional goals set out in the REV proceeding as laid out in this DSIP as well as in other documents and filings such as the Advanced Metering Infrastructure ("AMI") Business Plan (Appendix B). Through this time of significant change, O&R remains committed to providing continued safe and reliable service to its customers.

For more than 100 years, O&R has provided energy services and solutions to its customers. Since August 1899, when the originating entity (Rockland Light and Power Company) was first established to serve 350 customers in the Village of Nyack, NY, O&R's employees have been inseparable from the communities the Company now serves. O&R's system and processes are designed to safely

[1] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), Order Adopting Regulatory Policy Framework And Implementation Plan, (issued February 26, 2015)("Track One Order").
[2] REV Proceeding, Order Adopting Distributed System Implementation Plan Guidance, (issued April 20, 2016) ("DSIP Order").

and reliably serve all of its customers (presently over 232,000) in its New York service territory throughout Orange, Rockland, and Sullivan Counties. The weather adjusted system peak demand in 2015 was 1,617 MW in O&R's entire New York, New Jersey, and Pennsylvania territory, which includes 1,157 MW for New York Independent System Operator ("NYISO") portion. The New York electric system is comprised of 66 substations. There are 47 distribution stations, 7 transmission stations, 6 switching stations, and 6 single-customer stations in New York. The New York portion of the system has 574 mile of transmission lines, 3,047 miles of overhead distribution lines, 1,765 underground conductor miles, and approximately 139,541 poles.

O&R and Consolidated Edison Company of New York, Inc. ("Con Edison") are both wholly owned subsidiaries of Consolidated Edison, Inc. ("CEI") and where it is allowed by law and regulation, the companies share internal resources and services. As it relates to this DSIP, Shared Services includes some functions of planning and forecasting, as well as financial services, and is referenced throughout the document as Con Edison. Additionally, O&R has worked in conjunction with Con Edison in the development of this DSIP and in the broader approach to REV, employing Shared Services where appropriate and establishing consistent governance structures and strategic positions.

The Commission approved O&R's current electric rates in its Order issued in October 2015 in Case 14-E-0493.[3] Many of the established near term budgets and plans included in this DSIP are based on what was included in the Electric Rate Plan Order. O&R expects to file an electric base rate case in late November 2016 that will include, to the extent known, updated budgets and plans that will align with the Company's efforts to establish DSP functionality and further REV objectives as outlined in this DSIP.

In addition, the Company will begin implementing an AMI system which will, among other things, facilitate the Commission's REV policies and goals, reduce operating costs, accelerate identification of customer outages, and improve overall outage response and efficiency. The Electric Rate Plan Order details the Company plans to deploy an AMI system beginning in Rockland County. As was anticipated in the Electric Rate Plan Order, O&R will be seeking Commission approval to expand AMI deployment into Orange and Sullivan Counties, to cover the Company's entire New York service territory, in its upcoming electric base rate case filing. The AMI communications network and AMI meters deployed through this project will provide the foundation for implementing several of the key policy objectives stipulated by the Commission in the REV proceeding by improving system visibility, enhancing controls, and supporting advanced analytics that will provide customers the ability to actively participate in energy markets, control energy use, and take control of their monthly bill. Through the development of Green Button Connect ("GBC"), customers will also have the ability to share their own usage data with authorized third parties and increase the value they can receive from DER and other offerings.

Along with producing operational benefits, the AMI project will drive improvements in the convenience, speed, and quality of the services that the Company provides to all of its customers – both during routine business activities and during outage situations:

[3] Case 14-E-0493, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service*, Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan, (issued October 16, 2015) ("Electric Rate Plan Order").

Convenience: Examples of enhanced customer convenience include eliminating the need for manual reading of indoor meters and, within practical limits, offering customers flexible billing date options that better fit their financial circumstances.

Speed: AMI's planned near real-time data collection and electric service switching capabilities will increase the speed of customer services associated with handling customer calls and with activating and deactivating electric service.

Quality: AMI's ability to reliably collect accurate billing data from electric and gas meters will greatly reduce the number of estimated bills and the customer disputes regarding those bills.

Outage Detection and Restoration: AMI meters will detect the loss and restoration of electric power and will provide this information in near real-time to O&R's Outage Management System ("OMS"), augmenting the traditional outage notifications provided by customer calls and Supervisory Control and Data Acquisition ("SCADA") systems. This will enable the Company to identify outages more quickly and facilitate efficient restoration activities.

O&R is committed to implementing REV and helping achieve New York State's aggressive energy policy goals. O&R has established governance processes, as well as a Utility of the Future organization, and aligned resources around REV in order to work to eliminate barriers to achieving REV and DSP objectives. The Utility of the Future organization was established in June 2015 to organize and align the Company's approach to DER integration with the evolving energy distribution markets in New York. This new department has day-to-day REV initiative oversight and is responsible for framing the structure and developing the approach to REV at O&R. This includes coordinating the REV initiatives of the Company in alignment with Con Edison. This group is deemed critical by O&R to address customers' needs moving forward and assist the Company in adapting to the changing energy environment.

O&R has been engaged in integrating DER for many years, gaining experience conducting EE programs, registering Distributed Generation ("DG") interconnections, and recently soliciting DER solutions for targeted load relief in the Pomona Distributed Energy Resources Program ("Pomona Program"),[4] among other initiatives. The Company's successful implementation of the Pomona Program will guide its approach to soliciting Non-Wires Alternative ("NWA") solutions, described in detail in the Distribution System Planning chapter. The extent that current Company planning, operations, and administration activities already meet certain REV objectives will be described throughout this document, in addition to plans to strengthen those capabilities.

The Company believes that a meaningful stakeholder engagement process will be a critical component to developing the DSP. The Company is collaborating with the JU and conducting stakeholder engagement sessions to gain the valuable insights and input of other parties. The JU held a stakeholder engagement session regarding an electric system overview on February 29, 2016. The session included a tour of Con Edison's Learning Center training facility, where stakeholders were able to view and observe the operation of distribution system electrical equipment. The goal of the session was to serve as an informational forum for stakeholders to understand the process by which the electric system is planned. The topics covered were: transmission system overview, overhead distribution system

[4]Electric Rate Plan Order.

planning, underground distribution system planning, utility capital expenditures, and the JU stakeholder engagement process.

The Company has also held a Stakeholder Summit jointly with Con Edison on May 13, 2016 that focused on Initial DSIP content and solicited feedback on system data sharing. The all-day session hosted 34 stakeholders from various companies and organizations, and was rated favorably by 21 of 24 survey respondents, indicating that the session fulfilled its goal of providing information about the content of O&R's and Con Edison's Initial DSIP filings. The summit also provided an opportunity for the Companies to provide information around current and future availability of system and customer data as well as to discuss the data needs of stakeholders. The exchange served as a forerunner for a number of topics being developed further through the ongoing SDSIP stakeholder engagement process.

Going forward, the collaboration with the JU will be critical to establishing shared operating ideas and functionality to develop interoperability, state wide transparency, and a common look-and-feel for similar functions across New York utilities. The internal assessments and plans along with the collaborative work across utilities and stakeholders to develop these ideas, approaches, and processes will be instrumental in shaping the DSP. On May 5, 2016 the JU filed its DSIP Stakeholder Engagement Plan[5] in accordance with the DSIP Guidance Order.[6]

In addition to engaging stakeholders, an objective of the DSP is to engage customers and provide them with more information and opportunities to control their energy usage. Through foundational investments like AMI, GBC, and the Digital Customer Experience ("DCX"), the Company will provide customers more granular usage data that can be viewed through a streamlined platform, and easily transferred to authorized third parties. Working with third parties is yet another way to reach our customers. Third-party engagement can also help animate the market and bring innovative solutions to increase the efficiency of the grid and potentially lower customer bills.

It is important that REV proceeds at a measured pace that allows the Company to work with customers and third parties to test innovative concepts and technologies before they are fully implemented, as to not deviate from the high standards of safe and reliable service that O&R provides to its customers. This is consistent with the final Market Design and Platform Technology report, which states "achieving the REV vision requires planning, testing, learning, refining, and, where appropriate, setting rules and standards. Utilities, market participants, and regulators will learn from initial DSP investments and demonstrations and iterate in future evolution of the DSP markets."[7]

This DSIP outlines and defines the Company's initial steps in becoming the DSP Provider. The document's structure is aligned with the organization of topics contained in the DSIP Guidance Order.[8] First, the Company must evolve its forecasting and planning methodologies, tools, and processes to incorporate and account for the impacts of increased DER penetration. This will also include positioning O&R to take advantage of the opportunities presented by DER including the administration of NWAs and enabling the advantageous deployment of DER. The Company will provide information on locations

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[5] REV Proceeding, Joint Utilities' Response to the PSC's Final DSIP Guidance Order, (filed May 5, 2016).
[6] REV Proceeding, DSIP Order.
[7] REV Proceeding, Report of the Market Design and Platform Technology Working Group, August 17, 2015, p 32.
[8] REV Proceeding, DSIP Order.

where DER can provide the most benefit to the distribution system and ultimately the Company's customers. O&R will also outline what system data contributes to this analysis and what forecast information can be developed from this data to be shared with third parties in order to help identify future beneficial locations. Additionally, the Company must adapt the way that it operates the grid to incorporate and address both the opportunities and challenges inherent in increased DER penetration. This includes enhancing the monitoring of the system to view the impact of DER in real-time when facing contingencies and other forms of system stress, and potentially facilitating the employment of DER solutions to address such situations. The Company will continue to enhance its DER interconnection process so as to implement a more streamlined and transparent process for both individual customers and DER providers, while also better integrating information on interconnections into the forecasting and planning process. The Company also includes a summary of the current rollout plan and high level budget for AMI with a more detailed AMI Business Plan included as an appendix (Appendix B). Finally, O&R will continue to expand its ability to collect and analyze customer data. The information gained from the analysis of this data will equip customers, the Company, and DER providers with the insight to manage, facilitate, employ, and reap the benefits which DER provides. As a whole, these actions will establish the functionalities necessary for O&R to begin to serve as the DSP Provider.

In conjunction with the myriad changes required for O&R to serve as the DSP Provider, a number of foundational technology investments and enhancements will be required. The DSP Technology Roadmap Chapter examines the Company's current IT and communications capabilities, the near term DSP functionalities required, the gaps in meeting those requirements, and the plan to close those gaps and realize the DSP functionalities required over the next five years. Broadly, these enhancements include process, methodology, and model/tool enhancements to better analyze the impact of DER on forecasting and to integrate DER solutions and the attached Benefit Cost Analysis ("BCA") Handbook into the Company's planning process. With respect to grid operations, an Advanced Distribution Management System ("ADMS") will serve as a platform to organize and manage the functionality required to provide real-time visibility and control of grid assets and DER on the system. The collection of additional system data through the expansion of various equipment reporting back through Distribution Supervisory Control and Data Acquisition ("DSCADA") and other means will facilitate the Company's forecasting and planning processes, as well as provide DER providers with information about locations where DER can deliver the most benefit to the distribution system.

The Company will expand the collection and sharing of customer data, most significantly with the deployment of AMI across its service territory. AMI will provide customers with much greater insight into their energy usage, presenting them with the opportunity to make more informed decisions and lower their energy bills. AMI will also allow customers to share their own energy usage data with third parties through the Company's development of GBC, enabling them to better take advantage of various DER offerings. Finally, AMI will also provide the Company with more granular system data helping to further enhance many of the capabilities described above.

With the expansion of the amount of data to be provided to various participants, the dramatic increase in the number of devices connected to the system (both Company and third party owned), and the increasing automation of the management of the distribution system, the importance of cybersecurity only increases. As stated in the DSIP Guidance Order, "The deployment of systems that support greater degrees of situational awareness and flexibility simultaneously, ironically offer the opportunity to make our networks more secure and resilient if done correctly, and also potentially more vulnerable, if the appropriate protections are not applied."[9] In this ever changing environment the Company is committed to applying the latest tools and techniques to counter any emerging cybersecurity threats in order to maintain both the safe and reliable operation of the distribution system and the protection of customer's Personally Identifiable Information ("PII").

The Company sees markets evolving under REV through two avenues. The first is through the opening of the distribution planning process to consider NWAs and encourage DER providers to participate in solicitations for these resources. This may enable the Company to potentially defer capital expenditures while providing DER providers with the opportunity to bid on the provision of grid solutions. The second manner in which markets may emerge through REV is the migration to a transactive energy market. In O&R's view, this is the more ambitious and lengthy implementation of the two (and likely outside the five-year view of this DSIP); however, the Company is making foundational investments to move toward this vision of a more interactive and transaction-based market for energy at the distribution/customer level. Such a market will require significant monitoring and control of both utility and DER assets; the investments to facilitate these attributes include at a minimum AMI, ADMS, distribution automation, DCX, GBC, and the supporting communications infrastructure. These are long-term endeavors that will bring value to customers and the grid as they are implemented by improving customer engagement and enhancing the reliability of the system. They are also foundational investments facilitating the move to the more ambitious goal of the transactive distribution level market. O&R's plans to develop and enhance processes, capabilities, and technologies in order to encourage and facilitate the greater adoption of DER outlined in this DSIP will aid in the animation of markets and better serve customers in the near term and will position the Company to meet REV's long term objectives.

[9] REV Proceeding, DSIP Order, p. 3.

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Initial Distributed System Implementation Plan

Executive Summary

This document will define O&R's current practices and capabilities and its proposed efforts to become the dynamic DSP Provider as envisioned by the Commission. This Initial DSIP is the result of collaborative effort within the Company, with critical input from all pertinent parts of the organization including: Engineering, Electric Operations, and Customer Operations. The Distribution System Planning chapter describes how the Company is further refining planning processes to integrate DER solutions. The Distribution Grid Operations chapter describes how the Company is developing and adapting technologies to facilitate the integration of DER. The Advanced Metering Infrastructure chapter provides an overview of key components of the AMI Business Plan. The Customer Data chapter describes the current state of available customer data, plans to implement Green Button Connect, and plans to make more granular customer data available to Energy Service Companies ("ESCO"). Finally, the DSP Technology Roadmap Chapter will give an overview of the current state of information technology ("IT") and communications systems and the plan to achieve the functionalities required to implement the future state capabilities outlined in this DSIP. Appendices are also contained, including the BCA Handbook, the AMI Business Plan, a REV Demonstration projects summary, DSP Organizational Considerations, O&R's Organization Chart, Forecasted Corporate Expenditures – Project List, Cybersecurity and Privacy Strategy Framework, and an acronyms list.

Distribution System Planning

Forecasting of DER

The forecasting of some DER, such as EE, is a fairly mature process, and has been incorporated in the Company's forecasts for quite some time. In the fall of 2015, for the 2016 forecast and beyond, the forecasting of DG was modified to better account for the load reductions offered by these resources. The DG included in the peak load forecasting process are solar photovoltaic ("PV"), combined heat and power ("CHP") and other large generators, and energy storage. These contribute to reducing the peak demand subject to factors, such as contingency design of the system, type of DG, coincidence with peak load, number of DG(s) on the system, the size(s) of the DG, and incentives for production. These processes are described in the appropriate sections of this document. As the penetration of DER increases, the Company will develop methodologies, processes and models/tools to produce and use forecasts more dynamically. DER also contributes energy reductions in the volume forecast, as will be described later in this DSIP.

Based on current processes and available data, the Company is able to produce static peak data on an annual basis at the system and substation level along with energy forecast at the system level, and will make this information available to DER providers and other third parties as described below.

System Information Sharing

The Company is fully engaged with stakeholders through the Supplemental DSIP development and engagement process in determining the granularity of system data required to support increased penetration of DER. O&R and stakeholders also are developing the methodology for making relevant information derived from that data available to DER providers for the purpose of optimizing DER locations on the grid. This is a complex process which has system security and reliability implications. Ultimately, the objective is to establish processes and procedures that allow for external parties to deploy DER in locations where, and in a manner in which, the DER provides the most benefit to customers and the system. The Company, working with stakeholders and the JU, has proposed a strategy of providing DER providers with usable and actionable information rather than raw system data. As such, the Company can leverage its experience and expertise to present what would otherwise be an onerous amount of unprocessed data in a targeted and deliberate manner. This approach will allow third parties to gain meaningful insights into topics such as hosting capacity and beneficial locations. This cost-effective approach is focused on DER providers' priorities and addresses concerns related to data security and sensitivity.

O&R is already engaged in providing useful information to DER providers consistent with the Order Modifying Standardized Interconnection Requirements ("SIR Order"),[10] including information provided in the interconnection Pre-Application. In addition to the information on the Company's service territory and distribution system within this DSIP, system data will be provided on the Company's Solar and DG website[11] in conjunction with this filing. The ongoing Supplemental DSIP stakeholder process will further define what information will be shared in the future and the potential associated fee structure and protection/registration process.

Providing system data to third party providers requires a common cyber security and privacy framework that reflects best practices. Through coordination with the Commission, the JU, and stakeholders, the Company will address the exchange of system analysis and optimal DER locations, while maintaining customer protections and system security. The Commission's technical conferences on cybersecurity as well as the outcome of Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products, will inform the Company's practices. The security practices and procedures, to be detailed in the Supplemental DSIP, will address the protection of sensitive customer and grid information.

Beneficial Locations for DER Deployment

As part of its current integrated planning process, O&R includes the consideration of DER as an alternative to traditional capital infrastructure solutions. The Company's previous process reviewed each major capital infrastructure project that exceeds $5 million to determine if it can be cost-effectively deferred through the implementation of non-traditional alternative measures, such as DG, DR, and DSM. This screening is typically done when the project need is initially identified, or soon thereafter, and it has served as a means for determining project needs that can be fulfilled through NWA solutions. The Company is currently working through the JU Planning Working Group to update and refine the Company's DER Suitability review process to better take advantage of potential solutions that DER can provide. O&R will continue to expand this process and adapt it to meet the requirements outlined in the Commission's Order Establishing the Benefit Cost Analysis Framework ("BCA Order").[12]

O&R has identified three locations within its service territory in which DER could potentially assist in deferring capital infrastructure investment. These include Pomona, Monsey, and Wurtsboro. The Pomona Program was proposed and approved in O&R's most recent electric base rate case, and is described further below. The Monsey area was identified as a potential NWA, and details were

[10] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016).
[11] www.oru.com/distributedgeneration
[12] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework, (issued January 21, 2016).

provided on May 1, 2015[13] in compliance with the Track One Order.[14] The Company recently identified the Wurtsboro area as a potential NWA opportunity. In the cases of Monsey and Wurtsboro, the Company will conduct further analysis, in accordance with the BCA Framework Order, to determine the viability of the NWAs. If they prove to be favorable alternatives proposals, the Company will make a filing consistent with the Commission's Track Two Order. [15]

Pomona Distributed Energy Resources Program

Prior to this DSIP filing, the implementation of a NWA project within O&R's service territory has already begun with the Pomona Program. On October 16, 2015, the Commission approved the Pomona Program as part of the 2015 Electric Rate Order. The Company forecasts electric load growth in and around Pomona New York that will necessitate the construction of a new substation and associated 138 kV underground transmission loop commencing in 2019 in order to meet the Company's distribution design standards to meet the area's electric delivery system reliability risk requirements. Construction costs for the Pomona substation and associated transmission upgrades are estimated at $55.7 million. The Company anticipates that implementing targeted DER and DSM programs through a phased approach will provide up to 6.0 MW of peak load reduction sufficient to support deferral of construction of the Pomona substation for at least four years, while also providing increased contingency reliability.

Over the next two years, O&R expects to achieve 1.5 MW of peak load reduction in the Pomona area through DSM programs. Additionally, the Company is evaluating DER solution options for design and deployment that will account for up to an additional 4.5 MW of required load reduction. In 2015 O&R received 30 responses to its request for information ("RFI") during the initial program evaluation. The Company is reviewing and evaluating these responses as potential deployment options as part of the solution development process. Key to the process is determining variations in peak load among the various customer demographics (*e.g.*, residential, commercial, and industrial) and aligning solutions to target the appropriate customers and load. The Pomona Program and the associated process to identify and develop DER solutions will serve as a foundation for developing and improving the Company's NWA process and future projects.

Hosting Capacity

A methodology for determining hosting capacity and presenting that information to third-party DER providers is critical to assist in directing DER providers towards, and providing information on, locations where the likelihood of additional infrastructure investments required for DER to be interconnected are lowest. O&R concurs with the definition of hosting capacity outlined in the recent Electric Power Research Institute ("EPRI") whitepaper *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State* ("EPRI Hosting Capacity Whitepaper"). This whitepaper accurately defines hosting capacity as "the amount of DER that can be accommodated

[13] REV Proceeding, O&R NWA Monsey, (dated May 1, 2015).
[14] REV Proceeding, Track One Order, p. 131.
[15] REV Proceeding, Order Adopting A Ratemaking And Utility Revenue Model Policy Framework, (issued May 19, 2016)("Track Two Order").

without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades."[16]

The EPRI Gap Analysis[17] and SIR Order [18] served as the starting point for the Company's assessment. In February 2016, O&R developed a Distributed Generation Interconnection Circuit Map, located on the O&R Solar and DG site,[19] which indicates general areas/circuits where the cost to interconnect may be higher. Factors contributing to that additional cost include low minimal daytime load, aggregated DG already interconnected, smaller conductor (wire size), operating voltage and/or the number of applications in the queue on the feeder exceeding daytime load. The Company developed this map as an interim tool to assist the DG development community. The Company continues to work with DPS Staff, the JU, and various stakeholders to provide input into the development of hosting capacity methodology and data. It will be further informed by collaborative conferences facilitated by DPS Staff, the first of which is scheduled for July 6, 2016. A final definition and methodology for determining hosting capacity will be developed through the JU Supplemental DSIP Stakeholder Engagement process and filed in the Supplemental DSIP. O&R, along with Con Edison and the JU, will continue to refine and expand upon the methodologies for hosting capacity and ultimately expects to provide integrated information that connects hosting capacity and interconnection with the value to the distribution system as part of the LMP+D efforts.[20]

Distribution Grid Operations

DER Monitoring and Control

As the penetration of DER increases across the Company's service territory, the requirements, opportunities, impacts, and challenges generated by DER will expand. Establishing the appropriate level of visibility, monitoring, and control will be critical to realizing the most value to customers and the system from connected DER, while maintaining a safe and reliable grid.

The Company will need to develop new procedures and systems/tools, such as an ADMS platform, in order to better serve as the DSP, encourage the expansion of DER, and maintain safety and reliability on the new integrated grid – a critical requirement for all customers. With the continued increase in DER penetration, there will also be a requirement for additional focus on DER, and DG in particular, within the Company's Control Center. Eventually, this will likely result in the need for new skill sets and resources to monitor, manage, and take advantage of the benefits provided by DER on the system. In order to operate the more dynamic grid, increased technical skills will be needed within the

[16] Electric Power Research Institute, *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State.* Palo Alto, CA: 2016. 3002008848.
[17] Electric Power Research Institute, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, , September 2015.
[18] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016).
[19] http://www.oru.com/distributedgeneration
[20] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

Company's Control Center to analyze sensor inputs, coordinate load shifting, and likely monitor and control certain DER that can provide benefit or have an impact upon the system.

To that end, the Company believes it will be critically important to establish requirements for DER providers. These requirements should be consistent with DER contract obligations and interconnection requirements and expanded, as necessary, to include maintenance and emergency outage protocols, real-time monitoring and potentially control to maintain and manage reliability and safety. These evolving requirements should be developed jointly by all utilities, with input from stakeholders, and introduced within Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products or further explored through the Supplemental DSIP process.

There will also be opportunities when the Company's direct coordination of DER could provide added benefits to customers and the system. These may include dispatch-ability of large scale DER on peak days, aggregation of behind the meter DER to provide load reduction and facilitate NWAs, or the ability to adjust DER to provide voltage and/or VAR support when needed. Current and future REV Demonstration projects and other pilots will potentially inform the further development of these opportunities and the business cases surrounding them.

Cybersecurity

The Company recognizes that the increased flow of customer and system data enabled by REV and the DSP will also present risks that will need to be addressed by the Company's cybersecurity program. This need will only increase due to the increase in reliance on DER and the level of information that will need to be communicated to manage additional endpoints and increased complexity. The Company is committed to providing useful system and customer information, while not exposing data that might increase risk or have unintended consequences. Increasing risks must be met with thorough planning and adherence to cybersecurity principles.

In addition to the increased number of participants and data on the distribution system, the DSP will also facilitate the increased collection and sharing of customer usage data. Driven by AMI and made available through Green Button Download and GBC, customer data will allow customers to make more informed decisions regarding their energy usage and potentially lower their energy bills. The Company remains committed to protecting that data, including customers' PII.

Interconnection Process

O&R is committed to enhancing the customer experience and recognizes that as more customers use DER, their engagement with the Company will increase. The interconnection process is one of the ways in which customers will first experience DER participation, so it is critical that this process be as customer-friendly and seamless as possible. To that end, the Company is continuing to improve and streamline its interconnection process. O&R has begun to address gaps identified in the September 2015 report prepared by EPRI[21] for the New York State Energy Research and Development Authority ("NYSERDA"). The Company actively participated in the efforts to amend the New York State

[21] Electric Power Research Institute, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, September 2015.

Standardized Interconnection Requirements finalized on March 18, 2016. In addition, the Company has established an interconnection application portal[22] that will continue to be refined to meet requirements laid out in the Track One Order in order to further improve the customer experience.

Advanced Metering Infrastructure

The Company will begin implementing an AMI system to, among other things, facilitate the Commission's REV policies and goals, reduce operating costs, accelerate identification of customer outages, and improve overall outage response and efficiency. Pursuant to the Electric Rate Plan Order, O&R plans to deploy an AMI system beginning in Rockland County. As was anticipated in the Electric Rate Plan Order, O&R will be seeking additional approval to expand into Orange and Sullivan Counties to cover the Company's entire New York service territory, in its upcoming electric base rate case filing. High quality customer/stakeholder engagement and organizational change management will be essential to project success. Initial engagement activities have included stakeholder collaboration meetings on June 2, 2016 and June 14, 2016, with another planned for July 15, 2016.

During 2015, the Company began preparations for the roll-out of AMI meters in 2017. Preparations included: finalizing the detailed business case analyses for the project; selecting the necessary equipment, software, and services; and developing the AMI Business Implementation Plan. In 2016, the back-office infrastructure is being designed, configured, tested and will be brought on-line to support the initial AMI capabilities. This infrastructure development requires approximately twelve months and is needed before the first meters can be installed. Starting in early 2017, when all of the new back-office infrastructure systems are in place and tested, the Company's focus will shift from the internal architecture to deploying assets in the field. The field assets consist mainly of communications devices, electric meters, and gas modules. At this time, the Company is planning to install the communications infrastructure and meters over a three-year period (2017-2019 in Rockland County and 2018-2020 in Orange and Sullivan Counties). Business transformation activities and stakeholder/customer outreach and education have begun in advance of the field deployment and will continue throughout the deployment period. Plans for sequencing and timing the deployment across the service territory will continue to be refined with a complete and optimized deployment design by October 31, 2016.

In November 2015 Con Edison filed its AMI Business Plan with the Commission.[23] On March 17, 2016, the PSC issued an order approving Con Edison's AMI Business Plan subject to conditions,[24] including that Con Edison file a detailed customer engagement plan by July 29, 2016. O&R is developing an AMI Customer Engagement plan in conjunction with Con Edison to provide for the continuing engagement of customers and third parties, which it will file on July 29, 2016. Innovative rate structures to allow customers to take advantage of new capabilities, and an updated Benefit Cost Analysis

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[22] www.oru.com/distributedgeneration

[23] Case 15-E-0050, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service* ("Con Edison 2015 Electric Rate Case"), Con Edison AMI Business Plan, (filed November 16, 2015).

[24] Con Edison 2015 Electric Rate Case, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, (issued March 17, 2016).

consistent with the PSC's current BCA framework, are also being developed along with Con Edison for filing on July 29, 2016.

Customer Data

The Company is committed to enhancing customer knowledge and tools that will support effective management of the total energy bill. Market participants can also benefit from more granular customer data and engagement as a means to identify and respond to opportunities to develop cost-effective DER solutions that deliver value to customers while contributing to a more efficient distribution system. Determining the level of granularity of data needed by market participants and desired by customers is an iterative process that addresses customers' ability and willingness to engage in utility DER programs directly with third-party providers. This requires understanding the value of the operating costs associated with measuring, storing, managing, and communicating the data to customers and third parties along with consideration of customer data security (physical and cyber).

The Company is establishing new programs that will provide the Company and customers with granular customer data (*e.g.*, AMI and DCX). AMI will provide a foundation of information and communications capabilities that will enable the Company's customers to become informed and engaged energy consumers. Operating in concert with DCX, AMI will provide customers with the information necessary to help them manage their energy usage and manage costs. As part of DCX, the Company is also developing Green Button Download and ultimately GBC capabilities which will allow customers to gain insight into their energy usage data and share it with authorized third parties. In addition, the Company's Residential Customer Engagement and Marketplace Platform ("CEMP") REV Demonstration project, also known as MY ORU Store, is testing customer engagement strategies and will provide data on both customer response to energy usage information provided through the MY ORU Advisor as well as their willingness to engage third-party DER providers. The knowledge gained from the deployment of AMI and from REV Demonstrations will support on-going stakeholder engagement to determine what customer data is required, the corresponding value, and the effectiveness of customer engagement techniques and protocols.

As DER proliferate on the system, there is a growing need to provide customer data to inform customer decision making. This has both privacy and cybersecurity implications. In addition, there is a cost to obtain this data. O&R will continue to work through the DSIP and stakeholder engagement process to determine the initial value of the data and appropriate means of sharing this information with authorized parties. As the DSP evolves, the value of the data will be refined.

Data Privacy

As the Company refines customer data requirements and engagement, the security and privacy of customers and energy usage data and PII will be paramount. The Company is working to understand customer concerns through customer engagements and technical conferences. AMI, DCX, and REV Demonstrations all support customer privacy and data security protocol. In addition, the Company is coordinating with the JU on a common cyber security and privacy framework that reflects best practices and is sufficiently robust to accommodate anticipated REV requirements. These are on-going processes that will be discussed in this Initial DSIP and in more detail in the Supplemental DSIP.

DSP Technology Roadmap

In order for O&R to better serve customers as the DSP Provider, a number of foundational technology investments and enhancements will be required. The DSP Technology Roadmap examines the Company's current IT and communications capabilities, the current DSP functionalities required, the gaps in meeting those requirements, and the plan to close those gaps in order to develop the DSP functionalities proposed over the next five-year period and beyond. These plans are an early conceptualization of the foundational and functional requirements that will be necessary to fully support the programmatic changes that are envisioned and outlined in this DSIP, and will be followed up on and adjusted as necessary in future DSIPs. They are subject to change and modification in subsequent DSIP filings as technology and circumstances develop in this evolving utility environment.

O&R's approach to meeting the information technology system needs required for the DSP is predominantly model-based, and will require the implementation of new and sophisticated control systems and algorithms that will integrate with and leverage existing systems and related data. The foundation for this approach is the Company's Integrated System Model ("ISM"), which combines system assets from the Geographic Information System ("GIS"), customer data, and system operational states and measurements. The ISM is the basis for the sophistical control model that will ultimately be realized through the development and implementation of an ADMS.

An ADMS is the foundational platform that could be developed and integrated with other real-time systems and data sources, such as the Energy Management System ("EMS"), GIS, a Distribution SCADA system, Distribution Automation ("DA") devices, substation equipment, AMI, customer data, DG, and the OMS to enhance electric distribution system situational awareness, monitoring and control to improve reliability, resiliency and efficiency. ADMS is at the heart of how leading utilities presently are or are planning to monitor and control their distribution grids, and the Company expects to follow industry best practices in developing this technology infrastructure to facilitate REV objectives.

The initial technology investments will focus on building the necessary interfaces to engage customers, increase the volume and granularity of data, and enable greater DER penetration. The Company is continuously evaluating its technology needs, focusing on several key functional areas required to support DSP capabilities. REV objectives and evolving market needs will drive broad technology needs along the following lines:

- Integrating DER into forecasting and planning in order to encourage investment and potentially defer capital investment (*i.e.*, NWAs), to include use of the BCA Handbook;
- Sharing system information in order to aid providers in developing DER in beneficial locations and configurations;
- Achieving increased visibility and automation across the system in order to better plan for and operate the high DER penetration grid;
- Operating the dynamic two-way grid in a manner that encourages DER deployment, takes advantage of the opportunities DER provides, and is able to handle the challenges increased DER penetration can present; and
- Collecting and sharing much more granular customer data in order to empower customers in regard to their energy usage giving them both greater flexibility and opportunities to lower their bills.

BCA Framework

The BCA Framework is an integral part of the changes to the distribution planning processes and is required as an input to the DSIP. The BCA framework is the mechanism by which DER solutions will be compared both to other DER solutions and to traditional infrastructure solutions. The BCA Handbook which provides techniques for quantifying the benefit and costs identified in the BCA Order, included as Appendix A, is the result of a collaborative effort among the JU, as well as within the Company. The JU first developed the higher level methodology and template for the BCA Handbook to provide a common methodology to be applied in BCA across investment projects and portfolios. The Company then added specific data and information to tailor the BCA Handbook to O&R. Going forward, the Company will incorporate the use of the BCA Handbook into the Integrated Planning Process and update planning and modeling functionality in order to incorporate the analysis gained by the BCA process. The BCA Handbook, included as Appendix A, will be further developed through the Value of DER proceeding.

REV Demonstration Projects

O&R, aligned with the REV Track One Order and the PSC's Memorandum and Resolution on Demonstration Projects,[25] has begun one REV Demonstration project, a residential customer marketplace, and is currently examining opportunities for additional demonstration projects. The next focus area in which O&R intends to explore may involve testing the Platform Service Revenue ("PSR") potential for energy storage. In conjunction with Con Edison, O&R released a RFI focused on innovative energy storage business models, in February 2016.[26] The Company also intends to file a time varying rate demonstration project as required by the Electric Rate Plan Order. O&R continues to explore opportunities for future REV Demonstration projects. This includes a series of RFIs to solicit information on future potential REV Demonstration projects. Proposed future RFI solicitations will seek partners to pursue Low-Moderate Income solutions and Electric Vehicle Infrastructure opportunities.

[25] REV Proceeding, Memorandum and Resolution on Demonstration Projects, (issued December 12, 2014).
[26] REV Proceeding, Con Edison RFI - Innovative Energy Storage Business Models, (issued February 2, 2016).

Initial Distributed System Implementation Plan

Chapter 1 - Distribution System Planning

Distribution System Planning is a fundamental activity of the Company that facilitates safety, reliability, and cost management. This chapter addresses the current state of the forecasting and capital planning process, how DER are integrated throughout, and how these processes will evolve to integrate greater amounts of DER.`

O&R has extensive experience in integrated planning and has a mature forecasting process and electric delivery system planning process that includes DER consideration. The Company has forecasted Energy Efficiency, Demand Side Management ("DSM"), and Demand Reduction ("DR"), as load modifiers for years. In addition, the Company has recently incorporated forecasting additional forms of Distributed Generation, including photovoltaic (solar), CHP, and energy storage. The DER are included as load-reducing modifiers in the forecast to accurately assess the peak load the Company must serve through traditional infrastructure.

Forecasted loads, net of DER modification, drive load relief planning needs. When current system capabilities do not meet forecasted loads, planners must resolve a projected capability deficiency within a particular timeframe. Historically, these have been the constraints that bound the development of traditional utility solutions, with the most cost-effective of several solutions selected and implemented. The capital budgeting process includes and prioritizes these projects, among other categories of spending, into a yearly outlook that minimally includes a five-year horizon.

By providing load relief in a specific locational area of need, at specific peak times, DER could potentially provide an opportunity to defer some traditional investments, realizing savings for customers. O&R is demonstrating and testing this in the Pomona Program, where the Company intends to delay construction of the $55.7 million Pomona Substation and associated facilities by cost-effectively implementing DER and DSM programs that will provide up to 6.0 MW of peak load reduction.

O&R already includes consideration of DER solutions within its current Integrated Planning Process. The Company has previously implemented a review for each of its major capital infrastructure projects that exceed $5 million to determine if any can be cost-effectively deferred through the implementation of non-traditional alternative measures such as DG, DR, and DSM. This process will continue to be refined and expanded to incorporate the results of the JU stakeholder Suitability methodology and criteria, and to comply with the BCA Order.[27] The JU has collaboratively developed a BCA methodology. That methodology and the associated templates have been combined with Company specific data to develop O&R's BCA Handbook. The BCA Handbook will be incorporated into the Company's integrated planning process and forecasting and modeling tools will be upgraded to include its analysis.

In total, these efforts represent the Company's support of DER in every aspect of distribution system planning, from forecasting to implementing DER as potential solutions and deferrals for traditional solutions, in a manner that best serves O&R's customers and maintains the safety and reliability of the grid. The Company expects that these processes will evolve with greater DER penetration and increased experience.

[27] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework, (issued January 21, 2016).

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Forecast of Demand and Energy Growth

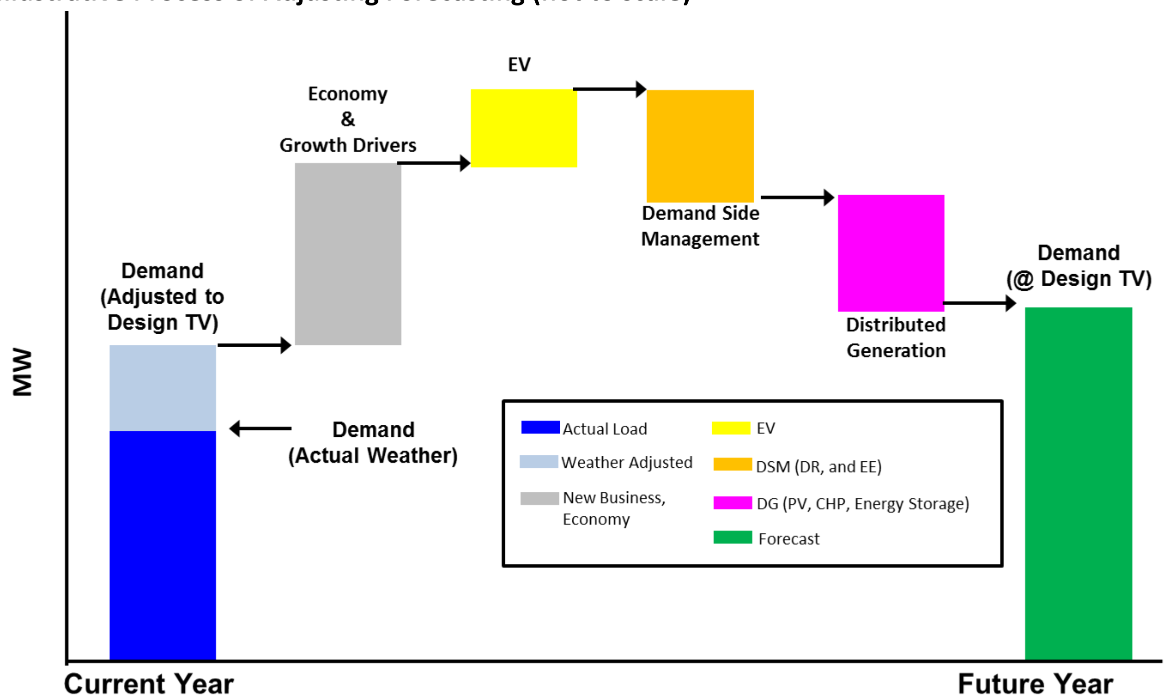
Overview of System Peak Demand Forecast

Demand Forecasting, Resource Planning at Con Edison develops the O&R Electric System Peak Forecast. The forecasting process is scheduled to be completed by the end of each summer. It has two major steps: analyzing the weather adjusted peak ("WAP") at the design temperature variable ("TV"), currently adjusted to 85°F for the past summer season and estimating the incremental future growth.

The WAP is based on the recent summer experience and pooled regression analysis provided by Forecasting Services at the end of the summer. The incremental growth is prepared by Demand Forecasting with inputs from supporting organizations, and it includes components which are considered significant to the electric system peak demand. Some of these components and their projections are provided by departments outside of Energy Management, while others are generated within Demand Forecasting by considering pending projects in O&R's service territory and local economic trends. The overview of forecasting components and methodology are described in Figure 1-1.

Figure 1-1

Illustrative Process of Adjusting Forecasting (not to scale)



On an annual basis, O&R Distribution Engineering ("Distribution Planning") performs its own regression analysis on historical actual peaks against temperature and population variables to determine the previous year's WAP load.

The previous year's WAP loads, determined by both Demand Forecasting and O&R Distribution Engineering methodologies, are internally compared for accuracy. Historically, this has resulted in a difference of less than 5 MW (*i.e.,* less than 0.4%) over the past seven years. Therefore, O&R's process has proven to be very accurate, and minor disparities have been attributed to varying new business loads and/or slight changes in transmission losses.

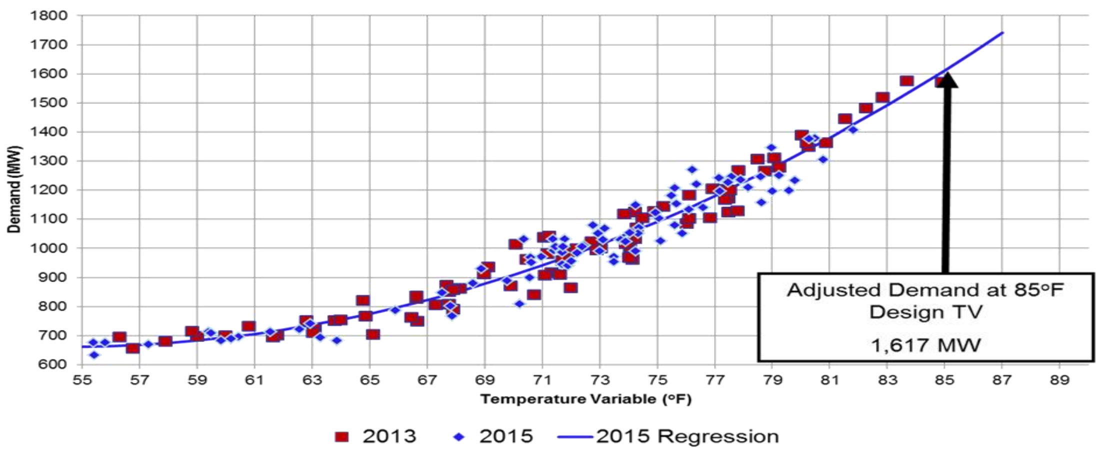
Weather Adjusted Peak Analysis

Demand Forecasting Approach

The Company develops its long-term Electric Peak Demand Forecast using internally developed models. Forecasting Services assesses the prior summer's actual daily peak demands and adjusts the overall season's peak demand to a thermal design condition based on a one-in-three probability of meeting a TV[28] design condition of 85°F. The method used to develop the WAP demand is regression analysis. An example of the regression used to determine the WAP demand can be found below.

Figure 1-2

Example: Regression Analysis to Determine WAP Demand



Distribution Engineering Approach

O&R's Distribution Planning group methodology assesses the prior summer's actual daily peak demands and adjusts the overall season's peak demand to a thermal design condition based on a one-in-three probability of meeting or exceeding a design condition over 30 years. Historical peak demands are regressed against TV and population to determine the WAP load for the entire system. An example of the regression used to determine the WAP load can be found below (this example shows O&R's entire system load —*e.g.*, NY, NJ and PA).

[28] TV factor used for Service Territory analysis is calculated as a weighted average of the highest three-hour temperature (called dry-bulb) and humidity (called wet-bulb) readings each day, as registered at the NWS stations at the White Plains Airport. Since heat "buildup" over a hot spell of a few days' duration significantly increases air conditioning use and stress on Con Edison's and O&R's electric system, the formula for calculating the Service Area TV on a daily basis incorporates three days' worth of data. The current day's weather is weighted at 70 percent, the previous day's at 20 percent, and two days before at 10 percent.

Table 1-1

Example WAP Load Regression

		2009	2010	2011	2012	2013	2014	2015
1	Actual Peak Load (MW)	1375.0	1572.0	1599.0	1508.0	1561.0	1357.0	1405.0
2	Load Reduction (MW)	0.0	5.0	29.0	1.3	15.0	0.0	0.0
3	DSM (cumulative)-MW	1.0	3.0	5.0	7.0	10.0	10.0	15.0
4	Int. Gen (MW)	2.0	1.8	0.0	0.8	0.8	0.8	0.8
5	Adjusted Load (MW)	1378.0	1581.8	1633.0	1517.1	1586.8	1367.8	1420.8
6	Transmission Losses	2.8%	3.2%	3.2%	2.0%	1.6%	2.4%	1.9%
7	TV (°)	80.8	85.0	86.5	80.1	83.7	79.7	81.8
8	Adjusted Load at 3.2% losses (MW)	1383.7	1581.7	1633.0	1535.9	1613.0	1379.7	1439.9
9	PV (cumulative) – MW	0.9	1.2	2.1	4.4	6.2	9.7	12.2
10	Final Load – MW	1384.6	1582.9	1635.1	1540.3	1619.2	1389.4	1452.0

System WAP line item descriptions:

Line 1: Actual peak load (MW) that has been recorded by System Operations. NOTE: If the peak day is interrupted by a storm or other emergency situation that affects the load shape, another peak day with slightly less value and TV may be used.

Line 2: Load Reduction includes any load that has tripped off due to interruption or part of a voluntary load reduction program. The measured reduced load based on the customer data or circuit profile is added back to the actual peak load. The forecast depends on the accuracy of data from the NYISO load reduction programs.

Line 3: The cumulative amount of DSM that has reduced peak load since the start of the load study (2009). This includes O&R Energy Efficiency Portfolio Standard ("EEPS") programs achievements and NYSERDA DSM program achievements coincident with system peak. This is only as accurate as the data/information that can be obtained from the program implementation and third parties.

Line 4: Any internal generation (DG) that is serving load at peak time is added to the system peak.

Line 5: The adjusted load is the total of the actual measured load, load reduction, efficiency programs (DSM), and internal generation (DG) to determine the "temperature/weather-affected" load for the system.

Line 6: The actual transmission losses at peak time by simply taking the difference of the overall system and substation loads. These are compared to the transmission losses of the WAP by transmission system modeling.

Line 7: The actual recorded TV at the time of system peak. The TV is determined by taking the average of the wet bulb and dry bulb temperatures, and then using the combined effect factoring in 70 percent contribution from the peak day, 20 percent from the previous day, and 10 percent from two days prior.

Line 8: All system loads are then calculated to the transmission losses at the start of the study (3.2 percent). This is to not allow loss improvements being misinterpreted as negative growth.

Line 9: The cumulative effect of the photovoltaic generation ("PV") at peak hour (27 percent output of the sum of all interconnected nameplate ratings converted to their AC contribution; refer to the Available Distributed Energy Resources section of this DSIP for an in depth explanation of how the PV peak coincidence is determined).

Line 10: The PV contribution is then added to the adjusted load at 3.2 percent transmission losses (Line 8) to determine the final load. This load is regressed against the TV and population variables to determine final WAP load.

Population

Population is determined by multiplying the number of residential customers in the area by the number of people per household (retrieved from US Census Bureau) and adding the number of commercial/industrial customers.

Table 1-2

Example: Weather Adjusted Peak Load Calculation

							1	2	3	4
YEAR	PK KW	TEMP	POP				Wthr Norm	Wthr Norm	Wthr Norm	Wthr Norm
2009	1384594	80.80	775540				1594708	1594708	1593708	1593008
2010	1582939	84.98	777076				1600504	1600504	1597504	1596504
2011	1635130	86.50	786001				1634196	1634196	1629196	1627496
2012	1540258	80.10	791376				1654486	1637569	1630569	1627069
2013	1619211	83.70	793276				1661656	1641309	1631309	1626409
2014	1389380	79.70	793492				1662474	1640443	1630443	1622743
2015	1452043	81.80	794150				1664956	1641220	1626220	1616620
2016		85.00					(LOAD)	(LOSS)	DSM	PV
2017										
					3yrgrwth		0.211%	0.074%	-0.089%	-0.215%

Line item descriptions:

Column 1: This column determines the WAP load at a design TV of 85° with transmission losses of 3.2 percent after regressing peak load (Pk KW) against TV (Temp) and population (pop). NOTE: The 3-year growth rate considering just load is 0.211 percent.

Column 2: This column puts the WAP loads at the proper transmission losses, which have been both measured and modeled. These loss improvements are primarily the result of infrastructure and system efficiency improvements. NOTE: The combination of load and transmission loss improvement has reduced the three-year growth to 0.074 percent.

Column 3: This column reduces the WAP load by the measured cumulative DSM.

Column 4: This column reduces the WAP load by the solar effect for peak hour (27 percent of interconnected nameplate rating) to determine the final WAP load for 2015 as determined by the O&R methodology. This final WAP value is then compared to the results obtained from the Con Edison methodology, as explained later in this section.

Long-term (20 Year) Electric System Peak Demand Forecast

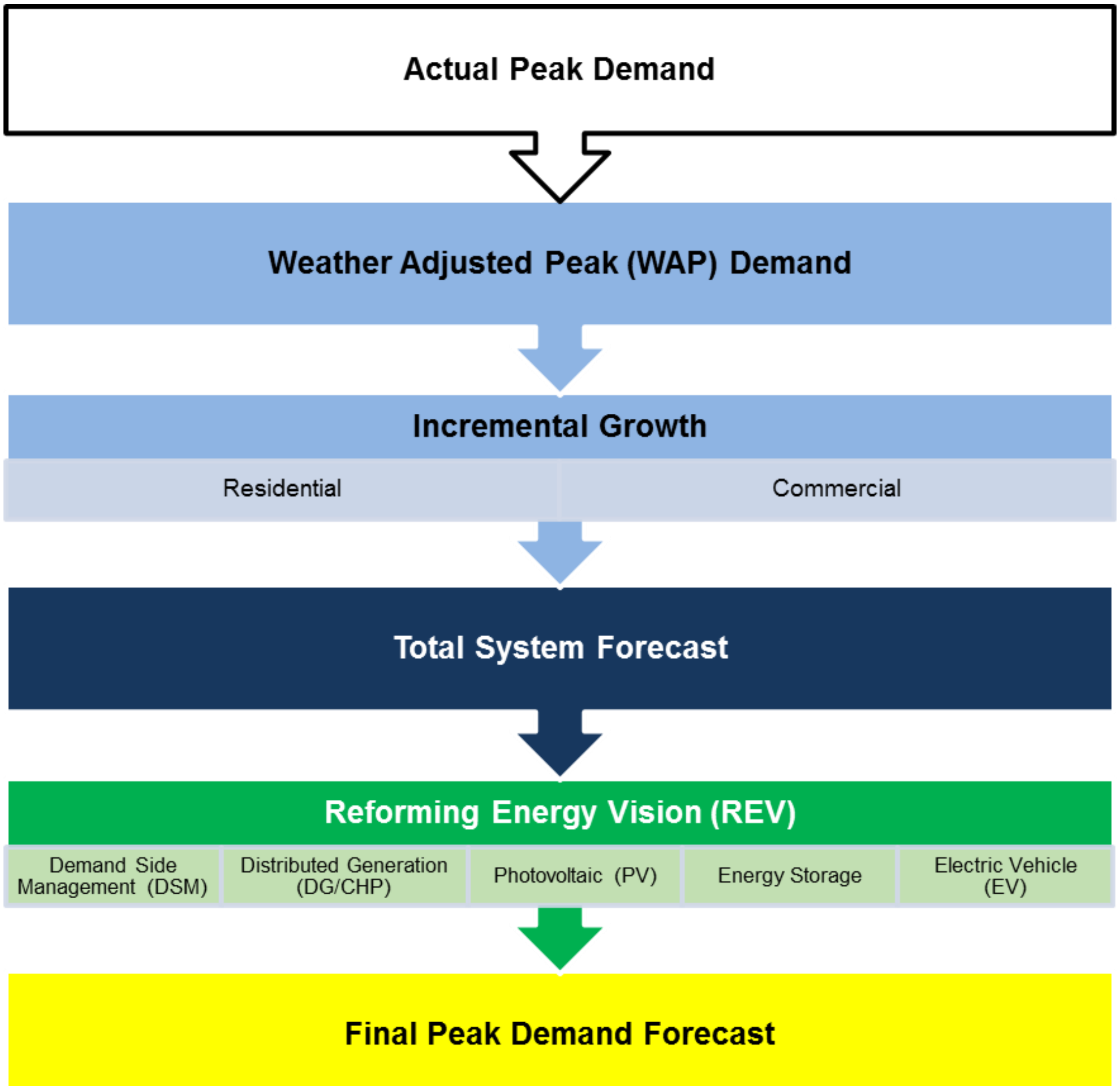
Once the WAP is determined, the next step in the process is to forecast the incremental growth over the next 20 years and add it to the weather-adjusted peak demand. In developing this forecast, demand forecasting utilizes an econometric model via third-party external statistical software. The economic model uses one or more economic indicator(s) to develop the best suitable incremental growths for the commercial and residential sectors, respectively. The key model drivers include, but are not limited to, gross county product and/or industrial production for the commercial sector; private non-manufacturing employment, households, and/or population for the residential sector; all of which are provided by Moody's. In considering the growth drivers, the commercial and residential sectors account for approximately 3/5 and 2/5 of the Company's peak demand respectively. Next the load growth or reduction attributed to the new business forecast is included, provided by project managers from the Company's Eastern, Western, and Central Divisions. Non-sector specific technology driven load growth includes growth from technology shifts, such as electric vehicles ("EV").

Inputs/modifiers which alter growth include the existing and newly introduced REV initiatives. The DSM programs include all EE programs that are expected to reduce the peak demand forecast over a five to six year horizon. These include both those administered externally by NYSERDA and those administered internally by O&R. The DR category includes the Commercial System Relief ("CSR") program administered by O&R. The other REV categories were introduced to include appropriately rated load reductions from new technologies including DG and Energy Storage. The REV load modifiers include input from the Con Edison DG Group and the O&R Technology Engineering Group. In a REV environment, it is expected that DER penetration will increase, and DER-specific forecasting methodologies will be evaluated and refined accordingly. The assumptions underlying each of these categories will be explained in further detail in the Available Distributed Energy Resource section of this Chapter.

The long-term O&R Electric Coincident Peak Demand Forecast is developed during the late summer/early fall to incorporate the most recent summer experience and to allow enough time for changes to the Company's work-plans to be developed prior to the start of the next summer season each year. The figure below conceptually shows the process to produce a system peak forecast.

Figure 1-3

O&R Electric Peak Demand Forecasting Process



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Five-Year System Coincident Peak Demand Forecast

Based on the forecasting methodology described above, the five-year system coincident peak demand forecast is presented below. This forecast was published in October 2015. Included are detailed notes on each line item presented below.

Table 1-3

O&R's Electric System Peak Demand Forecast for the NY Territory Only (in Megawatts)

		2015	2016	2017	2018	2019	2020
1	**Updated System Forecast (not rounded):**	**1156.9**	**1179.7**	**1200.0**	**1216.7**	**1227.6**	**1237.2**
2	MW Growth:		22.8	20.2	16.7	11.0	9.5
3	% Growth:		2.0%	1.7%	1.4%	0.9%	0.8%
4	**Additional MW Growth (Incremental Rolling, Cumulative starting in 2016)**						
5	Electric Vehicles (EVs)		0.0	0.1	0.1	0.2	0.2
6	**Load Modifiers (Incremental Rolling, Cumulative starting in 2016)**						
7	Photovoltaics/Solar (PVs)		-3.0	-13.0	-22.0	-26.0	-28.0
8	Other Distributed Generation (DG)		0.0	0.0	0.0	-1.0	-1.0
9	Energy Storage		0.0	0.0	0.0	-1.0	-1.0
10	**Coincident DSM (Incremental Rolling, Cumulative starting in 2016)**						
11	O&R EE		-5.7	-10.0	-14.3	-18.6	-22.9
12	NYSERDA EE		-3.3	-5.6	-7.9	-10.2	-12.5
13	Demand Response		-0.7	-0.7	-0.7	-0.7	-0.7
14	Total Incremental DSM:		-9.8	-6.6	-6.6	-6.6	-6.6
15	Total Incremental Rolling DSM:		-9.8	-16.4	-23.0	-29.6	-36.2
16	**System Forecast less DSM, less DG, PVs and Energy Storage + EVs**	**1,156.9**	**1,166.9**	**1,171.0**	**1,171.0**	**1,170.0**	**1,171.0**
17	MW Growth:		9.8	4.2	0.6	-1.1	0.4
18	**Rounded System Forecast less DSM, less DR and PVs + EVs**	**1,155.0**	**1,165.0**	**1,170.0**	**1,170.0**	**1,170.0**	**1,170.0**
19	MW Growth (Rounded):		10.0	5.0	0.0	0.0	0.0
20	% Growth:		*0.9%*	*0.4%*	*0.0%*	*0.0%*	*0.0%*
21	Note: 2015 Demand is Weather-Adjusted						

System forecast line item descriptions:

Line 1, Updated System Forecast (not rounded): The weather-adjusted peak (WAP).

Line 2, MW Growth: Cumulative growth of residential and commercial sectors.

Line 3, Percent Growth: Growth as a percentage of the base.

Line 5, Electric Vehicles (EVs): The incremental load growth associated with EV charging.

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Line 7, Photovoltaics/Solar (PVs): The peak load reduction associated with appropriately rated PV/Solar generation. This value is the cumulative MW impact from PV at coincidental peak hour (4:00 p.m. – 5:00 p.m.). The forecasting of PV, as with other DER types, involves determining both the impact of the DER and its future growth rate. To assess the impact of currently deployed Solar PV, the Company's DG Ombudsman provides nameplate kW capacity of PV jobs and application date. The above PV forecast was developed prior to the significant increase in volume of PV interconnection applications received by O&R in late 2015 and the first half of 2016, many of them 2 MW community solar projects. The 2017 forecast will take this growth into account, specifically to incorporate more information from the interconnection process that will factor in interconnected projects, approved applications, and a reasonable assumption of which remaining applications will potentially be approved and eventually installed. In addition, peak coincidence of PV output will continue to be taken into account and updated with the forecasted shift of the peak to later in the day as a result of increased DER penetration.

Line 8, Other Distributed Generation (DG): The peak load reduction associated with non-solar generators (*e.g.*, Combined Heat and Power (CHP), gas turbines).

Line 9, Energy Storage: The peak load reduction associated with appropriately rated energy storage systems.

Line 10, Coincident DSM (Incremental Rolling): Category heading for the seven lines below.

Line 11, O&R EE: Annual incremental rolling forecasted system coincident demand reductions from O&R's EE programs.

Line 12, NYSERDA EE: Annual incremental rolling forecasted system coincident demand reductions from NYSERDA's EE programs.

Line 13, DR: Annual incremental rolling forecasted system coincident demand reductions from commercial and residential demand response programs. Does not include NYISO DR.

Line 14, Total Incremental DSM: Annual incremental sum of peak reduction programs.

Line 15, Total Incremental Rolling DSM: Cumulative sum of peak reduction programs.

Line 16, System Forecast less DSM, less DG, PVs and Energy Storage + EVs: System forecast including all incremental growth and load modifiers.

Line 17, MW Growth: Net growth; sector growth plus technology driven growth less DER load modifiers.

Line 18, Rounded System Forecast less DSM, less DR and PVs + EVs: System Forecast rounded to the nearest 5 MW.

Line 19, MW Growth (Rounded): Net growth rounded to the nearest 5MW; sector growth plus technology driven growth less DER load modifiers.

Line 20, Percent Growth: Rounded MW Growth as a percentage of the rounded system forecast.

Line 21, Note: 2015 Demand is Weather-Adjusted – see above description of the weather adjustment methodology and process.

Expected Updates to the Peak Demand Forecast

The forecast presented above was developed through O&R's forecasting process, in conjunction with the Con Edison Demand Forecasting Group, and published in October 2015. Since October 2015 there have been a number of regulatory developments through REV related proceedings that will likely continue to drive DER growth. These are currently being taken into account in the ongoing forecasting process and will be reflected in the 2017 forecast published in October 2016. As such, the 2017 forecast will take into account updated information from the interconnection process including interconnected projects, approved applications, and a reasonable assumption of which remaining applications will potentially be approved and eventually installed. Additionally, peak coincidence of PV output will continue to be taken into account and updated with the forecasted shift of the peak to later in the day as a result of increased DER penetration. Forecasts for O&R's DR programs will also be updated. Below are initial updated estimates of solar/PV's and DR's impact on system peak demand. These will continue to be refined through the ongoing 2017 forecasting process and be finalized in October 2016.

Table 1-4

Expected Update to Impact of Solar PV on Electric System Peak Demand Forecast in MW (NY Portion Only)

		2015	2016	2017	2018	2019	2020
	Photovoltaics/Solar (PVs) (Incremental Rolling)		-2.0	-13.0	-21.0	-32.0	-44.0

Table 1-5

Expected Update to Impact of DR Programs on Electric System Peak Demand Forecast in MW (NY Portion Only)

		2015	2016	2017	2018	2019	2020
	Demand Response (Incremental Rolling)		-1.6	-2.5	-3.3	-4.1	-4.9

System Peak Day Load Shapes

Although O&R's forecasting methodology is currently targeted to generate an accurate single data point MW forecast for the system at peak hour, all 24 hours for the system peak day are analyzed. O&R's Distribution Planning Group uses the 24-hour load data for the total system and for each of the substation banks to provide load parameters as guidance for its Electric Operations and System Operations groups for switching scenarios during contingencies or for repairs and/or maintenance.

Five years forecasted system peak day load shapes are included, with the rest of O&R's system data located on the O&R Solar and DG website[29], in conjunction with this DSIP filing. The graphs for O&R contain a calculated hourly 0.97 percent Rockland Electric Company ("RECO") BIAS, which is O&R's New York estimated percentage of the system load that is served by New Jersey stations through state

[29] www.oru.com/distributedgeneration

line distribution ties. O&R operates the electric grid as one intertied grid system with little recognition for state line borders, other than to meter the flows across them. As a result, Company load shapes by state geographic territory are not necessary and have not been developed.

Note: Due to the difference of the impact from solar between 5:00 p.m. and 6:00 p.m. being almost one percent and the significant penetration of PV expected to interconnect and operate on the system in the upcoming years, there will be more reduction for the 5:00 p.m. hour than the 6:00 p.m. hour. This is projected to eventually shift the peak hour from 5:00 p.m. to 6:00 p.m. by 2024/2025.

Energy Forecast

Below is the annual system level energy forecast for the next five years:

Table 1-6

O&R's Electric System Energy Forecast for the NY portion only

Electric Sales Forecast – Total Volumes	
YEAR	**O&R (MWh)**
2016	3,923,346
2017	3,910,463
2018	3,887,833
2019	3,839,993
2020	3,801,451
2021	3,714,075

The billed delivery volume forecasts are based on various econometric and time series models. Models used for forecasting billed delivery volumes are done on a major classification basis, with the major classifications defined as residential, secondary including small primary (SC 2P), primary excluding small primary (SC 2P), lighting, and other public authority. These major classifications are comprised of various O&R service classes. The Company uses econometric time series models to forecast the billed delivery volumes for residential, secondary including small primary, primary excluding small primary, lighting and public authority.

The O&R models are developed employing two types of independent variables – weather and economic. Weather variables, in terms of heating and cooling degree days and billing days, are included in the models to account for delivery volume variations due to differences in weather conditions and billing days. Weather variables are included for all service classes except for lighting. Also included are key economic variables. The key economic variables in the various models are real average electric price, private non-manufacturing employment, and the number of customers. The residential and secondary models include real average electric price, private non-manufacturing employment, and the number of customer variables. The primary model includes real average electric price and the number of customer variables for their respective major classifications. The lighting model includes real average electric price, the number of customers, and burn hour variables. The public authority model does not include any economic variables and is therefore based solely on weather and billing day variables. The forecast includes the impact of customers' installation of solar panels. This is to capture the losses of delivery volumes as customers are now generating a portion of their energy requirements.

Substation Peak Demand Forecasts

A bottom-up forecast is prepared by O&R's Distribution Planning Group on an annual basis. The weather-adjusted coincidental peak demand for each substation is determined and the sum of the banks is compared to calculate the transmission losses at peak time. Using responsibility factors and percent imbalance, the individual WAP phase readings for the circuits at system peak are calculated. From the coincidental factor, the circuit's individual phase readings at the time the circuit's peak are determined. The substation-level forecasting process is similar to the system-level with some notable exceptions, as described below.

Substation Forecast Methodology

The Company develops long-term Substation Electric-Peak Demand forecasts for each of its substations by using internally developed models to determine their WAP load and forecasted load growths. An example of the methodology utilized for a particular load area is detailed below.

As with the system peak, Distribution Planning assesses the prior summer's TV (Column 5) and actual peak demands of the load area (Column 2), and accounts for reduced load from load reduction programs, interruptions, or PV impact toward the station's peak hour (Column 1). Stations are then grouped into load areas based on appropriate capacity sharing and historical switching capability (example shown contains Wisner Station and Hunt Station) to adjacent stations in order to minimize the effect of load transfers on growth rate. Historical peak loads (Column 4) are then regressed against TV (Column 5) and population (Column 6) to determine the weather-adjusted peak load (Column 7) for the load area.

Table 1-7

Example: Wisner/Greenwood Lake Load Area Growth Rate

1	2	3	4	5	6	7	8	9	10
PV	Actual Load	YEAR	PK KVA	TEMP	POP	Wthr Norm	Pv-yr	PV-cum.	WN -PV
6.6	39065	2009	39072	80.8	55929	46875	13.122	24.3	46868
9.1	47378	2010	47387	84.9	58949	47092	9.207	33.5	47083
10.5	49100	2011	49111	86.5	61969	47310	5.427	39.0	47299
14.5	43062	2012	43076	82.3	64989	47527	14.661	53.6	47513
25.7	46988	2013	47014	83.7	68009	47745	41.499	95.1	47719
57.8	39504	2014	39562	79.7	71029	47962	118.773	213.9	47905
568.7	40629	2015	41198	81.8	74050	48180	1892.538	2106.4	47611
		2016		85.0		48436			47867
		2017				48564			47996
		2018				49722			
		2019				50568			
		2020				51225			
						0.45%			-0.61%

Example load area line item descriptions:

Column 1: This is 27 percent (measured peak coincidence percentage for 4:00 p.m. – 5:00 p.m.) of the cumulative nameplate PV for the load area.

Column 2: The actual load of the load area after all other interrupted/reduced load is accounted for.

Column 4: The sum of Line 1 and Line 2.

Column 5: The TV at the time the peak occurred.

Column 6: The population of the load area. "Population" is determined by multiplying the number of residential customers in the area by the number of people per household (retrieved from US Census Bureau) and adding to the number of commercial/industrial customers.

Column 7: The WAP load of the load area. Average annual growth rate located at the bottom of the column.

Column 8: Nameplate PV (Annual): The annual nameplate PV installed to the load area.

Column 9: Cumulative Nameplate PV: The cumulative nameplate PV applied to the load area.

Column 10: The WAP load (column 7) – cumulative PV impact at peak hour (column 1). Average annual growth rate located at the bottom of the column.

Future Growth Rates for Load Area

After receiving the future system growth rates for the O&R system from Con Edison Demand Forecasting group, the known New Business block loads are subtracted out to determine a system growth rate for future years without New Business loads. These annual growth rates are divided by the past one-year system growth rate to determine annual multipliers. These multipliers are respectively multiplied by the past one-year growth rate of the load area to determine the future growth rates of the load area. Any known New Business loads for the load area are added to the respective circuits/banks. An example of the growth rate calculation is shown below.

Table 1-8

Example: Growth Rate Calculation

	1	2	3	4	5	6
		Growth		System load w/o	Growth	
	System load	w New Business	New Business	New Business	w/o New Business	Multiplier
2015	1617			1617		
2016	1649	1.9790%	28	1621	0.2474%	1.172377611
2017	1677	1.6980%	26	1623	0.1234%	0.584742319
2018	1700	1.3715%	5	1641	1.1091%	5.256195741
2019	1716	0.9412%	3	1654	0.7922%	3.754501792
2020	1729	0.7576%	3	1664	0.6046%	2.865378774
		0.2110%	Historic System Growth Rate			
			7			

Example growth rate calculation line item description:

Column 1: The forecasted system load, which includes known New Business block loads, not including DSM, DG or EVs.

Column 2: The future growth rate of forecasted loads, which include New Business block loads.

Column 3: Future known New Business block loads.

Column 4: The forecasted system load without adding known New Business block loads.

Column 5: The growth future growth rate of forecasted loads, which does not include New Business block loads.

Column 6: The multiplier is the quotient of Column 5 and Item 7.

Item 7: The previous (2014-2015) one-year growth of the system.

The multipliers (Column 6 above) are then applied to the past one-year growth rate of the load area, which is 0.45 percent in this example (see bottom of Column 7 on Table 1-7) to yield the future growth rates shown below.

Table 1-9

Example: Future Growth Rates

	Hunt/Wisner
2016	0.53%
2017	0.27%
2018	2.38%
2019	1.70%
2020	1.30%

These growth rates are applied to the 2015 WAP load of the load area (Column 7 on Table 1-7) to determine the future WAP load of the load area. NOTE: The cumulative amount of PV and its impact on peak hour is taken into account (Column 10 on Table 1-7) shows the impact to growth rate over the past year on the bottom of the column (-0.61 percent).

Dividing the Load Area into Substation Banks

Based on the previous year's peak load, the responsibility factor, which is the source's percentage of the load area, is calculated. This includes the banks and any portion of a circuit/bank that has been transferred to/from another load area. The responsibility factor is then applied to the WAP load of the load area for the respective year to determine the coincidental WAP load of the bank. The PV load does not get weather-adjusted. An example of apportioning load within the area is shown below.

Table 1-10

Example: Dividing of Load Area

1	2	
0.37%	152	79-8-13
31.11%	12640	Hunt Bank 384
48.07%	19532	Wisner Bank 280
20.44%	8305	Wisner Bank 380
100.00%	40629	

Example dividing load area line item description:

Column 1: Responsibility factor for each feed in the load area.

Column 2: Actual measured load of the previous year.

After removing the respective PV from the load area (569kW), the responsibility factors are applied to the future WAP loads (the 2016 WAP load for the load area is 47867KVA in Column 10 on the Wisner/Greenwood Lake load area example).

Table 1-11

Example: Responsibility Factors

		5yr avg %	2016 WNLoad
	PV		569
	79-8-13	0.37%	179
384	Hunt	31.11%	14892
280	Wisner	48.07%	23012
380	Wisner	20.44%	9785
		100.00%	47867

NOTE: The PV is factored into the load growth and anticipated to be present to reduce area load during the peak periods.

Determining Banks' Individual Peak:

The quotient of the bank's coincidental peak and individual peak from the previous year calculates the coincidental factor. Future WAP loads are divided by this coincidental factor to determine the bank's individual WAP. Any know New Business Loads or transfers are then taken into account to finalize the circuit's/bank's WAP future loads.

Substation Load Shapes

Although O&R's forecasting methodology is currently targeted to generate an accurate single data point MW forecast for the system and substations at peak hour, all 24 hours for the peak day are analyzed. O&R's Distribution Planning Group uses the 24-hour load data for the total system and for each of the substation banks to provide load parameters as guidance for its Electric Operations and System Operations groups for switching scenarios during contingencies, voltage guidelines for capacitor/load tap changer ("LTC") settings, distribution automation scenarios, or for repairs and/or maintenance.

The 24-hour data available typically includes more than just the peak day and is usually put in table format rather than load shape format. This data can be retrieved for any time of year, and is usually used for circuit and individual substation bank analysis rather than entire substation analysis.

Substation Forecast Data

Available Information

Station Data:

Near real-time telemetry data collected from O&R substations consists of circuit feeder amps as well as voltage and megawatts values at each transformer bank. There are five distribution stations in the O&R service territory that presently do not obtain or provide telemetry readings (Port Jervis, Summitville, Wurtsboro, Ringwood, and Pine Island). Instead, field readings are required on peak days, or load loggers are required to receive values for forecasting. Field readings are taken for Pine Island; however, this will no longer be required with plans for the retirement of the station in the near future, and the installation of Smart Fault Indicator sensors at the head-end of the circuits. These sensors have also been installed on the other four substations listed above. This allows O&R to receive intermittent data (15 minutes to hourly) for any selected period of time of the year. This has significantly enhanced visibility for forecasting and operations where only sparse data was available previously.

Solar Data:

Based on the penetration of PV and historical data to determine growth rate, the PV forecast has been used at the system level for the first time for the 2016 load. Although it is not used in the forecast for banks/circuits, the historical data is reviewed to project the potential amount of PV to be added to a circuit in the upcoming year. This value is arrived at by taking the proportional amount of PV for each circuit to the forecasted PV growth for the system. Prior to the application of DER forecasts to an overall circuit/substation bank forecast, an appropriate DER forecasting method must be developed and adopted. This is one of the important topics the JU is discussing as part of the Supplemental DSIP process. Only the PVs that were already in service at the time of peak or are in the queue with high confidence of interconnection and near-term operation are presently included in the circuit/bank forecast (see PV Forecast in Available Distributed Energy Resources section of this Chapter). Currently, the Company has only one large (2 MW) PV that provides monitored readings. Using this data and other measured data obtained by Con Edison, the output for peak hour (5:00 p.m.) is measure to be approximately 27 percent of the PV nameplate rating. At this time, 27 percent of the total PV value for contribution toward peak hour is used. As more PV systems with measured data are installed, the 27 percent figure will be verified and refined as appropriate. PVs are identified based on the circuit segment where they are located. If the segment is transferred to another circuit, the PV circuit identification follows to the correct circuit/bank. O&R is nearly complete with process updates that will make this automatic, which is critical to allow the System Planner to have greater visibility into the benefit that PVs are providing to the correct circuit/bank they are interconnected with, and to understand the system impacts from cloud cover. This will soon be part of the circuit/bank forecasting process. See the section on DER Peak Load Forecast in the Available Distributed Energy Resources section of this Chapter for further elaboration on the process.

Losses:

Transmission losses, which are simply the difference of system load and substation load, have been very accurate. However, it has been very difficult to measure distribution losses, particularly as load modifiers continue to proliferate across the system and there are gaps in data availability for their impacts throughout the load cycle. Additionally, while the coincidental substation load is available, the coincidental customer load is currently extremely difficult to determine/obtain. Customer data is not all retrieved at the same time, and therefore parsing the data significantly affects the accuracy of the customer load, which in turn affects the calculation of distribution losses. The installation of AMI will significantly improve this process. The capability to retrieve data from additional locations on the circuit, such as reclosers and other smart devices, will help and assist O&R Distribution Planning to identify areas where loss improvement is needed.

DSM:

Historically, arriving at an accurate estimate for the impact of DSM on the forecast has been extremely challenging. For internal or targeted DSM programs, information on program results is readily available. The location of the customer is known, and therefore the circuit/bank impacted is known. As of now, these programs have resulted in minimal reduction over a widespread area, and therefore have had little impact on the circuit/banks. The Company is in the process of expanding a targeted DSM program, and the resulting data will be easy to obtain and forecast as well. However, for other DSM programs, such as those administered by NYSERDA, O&R does not receive granular data on the amount of reduction that has been implemented or exactly where it is located within the O&R service territory. This has made any data from those programs difficult to use for system forecasting and impossible for circuit/bank forecasting. So far, the minimal reduction has had little impact on any one area when comparing sequential years. However, this issue is beginning to be addressed. NYSERDA is working on a process to provide detailed information to the Company regarding its programs within O&R's service territory, which will allow Customer Energy Services to identify the customer, circuit, and bank where the reduction has been or will be taking place. With this information, Distribution Planning can include this DSM in the system, bank, and circuit forecasting process. For further information on this process see section on DER Peak Load Forecast in the Available Distributed Energy Resources portion of this Chapter.

Data Availability and Granularity

Distribution system data includes data such as load, voltage, power quality, capacity, equipment and operating detail. DER information such as location, operating characteristics, and reliability are also forms of system data. The type of system data available and the frequency and granularity to which that data is available varies across the O&R service territory. Distribution system data requires multiple layers of analyses and degrees of context consideration to generate usable information to support multiple functions across the Company. This information allows for system operators and planners to enhance service reliability and resiliency and supports planning functions including demand forecasting and system contingency analysis, load flow, and DER forecasting as described in detail in the Distribution System Planning Chapter of this DSIP.

The information to be shared with third parties should allow DER providers and other third parties to make informed decisions. Considerable review and cleansing of raw data must be performed with a high level of local system knowledge and required experience to accurately interpret and transform this data into meaningful information regarding the potential locational benefit opportunities within the service territory. O&R has proposed providing DER providers with insightful information, with as much granularity as possible, as an output from the planning processes, to provide locations of system need and the ability of the system to host distributed generation. In addition, the Company along with the JU will continue to engage with stakeholders through the Supplemental DSIP development process to discuss the detail of insightful information that will provide significant and added value to DER providers. This value will become increasing vital as DER penetration grows and the system becomes more complex and dynamic.

An example of information valuable to DER providers that will be furnished by the Company is the Interconnection Pre-Application Report. As directed by the SIR Order,[30] once a potential applicant requests an interconnection Pre-Application Report and provides the Company with the required $750 fee, O&R provides the information outlined in Appendix D of the SIR Order, including circuit peak load, circuit minimum load, and voltage, among other information.

[30] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016).

Distribution system planners can perform analyses in a cost-effective manner, interpret results, and communicate information to facilitate market growth. By providing valuable insights instead of raw data or data without context, concerns of data security and sensitivity can be more appropriately managed. This was successfully accomplished by working with the JU and NYSERDA NY Prize Stage 1 awardees to provide system information that supported their Microgrid feasibility study efforts. Information provided included circuit peak load, forecasted bank growth rates and circuit reliability information.

O&R has also historically provided other system data to the public such as reliability statistics. O&R tracks all sustained outages greater than five minutes in duration and reports reliability statistics such as System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") on an annual basis at the Company and division levels. Circuit level information is also reported by SAIFI, CAIDI and through the utilization of the Company's own prioritization criteria and methodology. Reliability information at the substation level would require additional manual steps to make available.

System Data Collected

There are 220 feeders serving New York customers on the O&R system. The Company currently records amp readings for 207 circuit feeders via its SCADA network. O&R also receives MW and Mega Volt Ampere Reactive ("MVAR") readings for two circuits. This data is used as an input for the manual load forecasting process which is conducted annually. The Company currently has five years of feeder amperage data stored within the Company's data historian application known as "eDNA." Since the data is currently collected and used for preparing forecasted loads for peak hour only, manual steps would be required presently in order to retrieve, review, and analyze hourly load data for the entire year.

Voltage and power quality data are not available at the feeder level. Adding new data types such as three-phase voltage, Watts and VARs to the information currently being transmitted through SCADA would require substantial system changes. Where head-end circuit breaker microprocessor relays presently exist, they would need new DNP maps to the RTU and would require Substation crews to test out the new points. Breakers would need to be bypassed in order to test new data points. Additionally, not all relays have the ability to provide Watts and VARs, and not all circuits are currently protected with microprocessor type relays.

Data that is presently obtained from feeders is stored and can be accessed in eDNA on a near-real time basis (data intervals as frequently as four seconds). Data is stored in raw format and can be accessed internally via desktop or web client software. Any analysis performed on this data is typically done manually using Excel and is not currently shared with external parties.

The production of useful information from the aforementioned circuit data will be prioritized geographically based on areas identified as locations in which the distribution system could benefit from the installation of DER, as described in the Beneficial Locations section of this Chapter. In addition, the nature of information developed will be informed by the ongoing Supplemental DSIP Stakeholder Engagement process and efforts to assist DER providers in selecting target locations to invest capital.

Data Collection Expansion Plans

O&R has extensive plans to increase the collection of granular system data through SCADA as part of the Company's Distribution Automation and Technology expansion deployment. This will be accomplished through the deployment of additional and improved substation level metering data and through the deployment of AMI. O&R is in the process of installing and commissioning intelligent distribution equipment (*e.g.,* reclosers, motor operated air breaks ("MOABs"), and smart capacitors) in the field that will report back data (*e.g.*, voltage, amps, Watts, VARs) through the DSCADA system. The number of communicating, intelligent electronic devices on distribution feeders is currently over 150, with a total of 300 planned for installation by December of 2016. O&R's technology and automation expansion plans project the installation and commissioning of approximately 100 new devices annually for the next 10 to 15 year period as this technology and functionality promulgates throughout the electric delivery system. Plans exist to incorporate this data into eDNA. This effort will provide an increased amount of circuit data and enhance understanding of distribution circuit performance, as well as enable more effective analysis of the potential impacts of DG at specific locations.

O&R has also been systematically installing sensors throughout its service territory in order to provide additional data points for planning and forecasting purposes. The sensors record usable information such as amps, conductor temperature, and line sag. Approximately 200 sensors have been installed in New York. These sensors are installed in areas where gaps currently exist in data coverage, as well as to troubleshoot potential trouble spots.

The Company is evaluating communications and IT systems and device requirements to retrieve additional data such as Watts, VARs or power quality by circuit phase. Interim plans may include loggers at key system locations if data is currently not available. Expanding O&R's available system data will enhance the ability to perform accurate and detailed system modeling and enable additional planning capabilities. As part of the Company's improving integrated planning process, the expansion of data collection will be reviewed for areas where the effect of DER penetration on system planning and operational needs are determined to be the greatest. Expansion of data collection will also focus on areas where DER can provide the most benefit, particularly NWA locations. The details of some of these efforts are discussed in the Volt/VAR Optimization ("VVO") section of Chapter 2 - Distribution Grid Operations in this DSIP.

With the deployment of AMI meters within the O&R service territory, data related to every single end point along a circuit can be gathered. That data (Watts, VARs, power quality, voltage) can be used as additional sources of information to support demand response, outage management and maintenance management systems. DERs that are built and connected to circuits within the distribution system can also be connected to the AMI communications network and managed. The volume of energy provided, and even costs associated with that energy, can be tracked through the communication network. At an even more granular level, AMI data can potentially be used to identify usage patterns in targeted areas.

The ability of AMI communications and AMI meters to better monitor the Company's distribution system and performance of DER equipment can enhance the quality of service and system performance by enabling customer programs and technologies that may efficiently reduce demand and increase renewable generation. Real time monitoring of DER is essential to the DSP to track DER performance and capabilities both to make same day operational decisions and for near- term forecasts and scenario decisions. AMI data can and will significantly improve information that will be used for distribution planning, forecasting and contingency analysis. It will also eventually be fed into an ADMS to improve the management of the system in real time.

The Company is also interested in retrieving data on large interconnected PV systems. The ability for the utility to see the real time operating conditions such as voltage, Watts, VARs and power quality is beneficial as discussed in the Available Distributed Energy Resources section of Chapter 1 - Distribution System Planning Chapter in this DSIP.

System Information Sharing

The Company supports providing DER providers with insightful information resulting from, and in context with, utility planning processes performed by utility distribution planners. As part of the ongoing Supplemental DSIP Stakeholder Engagement process, O&R is actively working to identify what system information and insights will have the greatest value, as well as the timing of updates, in order to assess the relevance and value to DER providers; this is also being explored in the Value of DER proceeding.[31]

The Company is fully engaged with stakeholders in determining the granularity of system data required to support increased penetration of DER and in developing the methodology for making the data available to DER providers for the purpose of optimizing DER locations on the grid. This is a complex process which has system security and reliability implications. Ultimately, the objective is to establish processes and procedures which allow for external parties to employ DER in locations and in a manner in which they provide the most benefit to customers and the system. The Company, working with stakeholders and the Joint Utilities, has proposed a strategy of providing DER providers with planning information rather than raw system data. As such, the Company can leverage its experience and expertise to present what would otherwise be an onerous amount of unprocessed data in a targeted and deliberate way in order to allow third parties to gain meaningful insights into things such as hosting capacity and beneficial locations. This cost-effective approach is focused on DER providers' priorities and enables concerns of data security and sensitivity to be managed.

O&R is already engaged in providing useful information to DER providers consistent with the Order Modifying Standardized Interconnection Requirements[32]. As stipulated in those requirements, once a potential applicant requests an interconnection Pre-Application Report and provides the Company with the required $750 fee, O&R provides the following information:

[31] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources,* Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference (issued December 23, 2015).

[32] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016).

Figure 1-4

SIR Order Appendix D

Pre-Application Report: (Provided to Applicant by Utility – 10 Business Days)
Operating voltage of closest distribution line
Phasing at site
Approximate distance to 3-Phase (if only 1 or 2 phases nearby)
Circuit capacity (MW)
Fault current availability, if readily obtained
Circuit peak load for the previous calendar year
Circuit minimum load for the previous calendar year
Approximate distance (miles) between serving substation and project site
Number of substation banks
Total substation bank capacity (MW)
Total substation peak load (MW)
Aggregate existing distributed generation on the circuit (kW)
Aggregate queued distributed generation on the circuit (kW)

O&R is also providing a large amount of information on the Company's service territory and distribution system within this DSIP, consistent with the DSIP Guidance Order.[33] This information will be available on the O&R Solar and DG website[34] and includes:

- One year historic (2013) 8760 load data at the substation load area level;
- Five years forecasted 24-hour system peak day load curves;
- 2016 forecasted 24-hour peak load curves by substation load area; and
- 2015 actual 24-hour minimum load curves by substation load area.

The Company is making available the historical 8760 load data for each New York distribution substation as part of this filing and in response to the DSIP Guidance Order. The 8760 load data, from the year 2013, is the closest data available which represents the system peak and upon which the forecast is based. The 8760 load data is a raw data export and has not been reviewed and processed (*e.g.*, weather adjusted, evaluated for meter error, fully adjusted to account for DER load modifiers, etc.) by the methodology applied to the peak hour forecast. Additionally, given the dynamic and flexible nature of the grid, the data may indicate anomalous events where load has transferred between stations as part of ongoing resiliency and reliability work, system expansion, or system contingency.

As previously mentioned, the Company does not produce or use an 8760 load forecast, and is not aware of an existing accepted or widely recognized methodology to develop such a forecast. The Company is committed to further collaboration with stakeholders to determine what system data are "basic" versus "value added", and the appropriate fee structure for value added data. This topic will be further discussed as part of the Track Two proceeding and through the Supplemental DSIP stakeholder engagement.

[33] REV Proceeding, DSIP Order.
[34] www.oru.com/distributedgeneration

Providing system data to third-party providers requires a common cyber security and privacy framework that reflects best practices. Through coordination with the Commission, the JU, and stakeholders, the Company will exchange system analysis and optimal DER locations while maintaining consumer protections and system security. The Commission's technical conferences on cybersecurity, as well as the outcome of Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products, will inform the Company's practices. The security practices and procedures, to be detailed in the Supplemental DSIP, will address protection of sensitive grid information. In addition, any data or information released by O&R will need to be formally approved and must comply with O&R's system security policies, applicable privacy laws, and regulations.

O&R continues to invest in software tools to assist in transforming an ever increasing amount of raw data into useable information from which to guide O&R's business, such as tools that include the development of custom reports and application interfaces. These efforts include both in-house development and joint ventures with industry leading software vendors.

As previously discussed, O&R maintains historical records of near real time system data for transformer bank and circuit feeders. These data sets have been used and will be continued to be used to develop information regarding individual substation and circuit performance and characteristics useful to DER providers. An example of O&R providing useful information by analyzing these data sets is the "Distributed Generation Interconnection Circuit Map." This is currently also located on the O&R Solar and DG site[35] and indicates general areas/circuits where the cost to interconnect greater than 1 MW will be higher. Factors contributing to the determination of additional costs include low minimal daytime load, aggregated DG already interconnected, smaller conductor (wire size), operating voltage and/or the number of applications in the queue on the feeder exceeding daytime load. This interim map was developed prior to hosting capacity methodology being developed by the JU as part of the Supplemental DSIP Stakeholder Engagement process, in an effort to provide an interim tool to assist the distributed generation development community.

Building upon the Distributed Generation Interconnection Circuit Map, the Company envisions developing a more robust interactive system data map, highlighting the various areas specified as potential NWAs, as well as providing embedded information on each circuit to help DER providers make more informed investment decisions and provide maximum value to the system. Information that will be embedded in the map will likely include all circuits, voltage and phasing. The Company envisions that the system data map could eventually display hosting capacity once the definition and methodology are determined through the JU Supplemental DSIP Stakeholder Engagement process.

DER Penetration Forecast Impacts

In the near term, the Company expects to maintain and refine the existing processes for determining the WAP Load, projecting demand growth, and modifying the load to account for DER factors. The Company is ultimately responsible for maintaining safe and reliable service to all customers. As such, the latest system peak demand forecast credits DER as reducing load only for those DER which have been installed by the previous summer peak or in the time period between summer peak and completion of forecast. As DER penetration increases, verifying DER performance will become

[35] http://www.oru.com/distributedgeneration

more important to forecast demand accurately. The Company will re-evaluate the forecasting process iteratively to address any required changes driven by increased DER penetration or greater data availability.

DER have historically been included in the process as the various corresponding technologies have reached a substantial impact on the forecast. Each type of DER, and the corresponding assumptions, will be described in greater detail in the Available Distributed Energy Resources section of this Chapter. EE and DR programs are the most mature, and no changes are expected in the system forecasting process at this time. However, more granular information is expected to be available to the Company, particularly from NYSERDA DSM programs, on the location where the DSM has taken place, which in turn will allow O&R to show the impact to the circuit/bank as well as to the system. Additionally, PV and batteries were included for the first time for the 2016 forecast. Electric Vehicles are now in the forecast at a system level. As part of the planning process, a screening test is performed on all transmission/substation capital projects to see if the installation of DG/targeted DSM can defer the need date of the project based on the results of BCA evaluations and forecasts accordingly. This process has been performed since 2001.

Forecasting DERs, owned and operated by third parties, inherently increases the complexity of the forecasting process and thus makes accurately forecasting demand a more challenging task. As such, increasing DER penetration increases the complexity of forecasting. By design, there will be a time-lag in the forecasting process (to be discussed in greater detail in the Available Distributed Energy Resources section of this Chapter), to verify DER are present and operating as expected in order to maintain grid reliability and safety. As DER technology matures and penetration increases, so too does the cumulative learning applied to the forecasting process. The forecasting process will be updated to capture lessons learned and refine the accuracy of forecasts. To mitigate the complexity and risk associated with increased DER penetration, verifiable and standardized data from DER sources is required. Additional resources, such as personnel and/or data systems, may be required as the volume of inbound DER data increases.

As a part of the Planning Process, once forecasting is completed, a contingency analysis is performed on each circuit/bank to determine the portions of the system that do not meet design standards and are outside of defined risk tolerance, as well as the potential infrastructure projects required for improvement. Projects are then prioritized and run through a series of tests in an attempt to defer the project for the most cost-effective solution, including both traditional and DER solutions. This process will be refined, improved, and will incorporate the BCA Handbook going forward.

Top Down versus Bottom Up Forecasts

System Peak Demand Forecast

The demand growth for forecasts is determined using both top-down and bottom-up methodologies. While the top-down methodology from Con Edison Demand Forecasting group prepares a holistic view of macro-economic conditions that influence electric demand, and the top-down methodology from O&R uses historical peak demands that take future capital projects into account, the bottom-up methodology is focused on known new business jobs, how they are phased into the system, and the other more granular details that were described previously in this section.

The Con Edison residential top-down econometric model is performed by Con Edison Demand Forecasting Group. The long term residential model is based on an econometric model using 35 years of historical data. The key model drivers include, but are not limited to, private non-manufacturing employment and households are provided by Moody's. The economic historical data is analyzed to develop the model with best fit, using Ordinary Least Squares regression analysis; Demand Forecasting uses a statistical program, Eviews, for the regression analysis.

The Con Edison long term commercial model is based on the combination of top-down and bottom-up approach. The top-down process is based on an econometric model using 35 years of historical data. The key model drivers include, but not limited to, gross county product and industrial production provided by Moody's. The Con Edison economic historical data is analyzed to develop the model with best fit, using Ordinary Least Squares regression analysis; Demand Forecasting uses a statistical program, Eviews for the regression analysis. The bottom-up load growth or reduction attributed to the new business is included, provided by the O&R New Business Service Department. Generally, the bottom-up forecast horizon is no longer than three years. Historical average growth rates and recent economic trends with an econometric model are used to estimate the new business incremental growth for a long term forecast beyond the forecast provided by the O&R New Business Services.

Substation Peak Demand Forecast

O&R's bottom-up forecasting method provides an individual forecast for each substation bank and distribution circuit, which allows the Company to verify granular impacts of DER. Individual transformer bank data are then weather-adjusted and added to determine a coincidental substation load. When compared to the WAP system load, the percent transmission losses are compared to previous years' losses, as well as modeled values to verify accuracy. There are many variables that impact demand forecasting such as load, temperature, population, and now DERs. Since O&R's and Con Edison's different approaches provide similar results for system forecast, this is a good verification for that level. The top-down versus bottom-up forecasts shows the system and banks/circuits are in sync. Bank calculations from circuit individual phase readings versus actual bank measurements verifies bank accuracy.

DERs are forecasted using primarily bottom-up methodologies by accounting for known project or program totals. Energy Efficiency and Demand Response forecasts are based on program level projections based on historic and expected future performance. Distributed Generation, including all solar, CHP, and batteries are forecast using cumulative historical penetration, and known queued projects. New forecasting and appropriate assumption methodologies are needed to accurately extrapolate future growth rates. The forecasting of DER is described in greater detail in the Available Resource section.

Electric Vehicles are modifiers in the bottom-up methodology but are not considered as DER. The overall forecast for load growth as a result of EVs over the next five years is well below 1.0 MW. The most recent data provided by Distribution Engineering with DMV statistic reports are used to analyze the current and projected number of EV. Additional resources and studies performed by the DG group are used to develop the EV coincident system peak forecast. However, there is no locational data incorporated into the current forecast, so the distribution of expected load growth from EVs when spread across all circuits is negligible. There are many market factors that could impact the current EV forecast significantly. In the future, as the Company receives more fidelity surrounding both the location and amount of impact from EVs, that information could be incorporated into the bottom-up methodology.

The bottom-up and top-down methodology for demand growth does provide a more accurate peak forecast, distributed more accurately and granularly across the system. In alignment with the expected installation of DERs, the Company intends to continue and improve its DER forecasting methodology from a bottom up approach in order to rely on verifiable DERs to maintain system reliability.

Incorporation of DER Providers' Forecasts

As described in the methodology above, the Company includes many types of DER as load modifiers (typically reductions) to the electric peak demand forecasts for the coincident system forecast. To close the feedback loop, the Company evaluates its prior year's forecast to evaluate the forecasting models and adjust accordingly. The Company is interested in learning more about DER provider forecasts, and expects to discuss that as a topic in the stakeholder engagement process of the Supplemental DSIP and beyond. Of particular interest to the utility would be granular performance data of DER installed on the system and its coincidence with system peaks. Data received from DER providers could be applied to the electric peak demand forecasts to better determine the impact and benefits of installed DER on the system.

Available Distributed Energy Resources

The peak demand and energy forecasts previously described in the Forecast of Demand and Energy Growth section are used as inputs for other business processes. The peak demand forecasts, produced both for the summer and winter peaks at granular substation and circuit levels as well as at higher system levels, guide the infrastructure investment decisions directing capital to the areas of greatest need. Peak demand forecasts are also provided to the bulk level system planners. The volume forecast is used to determine the revenue forecast and ultimately set rates. DERs generally contribute as reductions to both peak demand and energy, and as such have the potential to defer traditional utility system expansion investments or reduce wholesale pricing. Information on such potential reductions, for both peak demand and energy forecasts, comes from a variety of sources and varies based on factors including the entity delivering the program and technology. If DERs are to be accounted for as a substitute for traditional T&D infrastructure, the level of performance and reliability must be at or nearly equivalent to that of the T&D it is replacing or deferring. The different factors and algorithms applied to the DER contributions to both forecasts are described in greater detail below.

DER Information Gathering Energy Efficiency and Demand Response Programs

For O&R, energy efficiency and demand response (collectively DSM programs) forecast data comes from the internal program managers who implement each program. Future energy and peak demand reductions are associated with filed and approved program goals and budgets adjusted by historic performance and future performance expectations. Information and data used to forecast NYSERDA programs operating in the O&R service territory are gathered from NYSERDA's regulatory filings and associated PSC orders. The Company has also been working with NYSERDA on obtaining more granular information on the performance of its energy efficiency programs in the O&R service territory. While the NYISO demand response programs are not included in forecasts, it will be important to further coordinate these programs as the Company evolves to becoming the DSP.

Solar PV

The forecasting of solar PV uses a number of inputs from various sources. As with other DG, the details of the expected date of operation and the capacity of the solar installation are collected from DER providers through the interconnection process. Growth rates are determined in the short-term through queued projects, through the interconnection process, and informed by long-term solar penetration studies (*e.g.*, NY SUN). Solar peak coincidence is determined by extrapolating sample metered PV data from existing installations. O&R currently has one large PV unit (2MW) operating in the service territory that reports back hourly data. Historically, data from that unit has been similar to data collected by Con Edison from its twenty metered PV units. Because Con Edison's solar output data is averaged across twenty units, it is used to estimate the solar peak coincidence. Each year the Company reconciles forecasted geographic dispersion of PV with actual installations so that PV generation is applied to the appropriate local areas, lead times of projects, and annual cadence of forecasting.

Non-Solar PV Distributed Generation

Distributed Generation inputs used in forecasts are collected from DER providers through the interconnection process. The nameplate DG capacity and the expected date of operation are provided through that process and verified by the Company. Furthermore, for large DG, operational performance data may be collected through interval meters or other mechanisms. Long-term growth of non-solar DG is extrapolated based on the historical penetration and currently queued projects.

Energy Storage

Energy storage is a separate line item in the peak demand forecast. While still a small component of the forecast, it is understood that advancements in technology may result in potential energy storage units installed throughout O&R's territory. Energy storage penetration and growth information are currently provided by O&R's Distribution Generation Ombudsman and through the interconnection process.

The Company recognizes that distributed battery energy storage is a relatively new technology with little data on technical and market potential in the Company's service territory. The Company has identified factors for adoption that it believes will indicate the future pace of distributed energy storage. These signposts include energy storage pricing by technology type, installed cost, policy treatment (*e.g.,* net metering, tax credits) and permitting.

DER Contributions to Peak Load and Energy Reduction Forecasts

A description of each DER type that contributes to the peak load and energy forecasts is included in the pages below. It is important to note that the forecasts and impacts presented in this document were developed during the normal forecasting cycle, but prior to several regulatory impacts such as the updated SIR, Community Net Metering, and specific solutions identified within the Pomona Program. Current forecasts will be updated to reflect appropriate interconnection projections from the dramatic increases in the interconnection queue in past year, as well as NWA solutions as they are identified and confirmed.

Demand Side Management Forecast Impacts

O&R-implemented Energy Efficiency programs are included in the energy forecasts, as are NYSERDA programs operating in the O&R service territory. Demand Response programs are not included in the energy forecast. Table 1-12 refers to the impact of DSM, including energy efficiency and demand response, on the system peak demand forecast. As shown in lines 10 through 15 in the system peak demand forecast, energy efficiency programs and demand response are expected to contribute 9.8MW of load reduction in 2016, ramping to cumulative 36.2MW of reduction by 2020.

Table 1-12

2016 – Impact of DSM on Electric System Peak Demand Forecast (in MW)

		2016	2017	2018	2019	2020
10	**Peak Coincident DSM (Incremental Rolling)**					
11	Orange and Rockland EE	-5.7	-10.0	-14.3	-18.6	-22.9
12	NYSERDA EE	-3.3	-5.6	-7.9	-10.2	-12.5
13	Demand Response	-0.7	-0.7	-0.7	-0.7	-0.7
14	Total Incremental DSM:	-9.8	-6.6	-6.6	-6.6	-6.6
15	Total Incremental Rolling DSM:	-9.8	-16.4	-23.0	-29.6	-36.2

As shown below, DSM Programs are expected to contribute 93,934 MWh of cumulative energy reduction in 2016, ramping up to 232,997 MWh of reduction in 2020.

Table 1-13

Impact of DSM on Energy Forecasts in MWh

Delivery Volume Adjustments (MWh) – DSM Programs		**2016**	**2017**	**2018**	**2019**	**2020**
O&R DSM Impact	Residential	(19,488)	(27,203)	(34,923)	(42,642)	(50,365)
	Secondary	(45,979)	(61,113)	(76,100)	(91,088)	(106,077)
	Primary	(27,508)	(39,032)	(50,693)	(62,365)	(74,031)
	Lighting	(0)	(0)	(0)	(0)	(0)
	Public Authority	(0)	(0)	(0)	(0)	(0)
	SC 25	(959)	(1,359)	(1,743)	(2,133)	(2,524)
O&R	**Total**	(93,934)	(128,0707	(163,459)	(198,228)	(232,997)

O&R forecasts the anticipated volume impacts of DSM programs in the service territory. The DSM forecast includes energy and demand impacts resulting from installation by month by service class.

All O&R EE programs are included in the volume forecasts, as are NYSERDA programs operating in the O&R service territory. Demand Response programs are not included in the volume forecast. Information on the expected future energy reductions comes from a variety of sources and vary based on the entity delivering the program. For O&R energy efficiency and demand response programs, expectations of future reductions are based upon a review of historical program performance. Future volume reductions are tied to filed and approved program goals and budgets, adjusted by historic performance and future performance improvement expectations. Information and data used to forecast NYSERDA programs operating in the O&R service territory are gathered from NYSERDA's regulatory filings and associated PSC orders and adjusted based on estimated program participation in the O&R service territory.

As described in detail below, there is a robust process and methodology for information gathering and modeling to forecast energy efficiency and demand response for inclusion in the O&R demand forecasts. The peak demand forecasts for the DSM programs utilize both historical program performance and estimated future growth rates as inputs along with MWh to MW conversion factors based on customer and measure types.

The volume forecast takes historical DSM program performance and estimated future growth rates as inputs and uses conversion factors based on customer and measure types. The volume DSM forecast has an output of MWh savings and MW demand reductions from DSM measures. Figure 1-5 below is a graphical process diagrams.

Figure 1-5
DSM Forecast Process

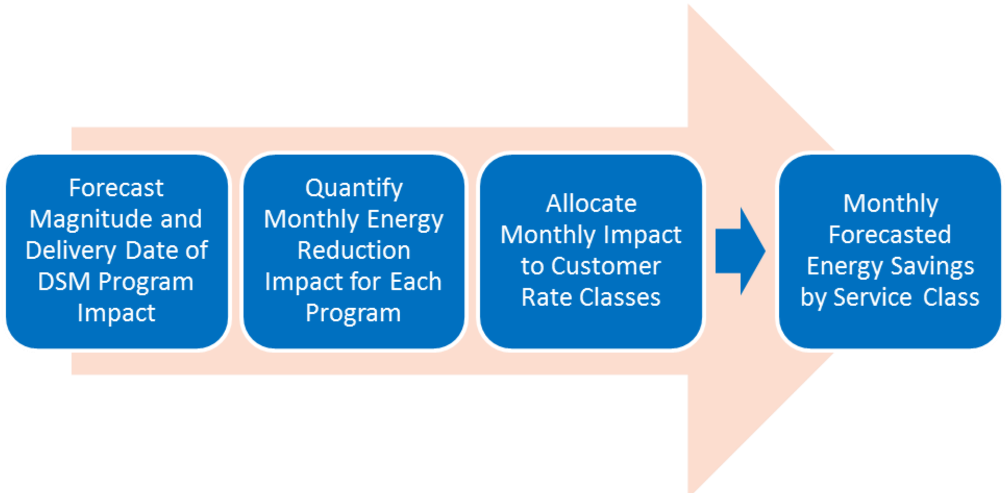
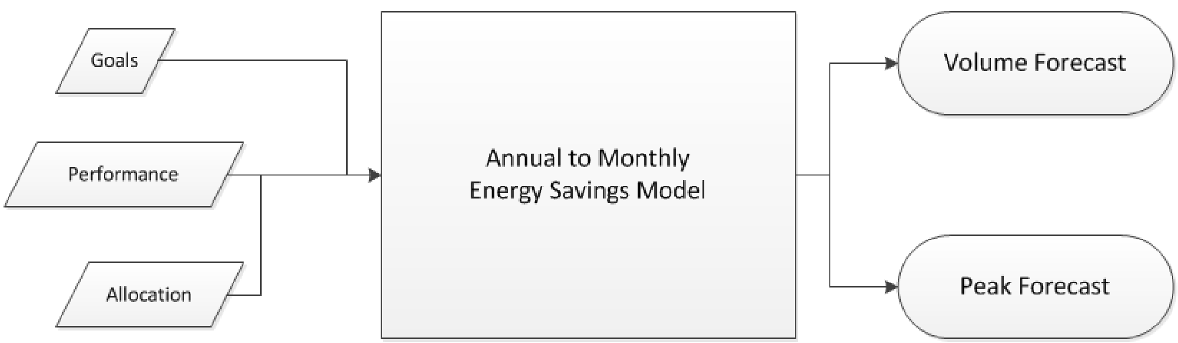


Figure 1-6
DSM Forecast Model



Programs Included in the DSM Forecasts

Energy Efficiency Programs

System-wide energy efficiency programs are designed to provide annual energy savings across the entire electric service territory. The majority of these programs result in some peak demand reduction. In order to incorporate the associated demand reductions of these programs into the load forecast, their expected magnitude, delivery date, hours of operation, and geographic location must also be analyzed and projected. Expected energy savings are distributed across the electrical system in the forecast using historical consumption data and customer demographic information. These energy savings are then converted to monthly peak demand savings using load shapes, which vary with the energy efficiency measures and specific customer segment related to each program. A geographic uncertainty factor is applied to the expected demand reductions to reflect the uncertainty of where the future savings from system wide programs will be realized. Energy efficiency program savings are projected monthly and annually into the future as far out as the programs are funded or highly likely to be funded. Incremental energy and demand reductions in years beyond funding certainty are not included in this forecast. The impacts of compliance with new energy efficiency codes and standards and customer-initiated energy efficiency that occurs outside O&R's EE programs are not included in the forecast.

Specific Energy Efficiency Programs

O&R Electric Programs

- Small Business Direct Install;
- C&I Existing Buildings Rebate; and
- Residential Efficient Products Rebate.

NYSERDA Electric Programs

- Statewide Residential Point-of-Sale;
- EmPower NY;
- Flex Tech / Technical Assistance;
- Electric Reduction in Master-Metered Multifamily Buildings;
- Existing Facilities; and
- Single Family Home Performance.

Demand Response Programs

The expected peak demand impacts of O&R's demand response programs are accounted for in the peak demand forecast. Accounting for the impact of demand response programs in the load forecast begins with the establishment of nominal baseline reductions based on program enrollments. Since O&R's current DR programs were initiated in 2015, future performance factors will be based on historical performance to determine the expected participant performance during peak demand events. Additionally, historic enrollment trends will be analyzed to determine customer re-enrollments and dropouts based on year-over-year trends. Growth projections for future enrollments beyond current year baselines for each demand response program will be determined based on historical program trends and future program expectations based on direct program manager inputs. Demand response program energy reductions have been *de minimis* and therefore these programs are not included in the volume forecast.

Specific Demand Response Programs

- O&R's Distribution Load Relief Program (DLRP) – Reservation Payment Option;
- O&R's Commercial System Relief Program (CSRP) – Reservation Payment Option;
- O&R's Direct Load Control (DLC) Program;
- DLRP and CSRP Voluntary Participation Option MWs are not included in the forecast. DLRP Reservation Payment Option MWs are not included in the system forecast; and
- NYISO DR Programs (SCR) are not included in the O&R DSM forecast as they are considered supply side resources in the Company forecasting process.

The forecast presented above was developed through O&R's forecasting process, in conjunction with the Con Edison Demand Forecasting Group, and published in October 2015. Since October 2015 there have been a number of regulatory developments through REV related proceedings that will likely continue to drive DER growth. As such, the 2017 forecast will take into account updated performance information from O&R's new DR programs. Below is an initial updated estimate of DR's impact on system peak demand. This estimate will continue to be refined through the ongoing 2017 forecasting process and be finalized in October 2016.

Table 1-14

Expected Update to Impact of DR Programs on Electric System Peak Demand Forecast in MW (NY Portion Only)

		2015	2016	2017	2018	2019	2020
	Demand Response (Incremental Rolling)		-1.6	-2.5	-3.3	-4.1	-4.9

Solar PV Forecast Impacts

Con Edison's Demand Forecasting Department provides the PV forecast for O&R. As shown in line 7 of the system forecast (and included below in Table 1-15 for reference), PV is expected to contribute 3 MW of load reduction in 2016, ramping to 28 MW of reduction by 2020. This is based on taking the nameplate capacity of the PV, converting to AC, derating it to account for coincidence with system peak, and accounting for NY SUN growth rates.

Table 1-15

Impact of 2016 Solar PV on Electric System Peak Demand Forecast in MW (NY Portion Only) - Cumulative AC MW at Peak Hour, starting in 2016

		2015	2016	2017	2018	2019	2020
7	Photovoltaics/Solar (PVs) (Incremental Rolling)		-3	-13	-22	-26	-28

The forecasting of solar PV, as with other DER types, involves determining both the impact of the DER and the future growth rate. To assess the impact of currently deployed Solar PV the Company's DG Ombudsman provides nameplate kW capacity of PV jobs and application date. The above PV forecast was developed prior to the significant increase in volume of PV interconnection applications received by O&R in late 2015 and the first half of 2016, many of them 2 MW community solar projects. The 2017 forecast will take into account more information from the interconnection process, approved applications, and a reasonable assumption of which remaining applications will potentially be approved and eventually installed. Additionally, peak coincidence of PV output will continue to be taken into account and updated with the forecasted shift of the peak to later in the day as a result of increased DER penetration. Below is an initial updated estimate of PV's impact on system peak demand. These estimates will continue to be refined through the ongoing forecasting process and finalized in the 2017 forecast to be published in October 2016.

Table 1-16

Expected Update to Impact of 2016 Solar PV on Electric System Peak Demand Forecast in MW (NY Portion Only) - Cumulative AC MW at Peak Hour, starting in 2016

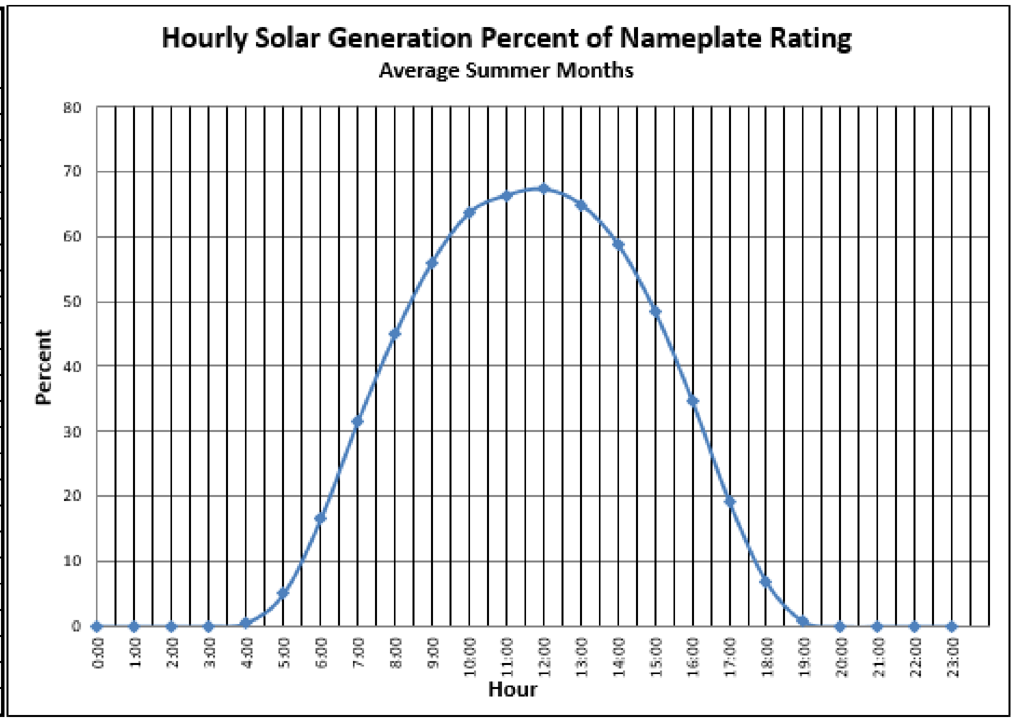
		2015	2016	2017	2018	2019	2020
	Photovoltaics/Solar (PVs) (Incremental Rolling)		-2	-13	-21	-32	-44

Distribution Engineering provides two more key components for assessing the impact of PV, the solar output per hour and the location of the PV project. The solar output for each hour is representative of three summer months (June-August) of data across 20 PVs in Con Edison's service territory. The output curve is represented in the figure below.

Figure 1-7

Measured Solar Output Curve

Hour	Average Summer Output
0:00	0.01
1:00	0.01
2:00	0.01
3:00	0.06
4:00	0.56
5:00	5.03
6:00	16.49
7:00	31.47
8:00	44.97
9:00	56.08
10:00	63.67
11:00	66.36
12:00	67.31
13:00	64.97
14:00	58.82
15:00	48.43
16:00	34.69
17:00	19.14
18:00	6.83
19:00	0.76
20:00	0.01
21:00	0.00
22:00	0.00
23:00	0.00



Each hour's output percentage is the average of the two hours bounding the system peak. The system peaks between 4:00 p.m. – 5:00 p.m.; therefore, the average of the bounding hourly values are used instead of one discreet number. The resultant solar output percentage is multiplied by a DC-to-AC conversion factor and the nameplate capacity to determine the impact of the solar generation. Distribution Engineering also advises where each PV job in queue is located. Without system information for each PV, it would be impossible to determine where PV is most prevalent, and where it has the greatest impact on the grid. To assess the growth rate of solar PV, the initial three years of growth are determined by using the interconnection queue. For the years beyond the queue, the DG Ombudsman works with Demand Forecasting using the best available data. For the 2019 forecast and beyond, growth rates were derived from NY Sun/NYSERDA data.

As noted earlier, for the initial PV forecast, certain assumptions below are defined to build the forecast model:

- Residential customers include any account under 10kW and commercial customers include any account over 10kW;
- Residential jobs go live 12 months after application date;
- Commercial jobs go live 18 months after application date;
- The peak occurs after July 1 of each summer;
- NYSUN/EIA growth rate for 2020 and beyond;
- Did not count pending jobs before 2014; and
- The jobs in the queue are distributed between 2016, 2017, and 2018.

Ten kW was selected as the appropriate divider between residential and commercial in order to apply the lead times of large and small PV projects to the forecast. The lead time assumptions for residential and commercial PV jobs are based on O&R's analysis of historical data. The O&R analysis currently indicates that a residential PV unit would go live 12 months after the application date and that a commercial PV unit would go live 18 months after the application date. For forecasting impacts, this means that some PV jobs will be live the summer after the application and others would be live two summers after the application. In addition, the assumptions regarding 'go-live' time will be updated and enhanced. July 1 was assumed as a representative peak day for purposes of developing the model. By selecting a mid-summer day, PV jobs that are in queue can be parsed into groups that will go live in the upcoming summer or the following summer.

Based on the lead times and interconnection queue, there is sufficient detail to determine which PV jobs will go live the next summer, but it does not contain enough information at the time the current year forecast is developed to determine how many PV jobs will be in operation by current year+2. Therefore, the number of PV installations for current year+2 must be extrapolated based on a combination of the interconnection queue used to forecast the current year and long-term growth assumptions.

As shown below, solar PV is expected to contribute 28,879 MWh of energy reduction in 2016, ramping up to 129,967 MWh of reduction in 2020.

Table 1-17

Impact of Solar Generation on Delivery Volume – MWh

Delivery Volume Adjustments (MWh) – Solar Generation		**2016**	**2017**	**2018**	**2019**	**2020**
O&R Solar Impact	Residential	(24,746)	(43,913)	(64,999)	(88,156)	(113,592)
	Secondary	(2,796)	(5,015)	(7,236)	(9,453)	(11,672)
	Primary	(1,337)	(2,179)	(3,021)	(3,862)	(4,703)
	Lighting	0	0	0	0	0
	Public Authority	0	0	0	0	0
	SC 25	0	0	0	0	0
O&R	**Total**	(28,879)	(51,107)	(75,256)	(101,471)	(129,967)

The solar energy forecast is determined by first evaluating the penetration of solar generation, measured as nameplate DC generation. In addition to future nameplate penetration, Con Edison's Revenue and Volume forecasting group reviews the prior year's average size of PV installations for both residential and commercial customers to determine how to split future growth into different sectors. The future solar penetration is then converted from AC nameplate to an energy reduction modifier using NYSERDA's matrix conversion calculator.

Non-Solar Distributed Generation

As shown in line 8 of the system forecast (and included below for reference), non-PV DG is expected to contribute 0 MW of load reduction in 2016, ramping to 1MW of reduction in 2020.

Table 1-18

Impact of 2016 Non-Solar DG on Electric System Peak Demand Forecast in MW (NY Portion Only) - Cumulative MW at Peak Hour, starting in 2016

		2015	2016	2017	2018	2019	2020
8	Non-PV Distributed Generation (DG) – Incremental Rolling		0	0	0	-1	-1

As part of O&R's Planning Process, a screening study is run on capital projects (transmission, substation, and distribution) more than $5 million to determine if DG and/or targeted DSM can defer a capital project. Currently, the Company is implementing the Pomona Program in order to defer the construction of the Pomona substation.

The Company is implementing most of its identified infrastructure projects to meet its design standards and reduce operating risk for both normal and contingency conditions that have accumulated over time. There are several projects that have been deferred for many years through the implementation of lower cost solutions and other alternatives that are due for implementation. These projects did not have potential for DER deferral over the years due to one or more of the following reasons: the significant amount of load reduction required to defer these projects, the minimal cost of the projects since local transmission availability already exists, or the drivers and subsequent benefits to be obtained from implementing the project require that it not be deferred any further. As these projects have been delayed, the cost of the projects has increased, the required load reduction has increased, and therefore, the DER deferral value has either remained constant or has reduced. Overall, these projects remain as the top priority projects to be constructed. The next phase of projects (likely in the Company's 5- to 10-year horizon) will simply maintain distribution standards with growth rates. Future projects (new substations) will require new transmission feeds, which will become extremely difficult to provide overhead paths. With underground transmission feeds, the cost for these future projects will be very expensive. Due to the minimal load reduction required to keep pace with load growth and the significant cost for traditional solutions, the chance for DER to defer these future projects will increase and be more realistic from a cost/benefit perspective.

The non-solar distributed generation load modifier may become a more important piece of the forecasting process due to potential increased penetration and REV policy changes. To continue to provide safe and reliable service at affordable rates, the Company has determined that backing up multiple non-solar DGs with O&R infrastructure is an unnecessary redundancy. Over time, as the DSP is built out, the Company will be able to monitor more DG devices and can further refine its approach.

Since non-solar DG can be dispatched at times of peak load, the impacts on the local grid could be greater and depend on several factors. These factors include the size of the DG, the redundancy of the local area station, the expected time of "go live", and engineering knowledge of the substation reliability and other local conditions. DG may or may not provide a value to the system.

Once the non-solar DG forecast is determined, the inputs are analyzed so that the system forecast displays the rolling incremental growth (in MW). DG growth is separated from battery growth and tracked independently. Currently, non-solar DG is expected to contribute 0 MWh of energy reduction from 2016 to 2020.

Energy Storage

As shown in Line 9 of the system forecast (and included below for reference), energy storage is expected to contribute 0 MW of load reduction in 2016, ramping to 1 MW of reduction in 2020.

Table 1-19

2016 – Impact Energy Storage on Electric System Peak Demand Forecast in MW (NY Portion Only) - Cumulative MW at Peak Hour, starting in 2016

		2015	2016	2017	2018	2019	2020
9	Energy Storage – Incremental Rolling		0.0	0.0	0.0	-1.0	-1.0

O&R recognizes that distributed energy storage is a relatively new technology with little data on technical and market potential in the Company's service territory. The Company has identified factors for adoption that it believes will indicate the future pace of distributed energy storage. These signposts include energy storage pricing (by technology type), installed cost, policy treatment (*e.g.,* net metering, tax credits) and permitting. Presently, the Company does not quantify the specific contribution of distributed energy storage to energy reduction and thus is not included in the energy forecasts. A potential future energy storage demonstration project may help to inform a methodology for better quantifying the contribution of distributed energy storage resources.

Electric Vehicle

As shown in Line 5 of the system forecast (and included below for reference), electric vehicles are expected to contribute 0 MW of load increase in 2016, ramping to 0.2 MW increase in 2020.

Table 1-20

2016 – Impact of 2016 Electric Vehicle on Electric System Peak Demand Forecast in MW (NY Portion Only) - Cumulative MW at Peak Hour, starting in 2016

		2015	2016	2017	2018	2019	2020
5	Electric Vehicle (EV) – Incremental Rolling		0	0.1	0.1	0.2	0.2

The EV forecast is introduced to reconcile the impact of EVs on coincident system peak. The most recent data provided by Distribution Engineering with DMV statistic reports are used to analyze the current and projected number of EVs. Additional resources and studies performed by the DG group are used to develop the EV coincident system peak forecast. The projection of EVs electric consumption during the coincident system peak is estimated for next five years with the assumptions below.

- DMV's 2014 data is used to count the number of EVs (base number).
- Year-over-year growth rates to estimate the total number of EVs are determined by Westchester's regression model, obtained from Con Edison's EV Forecast (Distribution Engineering).
- EV factors below sourced from NYISO projection are used to reconcile the system peak.

EV Peak Demand Coincident Factor	
Coincident (Usage) Rate @ 5 PM	0.1
Energy Usage / EV (kW)	4.5
Coincident Peak Effectiveness Factor @ 5 PM	**0.45**

DER Peak and Energy Planning Process

On an annual basis, O&R Distribution Engineering Planners perform a screening test on each transmission and substation capital project to determine if DER can defer the date of the project. For projects where deferral is possible, the screening study determines the value of the deferral using the present worth method, which calculates the change in present value revenue requirement between the original planned and revised budget after DER has been implemented. This value divided by the load reduction to defer the project ($/kW) is the value of the unit, or the maximum incentive O&R could pay to generators or customers for load relief. Once the required amount of MW to defer the project is confirmed and dates are set, it is applied to the forecast.

Energy Efficiency and Demand Response Programs

O&R forecasts the anticipated peak demand impacts of energy efficiency and demand response programs in our service territory in order to better assess future capital planning needs. The Company started performing screening studies using a software tool developed by E3 Energy + Environmental Economics in 2001 to evaluate the potential of NWAs to defer infrastructure investments. Demand reductions associated with these programs are included in the forecast as they can offset expectations for future load growth. This, in turn, could lead to the deferral of transmission and distribution assets that would otherwise be required to reliably supply the expected growth. In order to incorporate the impact of DSM programs in the load forecast, the DSM Forecast accounts for the magnitude, delivery date, operation, availability, and geographic distribution of the projected future demand reductions. The projected impact of energy efficiency and demand response programs are included as an explicit component of the Company's long-range load forecast. This load forecast is ultimately used to identify the need for future electric system capacity expansion projects. Going forward, O&R will continue to include energy efficiency, demand response, and any targeted efforts in its demand forecasts used for T&D planning. AMI may also be able to provide additional fidelity on the impact of various EE programs, and methodologies to incorporate that analysis into the forecast will be explored further following AMI meter rollout.

O&R develops and incorporates multiple forecasts for energy efficiency and demand response programs for use in Company planning as outlined below.

Electric Peak Summer System Coincident Forecast

O&R forecasts anticipated summer peak demand (MW) impacts of energy efficiency and demand response programs and projects in the Company's service territory in order to better predict future summer system peak demands. Demand Forecasting incorporates this DSM forecast into the Company's summer system peak demand forecast which is used by O&R and the NYISO.

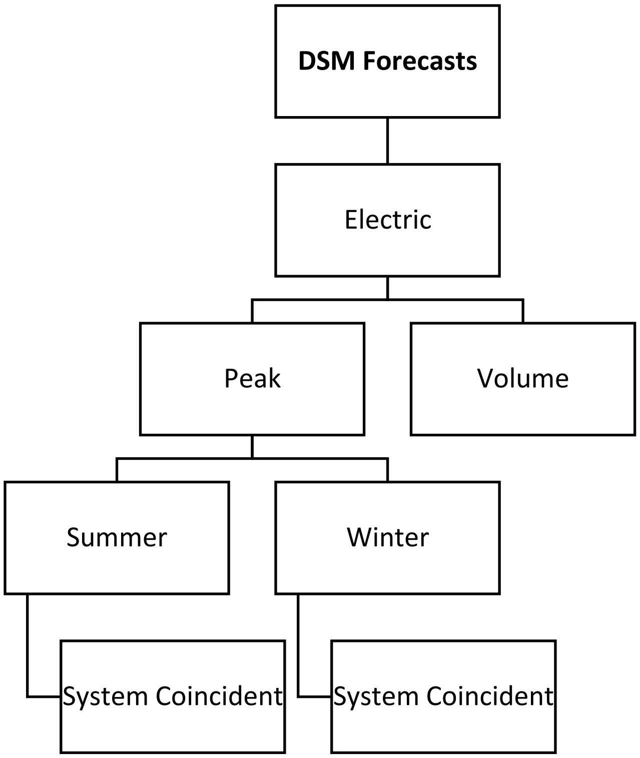
Electric Peak Summer Independent Bank Forecast

O&R forecasts anticipated summer peak demand (MW) for every substation bank/distribution circuit on an annual basis. The Company is currently investigating the potential of incorporating hourly load shapes into its energy efficiency program data tracking software to develop a database that will aggregate the customer load reduction by the segment number where the customer is located. Currently, engineering algorithms found in the New York State Technical Resource Manual are used to calculate the annual energy and demand savings associated to the energy savings measures installed. The annual energy savings would be allocated to an hourly load shape so that energy savings can be aggregated into an hourly load reduction. This detailed data will allow the Company to maintain the segment, circuit, and bank where the energy reduction(s) occur, even as circuit configurations change. This will allow the Company to apply the forecasted locations to the respective locations for load shaping in the planning process. O&R can then take this information and locate the segment, circuit, and bank the customer is currently located, as well as keep track as circuit configurations change.

O&R currently forecasts the anticipated volume impacts of energy efficiency programs in its service territory in order to better assess future revenue requirements. The Company started incorporating EE program reductions into the forecast in 2008 with the inception of its energy efficiency portfolio of programs and has added additional programs as they have been developed and implemented. The energy efficiency and demand management forecast includes energy and demand reductions by month by service class. Going forward, O&R will continue to include energy efficiency programs in its volume forecasts. The delivery volume forecast is used to determine the revenue forecast. The forecasts are used by the Company for rate cases and to assess capital requirement needs. The sendout forecast is used by the Energy Supply group to develop an energy supply cost forecast.

Figure 1-8

Current DSM Forecasts included in Planning



Solar PV and Distributed Generation

The forecasts produced by the Con Edison Demand Forecasting Group, including the weather-adjusted peak, demand growth assumptions, and DER-related load modifiers, are used as the input to several other business processes. The O&R Planning Engineers use the forecasted demand to perform reliability assessments, compare asset capacity against forecasted demand, and plan distribution infrastructure. These processes use forecasted demands without modification to plan infrastructure investments to meet demand. The details of the capital budgeting and distribution planning processes are addressed in greater detail later in the Delivery Infrastructure Capital Investment Plans of this Chapter.

Similar to the EE and DR programs, O&R forecasts the volume impacts of all DG (including Solar PV) as an energy reduction in the volume forecast. The revenue forecast is used by the Company for rate cases and to assess capital requirement needs. The DG forecast includes the GWh volume and MW demand of included reductions by month by service class. Going forward, O&R will continue to include DG in its volume forecasts. The delivery volume forecast is used to determine the revenue forecast. The sendout forecast is used by the Energy Supply Department to develop an energy supply cost forecast.

Energy Storage

O&R recognizes that due to the small number and limited visibility of installed energy storage systems as of 2015, the Company does not have adequate data to model the effect on peak load. However, the Company recognizes several factors for further study, including storage use and charging method. In general, an energy storage resource has a positive (additive) impact to the utility load when it charges from the grid, and a negative (subtractive) impact to load when it discharges. Charging at off peak times and discharging at peak times generally leads to less carbon intensive supply sources being utilized. Energy storage would have no impact to the grid if it charges using behind-the-meter generation.

Storage use, and its impact to peak load, varies by intended purpose (*e.g.* customer-peak shaving, demand response, direct utility-control) and size of resource. Customer-peak shaving is dependent on the time of the customer's peak, and may not be coincident with utility or NYISO peak. Resources used for a customer-specific energy needs may be unavailable at other times.

Presently, the Company does not quantify the specific contribution of distributed energy storage to energy reduction due to the limited number of installations. The Company acknowledges that as more distributed energy storage systems enter the market, more study will be necessary to better understand the effects on energy consumption. A potential future energy storage demonstration project may help to inform a methodology for better quantifying the contribution of distributed energy storage resources.

The Company recognizes that the addition of energy storage results in a net increase in energy usage, due to the round-trip efficiency of battery modules. The Company also recognizes that despite a net increase in energy usage, energy storage can result in a decrease in carbon due to energy arbitrage-charging from low/zero-carbon producing sources and discharging when otherwise higher carbon emitting generators would be used.

Whether the net increase in energy usage will affect the utility system is dependent on how the storage is charged. An energy resource charging from the grid would have a positive (additive) impact to delivered energy. A resource charging from behind-the-meter generation would have no impact to delivered energy. Other factors which could affect energy usage are the load curve of customers who adopt distributed energy storage, as well as their charging cycle and frequency, and capacity utilization of the storage resource.

DER Programs and Procedures to Increase the Quality and Value of DER

Programs

O&R's Pomona Distributed Energy Resource Program is currently working to develop DER in an area of the Company's service territory where it can provide the most value. The successful completion of the program will result in the employment of sufficient DER in the Pomona area to reduce up to 6.0 MW peak load and defer the construction of a $55.7 million substation for at least four years. For the Pomona Program, the Company is employing an iterative DER Portfolio Development Process where the remaining peak reduction needs (both amount of load and time frame) are constantly assessed, and DER solutions to meet those needs are explored and developed on a reoccurring basis. As further elaborated on in the Identify Beneficial Locations for DER Deployment Section of this Chapter, the Pomona Program will provide the Company with a learning experience and serve as a potential model for how the Company executes future NWA projects.

In addition, both current and potential future REV Demonstration projects provide opportunities to encourage the increase in both quantity and value of DER on the system. O&R's first REV Demonstration project will match specific DER and Energy Efficiency solutions to eligible customers and encourage the adoption of those DER products on the Company's Residential Customer Engagement and Marketplace Platform. O&R is also exploring future REV Demonstration projects that will further explore the benefits of DER. For instance, the recently released RFI solicited responses from third parties on innovative energy storage solutions to explore the potential to generate significant Platform Service Revenues for the utility from deploying energy storage. Additional RFIs are planned as well.

Procedures

The quantity and value of DER in the forecasting and planning process could be improved with better and additional information with respect to those resources. Uncertainty leads to negative adjustments to the forecasted contribution of DER. Program designs and contractual agreements for DERs that increase the level of certainty regarding the safety and reliability of the DER would increase the value of the DER in utility planning. Conversely, short-term commitments or the inability to provide reductions when needed by the utility can decrease the value of the DER in the utility forecasting and planning process. If DERs are to substitute for traditional T&D infrastructure, the level of performance and reliability must be at or nearly equivalent to that of the T&D it is replacing or deferring.

Energy Storage Programs and Procedures

The Company supports programs to address system needs that include utility monitoring and control to maintain reliability and maximize grid value. For scenarios where direct-utility control is not possible, the Company advocates for aligning utility revenue with costs, such as implementing critical peak pricing and time-of-use rates. Rate mechanisms may incentivize adoption of technologies for customers to manage their energy needs, such as distributed energy storage. The Company intends to take lessons learned from the Con Edison Virtual Power Plant REV Demonstration project to best integrate storage with utility operations and planning.

Demonstration Project Results

Implementation of O&R's first REV Demonstration project is still in its early stages, as described in the REV Demonstration Projects Appendix of this DSIP. The Company does not yet have the data to support an increase in DER. In addition, low to moderate income ("LMI") customer participation levels have yet to be determined, but will be incorporated into future tracking efforts.

Delivery Infrastructure Capital Investment Plans

System Design Standards and Reliability Design Standards

O&R's electric delivery system and reliability design standards (*e.g.*, "design standards") were developed to provide the Company with a uniform and appropriate methodology to operate and maintain an efficient and reliable electric delivery system and provide customers with the quality of service they expect. The standards are informed by regulatory requirements, safety codes and industry standards and best practices, and provides guidelines for all aspects of planning, design, system construction and maintenance.

The design standards promote the assessment of proper system operating performance with respect to risk for both ability to serve customer load and attendant customer hours of outage exposure. Service reliability is addressed with respect to both momentary and extended outages. Limits for various contingencies are described and promote proper location of local protective devices to meet those limits. Design, construction, and operational practices are also prescribed to minimize the probability of those contingencies.

Distribution Design Standards

Distribution Contingency Criteria

Circuit - To meet the design standards for a single-circuit contingency, 100 percent of its peak load must be restored utilizing available adjacent circuit ties within one hour using a maximum of four switching operations and resulting in less than 2,000 customer-hours of interruption.

Single-Bank Station - To meet the design standards for a single-transformer contingency in a single-transformer station, 60 percent of the bank's peak load must be restored through adjacent circuit ties within four hours. For an extended transformer outage, the mobile transformer must restore the remainder of the customer load within 24 hours and the entire event cannot exceed 60,000 customer-hours of interruption.

Two-Bank Station – To meet the design standards for a single-transformer contingency in a two-transformer substation:

1. For an outage less than four hours, the remaining bank and adjacent circuit ties must assume 100 percent of the entire substation peak load, while keeping the remaining in-service bank at or under Long Term Emergency ("LTE") ratings.
2. For an outage greater than four hours, the remaining bank must assume 100 percent of the in-service bank and 60 percent of the customer load of the lost bank with the assistance of adjacent circuit ties, keeping the bank at normal rating. The mobile transformer must then restore the remainder of the customer load within 24 hours, and the entire outage cannot exceed 60,000 customer-hours of interruption.

Phase Current Imbalance

The entire length of all three-phase circuits will be phase balanced by segment to provide proper balancing of load at the origin. The following equations will be applied for this procedure:

$$\% \, Current \, Imbalance = \frac{Highest - Avg}{Avg}$$

Where $Avg = \frac{1+2+3}{3}$

Highest = Current of the highest phase

If the circuit peak load is less than 150 amps, the maximum allowable imbalance is 15 percent. When the circuit peak load is equal to or greater than 150 amps, the maximum allowable imbalance is 10 percent.

Although phase balance is beneficial at all levels of loading, this is most important at peak conditions. Therefore, the above calculation should be applied to minimize the percentage of phase imbalance at peak.

Voltage Quality

Service voltages provided to the customer at the metering point will meet all applicable national standards and the requirements of the state regulatory authorities. These guidelines have been set to satisfy customer requirements and allow utilization equipment to operate within acceptable tolerances of their nominal ratings.

Table 1-21 below for service voltages is based upon ANSI Standard C84.1 1989 for Electric Power Systems and Equipment - Voltage Ratings (60 Hertz) and regulation tolerances of ±4 percent (for voltages less than 150 volts to ground). Range A is the acceptable voltage limits on the Orange and Rockland system. These are sustained voltages at the customer meter and do not include momentary voltage excursions less than five minutes in duration.

Due to practical design and operating condition limitations, particularly during abnormal or contingency type events, excursions outside of Range A will occur. These excursions should occur no more than four times in 24 hours and be limited to five minutes per occurrence. Acceptable limits for these excursions are shown in the table as Range B. When voltages are in Range B, corrective actions will be taken within a reasonable amount of time to improve to Range A. Sustained voltages outside of Range B will also occur due to conditions beyond local utility control. These should be infrequent and limited to one minute. Prompt corrective action will be taken if these conditions persist.

In conjunction with maintaining these service voltages, the distribution substation bus is maintained at 123 volts (1.025 p.u.) This reflects a practical level to achieve conservation through voltage reduction (“CVR”) under normal operating conditions.

Under system or statewide contingency conditions, a five percent voltage reduction may be required, and bus voltages may be lowered to 117 volts (0.975 p.u.) under these emergency situations. Sustained voltages outside of Range B may occur for durations over five minutes.

In addition to supplying voltage within acceptable ranges, the phase voltages provided in a three-phase service should be reasonably balanced to prevent loss of efficiency and motor de-rating. To limit motor de-rating to 90 percent, a maximum sustained imbalance of three percent is allowed at the meter under no-load conditions.

Table 1-21
Distribution Voltage Standards

SERVICE VOLTAGE	RANGE A	RANGE B
Secondary: 120/240	125/250 - 115/230	127/254 - 110/220
208Y/120	216/125 - 200/115	220/127 - 191/110
240/120	250/125 - 230/115	254/127 - 220/110
480Y/277	504/291 - 456/263	508/293 - 440/254
Primary: 2400	2496 - 2340	2540 - 2280
4160Y/2400	4326/2496 - 4050/2340	4400/2540 - 3950/2280
4800	4992 - 4680	5080 - 4560
13200Y/7620	13728/7925 - 12870/7430	13970/8070 - 12504/7240
34500Y/19920	35880/20716 - 33640/19420	36510/21080 - 32780/18930

$$\%\ \text{Voltage Imbalance} = \frac{V_{Highest} - V_{Avg}}{V_{Avg}}$$

$$\text{Where } V_{Avg} = \frac{V_1 + V_2 + V_3}{3}$$

and $V_{Highest}$ = the phase voltage with the highest difference from V_{Avg}.

Due to sustained imbalances caused by single phasing or tighter imbalance requirements of certain utilization equipment, the customer is expected to protect three-phase equipment with imbalance limit controls.

Finally, voltage changes on the primary distribution system within acceptable operating ranges will also be limited by the design standards. Voltage steps due to regulator or capacitor operation or closed loop switching activities are limited to a three percent change. For customer motor starting, the acceptable voltage drop on the primary system is one percent. When starting is infrequent and less than once per week, a drop of up to three percent may be tolerable.

Voltage Regulation

All distribution substation bus voltages are maintained at 123 volts (1.025 p.u.). The distribution primary line voltages are then regulated between 123 (1.025 p.u.) and 118 (0.983 p.u. volts). The range for the primary voltage level is achieved on the distribution circuits through many means. These include balancing loads on primary feeders, changing distribution and step-transformer taps, increasing feeder conductor size, changing feeder sections from single-phase to multi-phase and converting the primary voltage levels. Capacitor banks and regulators can also be used to maintain proper voltages. Capacitor banks are either fixed on the line or automatically switched with voltage-sensing controls. Most capacitor banks are three-phase units in multiples of 300 KVAR, up to 1,200 KVAR, and are located to provide up to ±2 percent regulation. Voltage regulators, providing ±10 percent regulation in 5/8 percent steps, can be used in both single-phase and three-phase applications. By maintaining primary distribution voltages between 123 and 118 volts, a three-volt drop through the distribution transformer, secondary system, and service can be tolerated. This primary voltage drop allows a minimum voltage at the customer's meter of 115 volts (0.96 p.u.). By maintaining proper voltage and KVAR support through the distribution circuit's load profile, the efficiency of the system is maintained within acceptable tolerances.

Transmission Design Standards

O&R's transmission design standards promote the reliability and adequacy of the local transmission system while meeting system load growth and assesses the risk of not meeting those standards during normal or contingency events. Annual comprehensive studies in accordance with the design standards are completed that result to local transmission plans where inadequacies are identified. These transmission planning design standards are meant to supplement the NYISO current planning process.

Bulk Power System

Planning guidelines and reliability criteria for the bulk power system ("BPS") are defined by the North American Electric Reliability Corporation ("NERC"), the Northeast Power Coordinating Council ("NPCC") and by the New York State Reliability Council ("NYSRC"). The NPCC's A-10 methodology determines what facilities are considered part of the BPS. Bulk power transmission planning is governed by the NYISO's planning process. The analysis and studies performed by the NYISO include, but are not limited to, thermal, voltage, stability, short circuit and breaker duty, and transfer limits.

Reliability

The reliability criteria, guidelines and policies for the New York Control Area ("NYCA") facilities are defined by NERC, NPCC and NYSRC.

Contingencies

All contingencies are defined by NERC, NPCC and NYSRC for the NYCA facilities.

Local Transmission System

Definition

The local transmission system consists of all electric facilities that are used to connect the BPS (*i.e.*, 345 kV generation systems) to the distribution system. The local transmission system includes all facilities operated at voltages between 34.5 kV and 138 kV and their supply transformers. However, some of O&R's facilities operating at 34.5 kV, such as those with direct load and customers connected to it that exist predominantly in the Company's Central and Western Divisions, are considered part of the distribution system.

The basic functions of the local transmission system are:

1. To deliver power from remote sites to load centers while operating within the electrical limitations of existing transmission facilities, and supplying service at the desired time and amounts in a reliable manner;
2. To accommodate system emergencies including outages of generation or transmission facilities without disruption of service; and
3. To dispatch generation from the most economical resources available while maintaining system reliability.

Reliability

No Loss of Load - The transmission system shall be designed and operated to a level where no loss of load will be allowed during reasonably foreseeable contingencies. Loss of small portions of a system, such as radial portions, will be tolerated provided these do not jeopardize the integrity of the overall transmission system.

Maintenance Outages - The transmission system shall be designed to allow for maintenance outages. In cases where a substation or customers are supplied from two sources, loss of load will be accepted for reasonably foreseeable contingencies with one supply out for maintenance.

Sufficient Capability - The transmission system shall be designed with sufficient capability as can be economically justified. Losses will be reduced where possible, optimum economic generation will be provided for and the ability to purchase or sell capacity and energy through various interconnections with other utilities will be maintained.

New Facilities - New facilities shall be designed to provide physical separation to minimize a single occurrence causing simultaneous loss of two supplies to the same distribution substation or load center.

Restoration of Service - The transfer of load by rearrangement of lines and busses via supervisory control and field switching and readjustment of generator outputs following outages are acceptable means to restore service.

Contingencies

The transmission system shall be designed to sustain the following contingencies during all load levels while meeting applicable voltage criteria and limiting equipment loadings to within applicable design ratings:

Reasonably Foreseeable Single Contingencies - The System shall be planned to sustain the following more probable single contingencies without loss of customer load, except for loss of those customers and substations which solely depend on the outage circuit:

1. Outage of a Single Circuit;
2. Outage of a Transformer;
3. Outage of a Bus Section; and
4. Outage of a Generator.

During any of the above contingencies, no facility will be loaded above its LTE limits.

Double Contingencies - The occurrences of the following specific double contingencies are to be examined for the consequences and possible solutions. In no case should they result in a system outage affecting more than ten percent of total system peak for a duration greater than four hours:

1. Transmission circuit and transformer within same substation or load area;
2. Generator and either a transformer or a transmission circuit within the same substation or load area;
3. Two transmission circuits on the same structure;
4. Two transformers within same substation; and
5. Two adjacent bus sections.

Extreme Contingencies - Extreme contingencies are the occurrence of multiple contingency events especially in the BPS that will subject the whole Transmission system to severe conditions. The occurrences of the following extreme contingencies, per NPCC criteria, are to be examined for possible consequences and solutions:

1. Loss of the entire capability of a generating station;
2. Loss of all lines emanating from a generating station, switching station or substation;
3. Loss of a Right of Way;
4. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, which delayed fault clearing and with due regarding to reclosing;
5. The sudden dropping of a large load or major load center;
6. The effect of severe power swings arising from disturbances outside the NPCC's interconnected system; and
7. Failure of a special protection system, to operate when required following the normal contingencies.

Voltage

The transmission system shall have supervisory or automatic controls capable of maintaining voltages at levels that will not exceed limits of the connected equipment during both normal and contingency conditions and will allow for meeting the criteria for customer voltage as defined in the Distribution Design Standards.

Normal Operating Conditions - The voltages on the Transmission System will be maintained within $\pm$ 5 percent of nominal voltage under normal conditions.

Single Contingency Operating Conditions - The maximum acceptable voltage deviation during single contingency conditions after LTC transformers have operated is five percent, but not less than 95 percent or greater than 105 percent of nominal voltage.

Reactive Requirements - Capacitors banks are installed in the transmission and distribution systems for voltage support, VAR support, power factor control, system efficiency and loss reduction. On the transmission system, capacitor banks are installed to provide voltage support during normal operating conditions and post-contingency conditions.

Generating Unit Stability

With all transmission facilities in service, generator unit stability shall be maintained on those facilities not directly involved in clearing the fault for:

1. A permanent three-phase fault or phase-to-ground fault on any generator transmission circuit, transformer or bus section cleared in normal time; and
2. A permanent phase-to-ground fault on any generator transmission circuit, transformer or bus section with delayed clearing.

Thermal Ratings

The methodology and criteria used by the Company in rating its transmission line facilities are in accordance with the latest report of the NYPP Task Force on Tie Line Ratings. The Valley Group's Rate Kit Program was utilized to calculate the thermal ratings for the overhead conductors. For underground cables, EPRI's Underground Transmission Design Tools ("UTDT") with the Alternative Cable Evaluation ("ACE") Program was used in the computation.

The transformer thermal ratings are derived from the latest version of EPRI's Power Transformer Loading Program ("PT LOAD"), which is based on the latest version of IEEE's "Guide for Loading Oil-Immersed Distribution and Power Transformer" (IEEE C57.91-1995).

System Frequency

Standard Frequency

The standard frequency on the O&R system is nominally 60 hertz. A sustained frequency excursion of ±0.2 hertz is an indication of a major load-generation imbalance and possible formation of an island. A load shedding program has been developed in order to provide selectivity and flexibility. Most generators are incapable of sustained operation below a specified minimum frequency, typically less than 58.5 hertz.

Automatic Under-frequency Load Shedding

Under-frequency relays are installed at various locations throughout the system to provide protection against widespread system disturbances. The Under-frequency Load Shedding Program ("UFLS") is updated each year for the NYISO and PJM.

Circuit Weight – The customers in the system are broken down by priority code. Each priority code is divided into sorting codes. The sorting codes represent the type of priority customer and each sorting code is provided a code weighting. Code weightings range from 150 for a hospital (sorting code 1) to a 1 for a residential medical emergency (sorting code 5). A circuit weight is calculated annually for each circuit based on the sum of code weightings from the priority of the customers that are located on the circuit. For example, a circuit containing a hospital (150), a nursing home (25) and a prison (2) would have a circuit weight of 177. Additional code weightings are also provided to critical Company services such as the energy control center, radio towers, pump houses, gate stations, and station services to critical 345kV stations.

Circuit weights are used for restoration when solving for contingencies, determining locations to install automation, prioritizing circuits for Manual Load Shedding, and complying with regulatory requirements, such as under-frequency load shedding.

Automation – The installation of automation on a circuit is determined based on the improvement of customers-miles. The product of customers and exposure (miles) calculates the maximum load-exposure (customer-miles) on a radial circuit with no automation. After examining locations along the circuit, the type of customers on the circuit, as well as the length of the circuit, the Company determines the proper type and location of automation (loop scheme, flip flop, mid-point) is determined to reduce customer-miles. Circuit weights are used in this calculation to emphasize the importance of critical customers. A single customer that contains a code weight of 150 (hospital) counts as 150 customers. After selecting a location for the automation, a new customer-mile is calculated for all portions of the mainline. The difference from the maximum load exposure calculates the savings of customer-miles. The ratio for customer-miles savings and number of devices required (cost) provides the best solution from a CBA.

Under-frequency (UF) relays – The available circuits with under-frequency relays are then prioritized by circuit weight. Excluding circuits with high priority customers, such as hospitals, and critical Company facilities and customers, the UF relays are then turned on for the higher-weighted circuits until the cumulative load for these circuits reaches the requirement for each level. The UF relays for the remaining circuits are turned off. The NPCC requirements are for three frequency settings based on the previous year's peak. The first setting requires 6.5 to 7.5 percent of the previous year's peak to be shed at 59.5 hertz. The second setting requires an additional 6.5 to 7.5 percent (13.5 to 14.5 percent cumulative) of the previous year's peak to be shed at 59.3 hertz. The third setting requires an additional 6.5 to 7.5 percent (20.5 to 21.5 percent cumulative) of the previous year's peak to be shed at 59.31 hertz. The fourth setting requires an additional 6.5 to 7.5 percent (27.5 to 28.5 percent cumulative) of the previous year's peak to be shed at 58.9 hertz. All of these settings have a time delay of 300ms. The final setting requires an additional 2 to 3 percent (29.5 to 31.5 percent cumulative) of the previous year's peak to be shed at 59.5 hertz with a 10 second time delay. Reliability-First Corporation (RF) requirements are for three frequency settings based on forecasted peak. The first setting requires 10 percent of the year's forecasted peak to be shed at 59.3hertz. The second setting requires 10 percent of the year's forecasted peak to be shed at 58.9 hertz. The third setting requires 10 percent of the year's forecasted peak to be shed at 58.5 hertz.

Manual Load Shedding - The Manual Load Shed Program is updated every year based on the new circuit weights and the circuits selected for the under-frequency program. Excluding the high priority customers, such as hospitals and other high priority facilities and customers, the circuits that do not have under-frequency relays and the circuits in which the UF relays are turned off are grouped together and prioritized by circuit weight in ascending order so that lower weighted circuits are available to shed first. When these circuits are completed, the circuits with under-frequency relays turned on are prioritized by circuit weight in ascending order. Finally, after these circuits are completed, the remaining circuits (high-prioritized circuits) are prioritized by circuit weight in ascending order as well. This significantly reduces the need of shedding any critical heavy-weighted circuits. Likewise, the circuits selected for UF load shedding remain available in order to meet NERC Reliability Requirement PRC-006, NPCC Directory #12.

Manual Load Shed Reports are prepared on an annual basis for the overall system, the NYISO portion of load, the PJM portion of load, and any known internal transmission contingencies that may require load shedding to maintain system conditions.

Figure 1-9

Restoration Priority Groupings

Restoration Priority Groupings						
Priority Code	**Code Category**	**Code Weighting**	**Sorting Code**	**# of Accts**	**sic code**	**Facility Type**
1	Hospitals	150	1	27	8062	Hospital
2	Public Health	25	2A	9	8059	Life Care Centers
		25	2B	49	8051	Nursing Homes
		10	2C	161	4941	Well Pumping Stations
		10	2D	25	4952	Sewer Pumping Plants
		8	2E	53	3663	Radio Tower / Telecommunications
		8	2F	30		Senior Citizens Complex's
		8	2G	2		Independent Living Centers
3	Safety	5	3A	55	9221	Police Department Facilities
		5	3B	117	9224	Fire Department Facilities
		5	3C	6	4119	Ambulance/Paramedical Facilities
		4	3D	11	2711	Specific Media Facilities
		4	3E	168	8221	Schools/Colleges
		4	3F	67	3661	Telephone Switching Stations
4	Critical Facilities	3	4A	71	9199	Municipal Buildings
		3	4B	7	181	Greenhouse Operations
		3	4C	87		Farmers with Refrigeration
		3	4D	81		Code 1 Business Customers
		3	4E	190		3 Shift manufacturing, data center, data processing, telcommunications
		3	4F	44		Departments of Public Works
		2	4G	45		Supermarkets
		2	4H	14	9223	Prisons
5	Priority Attention Customers	1	ME's	385		Residential Medical Emergency (separate list)
After a review of the overall circuit ratings, some priority 1, priority 2 and Code 1 customer circuits are weighted higher due to an analysis of their past and present sensitivity and exposure.						
	Total Accounts			**1704**		

Capital Budgeting Process

Each year, the Company performs detailed planning studies that determine electric load growth and assess the performance of the electric delivery system throughout a future forecast period with respect to its design standards. The Company's electric planning design standards that were summarized and described previously in this Chapter provide guidance to aid in prioritizing various electrical infrastructure projects for the O&R electric delivery system. The design standards are designed to balance the costs of infrastructure investment versus the benefit of mitigating the risk of significant outage events, as measured by both the amount of load/number of customers impacted and the anticipated duration of the outage. The implementation of these standards are a key input to the capital planning process, both short- and long-term, as they provide a process by which future risk mitigation investments are identified and prioritized. The electric design standards primarily incorporate risk assessment methodology that provides criteria to assess if the electric facilities are, or will be, operating outside of acceptable tolerances with respect to equipment loading, operating parameters and customer exposure. As part of its annual process, the Company completes a future ten-year assessment of the state of its operating infrastructure and approximately every three to five years completes a 20-year long range assessment and outlook to assist in O&R's long-term corporate vision and strategy. The nearest five-year requirements are documented as part of the Company's corporate budgeting and optimization process.

The annual planning process commences with forecasting the overall system load, loads for all of the transmission lines and transmission transformer banks, each individual substation transformer bank, and all of the distribution circuit loads for the upcoming summer. The impact of photovoltaics and other DG/DER, as well as other forms of DSM, such as EE programs and voluntary or program structured load reductions are all accounted for and factored into the forecasted growth rates to provide as accurate as possible growth projections for the forecast periods. Substation transformer banks and substations are grouped into specific load and geographic regions based on logical switching capabilities between adjacent stations and banks. The actual historical peak loads for each region are used within mathematical regression models, along with other relevant variables, to predict and determine the forecasted weather-adjusted peak loads through a future forecast period for each region. The Company then uses a process to apportion the regional growth and expected demands through the forecast period to each substation transformer bank and distribution circuit within the region. Any known block loads or transfers in the region are then accounted for and applied to the affected infrastructure accordingly.

O&R is currently evaluating methodologies to better forecast DG/DER at a circuit level. The Company's current modeling tool used in Distribution Engineering, Electrical Distribution Design's ("EDD") software tool Distribution Engineering Workstation ("DEW") will be investigated for potential use in the future during the annual forecasting and planning process.

The Company employs all of the projected loads determined through its forecasting process to perform operating reviews on each of its major assets, from its transmission lines and banks down through its distribution circuits, for both normal operating conditions and for the failure or temporary removal from service for those components through a detailed contingency analysis. As mentioned above, the results of the contingency analysis are evaluated with respect to O&R's design standards, which contain the risk assessment methodology that provides the specific criteria to assess if the electric facilities are, or will be, operating outside of acceptable tolerances with respect to equipment loading, operating parameters and customer exposure. If any of the assets do not meet their respective design standards at some point during the forecast period, a solution is determined, scheduled and prioritized as part of the Company capital budget development and prioritization process.

As part of the Company's annual planning processes, it periodically evaluates the need for, and appropriate timing to implement its identified capital projects (shown in Figure 1-10 below). The Company initially investigates if alternative and less costly traditional infrastructure investments or targeted non-traditional alternative measures, such as DG, DR, and EE, can substantially defer, reprioritize, or even eliminate more costly major capital infrastructure investments. Some of the traditional solutions could include constructing lower cost distribution projects to defer upgrading or building new substations, using technology and distribution automation for improved asset utilization to defer investment, reprioritizing and accelerating the construction of lower cost transmission and substation investments to defer more costly investments, or simply accepting risk for longer periods of time on projects with less exposure to accelerate the construction of higher risk projects. This is part of O&R's planning process and system review, and the Company has developed and implemented all of these alternative traditional solutions to defer higher cost major capital investments.

The Company has a two-step process for prioritizing its major electric capital infrastructure projects. The first is completed within the system planning process, and the identified projects are then prioritized against other Company projects through a corporate-wide prioritization methodology.

After all methods of alternate solutions are exhausted, the final project solutions are initially prioritized by engineering. Multiple drivers determine the priority of a project as part of this engineering focused prioritization methodology, and each driver has several possible components that contribute a weighted value. The key drivers include customer load, existing condition toward satisfying design standards, condition of equipment, relationship with respect to sequential project needs, reliability, new business, business expansion, and construction window availability. Other drivers, such as operating conditions, safety, losses and voltage improvements that provide additional benefits are considered. The total weight sets the priority of the project relative to other projects, and a selected portfolio is provided to be evaluated as part of the overall corporate prioritization process.

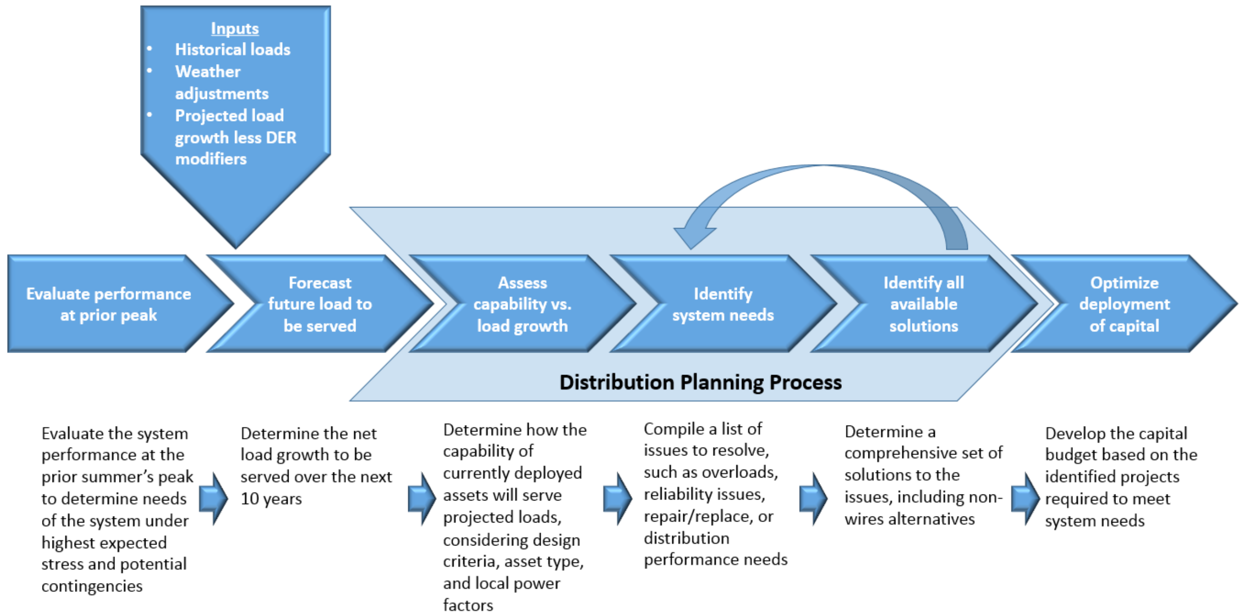
Once the proposed portfolio of engineering projects is selected based on technical review described above, the portfolio is submitted to the Corporate project optimization process and is analyzed using the Company's strategic alignment prioritization / optimization methodology and process. The projects are then ranked relative to each other based on their impact on the nine Corporate Strategic Drivers:

- Improve Customer Experience;
- Improve Public and Employee Safety;
- Provide Reliable Service;
- Reduce and Manage Risk;
- Reduce Costs to Customers;
- Strengthen and Develop Employees;
- Enhance External Relationships;
- Strengthen Company Processes; and
- Sustain Environmental Excellence.

The final project portfolio and drivers are reviewed and determined by a corporate committee comprised of Department Managers and subject matter experts, and ultimately approved by the Company's Corporate Governance Committee ("CGC").

Figure 1-10

O&R Capital Budgeting Process



Integrated Asset Management

The Company implements a comprehensive and integrated electric delivery system plan that couples the capital investment projects identified through the integrated planning process with certain asset management projects and programs designed to meet and maintain acceptable reliability standards and operating conditions.

Over the past 15 years, O&R has bolstered its capital infrastructure investment program and follows inspection and maintenance procedures that provide continual assessments of, and upgrades to, its electric transmission, substation and distribution delivery systems. O&R's capital infrastructure program focuses on both short-term and long-term initiatives to address the Company's design standards, load growth and aging assets. Maintenance, testing and condition assessment assist in determining life expectancy trends for assets. O&R's continued improvement and performance with respect to its System Average Interruption Frequency Index and System Average Interruption Duration Index reliability metrics, as well as improved performance trends in equipment related outages and customers affected per interruption, indicate that the Company's asset management programs are working effectively to maintain the safe, adequate and reliable service to customers. O&R's electric planning processes, capital infrastructure projects, and system inspection and maintenance ("I&M") programs comport with good utility practice.

O&R inspects, assesses, and maintains its transmission and substation ("T&S") system assets on a routine basis. Visual inspections and results from tests conducted during these inspection and maintenance procedures are the predominant methods of determining the assessed condition and equipment replacement plans. The transmission delivery system has the following I&M programs performed on set time cycle schedules: Overhead transmission patrols, Underground transmission inspections, vegetation management, and relay maintenance in accordance with the NPCC. Various substation class inspections, equipment testing, and maintenance programs are also completed which are based on documented time cycles.

O&R's asset management program for distribution assets is addressed by upgrades and replacements through the Company's capital infrastructure investment program and through its I&M programs, some with both capital and operations and maintenance ("O&M") spending components. The Company inspects, assesses, and maintains its distribution system assets on a routine and periodic basis. Visual inspections and results from tests conducted during these programs, inspections and maintenance procedures are the predominant methods of determining the assessed condition and equipment repair and replacement plans. The distribution delivery system has the following inspection and maintenance programs performed on a time cycle schedule: vegetation management, visual inspections, stray voltage testing, capacitor maintenance, regulator maintenance, recloser maintenance, infrared thermal inspections, circuit ownership, pole inspections, underground cable rehabilitation, and cable replacement.

The Company has also recently implemented several storm hardening and system resiliency initiatives to enhance system reliability during storm events. These programs include the following: selective undergrounding, enhanced Overhead system construction, enhanced transportation crossings, substation flood mitigation, enhanced vegetation management, and expanded system automation and grid enhancement technologies. The continued implementation of the Company's current infrastructure projects and service reliability programs, coupled with these forward-looking storm hardening and system resiliency projects and programs will improve the electric delivery systems capability to better withstand and recover from weather-related events.

Consideration of DER in the Capital Budgeting Process

In addition to the capital budgeting process described above, which already includes existing DER on the system, the Company has implemented a screening and review for each major capital infrastructure project that exceeds $5 million. This initial screening determines if the project can be cost-effectively deferred through the implementation of non-traditional alternative measures, such as DG, DER, DR, and DSM. This screening was typically done when the project need was initially identified, or soon thereafter.

Within this initial screening process, predominant project drivers were utilized to determine if deferral utilizing non-traditional alternative measures is possible. Projects that are driven by new customer demand, needed to improve reliability with attendant high risk circumstances, needed to address regulatory compliance (*e.g.*, NERC, FERC or NYISO requirements), for safety or operational issues, or are required to replace aging or obsolete equipment typically cannot be deferred with non-traditional alternative measures, and were excluded as part of the initial screening process. Deferral will typically only be possible for those projects that have a high cost, have small capacity deficit need, have low demand growth, and have a need date sufficiently far enough in the future to allow the non-traditional alternative measures to be installed with enough time and in sufficient quantity to allow deferral.

For those projects where there is a potential for deferral, the Company determines a present worth value for deferring the project. This present value savings (in terms of revenue requirement) is then divided by the load reduction required to defer the planned project in order to determine the value in dollars per kW ("$/kW"). The Company utilizes a hurdle rate of $150/kW as a hard stop in this part of the process. This hurdle rate is set high enough that the cost of solutions through alternative measures will definitively not be cost-beneficial with respect to traditional investment projects that have deferral values less than the hurdle rate. The hurdle rate is based on the PSC's adopted value for system-wide energy efficiency programs, but will be succeeded by the suitability criteria developed by the JU as part of the BCA Handbook. For projects that pass the hurdle rate, more detailed studies are performed that review the type of customers, the number of customers, and the load profiles for the circuits in the geographic area of the project, as well as the specific measures, technologies and their costs, to determine if enough capacity reductions can be achieved, and if so, the costs and benefits in comparison to the traditional investment. This integrated planning process and methodology has been utilized by O&R since 2000, and the modeling methodology tools and non-traditional alternative costs have been updated on an appropriate schedule through that time period to perform accurate benefit and cost studies. Two examples of the Company's non-traditional alternatives screening process are provided below:

Example of the DG and targeted DSM Screening Process (Hartley Road Substation)

The example below summarizes the investigation of a non-wires alternatives study/review performed by the Company that examined the potential to defer the need of the Hartley Road Substation.

First determine that load reduction can solve the problem.

Initial screen completed to determine if issues were customer driven, needed to improve reliability with attendant high risk circumstances, needed for addressing regulatory compliance (*e.g.*, NERC, FERC or NYISO requirements), for safety, or operational issues, or are required to replace aging or obsolete equipment. Identified in 2002, this project was originally scheduled to be in-service by 2008 to relieve the South Goshen 13kV Bank 189, which would be peaking at its normal rating, and provide a feed for a large future load (a new hospital projected to be energized in 2010/11). With the South Goshen Station having minimum approach distance ("M.A.D.") issues, as well as minimum distribution ties, there was little opportunity to unload the equipment for maintenance without providing an alternate/additional local source. At peak time, distribution loop schemes had to be disabled to prevent an adjacent station circuit from transferring to South Goshen and putting the circuit/bank over its thermal operating ratings. Due to the reliability implications, this was not an acceptable project for deferral. A non-wires alternatives screening study was still performed to verify the costs and potential benefits.

Next, determine the project timeline.

Typically for projects this size, at least 18 months from the current date is required for the commitment date of the project and at least 12 months beyond the commitment date is required for construction to meet the in-service date. The cost of each component of the project per year is applied.

Orange & Rockland

The cost of each component of the project per year is applied.

Figure 1-11

Hartley Road Cost by Component

	Expense Year	Energized Year	Total Cost ($000)	Excluded cost ($000)	Net Cost (000)	Equipment (Select)
Hartl Station	2006	2008	$ 79		$ 79	Dist Sub
Hartley UG Exits	2006	2008	$ 242		$ 242	Dist UG Circuit
Hartl Station	2007	2008	$ 1,583		$ 1,583	Dist Sub
Hartley UG Exits	2007	2008	$ 200		$ 200	Dist UG Circuit
Hartl Station	2008	2008	$ 5,000		$ 5,000	Dist Sub
Hartley OH Tap	2008	2008	$ 400		$ 400	Trans OH Circuit
Hartley UG Exits	2008	2008	$ 500		$ 500	Dist UG Circuit

The amount of MW required to defer the project each year is applied.

Table 1-22

Hartley Road MW Requirement

Year:	2008	2009	2010	2011	2012	2013	2014	2015	2016	2018
Minimum Total MW:	14.0	15.3	16.6	18.0	19.3	20.6	21.9	23.3	24.6	25.9

From these inputs, avoidable costs are calculated using the Present Worth Method.

Table 1-23

Hartley Road Present Worth Calculation

Avoidable Costs	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
$/kW (contract)	$ 46.28	$ 82.07	$ 109.99	$ 131.91	$ 149.16	$ 162.75	$ 173.40	$ 181.69	$ 188.08	$ 203.28
$/kW-yr (level)	$ 46.28	$ 42.75	$ 39.78	$ 37.23	$ 35.04	$ 33.11	$ 31.42	$ 29.91	$ 28.55	$ 28.81
Maximum Incentive	$ 647,953	$ 1,257,475	$ 1,830,847	$ 2,370,211	$ 2,877,586	$ 3,354,868	$ 3,803,843	$4,226,188	$ 4,623,484	$ 4,997,217

In Table 1-23 the value expressed as $/kW (contract) is the total value over the life of the deferral per kW of load reduction. The value expressed as $/kW-yr (level) is the levelized annual value of the change in revenue requirement. Maximum Incentive is the maximum cost that could be incurred by O&R for in-area generators, a DSM program, or any other DER to reduce load sufficiently to defer the capital infrastructure project while not increasing the revenue requirement, and thereby cost to customers. The value for Maximum Incentive shows the total change in revenue requirement if the capital infrastructure project could be deferred for the number of years shown in above table.

The required MW for reduction to defer the project was approximately 14 MW, and there was a substantial growth rate of over 3.2 percent that would likely outpace the potential additions of DER being cost-effective. Additionally, there was a need to install DG in at least two locations due to the size of the MW reduction required, and non-wires alternatives were determined to not be cost-effective with respect to the cost of the traditional solution.

NOTE: The station was deferred from its initially targeted in-service date as a result of risk reduction by implementing a lower cost distribution project and area circuit reconfigurations, as well as the need to construct higher priority projects ahead of Hartley Road.

Example of the DG and targeted DSM Screening Process (Pomona Substation)

The example below provides some detail from the initial investigation in 2014 for installing non-wires alternatives to potentially defer the need of the Pomona Substation for three years (until 2025).

First determine that load reduction can solve the problem.

Initial screen completed to determine if customer driven, needed to improve reliability with attendant high risk circumstances, needed for addressing regulatory compliance (*e.g.*, NERC, FERC or NYISO requirements), for safety, or operational issues, or are required to replace aging or obsolete equipment. This project was initially identified in 2007, and scheduled for an in-service date of 2016 to solve for a transmission reliability deficiency, and thus was not an appropriate project for deferral at the time. Alternate solutions later eliminated the transmission reliability need, and the Pomona Substation screening study was again performed in 2014 based on the distribution system needs and costs. In the second screening, the Company found that the forecasted growth anticipated in the first screening had not materialized due to the recession and economic circumstances from 2008 through 2014. As a result, the reliability risk was reduced. The Company incorporated this reduced operating risk into its capital investment and budgeting plans, and deferred the Pomona Substation in-service date until 2019.

Additional deferral was obtained by implementing a less costly traditional infrastructure solution: two new distribution circuits were extended into the Pomona area from the New Hempstead Substation in 2014. This allowed for the deferral of the Pomona Substation for an additional three years to (2022), resulting in a present worth savings of $5.6 million. After completion of the New Hempstead solution, the new Pomona Substation in-service date of 2022 provided an allowable timeframe to complete a new screening study, and the potential to defer the station further using non-wires alternatives.

Next, determine the project timeline.

As mentioned previously, with projects of this size, at least 18 months from the current date is required for the commitment date of the project and at least 12 months beyond the commitment date is required for the in-service date.

The cost of each component of the project per year is applied.

Figure 1-12

Pomona Cost by Component

	Yr of Cost Estimate	Energized Year	Total Cost ($000)	Excluded cost ($000)	Net Cost (000)	Equipment (Select)
Pomona Station	2021	2022	$ 10,000	$ -	$ 10,000	Dist Sub
UG Pomona to West Ha	2021	2022	$ 14,800	$ -	$ 14,800	Trans UG Circuit
Pomona Station	2022	2022	$ 17,800	$ -	$ 17,800	Dist Sub
Pomona UG Exits	2022	2022	$ 3,000		$ 3,000	Dist UG Circuit
WH Term	2022	2022	$ 1,100		$ 1,100	Trans Sub
UG Pomona to West Ha	2022	2022	$ 10,000		$ 10,000	Trans UG Circuit
					$ -	Trans UG Circuit
					$ -	Trans Sub
		Total Cost	$ 56,700	$ -	$ 56,700	

The amount of MW required to defer the project each year is applied.

Table 1-24

Pomona MW Requirement (2014 Initial Analysis)

Year:	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Minimum Total MW:	3.2	4.3	5.4	6.5	7.6	8.7	9.8	10.9	12.0	13.1

From these inputs, avoidable costs are calculated using the Present Worth Method.

Table 1-25

Pomona Present Worth Calculation (2014 Initial Analysis)

Avoidable Costs	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
$/kW (contract)	$ 1,543.85	$ 2,239.26	$ 2,607.09	$ 2,815.52	$ 2,935.30	$ 3,001.30	$ 3,032.70	$ 3,040.89	$ 3,033.02	$ 3,013.83
$/kW-yr (level)	$ 1,543.85	$ 1,148.91	$ 914.88	$ 760.05	$ 650.04	$ 567.85	$ 504.12	$ 453.24	$ 411.69	$ 377.12
Maximum Incentive	$ 4,940,332	$ 9,628,808	$ 14,078,266	$ 18,300,893	$ 22,308,252	$ 26,111,317	$ 29,720,503	$ 33,145,694	$ 36,396,269	$ 39,481,132

In Table 1-25 the value expressed as $/kW (contract) is the total value over the life of the deferral per kW of load reduction. The value expressed as $/kW-yr (level) is the levelized annual value of the change in revenue requirement. Maximum Incentive is the maximum cost that could be incurred by O&R for in-area generators, a DSM program, or any other DER to reduce load sufficiently to defer the capital infrastructure project while not increasing the revenue requirement, and thereby the cost to customers. The value for Maximum Incentive shows the total change in revenue requirement if the capital infrastructure project could be deferred for the number of years shown in above table. Considering the amount of load reduction needed (up to 6.0 MW) in the Pomona area, the Company determined that DER could produce enough achievable load reduction for a three-year deferral.

Conditions Favorable for Deferral

Through running these screens on all large capacity projects, Distribution Planners have observed that high cost projects that require a small amount of MW reduction to defer will provide the highest deferral value and therefore, are the best candidates for potential deferral. High cost areas with large capacity deficits and high load growth will generally not be strong candidates for DG and targeted DSM deferral because of the large amount of load reduction that would be needed to attain and sustain any deferral.

In the future, DER solutions will be evaluated against traditional projects utilizing the BCA Handbook methodology and cost tests. O&R will update and improve its current integrated planning methodology, project suitability criteria and processes, and models and tools to incorporate the new BCA Handbook methodology and cost tests. In all cases, any non-wires alternative solutions must provide equivalent availability and reliability of the traditional grid solution when needed to meet the projected load relief. Acceptable methodologies and processes to determine this must also be developed moving forward.

Transmission and Distribution Historical Spending

The historical spending amounts for transmission and distribution infrastructure are included below. The Company includes the substation costs as part of either distribution spending or transmission spending, depending on the main drivers and the solutions that the project is providing. Most of the substation costs are typically included in the distribution category.

Table 1-26

ORANGE AND ROCKLAND UTILITIES, INC. ACTUAL CAPITAL EXPENDITURES NY (T&D) ($000.0s)					
	2011	2012	2013	2014	2015
Orange and Rockland					
Distribution	$ 46,527.7	$ 64,007.3	$ 58,553.0	$ 56,477.3	$ 46,979.2
Tranmission	$ 11,220.7	$ 7,507.4	$ 19,784.6	$ 27,070.9	$ 28,211.4
Total O&R	**$ 57,748.4**	**$ 71,514.7**	**$ 78,337.6**	**$ 83,548.2**	**$ 75,190.6**
* Substation Costs are embedded into Distribution and Transmission					

Transmission and Distribution Capital Budgets

The transmission and distribution capital budgets for the forward five-year period are included below. The figures below are derived from the 2016 budget. Forecast capital expenditures will continue to be refined through the 2017 budget process and filed in the upcoming electric base rate case. The potential approval of future NWA projects will also have an impact on future budget estimates. Forecast capital expenditures by project group are also included below, and a detailed project listing is included in Appendix F.

Table 1-27

ORANGE AND ROCKLAND UTILITIES, INC. FORECAST CAPITAL EXPENDITURES NY ONLY (T&D) ($000.0s)					
	2016	2017	2018	2019	2020
Orange and Rockland					
Distribution	$ 55,561.3	$ 61,647.0	$ 64,320.7	$ 63,842.4	$ 68,871.6
Tranmission	$ 24,957.9	$ 33,829.8	$ 30,959.4	$ 21,750.0	$ 14,408.5
Total O&R	**$ 80,519.2**	**$ 95,476.8**	**$ 95,280.1**	**$ 85,592.4**	**$ 83,280.1**
* Substation Costs are embedded into Distribution and Transmission					

Orange & Rockland

Table 1-28

Distribution and Transmission Forecasted Capital Budget by Project Group

ORANGE AND ROCKLAND UTILITIES, INC. FORECAST CAPITAL EXPENDITURES NY ONLY (T&D) By Project ($000.0s)					
Function Code	2016	2017	2018	2019	2020
Information Technology	3,644.45	6,230.40	6,230.40	6,230.07	3,089.94
Equipment Purchases	8,627.21	5,141.10	5,312.53	5,420.59	5,450.07
Safety/security	5,127.10	3,886.59	2,235.39	1,741.12	240.06
Storm Hardening	5,402.40	4,082.33	4,076.59	4,413.95	4,127.48
Risk Reduction	39,842.97	62,197.42	54,320.05	46,173.67	34,536.21
New Business	8,243.63	4,179.26	4,992.47	6,492.54	7,822.06
Replacement	4,753.58	2,156.45	9,873.43	8,014.39	4,096.37
Municipal infrastructure support	296.12	269.10	285.94	315.17	400.15
System Expansion	4,581.78	7,334.17	7,953.33	6,790.91	23,517.76
Total	**80,519.23**	**95,476.81**	**95,280.14**	**85,592.41**	**83,280.08**

Historical Spending – IT, Communications, and Shared Services

The historical spending and forecasted budget for IR, Shared Services, and Common is included in Table 1-29 below. IR consists of IT and communications systems residing at O&R.

Table 1-29

ORANGE AND ROCKLAND UTILITIES, INC. ACTUAL CAPITAL EXPENDITURES NY Common ($000.0s)					
	2011	2012	2013	2014	2015
Orange and Rockland					
IR (IT and Communications)	$ 1,276.90	$ 4,263.00	$ 3,966.00	$ 4,103.90	$ 5,767.10
Shared Services	$ 3,521.80	$ 2,069.10	$ 793.60	$ 267.70	$ 392.30
Common	$ 3,626.20	$ 7,090.60	$ 12,112.40	$ 12,201.60	$ 17,704.60
Total O&R	**$ 8,424.9**	**$ 13,422.7**	**$ 16,872.0**	**$ 16,573.2**	**$ 23,864.0**
*** Common includes (Transportation, Facilities , Security, Payment processing, Public affairs)**					

Transmission and Distribution Projects with Deferral Potential

Projects with DER Potential

Wurtsboro

Risk:

The Wurtsboro Substation is a single-bank station that serves approximately 2,086 customers near the end of the Company's service territory and contains a single 5MVA 34.5/4.8kV bank (Bank 29) that feeds two long distribution circuits. Normally fed by Circuit 5-3-34 out of Cuddebackville, the station is backed up with a loop scheme from the 109-4-34 circuit from the Washington Heights substation. As a 4.8kV station, any ties to adjacent 13kV stations are limited since they must go through step transformers. Due to the budgeted retirement/replacement of these 4.8kV stations, when Mobile Transformer 1 was replaced, it was not ordered with 4.8kV secondary taps. As a result, O&R does not have a mobile transformer that can back up this station. The only backup in the event of a bank failure are the three sets of step transformers fed from the tail-end of the primary and backup 34kV circuits that supply the Wurtsboro Substation. The 2016 peak weather normalized forecast for Bank 29 is 3.2MVA. Although these steps can provide 100 percent backup at peak time, a bank outage will result in 8,344 customer hours of interruption due to response and switching time.

In addition, Bank 29 has no LTC which makes it difficult to maintain adequate station voltage. This requires voltage support on the 34kV sub-transmission lines to the station as well as the 4.8kV distribution circuits for both normal contingency conditions. The 600 amp bus switch on the 4.8kV side of Bank 29 limits the normal rating of the bank to 5MVA (Bank 29 LTE 8.4MVA). This is one of the three remaining stations without supervisory control, this station also lacks communication. Therefore, there is no way to control breakers, or even monitor the status of breakers or voltage at the station without sending a crew. The Wurtsboro Station also has M.A.D. issues which require the breakers for both circuits to be opened for clearance when performing maintenance work within the substation.

Non-Wires Alternative Screening:

Due to the age and constrained operating parameters of the existing station, an upgrade to the station has been planned. The upgrade of the Wurtsboro Station to a two-bank station at 13.2kV was originally scheduled for 2009. In addition to upgrading the Wurtsboro Station, the exposure on the 34kV lines that feed the station was to be significantly reduced with the construction of a 69kV loop between four stations. From a new distribution station (Fair Oaks), the transmission feed to Wurtsboro would have been constructed for 69kV (remain operated at 34kV). Due to delay on the construction of the 69kV loop, and because it is fed by two of the longest and worst performing circuits in the system (Circuit 5-3-34 and Circuit 109-4-34), the Wurtsboro Station remains one of the worst performing areas in the system.

After the installation of smart fault indicators to retrieve readings, and additional regulators to cover contingency conditions, reliability has significantly been improved for both the Wurtsboro circuits and bank and deferred the need for the station upgrade.

The upgrade of the Wurtsboro station is still being designed. To construct the new substation, the Wurtsboro load of 3.2MVA must be transferred to three (3) - 1500kVA, 34.5kV/4.8kV step transformer banks. Due to location, circuit configuration, and voltage constraints, it is not possible to balance the load equally between step banks or to add a fourth step bank to improve reliability. If a contingency occurs on the most heavily loaded step bank at peak time, approximately 1.3MVA (41% of station load) will remain out of service until the step bank can be replaced. In addition to construction, since no mobile or spare transformer is available, the step banks must be capable of supporting the Wurtsboro load until the new station is constructed. Essentially, this will become the new normal configuration for Wurtsboro at that time. Either during construction or following the failure of Bank 29, the Wurtsboro Substation would fail the distribution design standard with less than the required 60% backup.

Alternatives:

If 1.3 MW of NWA load relief can be attained, the station construction can be deferred until 2023. This will coincide with the in service dates for the transmission upgrades. Although the growth rate in the area is less than one percent, if an unforeseen large load (500kW) is added in the future it will significantly increase the load on the bank, which will require additional cost for construction due to the difficulty in unloading.

Monsey

Risks:

The Monsey Substation is comprised of two 138-13.2kV, 25 MVA transformers (Banks 144 and 244) each serving three distribution circuits and operated with the low side tie breaker in the normally open position. Bank 144 and Bank 244 have a nameplate rating of 25MVA, a normal rating of 34.3MVA and a LTE four hour rating of 37.8MVA. The Monsey Substation presently serves 9,329 customers, the majority of which are residential.

There are six existing Monsey circuits, with the heaviest-loaded being circuit 44-2-13 at 485 amps, which exceeds its relief rating of 480 amps. Prior to 2016, the 44-3-13 circuit was the heaviest loaded circuit, and in early 2016 a spare circuit (44-1-13) was established to provide relief to this circuit. The loadings on the Monsey circuits do not allow for the appropriate relief during contingency conditions, thereby creating design standard exceptions.

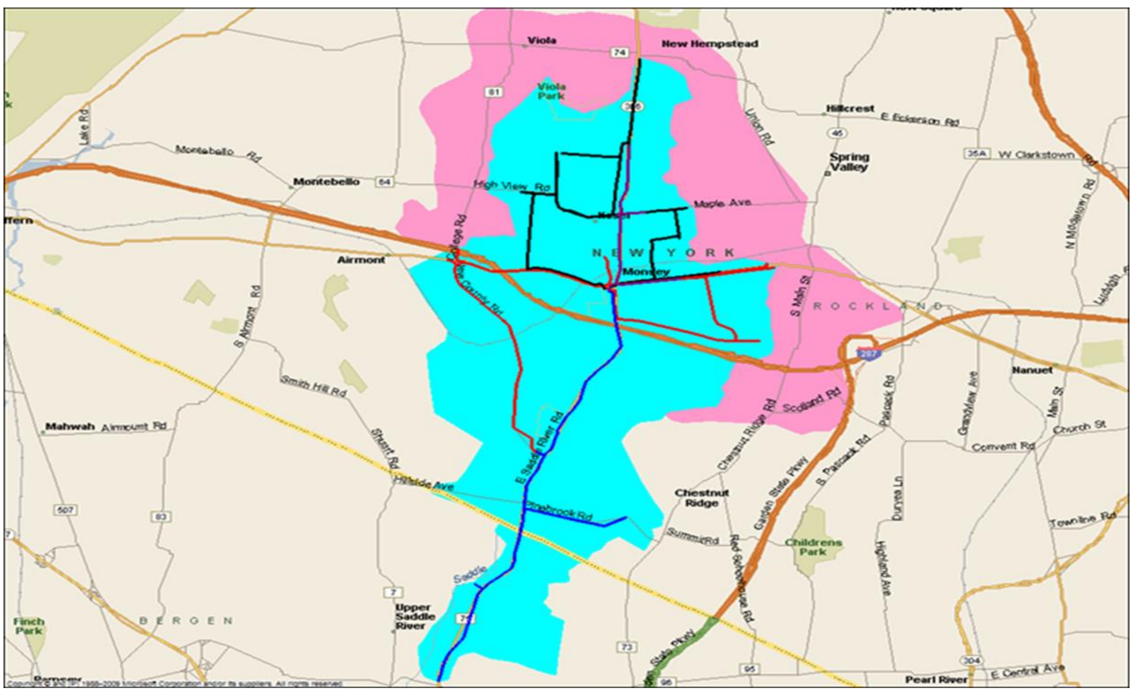
The load growth in the area is currently 0.69 percent and expected to increase significantly within the next few years. In 2016, Bank 144 is projected to be at 8.4 percent above its nameplate (27.1MVA) and 79 percent of its normal rating. By 2018, Bank 144 is projected to be at 10.6 percent above its nameplate (27.65MVA) and 80 percent of its normal rating. In 2016, Bank 244 is projected to be loaded to 15.2 percent above its nameplate (28.8MVA) and 84 percent of its normal rating. By 2018, Bank 244 is projected to be loaded to 17.5 percent above its nameplate (29.38MVA) and 86 percent of its normal rating.

Because the circuits are heavily loaded, in the event of a bank contingency, minimal backup is provided by the remaining bank, and the area will rely on available circuit ties to restore customer load. This further highlights the need to reduce circuit loadings to improve tie capability during contingencies.

Non-Wires Alternative Screening:

Station Improvements would be needed by 2018, and therefore DER should be solicited for 1.7MW to be implemented during the 2016 to 2018 period. To defer the station upgrade further, 3.6MW would be needed by 2021. The significant growth rate may make this area a challenge to substitute the traditional infrastructure upgrades with a NWA solution. This amount of load reduction in the area identified on the map below will provide sufficient capacity reductions to defer the traditional alternative for a two to three year period. With respect to the map below, the Monsey Substation directly serves the blue geographic area serving a total of 9,329 customers. Expanding the load area to include an additional approximately 3,000 customers in the pink shaded geographic region, which encompasses the fringe end of circuits from the adjacent Burns and Tallman Substations, will also assist the Monsey area for circuit contingencies. To the extent that sufficient DER are not in place with confirmed diversified capacity reductions by and through the summer of 2018, the Company will commence execution of its traditional wires solution.

Figure 1-13
Monsey Area



Alternatives:

The Company presently anticipates the traditional wires solution to include the upgrade of the Monsey Substation, which will require the replacement of the two 25MVA transformers with two 50MVA transformers and the addition of four distribution circuits and new switchgear by 2021. The current substation site is being reviewed, and to the extent this site cannot support these upgrades, the traditional solution may require the construction of a new substation in the Monsey area.

Pomona Substation

Risk:

The Pomona area is served by two substations, New Hempstead and West Haverstraw, a mobile transformer (Mobile #3) at the Little Tor substation site, as well as the tail end of two additional circuits from the Tallman and Stony Point substations. These circuits are relatively long at 5.7 miles and 9.3 miles from their stations, respectively. The other circuits that supply the Pomona area are 27-7-13 from West Haverstraw and 45-5-13 from New Hempstead. These circuits are 4.5 miles and 5.4 miles from each station, respectively. The area consists of primarily residential customers.

The New Hempstead Substation was upgraded in 2014 to two 50 MVA – 138/13.2kV transformer banks (Bank 345 and Bank 445) and ten circuit positions. The 2016 weather-adjusted forecasted peak load for Bank 345 and Bank 445 is 34.8 MVA and 37.6 MVA, respectively. With the new larger banks, either bank can carry the entire station load during a bank or bus contingency. The new station also has load tap changers to regulate voltage during normal and contingency conditions. Since 2012, Mobile #3 has been at the Little Tor Substation site serving approximately 8.6 MVA of load at peak time.

The West Haverstraw Substation has two 35 MVA – 138/13.2kVtransformer banks (Bank 127 & Bank 227) and eight circuit positions. The 2016 WAP peak load for Bank 127 and Bank 227 is 31.6 MVA and 21.6 MVA, respectively. For a contingency on either bank at peak time the lost load can be restored using a combination of the remaining bank and adjacent circuit ties.

The 208 acre parcel of land adjacent to the proposed Pomona substation site is planned to house 500 new multi-family units and other retail and commercial development. In addition to this development, much of the surrounding area has been or will be purchased for future development. The future plans for this area may be a very dense community housing and associated support services and facilities. Additional development is also being proposed in the area including several retail stores, including a supermarket, and a large condominium complex.

If significant New Business load growth occurs in this area, it will be difficult to serve from the existing circuits and would negatively impact current circuit performance. Depending on the size and rate of new load growth, it will likely cause the existing circuits to fail the distribution design standard.

Proposed Improvements:

In order to meet the distribution design standards and significantly improve the electric delivery system reliability in this area, this project proposes the installation of a 138kV underground transmission feed, two 50 MVA – 138/13.2kV transformer banks with load tap changers. The project proposes new 13.2 kV switchgear with ten distribution circuit positions. Six circuits are to be used initially and four are provisioned for future use. To help defer the need of the Pomona substation, two of the new circuits from New Hempstead will be used to serve the Pomona area.

Benefits:

The two 13.2 kV transformer banks will provide sufficient capacity for future load growth in the Pomona area and provide relief and improved backup to the New Hempstead, Tallman, West

Haverstraw, and Stony Point substations. The addition of the new substation will significantly reduce exposure (circuit miles) on those circuits greatly improving customer reliability.

The additional capacity and circuits from the new station will permit advanced automation to be installed between the new station and existing distribution ties. This will further improve circuit performance both in storm and non-storm conditions. This type of automation is difficult to install at this time due to existing circuit length and loading. The load tap changers at the new station will provide for optimum voltage control under all load conditions/contingencies and provide better voltage regulation to the local customers.

Non-Wires Alternative Screening:

If the Company achieves a significant amount of load reduction in the Pomona area it could be enough to defer the cost of installing the 138kV line, and other associated substation upgrades that are driven by expected load growth in the Pomona area. The expected cost of these upgrades would be around $65 million. By deferring these costs for up to three years, the present worth savings would be approximately $14 million. The Pomona Program, a non-wires alternative program, was included and approved by the Commission in October 2015 in its Electric Rate Plan Order. The program, which is described further in Beneficial Locations section, may include a combination of DG, DSM, and battery storage to achieve load reduction to defer the substation.

Projects that must be Constructed - Non-Wires Alternatives will not Defer

2016

Blue Lake Station: This is not a deferral candidate because it was an in-flight project at the time of DSIP development. This customer-driven project was energized in May 2016.

Sterling Forest Tap: This is not a deferral candidate because it is an in-flight project with the primary purpose to improve transmission reliability for a 69kV transmission loop that serves seven distribution substations, and an in-service date of late 2016. Non-wires alternatives cannot solve for the reliability need that is provided by the traditional infrastructure solution. The Company has determined that this project must be constructed as a traditional infrastructure solution.

2017

Line 702 Reconductor: This is an in-flight project. This primary need for the project is to bolster the transmission backbone through Rockland County to substantially improve reliability for O&R's entire Eastern Operating Division. It is the first project towards completing a 138kV transmission loop, between the Burns Substation in New York and the Harings Corner Substation in northern New Jersey. There is also high growth rate on the local electric delivery facilities from new and expanding data center loads. Non-wires alternatives cannot solve for the reliability need that is provided by the traditional infrastructure solution. This project also assists the Company to meet FERC/NERC TPL Standards. This project must be constructed as a traditional infrastructure solution.

Deerpark:

Risk:

The 34kV Port Jervis load pocket is served by three sources: Rio Bank 53, Line 10 out of Cuddebackville, and Line 111/Bank 2103 out of Westtown. These three sources feed Port Jervis Bank

26, Rio Circuit 3-1-34, the Line 10 customers along Route 209, and the entire Pike County system (Matamoras Station and Line 7). This is a total of 13,815 customers. At the 2016 system forecasted peak load of 1630 MW, this load pocket is approximately 54 MW. For a contingency on Line 111/Bank 2103 at peak time, the remaining lines (Line 18 and Line 10) would reach their normal rating and circuits would reach their minimum voltage limit. Within the next year or two, this contingency at peak time will require load shedding.

Original plans were to install four transformers (two 69/34.5kV banks and two 69/13.2kV banks) at the Port Jervis Substation site. The 13kV banks would provide service and backup for the local distribution while the two 34kV transformers would provide primary/backup for the local 34.5kV system. However, construction challenges and lack of space at Port Jervis required that the 13kV distribution banks be installed at Port Jervis and the 34kV banks be installed at Deerpark.

At the end of 2013, a failure on Rio Bank 53 left two sources to feed the Port Jervis load pocket. Due to local terrain and bridge limitations, the Company could not transport a bank of the same size to the location of the Rio bank and had to replace it with a smaller transformer. Although Line 18 was still the limiting element of the bank's summer normal rating, the smaller bank limited the LTE rating of Line 18 throughout the year. Due to this, the load in the Port Jervis pocket exceeds the combined rating of the two remaining sources under single contingency conditions for extended periods of the year.

In order to provide load relief for the 34kV load pocket, a 69kV line was energized from Westtown to feed a 69/13.2kV mobile at the Deerpark site. The mobile (Mobile #6) at the Deerpark site provides relief and backup for Port Jervis Circuit 6-8-13, Port Jervis Bank 26, and the Port Jervis load pocket. Port Jervis Circuit 6-8-13 is a very long and exposed circuit serving over 3,100 customers and has been the second worst performing circuit for the last two years. The relief to the 34kV Port Jervis load pocket (7MW) allows the smaller Rio bank to be capable of covering any single contingency until the permanent solution (*i.e.*, the construction of the Deerpark Station) is completed.

This project proposes the installation of two 50MVA, 69/34.5kV transformer banks with load tap changers and a 34.5kV switchgear lineup with four circuit positions (two for each bank). The project will also include a 35MVA 69/13.2kV bank with a single overhead circuit exit that will assume the existing Mobile #6 circuit load.

Transmission Lines 111 and 14 will form a temporary 69kV loop at the Deerpark site. When the Port Jervis Substation project is completed, Line 14 will simply extend in and out at the Deerpark Station and the 69kV loop will be completed at Port Jervis.

When the Port Jervis upgrade is completed, this will significantly reduce contingency exposure in the load pocket. Constructing the Deerpark Station will eliminate a single bus contingency from losing two banks (a single 34kV bank and a single 13kV bank), which will significantly reduce exposure and improve reliability.

Along with the closed 69kV transmission loop, which will improve transmission reliability, the Deerpark Station will provide a strong source with which to maintain local area reliability while the Port Jervis Substation is being upgraded. The two 34kV Deerpark banks will unload the 34kV bus at Port Jervis and serve the local area 34kV system, while the 69/13kV Deerpark bank will assist in the unloading of Port Jervis Bank 26.

Additionally, the 69/34.5kV 50 MVA Deerpark banks will split the load/exposure on Circuit 5-10-34, which is the twelfth worst performing circuit. This will reduce the exposure and load on the circuit, which will allow Deerpark to provide a stronger backup for Cuddebackville Bank 15 in the event of a bank failure at peak time.

NWA Screening:

This is an in-flight project for which the Company has already obtained municipal approvals and purchased certain equipment. More importantly, as described in detail above, this project is required to improve both distribution and transmission system reliability. It is also required to accommodate the Port Jervis Substation Upgrade, as the existing station must be completely removed from service for more than a year to accommodate the new construction plan required (see more information in the Port Jervis project section with respect to the area reliability issues and project needs). NWA solutions do not address these project drivers. The Deerpark Substation project is scheduled to be in service in 2017. Even if NWA solutions were appropriate to address the project drivers, the required in-service date is too close to attain and implement meaningful NWA solutions. As such, the Company has determined that NWA solutions are not appropriate to defer this project, and the Deerpark Substation must be constructed as a traditional infrastructure solution.

2018 to 2020 Projects (in order of risk)

North Rockland Substation

Risk:

The purpose of this project is to improve transmission reliability for the Company's entire Eastern Division. Since the closing of the Lovett Generating Plant, several projects were identified that are required to maintain reliability to levels that were in place prior to the Generation retirement. These projects were the reconductor of Transmission Line 60, the addition of several substation capacitor banks in the Eastern Division, and the installation of a new 345-138kV source in the northern portion of Rockland County. The first two have been completed and are in-service, and the final project is the North Rockland Substation. Additionally, the NYISO through the reliability needs assessment ("RNA") study process has identified that a contingency on a Line 67/Line 68 structure would trip two 345/138kV sources into the O&R system, and leave only the recently re-conductored 138kV Line 60 and 69kV Line 652 to serve approximately 52 percent of the Company's entire system load. At peak time, this contingency would require significant load shedding (approximately 270MW and over 40,600 customers) to reduce the resultant line overloading to within acceptable operating ratings.

NWA Screening:

Even though non-traditional solutions cannot solve for the project drivers, in 2010, an NWA study was prepared and determined that such alternatives could not defer the North Rockland Substation. Since this contingency already caused the need to shed significant load to keep the remaining lines from exceeding their LTE ratings, the amount of capacity required to defer the project would be even more than 300MW to account for redundancy. Based on the substantial amount of capacity required for deferral, the NYISO RNA requirement to construct the project for regional reliability assessment needs, and the fact the NWA measures cannot solve for the reliability need that the traditional infrastructure investment provides, this project cannot be deferred by NWA's and must be constructed as a traditional infrastructure solution.

West Nyack 138kV Bus/Harings Corner 138kV Bus/Line 701

Risk:

The primary purpose of these three projects is to continue to transmission system backbone upgrade described in the Line 702 project to fortify and expand the 138kV transmission system capacity and reliability in the Eastern Division for both Rockland County and Bergen County. These projects will reduce the 69kV load pocket, improve transmission losses, and the larger transformers at both West Nyack and Harings Corner will improve reliability for their respective areas. Although each project provides individual benefits, the combination of all three projects are complementary and is required to provide the needed solution. 2016 area load growth of 0.87 percent coupled with contingencies on the 138kV transmission system would force significant overloads onto the 69kV system. As discussed in the Line 702 project discussion, these projects assist the Company to meet FERC/NERC TPL Standards. Non-wires alternatives cannot solve for the reliability need that is provided by the traditional infrastructure solution. As a result, the Company has determined that these projects must be constructed.

NWA Screening:

This project was removed from NWA consideration upon the initial screening step in O&R's integrated planning process. This project is for transmission reliability and to assist in meeting FERC/NERC TPL standards.

West Warwick Substation

Risk:

The Warwick Area is presently served by the Wisner Substation. The station is located at the extreme eastern end of the load area it serves, which is approximately 59 square miles and contains approximately 8,000 customers. The Wisner station is served by two 69kV transmission lines: one from Sugarloaf and one from Hunt. Without transmission breakers to protect the station, in the event of a contingency on either line the entire station is out of service until the line can be sectionalized and the unfaulted line portions restored. The Wisner Substation contains two 25MVA 69/13.2kV transformers without load tap changers that feed five distribution circuits. There is no automatic transfer scheme between the two banks, therefore the load cannot be assumed by the remaining bank until field personnel arrive to switch. Due to switching time and forecasted load growth, a contingency on Bank 280 at peak time in 2019 would cause approximately 18,000 customer-hours of interruption. With both banks being fed from the same 69kV bus, a single contingency on this bus would force both banks out of service. At peak time, less than 30 percent of the entire station load could be restored through distribution circuit ties. This would leave over 5,800 customers out of service and approximately 20.2 MW of load out of service until repairs were affected. The circuits are very long with high exposure and with multiple spurs, which results in the circuits averaging over 35 circuit-miles each. To meet the Distribution Design Standards and provide 100 percent backup in the event of a circuit contingency, multiple switching moves are necessary due to the circuit loads and in order to prevent voltage problems on the long circuits. Four of the distribution circuits presently do not meet the design standards. The construction of this station continues to be delayed while the Company obtains appropriate ROW to construct the transmission feeds to the new substation.

Example:

On December 13, 2010, an incident occurred at the Wisner Station that affected 7,907 customers. The customers were out for 1,552,637 customer minutes which resulted to an incident CAIDI of 196.4 minutes.

NWA Screening:

Distribution projects are being constructed to prepare the paths of the West Warwick circuits, however they simply improve switching capability for circuit contingency conditions. This does not improve capacity of the circuits, reduce circuit exposure, or improve conditions for the Wisner Substation bank or bus contingencies. The Wisner area fails the Company distribution design standards. The Wisner Station also has numerous operating issues that affect reliability such as M.A.D. issues, a bus switch that limits the capability of the bank, no load tap changer on either bank, no transmission breakers to protect the station from a momentary interruption on the transmission lines, no bus tie breaker (only a switch), and both distribution banks are fed from the same 69kV bus. A combination of all these issues has made this a poor reliability operating area. As a result of the project drivers requiring large amount of capacity required for NWA deferral (approximately 31MW) that would have to be dispersed in specific quantities in numerous locations across the area, in combination with the substantial reliability and operating issues identified, this solution cannot be addressed by NWA alternatives. As a result, the Company has determined that this project must be constructed as a traditional infrastructure solution.

LINE 6 to 69kV Bullville to Washington Heights

Risk:

This project is required to improve reliability and resiliency for the western portion of the Company's Northern Division transmission system and its interconnected substations. The purpose of this project is to construct a fourth source into the Northern 34kV load pocket and it will be the first step of upgrading the existing loop system to 69kV to improve reliability for the area. The Northern Load Pocket is currently served from three 34kV sources (Line 6 out of Shoemaker, Line 3 out of Cuddebackville, and Circuit 109-4-34 out of Washington Heights). These lines not only serve four distribution substations, they also directly serve distributed load along their path. These lines are extremely long, have high exposure along primary vehicular thoroughfares, and are perennially at the top of the Company worst performing circuit lists. A contingency on any of the lines at peak time results in capacity and operating voltage issues, and extends operating exposure to an unacceptable level of risk.

This project has already been delayed for approximately ten years, through the implementation of lower cost distribution projects and distribution automation. These measures have maintained appropriate backup for contingency conditions in the area, minimized risk while higher priority projects were/are constructed, and resulted in significant savings to customers. At this point the need for the project cannot be further deferred past the proposed in-service date of 2019.

NWA Screening:

This project was removed from NWA consideration upon the initial screening step in O&R integrated planning process. The primary need for this project is transmission reliability and reducing system exposure. Non-wires alternatives cannot address the project needs and drivers that are solved by the traditional infrastructure solution.

Blooming Grove Station Upgrade

Risk:

The Blooming Grove Substation is currently a single bank substation with a 25MVA 69/13.2kV transformer. The substation serves approximately 6,600 customers in an area at the extreme northern end of O&R's service territory. The 69kV Blooming Grove substation is on a radial transmission feed (Line 96) from Monroe with restricted available transmission switchable backup from Central Hudson's limited capacity WM tie Line. The need for this station upgrade was identified in 2005. Due to load growth and limited backup, two circuits failed the Distribution Design Standards and were in the top 20 worst performing circuits. In order to defer the station upgrade, a fourth distribution circuit was added to provide load relief and backup for the existing circuits in 2009 and has allowed all the circuits to pass the design standards. The single-bank station only has two extremely long distribution ties to adjacent stations. Therefore, in the event of a bank contingency currently, approximately 48 percent of the area load would be out of service until a mobile transformer is installed, resulting in 87,700 customer-hours of interruption, which makes the bank fail the Distribution Design Standards.

Example:

On May 12, 2007, an incident occurred at the Blooming Grove Station that affected 5,795 customers. The customers were out for 644,320 customer minutes which resulted to an incident CAIDI of 111.2. Similarly, an incident occurred on May 31, 2015 that affected 5,399 customers. The customers were out for 488,523 customer minutes which resulted to an incident CAIDI of 90.5.

NWA Screening:

Approximately 10MW of NWA capacity or load reduction is required to address the capacity deficit to meet design standards. Based on the significant cost to install the required NWA alternatives with respect to the traditional infrastructure cost, in addition to the improved circuit availability and tie capability to improve reliability for circuit contingencies, this project was determined not to be an appropriate candidate for a NWA solutions.

A smaller DER solution will be investigated for the Washingtonville area that can potentially defer a series of smaller distribution projects, which will provide an additional source to the area and assist in meeting the distribution circuit design standards until the station is constructed.

Port Jervis Upgrade

Risk:

This is an in-flight project for which the Company has obtained municipal approvals and purchased materials. The Port Jervis Substation, located at the extreme western end of the Company's service territory, serves a single 13kV distribution bank and a feed to the local 34.5kV system.

The Port Jervis Substation was originally identified for upgrade in 2000. At that time, the station served an isolated 13kV load pocket with backup only to small portions of the tail-end of the circuits from step transformers off the 34kV system, and from a capacity limited 20-mile 13kV distribution tie to Shoemaker (Middletown). With plans to upgrade Port Jervis, other improvements had to be made first in order to provide a 69kV source and locations to unload the Port Jervis Substation for construction since extremely restricted backup existed.

A number of infrastructure upgrades were implemented to allow the Company to continue to meet design standards and defer the Port Jervis Substation. In 2003, the 34kV Line 11 from Shoemaker to Westtown (half way to Port Jervis) was upgraded to 69kV and a second line (Line 14) was installed. A mobile transformer was installed at the proposed Westtown site to assist in serving load and to address contingency conditions.

In 2005, the Westtown Substation was constructed to provide load relief and backup for the Port Jervis Substation. Likewise, the Matamoras Station was constructed, which also provided backup for Port Jervis and allowed the construction of the second part of Line 11/Line 14 from Westtown to Port Jervis. The backup for these two stations allowed Port Jervis to meet the Distribution Design Standards until 2011.

The Company's revision of its Distribution Design Standards in 2012 increased the allowable number of customer-hours of interruption, which allowed Port Jervis Bank 26 to pass design standards for a number of additional years.

The Port Jervis Load Pocket is served by Rio Bank 53, Cuddebackville Line 10, and Westtown Bank 2103 (Line 111). The load pocket includes the customers served by the 13kV Port Jervis bank, distributed load off the 34kV Line 10 along Route 209, and the customers on Rio Circuit 3-1-34. At the end of 2013, a failed 35 MVA Rio Bank 53 was replaced with an 18 MVA transformer due to the cost, weight and difficulty of transporting a replacement 35MVA bank to Rio and over a damaged bridge to the site. In order to allow the 18MVA bank to cover all contingencies of the 34kV load pocket for peak period, a mobile transformer was installed off a 69kV transmission line (Line 14) at the Deerpark site to feed a portion of a Port Jervis circuit and reduce the load pocket. Along with the reduced cost for replacing Bank 53, this solution provided load relief for a heavily-loaded Port Jervis circuit (Circuit 6-8-13) and bank (Bank 26), as well as limited backup for the area.

The single 13.2kV 20MVA transformer (Bank 26) serves three distribution circuits, was forecasted to peak at 20.6 MVA, and does not have an LTC. Besides the non-LTC transformer, which results in operating issues on the extremely long exposure distribution circuits, the older station design and equipment limit the emergency rating of the bank are approaching their end of life, and there are several minimum approach distance issues that that require the station to be de-energized for maintenance. The existing three distribution circuits serve almost 7,000 customers along two extremely long and high exposure circuit paths with long radial spurs off them, causing them to perennially be two of the worst performing distribution circuits for the Company.

NWA Screening:

As a result of the poor reliability issues in the Port Jervis area, the substantial operating and maintenance issues, and the prior deferral of this project for over 15 years are pushing the existing assets closer to their end of life, the Company has determined that this project is not an appropriate candidate for NWA deferral. NWA solutions cannot address the project drivers, and thus the traditional infrastructure project must be constructed.

Little Tor

Risk:

This is an in-flight project for which the Company has already spent over eight years in the municipal approval process and purchased materials. It has also placed a mobile transformer in service at the proposed substation site for the past three years in order to serve the area load demand under normal operating conditions.

The New City area is located between the New Hempstead, Congers, and West Haverstraw Substations. These three substations and the temporary mobile transformer at the Little Tor site serve a combined total of approximately 35,807 customers and 187 MVA of load at peak time. Approximately 45 percent of this load is supplied from the New Hempstead Substation and the Little Tor mobile transformer. In 2014, the New Hempstead Substation was upgraded to two 50MVA, 138kV to 13.2kV transformer banks. In addition, the number of circuit positions was increased from eight to ten. New Hempstead Circuits 45-3-13 & 45-8-13 continue to operate at or above their relief rating (480 Amps) and require cascade switching to provide backup at peak time, which forces both circuits to no longer meet the Distribution Design Standards.

The Congers Substation has two 35MVA, 138kV to 13.2kV transformer banks. Due to the relief and backup provided by the mobile transformer at the Little Tor site, all of the Congers circuits have 100 percent backup for an individual circuit contingency. However the mobile is a temporary solution and its eventual removal would cause some of the Congers and New Hempstead circuits to fail the distribution design standards.

The West Haverstraw Substation has two 35MVA, 138kV to 13.2 kV transformer banks. The substation supplies a total of eight circuits (four from each bank). Circuit 27-2-13 supplies 2,416 customers including a 13.2/34.5kV transformer that feeds a dedicated overhead line to a single customer (Tilcon). This overhead line travels south along the transmission ROW approximately 7,000 feet from West Haverstraw to the Little Tor substation site. At this point, the line continues east an additional 19,000 feet to the customer. Due to the length and route that this circuit takes, it has a high exposure to tree contacts and other reliability issues. These outages affect the electric service to Tilcon and increase the number of momentary outages other customers on the circuit experience. In the event of a contingency on Circuit 27-2-13, there is not enough available capacity to cover 100 percent of the circuit's load. Therefore, Circuit 27-2-13 does not meet the Distribution Design Standards.

The Little Tor Station continues to be required to allow the New Hempstead, Congers, and West Haverstraw Substations to meet the Distribution Design Standards, and could also assist in helping to defer the Pomona Substation project.

NWA Screening:

This is an in-flight project that the Company has already expended considerable time, effort and cost. In addition significant area reliability issues exist and will exacerbate with the removal of the mobile, which cannot remain in permanent service. As a result, the Company had determined this is not an appropriate candidate for NWA deferral. Even though the Company has determined that deferral is not an appropriate option for this project, a revised screening analysis was performed after the construction of the New Hempstead Substation to review the potential for NWA deferral. The screening analysis concluded that due to the substantial area reliability issues that still exist, the high amount of capacity reduction needed for deferral (approximately 13 MW spread across four different locations) and the low substation costs relative to the potential cost of the NWA deferral measures, this project is not appropriate for NWA deferral and should be constructed.

Line 51 upgrade

Risk:

Line 51 is a 138 kV line that emanates from the Ramapo Substation (New York) and terminates at the South Mahwah Substation in New Jersey. Although the majority of its five-mile stretch consists of 1033.5 MCM ACSR, the limiting element is a 900 foot section of 795 MCM ACSR just outside of the Ramapo Substation. Recent summer studies indicated that a contingency on South Mahwah 345/138 kV Bank 258 will load Line 51 above its LTE rating. This situation will worsen with time as the load in the area continues to escalate.

This project proposes to replace the existing overhead 795 MCM ACSR portion of Line 51 with an underground transmission system increasing its thermal ratings by approximately 20 percent. Placement of this portion of line 51 underground will also eliminate two crossings of Line 51 over transmission Lines 52 and 60 in this area, thereby reducing the exposure to a triple circuit transmission outage. The increase in thermal ratings will make its operation more reliable at system peak even during emergency conditions for the foreseeable future.

NWA Screening:

This project is required for reliability improvement required by changes in construction configuration. NWA solutions do not address the project drivers. Therefore, O&R's screening process eliminated this project from NWA consideration and this project must be constructed as a traditional infrastructure solution.

Swinging Bridge

Risk:

The Swinging Bridge Substation is a 69kV single-bank distribution station. The station is served by a radial 69kV line (Line 9), as well as two hydro generators. The two generators (approximately 11MW), which are owned and operated by Eagle Creek, feed into two separate 4.16kV busses that step up into the 69kV bus where they meet Line 9 to feed into the system. Also at this point, a 2.5MVA 69/13.2kV non-LTC distribution bank (Bank 41) is located to serve minimal local load. Bank 41 only peaked at 30kW in 2015 and has a 2016 WAP forecasted peak of 30kW.

The Mongaup Substation is a single-bank distribution station with a 7.5 MVA 69/13.2 kV transformer (Bank 12) that feeds one radial distribution circuit. This 1950 vintage transformer has a load tap changer (LTC) to maintain adequate voltage for this long radial circuit. Although the 2015 actual peak for Bank 12 was only 1.0MVA, and the 2016 weather-adjusted forecasted peak is 1.3MVA, and the circuit peaks below 100Amps, both the radial circuit/bank fail design standards due to no backup in the event of a failure on the respective device at any time of year. Although a 69/13.2kV mobile can be installed (Mobile #1) to cover a bank contingency, it's extremely difficult due to the geography and terrain and typically not cost-effective to transfer a mobile to this remote location, and then to tap to Line 9 and Circuit 2-1-13 to restore 630 customers. The historical load growth for the Mongaup area has been very low (0.1 percent), but potential for a large 2400 lot development (Lost Lake) has been discussed near the Town of Thompson/Town of Forestburg border. Therefore, it is much more important to provide backup for Mongaup Bank 12 closer to the load; this solution could be provided by Swinging Bridge.

This project proposes the installation of a 13kV UG Circuit Exit along the path of the transmission ROW from the Swinging Bridge Station to County Route 43. Along with distribution projects along CR43, the 13kV UG Circuit Exit out of Swinging Bridge will utilize the existing capacity at Swinging Bridge Bank 41 and provide 100 percent backup for Mongaup Bank 12 and circuit 2-1-13, as well as portions of Rio Circuit 3-1-34/13 year round.

NWA Screening:

Both Mongaup Bank 12 and Circuit 2-1-13 are radial fed. Therefore, no matter how much NWA solutions are applied to the Mongaup sources they will remain radial fed and no benefit will be gained. This project is reliability driven. Swinging Bridge will provide 100 percent backup for Mongaup from another source that is not currently present. As a result, NWA's are not viable for this project and the traditional infrastructure solution must be constructed.

Areas with Large Budgetary Changes

The Commission approved the Company's current electric rate plan with the Electric Rate Plan Order. With respect to traditional infrastructure investment projects, large budgetary changes from the Company's current electric rate plan, due to implementation of DSIP related projects, are not anticipated. O&R currently expects to file its next electric base rate case, with updated budgets, in November 2016. The Company expects that such filing will include budgetary changes that reflect investments that will be necessary for the Company to expand it capabilities to perform as the DSP.

Identify Beneficial Locations for DER Deployment

The value of DER to the electric distribution system, and ultimately the customer, depends on DER's location on the grid. Also, the duration, timing, and quality of service provided by DER factors significantly into the benefits they provide. Based on its technology, attributes, location, and operation, DER may have net benefits or net costs to the electric system. To rely on DER as part of the planned-and-operated local distribution grid, the Company will need to have programs and/or procurement approaches intended to lead to DER with particular attributes, scales, and locations on the grid. The JU, along with DPS Staff and other stakeholders, are currently engaged in determining the benefit/cost concepts for evaluating when and where DER installations might provide value to the distribution system through the Locational Marginal Price plus the Value of Distribution ("LMP+D") methodology, and other initiatives such as improved planning and hosting capacity methodologies and processes.

An opportunity for great value resides with the ability of a particular DER technology and/or application (or a portfolio of DER) to defer specific distribution-system upgrades, and to do so with the same degree of necessary reliability and/or functionality afforded by traditional distribution investments. O&R implements an integrated planning process and methodology whereby it not only reviews and identifies traditional infrastructure projects, but the Company also screens and reviews these major capital investment projects with respect to targeted non-traditional alternative DER measures. See the Delivery Infrastructure Capital Investment Plans section of this Chapter.

NWA Suitability Criteria

The design and implementation of the DER sourcing processes will continue to evolve as experience is gained from demonstration projects and as utilities begin to incorporate NWAs as a routine aspect of distribution system planning. A major component of this evolution is the development of suitability criteria that can help utilities identify NWAs with the best chance of success in a competitive procurement process. These criteria represent the initial high level principles that will serve as the starting point for the development of proposed NWA suitability criteria to be included in the JU's forthcoming Supplemental DSIP filing.

The application of suitability criteria for NWAs can help utilities identify projects where DER solutions have the greatest chance of successfully deferring or eliminating the need for traditional grid infrastructure. To the extent the criteria target those projects where DER have the greatest chance of providing comparable value and being chosen in a competitive solicitation, they can help make the DER procurement process more efficient and cost-effective for utilities and market participants. In addition, the criteria would provide DER developers with greater clarity, certainty and long-term visibility to the market and help avoid misallocation of time and resources for both developers and utilities. As these criteria are incorporated into planning processes, they will provide a means by which DER procurement can become a routine aspect of system planning.

In designing the NWA suitability criteria, it is important that they not be overly restrictive, such that the criteria eliminate potentially valuable projects. Also, the criteria should be sufficiently adaptive to allow utilities to incorporate experience gained with DER procurement and respond to changing cost structures and market conditions. Additionally, the criteria should reflect stakeholder input and experience. To that end, the JU has launched a stakeholder engagement process in conjunction with the preparation of the Supplemental DSIP filing that will solicit input from stakeholders on the NWA suitability criteria described below.

NWA suitability criteria captures the various dimensions of project characteristics that influence the ability of the project to defer or avoid traditional utility infrastructure. These include (1) the type of work and category of project, (2) the lead time of the project relative to the need date on the system, and (3) the cost structure of the project.

Type of Work

The type of work places the project into broad categories of utility projects that can help bound their overall suitability. For example, to the extent that capacity concerns (thermal load, voltage, power quality) represent a large share of projects with high potential for DER solicitation, projects in this category would have a relatively high project applicability. Reliability work to put in place system enhancements to mitigate interruption risk might be difficult to displace, but reliability projects that mitigate outage impacts could be well suited to DER. New business might be a great opportunity for DER to work with customers directly prior to issuance of their load letter rather than addressing capacity issues through a NWA solicitation. Therefore, in the context of NWA suitability, the project applicability for new business projects might be relatively low despite fruitful opportunities for DERs to participate in other avenues.

In some cases, the type of work does not lend itself to procurement of DER. In the case of planned repairs or replacements of existing infrastructure, the ability of NWAs to displace the utility solution must include the repair or replacement of the asset or otherwise obviate the need for the asset altogether. To the extent that asset condition upgrades are needed to maintain safety and reliability of the system, this type of work will likely need to meet a very high standard of availability and performance and, therefore, might have a relatively low project applicability with respect to NWAs. The same could be said for damage failure repairs that must be addressed under extremely short timeframes, as well as non-T&D infrastructure such as telecommunications, tools, and systems.

Lead Time Required

For a NWA project to be successful from a timing perspective, the DER must be able to be procured and implemented prior to when a solution is needed on the system. The time needed to design and implement a competitive solicitation will depend on the scale and complexity of the project. This includes the time needed to produce the Request for Proposal (“RFP”), collect proposals, review bids, undertake purchasing processes, secure board approval, and contract with the winning bidder(s). The DER solicitation time is typically 10 to 20 months based on recent NWA experience. The timeframe for the implementation of the solution is also a function of scale and complexity, and is typically in the range of 20 to 40 months. Therefore, based on recent experience, the minimum amount of lead time required is typically 30 to 60 months in advance of when it is needed on the system. Additional experience conducting competitive solicitations for DER and implementing NWA solutions can help to achieve greater efficiencies. Therefore, the lead time criteria should be updated regularly to reflect current experience.

Cost Structure

Finally, the cost of the utility project will have an impact on its suitability for a DER solicitation. In some cases, a utility solution might be available at such a low cost that it would not be efficient or cost effective to carry out a competitive solicitation for DER to meet the need. The cost used as a threshold should be set so that it does not overly restrict project suitability for NWA consideration. It could perhaps be implemented as a guidance criteria in parallel with the type of work considerations described above as opposed to a bright line test. The specific design and implementation of these criteria will continue to evolve and the input provided by the stakeholder engagement groups will help to inform the JU's development of these concepts.

Information Necessary for NWA Solutions

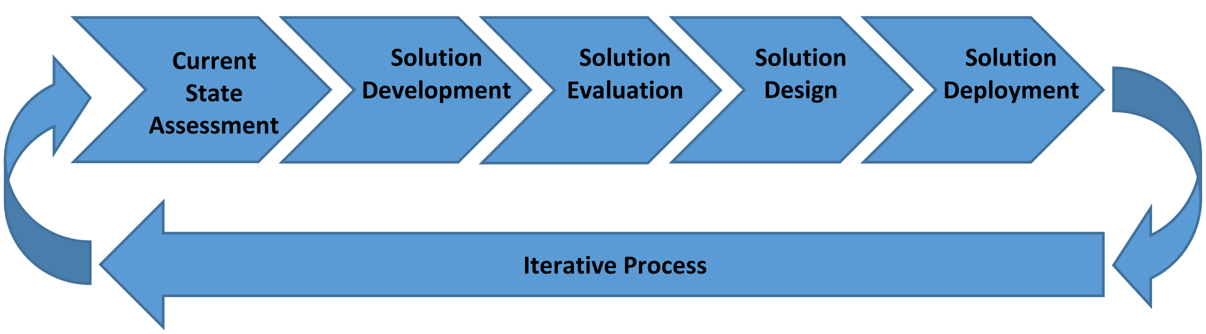
In order for a NWA project to be successful, DER must provide specific load reductions at the appropriate time, both hourly and seasonally. The Company will develop the required load reduction curve for each NWA which will illustrate the load needed to be reduced based on the peak day hourly profile. This curve will allow DER providers to match DER output with the hourly requirement so that the load is being matched at the appropriate time. In addition, an area map will also be prepared to show the target areas for the DER deployment.

As per the Track Two Order, "Until platform markets are fully developed, distinct NWA projects are a means by which third-party investment can be integrated with utility systems to improve efficiency and reduce bills. As we did in the BQDM proceeding, we expect to approve NWA projects that will result in customer savings, with earnings opportunities for utilities that are commensurate with or superior to earnings that can be achieved through traditional investments."[36] Prior to releasing the NWA load and location information to the NWA development process, the Company will apply to the Commission for earning incentives for the NWA.

NWA Development Process

Once DER is identified as a potential solution to traditional utility infrastructure development, the Company will utilize a Portfolio Development Process similar to the one shown in Figure 1-14 to develop a set of DER solutions. The Company will iteratively execute the Portfolio Development Process to assess the current state and develop and deploy new solutions if cost beneficial and if it is determined to be favorable when compared to traditional infrastructure solution(s). Through this process, the Company seeks to encourage an expanding robust and diverse DER marketplace that facilitates DER provider participation to take advantage of the REV Proceeding's outcomes and knowledge gained from on-going REV demonstration projects.

Figure 1-14



DER Program Portfolio Development Process

[36] REV Proceeding, Track Two Order, pp. 46-47.

The Company will gather and evaluate information on DER solution sets targeted to reduce peak load. This will be accomplished through a RFI process and engagement with Staff and other stakeholders. This will be in addition to the on-going evaluation of the Company's current DSM programs and current and planned REV Demonstration projects.

Through the RFI process, the Company will receive a range of existing and emerging technology solutions and gain insight into prevailing prices and the state of the marketplace. Solutions obtained from previous RFI processes (*e.g.*, Pomona Program) have included Energy Efficiency, Energy Storage, Demand Response, solar, microgrid, gas and co-generation, and grid management/optimization. Some of the solutions offered included a mixture of the above resources. The Company will employ this RFI process, as necessary, throughout a NWA program lifecycle which will be dependent on the outcomes of current state reviews, the advancement of technology, and an assessment of the sufficiency of the current set of solutions.

Once RFI responses are received, the Company will use an Evaluation Committee to assess potential peak load reduction solutions and develop a portfolio of solutions. The Evaluation Committee will evaluate proposals with the objective of identifying an aggregate of solutions that provide the most optimal and cost-effective means to achieve the needed peak load reduction in accordance with the Company's BCA handbook. Refinement of the Company's established DSM programs and benefits from O&R's REV demonstration projects will be evaluated as part of the solution set. Evaluation criteria will include, but are not be limited to:

1. Viability - the extent to which the proposed solution would address the capacity deferral and resiliency needs of the program area;
2. Functionality - the extent to which the proposed solution would provide the needed demand reductions;
3. Environmental and community impacts associated with the proposed solution;
4. Cost-effectiveness of the proposed solution;
5. Timeliness - the ability to meet O&R's schedule and project deployment requirements;
6. Reliability, particularly as compared to other proposed solutions; and
7. Applicability to REV- supports the objectives and criteria of REV.

Each potential solution selected by the Evaluation Committee will undergo a design and development process. These processes may be coordinated with customers, the community, and stakeholders. Performance standards based on measurement and verification protocols developed by the Company and in consultation with outside experts, where appropriate, will be included in the design of all solutions.

The installation of AMI will also inform the options available to these types of programs. AMI will provide a foundation of information and communications capabilities that will enable the collection of more granular data. The information derived from these data will lead to a better understanding of the need and timing for a specific NWA. More granular data will also contribute to the effectiveness of the portfolio of solutions and provide the flexibility to better tailor the solutions to specific times, levels of reduction, and customer types.

The solution deployment will be processed through O&R's standard procurement process. As appropriate, the Company intends to conduct solicitation through a RFP or tariff. The Company expects the solution deployment to be a continuous process. The various solutions may be solicited, designed and deployed in stages as well as tiered over the program timeline. This will enable progressive assessment of solution effectiveness and the ability to modify solutions, as required. This ongoing process will continue to be necessary and tied to the planning and forecasting process to determine if the area needs are still being met cost-effectively or if the Company must proceed with the traditional infrastructure solution, or a combination thereof.

The DER Development and RFI/RFP procurement process described above will be a new and substantially incremental workload for the O&R. In addition to changing and expanding some responsibilities for existing employees in some of the Evaluation Committee organizations, the Company envisions that new and dedicated resources will also be needed to implement a new organizational structure that will have the overall responsibility for the application, analysis, and implementation of this process and associated NWA and DER procurement programs. These new and dedicated employee resources will prepare the RFI and RFP packages, as well as evaluate the submitted proposals for NWAs. These roles will be fulfilled by procurement specialists and subject matter experts ("SME") familiar with the different types of DER, interconnection, planning and the intricacies of the distribution system in order to accurately evaluate the DER benefit. The Company's intended use of these new resources in coordination with existing SME personnel to perform these new functions will allow the Company the ability to establish a portfolio of solutions which will meet the time varying demand profiles and generate a database of costs associated with each type of solution to further enhance the iterative Portfolio Development Process. The Company will then prepare the RFPs for the identified solution types, taking into account the required performance for the selected solutions and then assuring compliance with the prepared specifications developed with the RFP.

Beneficial Locations

Infrastructure Deferral

The Delivery Infrastructure Capital Investment Plans section of this Chapter lists the major capital investment projects that are currently planned for implementation. These project descriptions also include the results of the current O&R DER screening process. This process uses present worth value to determine if DER is a cost effective substitute to the proposed traditional utility infrastructure improvement. In addition, DER can only be used as a deferral if all of the following conditions apply: (a) DER capacity in the correct amount is certain to be available at the time of the relevant circuit or substation transformer peak (capacity need); (b) the DER is connected at the correct locations; and (c) the DER is controlled or managed to avoid any unavailability that could affect reliability or safety. With respect to meeting the required system capacity, the DER solutions must be configured to meet the time varying load profile associated with the required load reduction. For example, if solar is used as part of a solution and is sized to meet the peak demand, the solar output must also produce the required capacity reductions simultaneously with, and for the duration of the peak demand. If not, then an additional or alternate solution must be examined to meet this demand.

Currently, the integrated planning process has identified three areas in the O&R service territory that have the potential for a DER solution to defer capital investments. These include the previously discussed Pomona Program, the NWA proposal filed with the PSC in May 2015 for Monsey, NY,[37] and a

[37] REV Proceeding, OR NWA Monsey, (dated May 1, 2015).

newly identified opportunity in Wurtsboro, NY. As mentioned in the Executive Summary, the RFI process is currently in progress for Pomona with a variety of DER solutions under consideration to satisfy the reduction for the established load profile. The required reductions in the peak load profiles for both the Monsey and Wurtsboro areas are being developed. Once developed, the RFI process will be initiated and solutions considered to meet the necessary load reductions. In order for the DER solution will have the desired effect, the amount of peak reduction achieved must be matched with the time varying load profile, and the solutions must prove to contain equal reliability and redundancy to the traditional infrastructure alternative.

Operational Benefits

As previously mentioned, the greatest benefit from DER deployment is in the area of capital deferral, however, operational benefits are also a consideration. O&R's distribution design standards for a single circuit contingency requires that 100 percent of its peak load be restored from adjacent circuits within one hour using a maximum of four switching operations. A circuit contingency analysis provides a basis for identifying areas where DER has the potential to provide backup during circuit contingencies. Many of these conditions are solved using traditional capital improvements, but are screened for DER when the need is identified. O&R also performs post-summer operating reviews which have the potential of identifying areas that may require additional voltage support or experience reliability issues. Through the contingency and post-summer reviews O&R has identified two areas where DER may provide solutions for these types of conditions. These areas are in Woodbury and Washingtonville. Since these needs are based on contingency conditions, additional analysis is required to determine how DER could be evaluated and valued as a solution. This type of situation complicates the determination of the DER value to the system since it is not necessarily deferral based.

BCA Handbook Integration

It is O&R's intent to integrate the methodologies outlined in the BCA Handbook with its current DER screening process. The BCA Handbook enables the careful comparison of the value of the benefits obtained through a potential project or action with respect to the costs incurred effectuating that project or action, generally considered through the systematic quantification of the net present value of the project or action under consideration. This will allow proposed DER solutions to be compared to traditional utility solutions based on benefits to O&R, the customer, as well as to society and the environment. The O&R BCA Handbook (Appendix A) will be incorporated into O&R's Integrated Planning Process and the Company will periodically update planning and modeling processes and functionality in order to incorporate the analysis gained by the BCA process.

Hosting Capacity

O&R concurs with the definition of hosting capacity outlined in the recent EPRI Hosting Capacity Whitepaper.[38] The EPRI Whitepaper accurately defines hosting capacity and addresses the inherent variability of hosting capacity on a dynamic grid, in the excerpt below:

> Hosting capacity of a distribution system is the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades. Hosting capacity can vary across many feeders, along a single distribution feeder, as well as within a secondary distribution system. Hosting capacity will also change over time as the distribution system infrastructure and operations change.

Hosting capacity can be used to inform utility interconnection and planning processes and to support a DER provider's understanding of more favorable locations for interconnection and where the value of DERs can be maximized (where DER provide benefits without incurring additional costs). As defined in the EPRI Whitepaper, the key factors that influence hosting capacity methods are DER location, DER technology, and Feeder Design and Operation, excerpted below:

> **DER Location** - The hosting capacity for any feeder is not one single value but a range of values that depend upon a number of factors, mainly DER location. An effective method must consider all possible single, centralized locations along a feeder as well as the aggregate impacts of highly distributed DER. Also inherent to DER location is the consideration of phasing of the feeder at that location (*i.e.*, connected to the three-phase main trunk or a single-phase lateral).
>
> EPRI research has shown that significant levels of small DER spread throughout a single distribution feeder can have a considerable adverse impact on the distribution system performance. This is often neglected in many studies. Likewise, the impact of large centralized DER has been shown to have a significant but widely varying impact depending upon where it is located along the distribution system.[39]
>
> The amount and location of existing DER that are already interconnected can greatly impact the hosting capacity of any given feeder and therefore must be taken into consideration as well.
>
> **DER Technology** - The type of DER is another critical component since variable DER such as solar and wind have a vastly different distribution impact when compared to other forms of dispatchable DER such as energy storage. The differences primarily emanate from the ability, or lack thereof, to control the DER and when the DER is available. Care must be taken when considering specific technologies and how they interact with the grid.
>
> Variable generation such as solar and wind are similar in that they are for the most part non-dispatchable resources. Even though they are both an intermittent resource their impact to the system is dependent on the time of day they provide power. The impact of inverter-based

[38] Electric Power Research Institute, *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State.* Palo Alto, CA: 2016. 3002008848

[39] Electric Power Research Institute, *Distributed Photovoltaic Feeder Analysis: Preliminary Findings from Hosting Capacity Analysis of 18 Distribution Feeders.* Palo Alto, CA: 2013. 3002001245.

technologies can change when advanced inverters that have additional grid support functionality are used. In some cases, this functionality can help reduce the impact of the intermittent resource by providing voltage support. However, advanced inverters may not always reduce impact. Identifying the appropriate settings for operation is critical.

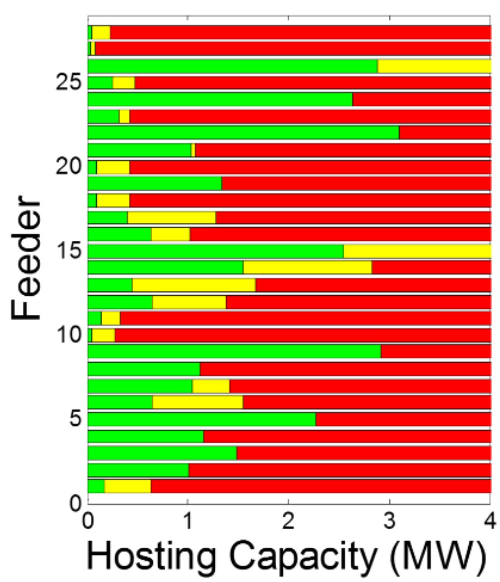
The Hosting Capacity method should be technology neutral and be able to consider any type of DER by inputting various load shapes. The specific technology determines how the analysis is setup to properly quantify the unique impacts of the particular resource. PV is the most prominent technology being installed currently and the near term focus of efforts in New York.

Feeder Design and Operation - Distribution feeder characteristics also determine how much DER can be hosted. Voltage class, feeder topology, and load location are just some of the factors that determine what level can be accommodated and where. Additionally, the operation of the system, like voltage control schemes and radial/network topology, can have an impact on the amount of DER that can be accommodated and where. As load varies over time, the amount of DER that can be integrated is impacted as well. For example, with solar PV the most limiting load level often occurs during mid-day when some feeders are at their minimum load levels.

The Hosting Capacity method must consider the actual feeder design and operation. These characteristics result in a dynamic interaction that must be examined in the power flow solution of the complete feeder model. Figure 1-15 summarizes hosting capacity results on 28 different feeders. Each has a unique hosting capacity based on the factors described above when looking at PV.

Figure 1-15

EPRI Feeder Hosting Capacity Study Results



The Company's initial efforts to provide hosting capacity maps will be focused on locations where DER can easily connect to the distribution system. As such, the Company and the JU are proposing a phased approach to the implementation of distribution system hosting capacity maps. The hosting capacity implementation map, as defined in the EPRI Hosting Capacity Whitepaper, is conceptually structured in four phases:

- Phase 1 will provide basic distribution system level indicators;
- Phase 2 will involve more detailed hosting capacity evaluations;
- Phase 3 will provide advanced hosting capacity evaluations; and
- Phase 4 will provide fully integrated DER value assessments.

The development of the subsequent phases of hosting capacity maps will be largely informed by parallel proceedings related to the value of DER to the distribution system. The Company continues to work with DPS staff, the JU, and various stakeholders to provide input into the development of hosting capacity methodology and data. It will also be further informed by collaborative conferences facilitated by DPS Staff, the first of which is scheduled for July 6, 2016.

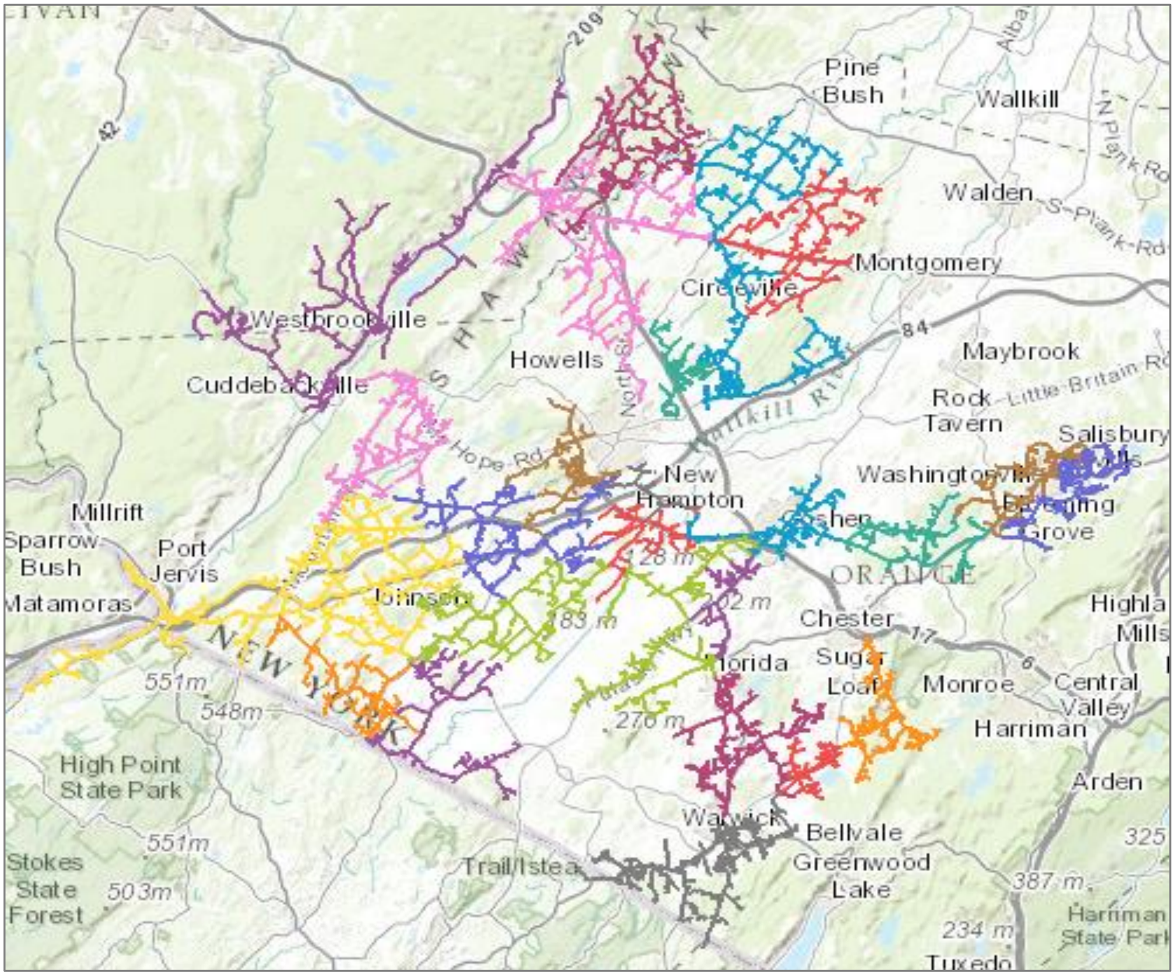
As a first step in this process, O&R has developed a Distributed Generation Interconnection Circuit Map[40] (Figure 1-16) which displays general areas/circuits where the cost to interconnect may be higher due to low minimal daytime load, aggregated distributed generation already interconnected, smaller conductors (wire size), operating voltage, and/or the number of applications in the queue on the feeder exceeding daytime load. The indicated areas do not obviate the need for detailed interconnection studies, but should help guide DER providers towards areas of lower interconnection cost. This approach will provide interim guidance to developers when siting DG resources until a more in-depth and comprehensive hosting capacity methodology is completed.

The Company is in the process of upgrading the current Distributed Generation Interconnection Circuit Map to include all circuits on the O&R distribution system. The circuit voltage and phasing will also be embedded and available, providing additional guidance and reference for DER providers. A final definition and methodology for determining hosting capacity will be developed through the JU Supplemental DSIP Stakeholder Engagement process and filed in the Supplemental DSIP. Once the final definition and methodology are established O&R will update its DG Interconnection Circuit Map accordingly.

[40] www.oru.com/distributedgeneration

Figure 1-16

O&R Distributed Generation Interconnection Circuit Map



Initial Distributed System Implementation Plan

Chapter 2 - Distribution Grid Operations

This chapter outlines how DER interact with the grid, what processes and monitoring are required to safely operate in a DER-rich environment, how cybersecurity concerns are addressed, how the Company is approaching Volt/VAR Optimization capabilities, and how DER can be more seamlessly interconnected.

To date, penetration levels of different types of DER have been manageably low and have not materially impacted the way the Company maintains reliable delivery of service across its territory. As DER penetration increases, as forecasted, the positive effects of these resources, along with the accompanying challenges, to the distribution system will become evident. In this chapter, the Company references different existing processes and procedures and evaluates how those will need to be modified with the increased penetration of DER.

As the penetration of DER increases across the Company's service territory, the requirements, impacts, and opportunities generated by that DER will also expand. Establishing the appropriate level of visibility, monitoring, and control will be critical to realizing the most value to customers and the system from DER and maintaining a safe and reliable grid. This will be achieved through a variety of investments including expanded distribution automation, the rollout of AMI, and the development of an ADMS platform.

The Company envisions the establishment of a set of standards for DER providers. This would be consistent with existing DER contracts, NY Standardized Interconnection Requirements,[41] and be expanded as necessary to include provisions for maintenance and emergency outage protocols, required levels of monitoring and control based on the DER necessity for reliability, obligations to provide data to the utility in order to maintain safety and reliability, and contractual obligations/penalties for programs such as NWAs and demonstration projects. These standards will allow customers and the Company to receive the most value from DER and should be developed jointly by the JUs and stakeholders as part of the Supplemental DSIP process. This topic may also be introduced within Case 15-M-0180.[42]

Monitoring of DER will be necessary to maintain the safe and reliable operation of the grid. In addition, there will be opportunities where the Company's direct coordination with DER could provide added benefits to customers and the system. These may include dispatch of large scale DER on peak days, aggregation of behind the meter DER to provide load reduction and facilitate NWAs, the ability to tap DER to provide Volt/VAR and other ancillary services. Current and future REV demonstration projects and other pilots will inform the further development of these opportunities and the associated business cases.

The Company recognizes that the increased flow of customer and system data enabled by REV and the DSP will also present risks that will need to be addressed by the Company's cybersecurity program. It is a critical issue, irrespective of the level of DER penetration, but takes on increased importance in a high-DER penetration environment due to the increase in information being

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[41] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less,* Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016).

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

communicated and the need to manage many more endpoints. The Company remains committed to providing useful system and customer information while not exposing data that might present opportunities for malicious actors. Increasing risks must be met with thorough planning and adherence to cybersecurity principles.

Volt/VAR Optimization represents a unique ability to more efficiently operate the grid. The capabilities included as part of the VVO umbrella include peak demand management through voltage reduction, continuous voltage optimization to deliver specified voltage more efficiently, and optimizing VARs to improve power factors. The Company envisions a phased approach to VVO through the deployment of various VVO supporting equipment, the incorporation of AMI, and the development of an ADMS.

Finally, the Company addresses its continued improvements to the interconnection process. The Company has begun to address gaps identified in the September 2015 report prepared by EPRI[43] for NYSERDA in conjunction with the efforts to amend the New York State SIR. In addition, the Company has established an interconnection application portal, which will be further refined to meet the requirements outlined in the Track One Order and to better serve customers.

[43] Electric Power Research Institute, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, Final Report, September 2015.

System Operations

Expected Near-Term Effects of Increased DER Penetration on Grid Operations

In the current state, the existing levels of DER penetration are not significant enough to cause dramatic effects on O&R's ability to serve its customers. The Company will maintain the same level of reliability for its customers regardless of DER penetration. The table below indicates the levels of net-metered DG capacity installed and currently in the queue (this includes all current applications, not just those approved) as of May 31, 2016.

Table 2-1

Net-Metered DG Capacity Installed and in Application Queue

Net-Metered DG Installations MW Capacity	NY
Total MW Connected	39
Total MW Proposed	475
Grand Total MW	514
Record Peak System Load	1157

O&R has identified some potential near term opportunities and challenges as DER (photovoltaic, wind, energy storage, CHP and other continuous power sources, and demand side management) penetration grows in the O&R service territory.

An opportunity from an increased penetration of DER that could provide great value will be peak shaving (relieve capacity constraints on the system) and peak shifting (movement of the peak hour to another timeframe). As intermittent DG sources (PV and wind) are coupled with storage, these effects could be planned for and relied upon. While DER can provide a variety of benefits to customers and the grid, there are also challenges that will need to be taken into consideration and overcome through collaboration with DER providers as DER penetration grows.

Voltage fluctuations that are inherent to intermittent DG not coupled with storage or smart inverters can put increased stress on the Company's equipment as well as affect the power quality and reliable delivery of power to customers. Existing voltage control devices are designed to maintain voltage at prescribed operating levels by correcting for voltage drop due to radial power flow. Since the distribution circuits' loading patterns change because of DGs' intermittent generation, the existing voltage control devices may no longer provide proper voltage regulation, which, if allowed to persist, could cause failure of utility and customer equipment. The existing voltage support devices such as capacitors, voltage regulators, and transformers could be supplemented by DER provided they can demonstrate similar, if not identical levels of performance and reliability commensurate to traditional voltage support devices. In addition, O&R will likely need to deploy Volt/VAR control and optimization schemes to manage voltage and power factor across the distribution system. These system upgrades are essential to maintain grid reliability and regulated voltage levels on the distribution system while facilitating increased growth of DER throughout O&R's service territory.

Fault clearing and locating will become more complex as multiple sources of power are increasingly present on the system. Faults on circuits with DG have the potential of producing mis-coordination between reclosers and fuses in the distribution circuit. They can also produce fuse mis-coordination and potential station relay mis-operations, primarily due to the increase in available fault current levels. DG can also increase fault currents where the cumulative effects can exceed equipment ratings and potentially cause catastrophic failures which could lead to reliability and safety issues on the system. Many of these issues should be addressed through the interconnection process and Coordinated Electric System Interconnection Review ("CESIR"), as outlined in the SIR Order.[44] However, as DG penetration increases, these challenges may require more in-depth study and further collaboration with DER providers.

Substation reverse power flow is a new challenge for O&R as the amount of proposed DG on the system increases. Existing protective relays are specified and set to operate unidirectionally (from substations to loads) at the current fault duties and coordinated with downstream protective devices so that the least amount of customers will be interrupted. Multiple DGs on the circuits can mean there are many power sources on the circuit and this makes protection and coordination studies much more complex. In many cases, the existing unidirectional protective relays may need to be replaced with bidirectional or other advanced relays to maintain proper protection. More automation will likely be required on substation tap changers in locations where automation is less advanced. Tap changers will experience additional usage and maintenance and replacement costs associated with the tap changers will rise due to this increased wear and tear. Again, these issues should be identified through the interconnection process, and solutions should be developed by working with DG developers.

An important safety concern associated with increased penetration of DG is unintentional islanding. Unintentional islanding could occur if a DG system continues to energize a portion of a circuit after the circuit is disconnected from its primary utility source following a system fault or utility switching action. While current interconnection standards are such that the inverters are designed to disconnect such a DG from the system, precautions must be taken as these systems get older and maintenance procedures associated with significant DG installations are unknown. The potential for inverter systems with anti-islanding designs operating in an islanded condition when they should have tripped off the system remains a safety concern that must be overcome through collaboration between the Company and DER providers. These issues are being discussed in the NYS SIR proceeding technical working group. The Company's position is that DG installations paired with inverters greater than 1MW will be equipped with a Company-owned device that will enable the DG to be disconnected from the system when the utility source is not present. DG installations paired with inverters smaller than 1MW and all other DG installations will be evaluated through an engineering analysis within the interconnection process to determine if an automatic disconnection is required.

Listed below are the most common DG types and the opportunities and challenges they could present to the distribution system:

[44] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016).

Table 2-2

DER Opportunities and Challenges

Type of DER	Effect
Intermittent (PV, Wind)	Opportunity: • Helps shape the load curve and reduce peak load for day peaking circuits, reducing the stress on system components • Smart inverters may potentially provide voltage and reactive support Challenge: • Intermittent source of power • Currently, no reactive power control, which can exacerbate voltage fluctuations
Utility Scale and Residential Storage (Battery)	Opportunity: • Can be used to time-shift and reduce peak loads on the circuit. • If batteries are coupled with smart inverters, reactive power control and support could be realized Challenge: • Currently, no mechanism to incentivize behind-the-meter batteries to predictably charge and discharge. • Need for process and procedures regarding battery discharge and charging • Different chemical compositions of batteries could add additional safety and operational complexities
Combined Heat and Power (CHP)	Opportunity: • Provides continuous power • Could be used during a contingency • May have black-start capabilities Challenges: • Dispatchable only at owner's discretion and may not be available at a time of system need • Maintenance procedures vary by owners • If not operating, the system may have to serve a significant amount of additional load
Microgrids	Opportunity: • May provide continuous power • Could be used during a contingency • May have black-start capabilities Challenges: • Interconnection processes and procedures will need to be developed to address how the micro-grid will be utilized during times of system stress (outages) and times of system maintenance (worker protection) • Dispatchable only at owners discretion and may not be available at a time of system need

Type of DER	Effect
	• Maintenance procedures vary by owners
Rotating Generation	Opportunity: • Provides continuous power • Could be used during a contingency • May have black-start capabilities Challenges: • Can contribute substantial amounts of fault current into the system • Can potentially operate in an islanded state • Dispatchable only at owner's discretion and may not be available at a time of system need • Maintenance procedures vary by owners
Demand Response	Opportunity: • Can be used to shave peak load • Dispatchable Challenge: • Limited in duration • Potential conflicts in overlap with NYISO program and Company program • Customer fatigue
Energy Efficiency	Opportunity: • Reduces stress on infrastructure components by lowering overall system load • Can be targeted to specific areas Challenge: • Not dispatchable • Sustainability and penetration limitations

Policy and Process Changes

It is O&R's responsibility to maintain the safety and reliability of the electric distribution system for its customers. As with all equipment and components connected to the gird, O&R must work alongside DER providers to make certain that DER do not adversely affect the safety and reliability of the electric distribution system.

Energy Efficiency and Demand Response do not require the customer to generate or export electric power. These technologies only reduce the demand and energy consumption of the customers participating in these programs. Encouraging or expanding these technologies thus will not have any adverse effects on the safety and reliability of the electric distribution system. DG technologies generate and, at times, export electric power. As a result, they have the potential to affect the reliability, power quality, and safety of the electric distribution system, as well as the safety of the line maintenance worker.

As the penetration level of DG on the system increases, revised safety protocols are being adopted to maintain the safety of the line worker. As mentioned above, unintentional islanding of DG is a safety concern that requires a change in the interconnection standards that govern the installation of larger DG. The majority of maintenance work that is done on the distribution system uses live line work methods (the circuit breaker and automatic field devices are placed in “one fast trip” mode). Unintentional islanding will circumvent these protections and potentially place the line worker in harm’s way. Interconnection standards, requirements, and procedures are the best way to enable DG to be interconnected (installed) in a manner that safeguards against adverse effects towards power quality, reliability, and safety. Larger DG installations (1MW+) paired with an inverter require an automatic device at the point of interconnection that will coordinate with current live line work practices. For the smaller sized DG paired with an inverter and all other DG installations, the Company has updated its application process to include an engineering review that will dictate the level of protection from the DG that is needed. If an installation was built prior to the introduction of these new SIR standards, the Company reserves the right to isolate the DG while work on the lines is underway.

Another consideration is the safety and reliability of the distribution system. Certain power quality (“PQ”) issues, such as voltage fluctuations, can potentially harm both the customer’s and the Company’s equipment. The automatic devices installed with appropriate monitoring capabilities that are placed at the interconnection point will address this issue as they can be programmed to isolate the DG if operating parameters are not within tolerance. As DG penetration increases, these requirements will continue to be refined and administered to protect the reliability and safety of the electric distribution system.

As larger DG provider’s applications are approved, the ability for reverse power flow to occur into a substation bus or into the transmission system increases. In order to accommodate these systems, revised protection standards will need to be developed and new substation and field equipment will need to be installed or upgraded to comply with these new requirements. Increased maintenance activity will likely be required on substation tap changers, and distribution reactive devices such as capacitor banks and voltage regulators. These devices may need to be updated with new settings, new hardware, or even relocated to operate efficiently. Protection settings and methodologies will also need to be incorporated into the review. Processes, procedures, equipment, control systems, and communications will be needed to provide the operator with the ability to curtail DGs in the event of overloads or adverse operating parameters.

As penetration of DER on the system increases, the Control Center will require additional staffing to monitor, control, and dispatch DER as the Company’s role as the DSP expands. Currently the operator’s functions consist of executing planned and emergency switching, providing live line work protection, sending notifications to internal and external entities, managing system outages, and supervising the OMS dispatchers. Operator skill sets will need to expand to include monitoring, controlling, and dispatching DER. Micro-grids, CHP sites, battery storage, and reverse flow through substations are becoming more prevalent on the system and the coordination of these technologies with providers will be critical in order to capture the most value from these systems for customers. While many of these functions have the potential to be automated through an ADMS, an engineering background will be needed to analyze sensor inputs, coordinate load shifting, and respond to DER that are having an impact upon the system. Possible opportunities for third-party aggregation and dispatch of DER should also be explored, and will require close interaction and coordination with the Control Center.

Visibility and Communication Protocols

Currently O&R has limited visibility and communications with the DGs on the distribution system. While larger commercial installations have metering and sensing that provides visibility into these systems, the information is not aggregated or displayed to the O&R Control Center Operator in a readily available manner. The current penetration level of larger DGs has not necessitated the need for additional visibility, but considering the amount of DG currently in the DG queue, specifically PV applications, this is likely to change in the near term. The SIR Order states that "with respect to the transmission of real-time data, this is best left to the REV proceeding, which is exploring such options as part of the Distribution System Provider responsibilities." [45] It is the Company's current position that all DG with name plate generation greater than 1MW in O&R's service territory will be equipped with a meter or monitoring allowing for the real-time transmission of data to the utility. The Company will conduct an engineering analysis for all other DG installations to determine if metering and monitoring is necessary. In addition, there are currently no communication protocols in place to gain visibility into the residential systems. These systems are currently visible on our Geographic Information System with name plate information only. As with the commercial installations, the penetration levels of the residential DG has not yet necessitated the need for more visibility. However, as the penetration of residential DG increases their aggregate effect will likely become more relevant for the both the opportunities they could provide and the potential impact they could have on the system.

As DG penetration levels grow however, it will be imperative that the Company is able to gain more visibility and gather real time information regarding the distribution system and each DG installation individually in order to serve in the role of the DSP. O&R will need to implement more advanced methods to monitor and control the DG on the system. The ability to see and react to problems will be necessary. As stated above, O&R already has protocols for communicating with larger scale DG installations. This information is available on the DSCADA system on an individual basis, however; it is not aggregated, analyzed and displayed on a system basis. For a short-term increase in visibility, O&R will research the feasibility of providing alarms to the CCO if the information that is received from the larger DG installations indicate that preset parameters are not being met. This will allow system issues that are caused by the DG installations to be addressed as they arise.

As AMI is installed in the Company's territory, visibility into residential systems and smaller commercial DG installations will increase. The ability of AMI communications and smart meters to better monitor the Company's distribution system and performance of DER equipment can enhance quality of service and performance by enabling customer programs and technologies that may efficiently reduce demand and increase renewable generation. Real time monitoring of DER is essential to the DSP to track DER performance and capabilities both to make same day operational decisions and for near-term forecasts and scenario decisions.

With the growth of the amount of information that is being gathered, the need for a system that will aggregate, analyze and display the information to the operator will become a necessity. O&R is currently researching the implementation of an ADMS. This system should increase the visibility into the

[45] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016),p. 23.

distribution system by taking inputs from field sensors/meters, AMI, automated devices and fault indicators by aggregating, analyzing and displaying the information in a usable format for the CCO to monitor and control the system with a high level of situational awareness. Further study must be done in order to determine the optimal configuration for the dispatch of DER for different situations and resources, whether it be dispatched directly by the Control Center or aggregated and managed by a third party acting upon Control Center input.

Operational Needs – Normal, Outage, and System Stress

As operational needs change and the system grows, an organized and economical plan must be in place to respond. Design criteria were developed to provide the Company with a uniform methodology to operate and maintain an efficient and reliable electric distribution system and provide customers with the quality of service they expect. They are informed by regulatory requirements, safety codes and industry standards and provide guidelines for all aspects of the process from planning and design to system construction and maintenance. Three areas of operational needs are discussed in the following paragraphs; the need to maintain certain voltage parameters, the criteria for thermal limitations on the system and the need for adequate system/worker protection. As DER penetration on the system increases, during times of contingency and system stress the various impacts of that DER may have to be addressed in order to maintain reliability, power quality, and safety.

Voltage Parameters

Service voltages provided to the customer at the metering point meet all applicable national standards and the requirements of the state regulatory authorities. These guidelines have been set to satisfy customer requirements and allow utility equipment to operate within acceptable tolerances of their nominal ratings. The following table for service voltages is based upon ANSI Standard C84.1 1989 for Electric Power Systems and Equipment.

Service Voltage	Normal voltage limits – Range A	Contingency voltage limits – Range B
120	126/114	127/110

Range A is the acceptable voltage limits on the Orange and Rockland system. These are sustained voltages at the customer meter and do not include momentary voltage excursions less than five minutes in duration. Due to practical design and operating condition limitations, excursions outside of Range A will occur. Acceptable limits for these excursions are shown in the table as Range B. When voltages are in Range B, corrective actions will be taken within a reasonable amount of time to improve to Range A.

In conjunction with maintaining these service voltages, the distribution substation bus is maintained at 123 volts. This reflects a practical level to achieve conservation through voltage reduction (“CVR”) under normal operating conditions. Under system or statewide contingency conditions, a 5 percent voltage reduction may be required, and bus voltages may be lowered to 117 volts under these emergency situations.

The distribution primary line voltages are regulated between 123 and 118 volts. The range for the primary voltage level is achieved on the distribution circuits through many means. These include setting substation tap changer positions, balancing loads on primary feeders, changing distribution and step-transformer taps and operating capacitor banks and voltage regulators. By maintaining primary distribution voltages between 123 and 118 volts, a three-volt drop through the distribution transformer, secondaries, and service can be tolerated. By maintaining proper voltage and KVAR support through the distribution circuits load levels, the efficiency of the system is maintained as well.

Special attention with respect to DER on the system will be required for periods of distribution system stress such as high/low voltage conditions. In cases where high voltage conditions are created by DER, the ability to control or curtail the output will be necessary in order to mitigate the effects on the system. Alternatively, having the ability to dispatch DER may prove valuable to correcting low voltage conditions on distribution circuits.

Thermal Limits

Substation transformer ratings are calculated based on the daily load cycle on the particular transformer, the average variable ambient temperature, the permitted loss of transformer life, and the specific transformer characteristics. The ratings provided reflect 24-hour (Normal-Continuous), 4-hour (Long Term Emergency or LTE), and 15-minute (Short Term Emergency or STE) capabilities. The 24-hour rating (Normal) is the maximum load the transformer is capable of carrying without any loss of life every day of the year. The 4-hour rating (LTE) is the maximum load that a transformer can carry under emergency conditions for a period no longer than 4 hours. The 15-minute rating (STE) is the maximum load that a transformer can carry under emergency conditions with a 1 percent loss of life. Operation of such equipment above any of the above ratings requires field switching/load shedding to relieve the overload condition and to get below the specific ratings within predetermined amounts of time.

It is important that during switching operations on the distribution system, DG penetration is factored into the total load being transferred. Having the aggregate DG capacity included in load calculations will prevent negative impacts to the system. If the DG load is not accounted for it could cause reverse power flow to occur into a substation bus not configured for reverse power flow, which could ultimately cause backfeed into the transmission system and other protection mis-coordination issues as described previously. Distribution automation equipment will also have to be revisited to determine that the intended operation of auto loops will not be affected by DER penetration. In these situations, the ability to control or curtail the DG may be necessary. In situations where auto loop operation and switching scenarios will cause capacity issues on circuits that are not set up for reverse power flow through the substation, or where potential mismatch of load to generation may occur, the Company reserves the right to disconnect DG from the system until normal circuit configurations are resumed. In the interim period, DER capacity can be identified, and it will be noted where it results in a possible loading issue. For the long term outlook, an ADMS will allow an operator to run state estimation through simulation modeling switching scenarios where DG is considered. In addition, having the ability to dispatch DG may help thermal capacity on distribution circuits by shaving peak load.

Protection

One of the main objectives of the distribution protection scheme is to minimize momentary interruptions and the number of customers affected by a permanent fault that occurs on the distribution system. This is accomplished by allowing all down-line devices to clear a fault before the upstream devices begin to operate. Distribution system protection is accomplished using reclosing circuit breakers in the substation; recloser/sectionalizers on the circuit trunk; and three-phase sectionalizers and single phase fuses for radial taps off the circuit trunk. Protection for the distribution circuits begins at the substation. By using circuit breakers and/or reclosers in the station, a distribution fault can be isolated from station equipment without causing equipment damage. Coordination between the low-side protection devices and the high-side fuses and/or transrupters of the station transformer must be maintained. This coordination prevents the operation of transmission system protection for a distribution fault.

Another very important function of the distribution protection schemes is to provide protection for line personnel conducting maintenance work on the system. To facilitate work on the system while elements are energized (*i.e.*, "live line work"), live line work protection is needed to protect the line crews in the event of an accident. DER applications able to produce significant fault current would be considered as an additional source into the system and will need to be considered for added protection at the point of interconnection. This will serve to avoid unintentional islanding when the circuit is de-energized and not place line personnel in harm's way.

Implementing protocols like Fault Location, Isolation, and Service Restoration measures have proved beneficial to distribution system reliability. O&R's Distribution Automation installation projects implemented on multiple adjacent circuit pairs have enabled operator control through a Distribution SCADA system to execute FLISR measures. DSCADA controlled devices such as Reclosers, Motor Operated Air Break devices, Regulators, Line Sensors, and Capacitors are developed and deployed, or are being developed through Research and Development projects for enhanced situational awareness and system control, which is necessary for a dynamic DER penetrated environment. The installation of Smart Fault sensors in strategic locations has helped improve restoration efforts and fault locating. Capital projects expanding deployment of Smart Grid concepts and advanced distribution automation are creating a more proactive and resilient system.

To compliment expanded distribution automation and Intelligent Electronic Device placement, it is currently the Company's plan to replace the DSCADA system within a new ADMS application which will incorporate a dynamic integrated system model of the real-time distribution, substation, and transmission systems. It will also incorporate all appropriate Energy Management Systems, SCADA, DSCADA, and external sensors with the current system topology to accomplish accurate power flows and system state estimation calculations. This will be necessary for precise modelling and control for system protection, reliability, and power quality evaluation for periods of system stress and normal activity.

Cybersecurity and Privacy

Events on the world stage underscore the increasing need for cybersecurity of information technology and operational technology. There have been a number of high profile hacks that demonstrate the need to address cyber security, including SONY and The Office of Personnel Management. More specifically, as it relates to the electric industry, in December 2015, Ukrainian utilities experienced a cyber-attack that caused a one to six hours electric outage for 230,000 customers and physical damage to substation equipment.[46] The Department of Energy's Quadrennial Report,

[46] http://www.nytimes.com/2016/03/01/us/politics/utilities-cautioned-about-potential-for-a-cyberattack-after-ukraines.html?_r=0

issued in 2015, indicates "there is also evidence that nation states are increasing cyber-spying and attacks on U.S. utilities and equipment suppliers."[47]

Description of Company's Cybersecurity Program

The cybersecurity threat landscape is constantly evolving and expanding. Malicious software and intrusions are becoming more sophisticated. The actors are changing and they are increasingly developing skills to use stealth techniques that over time attempt to evade and disable available detection mechanisms. These actors methodically attempt to exploit vulnerabilities in access controls and software products using slow, persistent attacks to compromise weaknesses, a technique referred to as Advanced Persistent Threat. As a result, the Company considers it critical to continuously improve its defense posture through technology investments. The Company maintains a comprehensive cybersecurity program designed to protect Company computing equipment, such as computers, servers, business applications and data, and high value networks from unauthorized access from both external and internal threats. In addition, the Company works to collaborate with law enforcement, regulatory agencies and industry resources.

While the details that underlie these dimensions may change over time, the Company's cybersecurity program is built on the following foundational principles:

- Cybersecurity should be based on a comprehensive risk assessment, including increased focus around the security tenants confidentiality, integrity and availability that apply to the items being protected.
- Cybersecurity is designed into all computing and communications elements used by the Company and its customers.
- Computing networks are segmented so that higher value networks are separated from the corporate information network.
- The defense posture is layered, eliminating dependence on any one cybersecurity defense.
- Regular vulnerability assessments and penetration tests are conducted by third parties.
- Access to computing and communications assets are limited based on "least privilege needed", which grants access to information and resources only to those parties which have a legitimate purpose.
- Redundancy and diversity are built for all components to reduce impact and aid recovery.

Computer security is expected to remain a major concern for the Company for both the short and long term.

The Company continuously improves its defenses. They meet these foundational principles, the Company promotes cybersecurity actions from three main perspectives: (1) preventing and educating, (2) monitoring, detecting, and alerting, and (3) responding to incidents, including recovery/mitigation. These are defined below, with examples of existing and planned programs in each category:

[47] U. S. Department of Energy, *Quadrennial Technology Review 2015*, Chapter 3: Enabling Modernization of the Electric Power System, Technology Assessment, Cyber and Physical Security, , p. 1.

- **Prevention and Education** – Measures respectively aimed at avoiding attacks on the system and providing employees with information on their role in preventing cyber intrusions
    - Expand the use of intrusion prevention technologies
    - Expand the use of next generation web and database firewall technologies
    - Deploy the next generation of remote access technologies which take advantage of better authentication methods like Adaptive Authentication and Mobile Device Managers ("MDM")
    - Improve employee awareness about cybersecurity through training and communication
- **Monitoring, Detection, and Alerting** – Measures aimed at monitoring the computing network to detect threats and vulnerabilities, and once detected, alerting necessary personnel
    - Utilize the Network Operations Center ("NOC") for 24x7 monitoring
    - Work with external entities that provide the Company with information on potential threats on a real-time basis through vulnerability assessments and penetration tests
- **Responding to Incidents, including recovery and mitigation** – Measures aimed at minimizing the impacts of a breach
    - Use forensic procedures to determine what occurred and how to address and correct the issue, in the event of a breach.

In addition to these three perspectives, the Company has implemented a formal cybersecurity policy across the enterprise using International Standardization Organization ("ISO") Standard 27002 as a reference model. The foundation of ISO 27002 maintains the confidentiality, integrity, and availability of systems and data through a process to regularly evaluate all aspects of the program, including review of policies, standards, and procedures in addition to the actual implementation of technical controls. These three objectives support the Company's goal to provide reliable electric and gas service to its customers – commercial entities, government agencies, and residential consumers.

Con Edison and O&R have a portfolio of over 500 business applications. Cybersecurity for these business applications begins with a corporate governance process that establishes requirements for application information security and control. Cybersecurity governance is supported by the Companies' executive team and is communicated through corporate policies and instructions. . These corporate policies and other supporting procedures provide specific requirements business owners and application developers must meet for software development and business application security, including the framework for application software development and support. Items contained in these policies and procedures include asset classification, sensitive information protection, control of information exchanges with business partners and other external organizations, business application access controls, user access management, and disaster recovery.

The foundational principles require that the Company protects its systems. Business application assets are protected by security controls, including those designed for information in databases and accessible through software applications. These controls are built in to the applications during system design and implementation through the use of a Software Development Life Cycle ("SDLC") process. The SDLC process is a formal process that requires the business owner to maintain the system with up to date information as well as to keep it sustainable. This includes patching and updating systems as necessary. Key governing principles applied to new systems following the SDLC process include:

- Architecture reviews of procured systems for proper design and incorporation of security controls;
- Secured coding principles utilized for developed applications;
- Role based access controls implemented throughout the system;
- Systems designed to ensure data flows follow data pull techniques from “High Trust” to “Lower Trust” networks. Data is never to be pushed into “High Trust” from “Low Trust” networks;
- External data exchanges are encrypted to protect information transmitted between business applications and external organizations; and
- Authentication techniques utilized by users and system components.

The Company participated in the JU team, consisting of National Grid, Central Hudson and the Companies, to address these concerns and with the team developed a framework (Appendix G) for applying cybersecurity and privacy policy for REV initiatives. The Company applied concepts from the JU framework to develop its cybersecurity and privacy policies. The following baseline controls have already been implemented as part of the Companies’ cybersecurity program and will be used to develop and maintain its REV cyber-security program.

Cybersecurity Plan for New Corporate Initiatives including AMI and REV

The increased flow of customer and system data enabled by REV and the DSP will present risks that will need to be addressed as part of the Company’s cybersecurity program. It is a critical issue, irrespective of the level of DER penetration, but takes on increased importance in a high-DER penetration environment due to the increase in information being communicated and the need to manage additional endpoints and complexity. The Company remains committed to providing useful system and customer information and to secure systems so that data is not exposed, which data, if exposed, could that might present opportunities for exploitation.

In addition to the increased number of participants and data on the distribution system, the DSP will also facilitate the increased collection and sharing of customer usage data. Driven by AMI and made available through Green Button Download and Green Button Connect, customer data will allow customers to make more informed decisions regarding their energy usage. With a dramatic increase in the amount of customer data collected and shared, especially with third parties, the Company remains committed to protecting customer PII. That same commitment must be maintained by third parties and DER Providers that have authorized access to system and customer data.

New corporate initiatives include the use of devices (Smart Meters, distributed generation systems, etc.) not deployed within the Corporate Network. These devices add significant risk to the Company as they are outside the Company’s physical security controls. Accordingly, external devices and systems are designed for the integrity of the network and data being returned to Company-managed systems. Key principles used for these initiatives include all previously discussed controls and the following for all physically uncontrolled devices (meters, solar panels, etc.):

- Devices must be identified during the manufacturing process as a device intended for the Company’s system;

- Authentication to and use of dedicated, encrypted networks for the secured transmission of data from external devices;
- External data collected and temporarily stored in a “Low Trust” zone until pulled into the corporate environment from a “High Trust” zone;
- Control/change activities initiated from management systems to external devices authenticate to the external device;
- Software/firmware updates are received from the vendor via secured and validated means;
- Physical access to external devices are initiated with authorization and authentication controls; and
- Logging of all approved changes/commands with alerting of unauthorized activities.

Baseline Cybersecurity Controls

1. A governance program, lead senior management, should be established to reinforce the business need for an effective, holistic, risk based approach to managing cybersecurity and privacy, so that best practice and controls are part of REV initiatives.

2. The data, personnel, devices, systems and facilities that enable REV initiatives should be identified and managed consistent with a risk based approach and their relative importance to REV program(s).

3. Access control.
    a. Authentication: All data communications between systems and devices must be authenticated.
    b. Enforce Least Privilege: Only the minimum possible privileges should be granted to a user, technology or a process for accessing an information asset.
    c. Approval processes and prompt removal of access exists for access to systems. Periodic review of access controls should be performed.

4. Awareness and training. Policies and procedures should be established for the effective implementation of a cybersecurity training and awareness program.

5. Audit and Accountability. Logging of critical systems events, transactions, and systems must be performed, analyzed, and retained.

6. Security Assessment and Authorization. Regular external vulnerability and penetration tests should be performed.

7. Configuration Management. Devices should have a standard and approved configuration and a system that exists to manage changes and configuration versions. There should be a formal change management approval and tracking process.

8. Contingency Planning. Backup and recovery plans should exist for electronic assets.

9. Identification and Authentication. Assets need to be identified and validated in an asset inventory system.

10. Incident Response. Incident response plans should exist and must be exercised. Utilities should implement an incident handling capability for security events, including detection and analysis, containment, and recovery.

11. Maintenance. Patching procedures should exist. Supportable technology versions should be used where technically feasible.

12. Media Protection. Procedures and controls must exist for the secure use, transport, and disposal of electronic equipment and removable media.

13. Physical and Environmental Protection. Access to physical assets must be authorized, controlled, and monitored.

14. Planning. Planning for protecting confidentiality, integrity and availability of information and systems should be incorporated into system development and maintenance.

15. Personnel Security. Access to an information system should be revoked in a timely manner when an individual is terminated or is no longer authorized to have access to the system.

16. Risk Assessment. The utility should conduct periodic assessments of risk from the unauthorized access, use, modification, or disruption of an information system.

17. System and Services Acquisition. Security evaluations and assessments should be included in the capital planning and investment process. Information Security assessments should be performed for acquisitions of systems and services.

18. System and Communications Protection.
    a. Applications, systems, data, and roles should be respectively isolated in a way to support least privilege principles.
    b. Information systems should prevent unauthorized and unintended information transfers.
    c. Strong encryption solutions and secure channels should be used to protect data.
    d. Data flows should be architected so that lower security zones should not have direct access to higher security zones.

19. System and Information Integrity.
    a. Utilities should identify, report, and correct information system errors or flaws, such as those that may introduce vulnerabilities into an information system.

b. Security-relevant software and firmware updates should be installed in a timely manner.
c. The utility should protect against malicious code injection in technology assets.
d. Information systems should be monitored to detect anomalous or malicious behavior.
e. Tools should be employed to detect for unauthorized system changes.

20. Program Management. Utilities should develop and maintain an organization-wide information security program to address the above.

Baseline Privacy Elements

1. **Management**: The entity defines, documents, communicates, and assigns accountability for its privacy policies and procedures.
2. **Notice**: The entity provides notice about its privacy policies and procedures and identifies the purposes for which personal information is collected, used, retained, and disclosed.
3. **Choice and Consent**: The entity describes the choices available to the individual and obtains implicit or explicit consent with respect to the collection, use, and disclosure of personal information.
4. **Collection**: The entity collects personal information only for the purposes identified in the notice.
5. **Use, Retention and Disposal**: The entity limits the use of personal information to the purposes identified in the notice and for which the individual has provided implicit or explicit consent. The entity retains personal information for only as long as necessary to fulfill the stated purposes or as required by law or regulations and thereafter appropriately disposes of such information.
6. **Access**: The entity provides individuals with access to their personal information for review and update.
7. **Disclosure to third parties**: The entity discloses personal information to third parties only for the purposes identified in the notice and with the implicit or explicit consent of the individual.
8. **Security for Privacy**: The entity protects personal information against unauthorized access (both physical and logical).
9. **Quality**: The entity maintains accurate, complete and relevant personal information for the purposes identified in the notice.
10. **Monitoring and Enforcement**: The entity monitors compliance with its privacy policies and procedures and has procedures to address privacy related inquiries, complaints and disputes.

Volt/VAR Optimization (VVO)

VVO Implementation Plans

O&R considers Volt/VAR Optimization as the ability to operate the distribution system within an optimal voltage range throughout the annual load cycle without violating the ANSI voltage standards and maintaining system safety, reliability and efficiency. The plan will require O&R to evaluate the current deployment of substation and distribution automation and communications technology as it pertains to successfully deploying an Integrated Volt VAR Control ("IVVC") system. This system would have control over voltage and VAR regulating devices that would enable the Company to operate distribution feeders in an advanced voltage optimization mode.

O&R's service voltage quality requirement is based upon ANSI Standard for Electric Power Systems and Equipment. ANSI Range A is the acceptable voltage limit on the O&R system. The distribution substation bus is currently designed to maintain 123 volts on average within an appropriate bandwidth. This reflects a practical level to achieve conservation through voltage reduction under normal operating conditions. Distribution circuit voltages are dynamically regulated through the coordinated operation of the following: by moving substation transformer tap positions either through fixed taps or through load tap changing equipment where available, by placing substation and distribution level capacitor banks in or out of service, and through voltage regulators as required. Computer modeling at various loading conditions facilitates the planning of this operation.

O&R is working towards a phased approach plan for operating the future state of the grid through an Industrial Control System ("ICS") to optimize the distribution system operating voltage, provide opportunities to third-party DG/DER providers for voltage and VAR support and mitigate any adverse impact to voltage system conditions operating outside of utility requirements and specifications due to DG variability. O&R is already implementing volt/VAR control to maintain certain levels of efficiency by operating the system through automated local controller set points on its substation LTCs, distribution capacitors, and distribution regulators with the availability of remote manual LTC control by its System Operators. In order to achieve improved levels of efficiency toward optimization throughout the load cycle, O&R will be required to coordinate in real time the operation of its automated voltage and VAR supporting devices with third-party DER/DG equipment through real-time monitoring and SCADA communications that provide distribution status to the ICS and system operators. O&R will take a phased approach by first understanding the current ability to communicate and control existing voltage supporting equipment and then measuring its abilities against engineering practices and standards to identify any gaps in the current state that initially limit system wide VVO. To deploy and coordinate various types of VVO supporting equipment for different distribution configurations, an Advanced Distribution Management System will be the ICS tool that enables the provision of the real time calculations and control required to operate the system in this highly efficient proposed future state. With an ADMS, the control of the substation bank LTC would be the first device to provide voltage optimization and would be O&R's minimal starting point of VVO deployment. VVO capability will improve as distribution voltage and VAR controlling field devices get commissioned into SCADA as part of the Company's Distribution Automation and Technology expansion deployment, through the deployment of additional and improved substation level metering data, and through AMI deployment. Each state of feeder deployment will have its own level of VVO benefits. The first stage of validating VVO solutions prior to system wide deployment would be to implement pilot programs for VVO on select feeders with enhanced automation.

O&R plans to perform a scoping study for an ADMS. This system is envisioned to have advanced applications such as IVVC, FLISR, Switch Order Management, and Distributed Energy Resource Management System ("DERMS"). To successfully deploy VVO in its proposed end state, the IVVC mentioned above will utilize SCADA control through ADMS applications. This will require data connections to the Energy Management System, AMI near real-time data, and will utilize O&R's existing Integrated System Model to provide power flow and state estimation to achieve VVO. IVVC is the centralized coordinated control of distribution feeder capacitor banks, voltage regulators, substation load tap changers, and potentially in the future, smart inverters to optimize the feeder's voltage and VAR profiles. The EMS system will need to be configured to provide real-time head end feeder data and voltage control to an ADMS. The control interface between the systems will need to be evaluated and vetted for any cyber security concerns and verify NERC Critical Infrastructure Protection ("CIP") compliance can be met. In addition to the data connection and communication requirements, equipment in the substation will need to be evaluated, and upgraded, and/or installed to verify the proper control and communication capability exists to enable this functionality. As it becomes available, AMI data will provide an ADMS with a voltage reading at each customer location and will alert the system to any voltage violation with more granularity, allowing an ADMS system to operate more towards the limits in the allowable ANSI limit range, thus improving efficiency and reducing system losses. AMI will increase the amount of information available to grid operators and planners, enabling O&R to better control voltage across the system, leading to a reduction in overall energy consumption. As a result, the Company will potentially be able to reduce the amount of power purchased and consumed, reducing the amount of electricity generated and the associated carbon emissions.

In the future, an ADMS could eventually monitor and potentially control DER assets as part of an optimal operating control methodology, and open opportunities for third-party pilots and REV demonstration projects to be conducted with O&R.

O&R is continuing its deployment of enhanced automation devices with line sensing on looped circuit pairs. Distribution circuit enhancements are being designed using our Distribution Engineering Workstation load flow analysis tool to phase balance and select optimal cap bank location, which is a prerequisite for VVO. SCADA enabled capacitor bank controls will be deployed with each circuit enhancement. Control of these devices will be required by an ADMS for IVVC.

The systems that need to be brought online for distribution control and efficiency will depend on the data gathered from electric system measurements and control settings. As of today, Watt and VAR readings for the majority of the Company's substation banks are provided through the SCADA system. The Company's substation distribution breaker meter data does not provide Watt and VAR readings through the SCADA system and would be required for VVO. These measurements are required for VVO applications to make real-time system adjustments. The tap changer controls on substation transformers where they are available are not all based on newer technology that can be accessed and controlled through remote interface. In order to remotely adjust LTC settings, upgraded equipment will be necessary in many instances. O&R will conduct an inventory of all substation breaker relays and transformer load tap changer control types to determine if the existing equipment can be used for VVO. This effort is expected to be complete in 2017. Once this inventory is complete, work can begin on developing an upgrade plan for all units that do not meet the requirements for VVO function. The station inventory, relay, and control setting will need to be part of the VVO process and control system as most applications require the protection settings and voltage control set points to operate correctly. O&R will need to evaluate an asset management solution that will feed the data to an ADMS. O&R will also need to install remote control capability of transformer LTC settings that will work in conjunction with an ADMS system and VVO controller.

O&R will need to develop a standard for all new substation installations/upgrades to prescribe that new distribution breaker relays and LTC controllers are to have the required communication path, protocols, metering values (Watts, VARs, Set points), and setting functions for SCADA operation as it pertains to IVVC. Part of this standards development effort would be to evaluate the current state of substation communications and develop a solution for high speed data transfer to handle the increased metering data along with the command and control required for VVO deployment. Evaluations are expected to be completed in 2017. As the electric distribution system transforms from a radial system to a bidirectional one with the growing forecasted DG penetration, high speed data will be needed to monitor the power quality of the feeders as backfeed and fluctuating voltage conditions will become more common.

Available technologies will be evaluated to develop requirements for third-party technologies capable of providing VVO support. The evaluation process will identify the systems, protocols, secure communications, and metering that could facilitate third-party technology interactions, as well as the need for a DERMS to monitor and potentially manage and control third-party VVO equipment. The impact on CIP compliance with interacting with third-party systems must also be evaluated. As with any equipment or systems connected to the distribution system, if compromised, these systems could have an effect on the grid and service to customers. The evaluation will also explore ways for the Line Workers to safely work on the live distribution system with third-party equipment.

Finally, pilot programs to validate third-party technology that can support VVO functionality accurately and reliably for electric customers will be considered. A market model would need to be created before any third parties could provide VVO services.

VVO Capabilities Cost and Benefits

When the substation relay and LTC control inventory, described above, is complete, a cost estimate can be developed for VVO related equipment upgrades and the resultant ongoing O&M charges. The Company will then develop a plan for resource requirements to build out VVO functionality and resource requirements to maintain the new system. Next, an evaluation will be completed on the impact on data bandwidth, cyber security, communication infrastructure, identify required upgrades to LTC controls and other substation equipment such as protection systems, field forces for maintenance, and new cyber secure communications for DER. It is anticipated that VVO will demand more operations from substation transformers, distribution capacitors and voltage regulators, which will require additional maintenance activities and will shorten the life of the equipment. Therefore additional operational cost of the units will be considered as part of the overall cost to implement. Finally, the Company will prepare a benefit cost analysis for applying VVO to the entire system, and compare cost savings with costs for deployment and maintenance. In fully deploying VVO, and through pilot programs, O&R will develop and evaluate a philosophy for how best to optimize the operation of distribution capacitors, regulators and substation LTC in order to minimize wear and tear.

Additionally, the Company would explore opportunities to utilize third-party equipment to lessen the burden on the substation LTC.

Once full VVO is implemented it will be critical for the Company to carefully measure and verify the benefits attributed to optimization. Identifying the specific contribution from VVO will be challenging as this functionality is often deployed in conjunction with other peak shaving or energy saving measures. The methodology by which this is determined should make use of SCADA and AMI data as needed and involve stakeholder input, potentially as part of the Supplemental DSIP process.

Operating the system at optimal voltages will reduce total energy consumption as well as the associated emissions produced during power generation. Once all activities described above are completed, the Company will be able to leverage AMI and an ADMS to implement VVO, allowing the Company to reduce energy usage in the distribution grid and achieve a positive environmental impact of reducing CO_2 emissions in New York State.

Interconnection Process

O&R Interconnection Process Compliance with Track One Order

The Commission's Track One Order required that each utility have an interconnection online portal with certain capabilities (initial phase) by the time of the Initial DSIP filing. In addition, utilities are to report on their progress on a second phase of expanded capabilities in the same filing.

The New York State Standardized Interconnection Requirements[48] were established to provide a framework for processing applications to interconnect distributed generation systems to the State's investor-owned utilities' electric distribution systems. The SIR, updated March 2016, serves as the process guidelines for interconnection of DG systems up to 5MW, with any requests to interconnect to the transmission system handled by the NYISO utilizing the Federal Energy Regulatory Commission ("FERC") interconnection process. The SIR lays out a six-step procedure for DG systems 50 kW or less and an eleven-step procedure for DG systems from 50kW to 5MW of aggregate nameplate capacity which includes a more detailed impact study, known as the Coordinated Electric System Interconnection Review. Additionally, the NY PSC has established a state DG Ombudsman council, with representation from each utility in order to further coordinate on interconnection issues. This was modeled on a recognized best practice at Con Edison and adopted state-wide.

The Commission's Track One Order states:

> *For phase one capabilities, the customer should be able to apply through an online portal, with management and screening, including any needed impact studies such as load flow and fault potential based on DER penetration levels, occurring automatically with a decision issued to the customer in a timely manner. Each utility will be required to have these functionalities in operation by the time of their initial DSIP filing.* [49]

Phase one of the interconnection process improvement explicitly calls for a streamlining of New York State's current interconnection approval process to reduce administrative burden, increase transparency, and adequately prepare for greater amounts of DG deployment.

In phase one, using the SIR as a framework, the Track One Order asserts that each utility must establish the following functionalities while working toward a consistent state-wide look and feel:

- Ability to apply online;
- Automatically managing the application approval process;
- Responding in a consistent and timely manner;
- Providing standardized contract forms and terms;
- Enabling transparency into the process;
- Supporting the status tracking of times to approval and who is responsible;
- Sharing information via a publicly maintained queue;

[48] Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection Requirements, (issued March 18, 2016).
[49] REV Proceeding, Track One Order, p. 92.

- Providing automated technical screening and impact studies; and
- Improved timeliness for identification of study requirements.

The Track One Order states:

> *For phase two capabilities, the automated application and management process should be integrated with grid optimization planning. This will expand on simple measurement of DER penetration, to include modeling of potential system impacts of DER (both beneficial and adverse) on load flows and system protection at the feeder or more granular level. This should include risk assessment of the potential for DER to reduce system congestion, and for DER with ride-through capabilities to assist with a resilient response to system events. Phase two capabilities should result in economically desirable DER projects having ready access to interconnection approval, and potential market participants having ready access to information to assess the viability of a project from a system interconnection standpoint. Progress toward achieving phase two capabilities should be reported in each utility's initial DSIP.* [50]

EPRI was commissioned by the PSC and NYSERDA to explore the utility challenges and opportunities of further streamlining their current SIR interconnection processes, and instituting an Interconnection Online Application Portal ("IOAP") endowed with the Track One Order's specified level of functionality. In particular, the EPRI research effort focused on determining each utility's current interconnection applications practices and processes to develop a baseline for understanding the collective readiness of New York's utilities to meet REV's phase one goals.[51]

The objectives of EPRI's gap analysis included:

- Charting each utility's existing interconnection capabilities, including the conditions and approaches associated with the processing of interconnection applications
- Determining each utility's potential to implement an online portal as stipulated by REV phase one by, among other things, diagnosing existing tools and work flows in addition to their integration with utility functions
- Providing a best estimate of each utility's capability and timeline to design, develop, and implement an IOAP.

The EPRI analysis identified the following gaps in O&R's ability to achieve the REV Track One Order phase one objectives:

1. The website does not currently have the capability for the applicant to view the status of all amounts paid and/or due to the utility. (see SIR Section I.D.5)
2. There is currently a high degree of manual work required for technical reviews (screening, impact studies, etc.); expanded automation of technical reviews and screens, as well as integration into the existing work management system, is currently being explored to meet phase one objectives.

[50] REV Proceeding, Track One Order, p. 93.

[51] Electric Power Research Institute, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, Final Report, September 2015.

3. The technology to perform advanced screenings linked to the application portal has yet to be fully functional at this time in the industry; the timeline to meet this requirement needs to be adjusted to accommodate the market and industry to achieve this target.
4. The cost to integrate with existing internal systems and to train employees and customers has not been discussed.
5. Releasing data to a third party is a concern; O&R's model is proprietary, and there is value in its data and information systems; a Non-Disclosure Agreement ("NDA") would be needed with any vendor, and data and models may need to stay behind the wall within our realm.

As referenced in EPRI's analysis above, as of September 2015 the Company had an online portal to accept applications via New Business's application management software and Project Center. After reviewing additional enhancements, it was determined that the cost to modify the current software was cost prohibitive for the benefit obtained. While a simplified and more streamlined application management process could enhance the customer experience, as well as reduce the time needed to process applications, the tool proved too costly for the scale of enhancements required in Phase 2.

Prior to the REV Track One Order being released, the Company was in the process of reviewing new software to enhance the business processing of applications. That effort was paused due to the Gap Analysis being performed throughout the state by EPRI. The gaps identified by that process are part of this Initial DSIP and the Supplemental DSIP due in November.

O&R is making strides to close the gaps identified in the EPRI assessment as well as meet the tasks identified for Phase 2, which includes the integration of an automated application and management process with grid optimization planning

Smart tagging of DER locations within O&R's mapping system began in December 2015. With the DG type, location and output mapped, the Company can perform detailed analysis of the impacts of DER currently connected in addition to areas where DER interconnection would benefit the system. The project to map all 3000+ DER currently approved on the system was completed in January 2016. O&R is reviewing a process to automate the placement of DER symbols at each premise but will continue to manually install the symbology with each new DG installation.

Interconnection Portal Development and Optimization of Planning

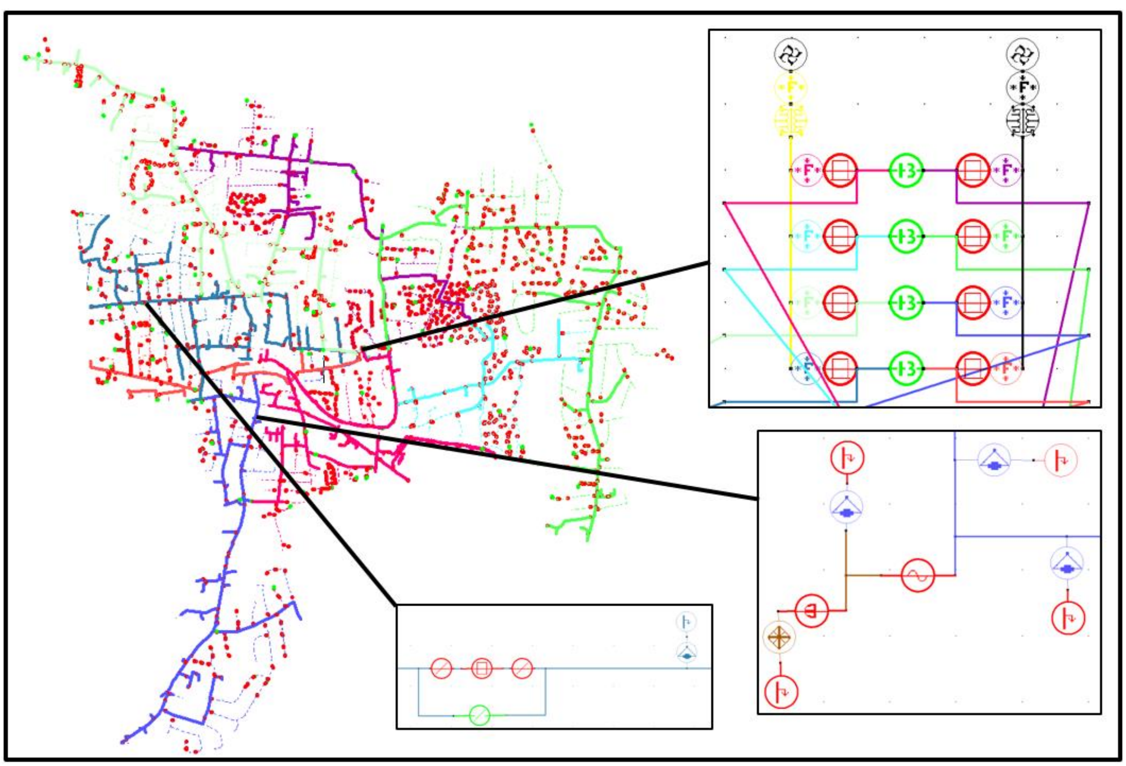
In March 2016, the Company began utilizing Clean Power Research's ("CPR") PowerClerk Interconnect software for processing applications. PowerClerk Interconnect is built upon the PowerClerk Incentives platform, the industry-leading software platform for renewable energy incentive processing. A hosted, web-based application, PowerClerk Incentives is used today to process about 70 percent of the solar (PV) incentive applications (by volume) in the U.S. It is also used to manage other technologies including solar hot water, wind and small hydro.

PowerClerk Interconnect integrates best practices and self-service features for administrators to define and control the workflow, application forms and more to handle a variety of interconnection scenarios in various states of change/process flow. O&R now utilizes PowerClerk to accept and process applications, sending automatic communications, setting project deadlines, and running reports through an easy to use administrative user interface. This automation closes Gap 2 identified in the EPRI report regarding automation. Technical screening will be addressed in the NYSERDA Project discussed below.

Applicants seeking interconnection for renewable energy systems with the administrator utility fill out applications, electronically sign documents, and later review their application status throughout processing. This will close Gap 1 identified in the EPRI Report regarding the status of payments due from the customer or processed by the utility. The introduction of this software closes Gaps 1 and 4 and helps closes Gap 2 as identified in the EPRI Assessment of NY State Readiness for DG Interconnection.

Currently, O&R uses a model-centric approach for design philosophy. With the model-centric approach, the same root Integrated System Model is used across all functions – planning, design, economic evaluation, training, real-time analysis, and real-time control. The ISM will be used to calculate alternative operating conditions and provide control or control alternatives under extreme or abnormal operating conditions (*i.e.*, storms) as well as under "blue sky" conditions. The ISM uses Distribution Engineering Workstation software, and provides a one-to-one representation of O&R's electrical system corresponding to its geospatial orientation in the service territory. O&R integrates data from GIS, Computer Aided Design , and transmission system models together into the single analysis model, relating customer load, customer load research statistics, SCADA measurements, EMS measurements, weather (historical and forecast) measurements, outage data, solar generation, and other data to appropriate equipment modeled in the ISM. DEW directly calculates power flows using the ISM. The ISM for the O&R distribution system is illustrated in Figure 2-1. O&R also models the transmission system in its ISM (not shown in Figure 2-1).

Figure 2-1
O&R Integrated System Model

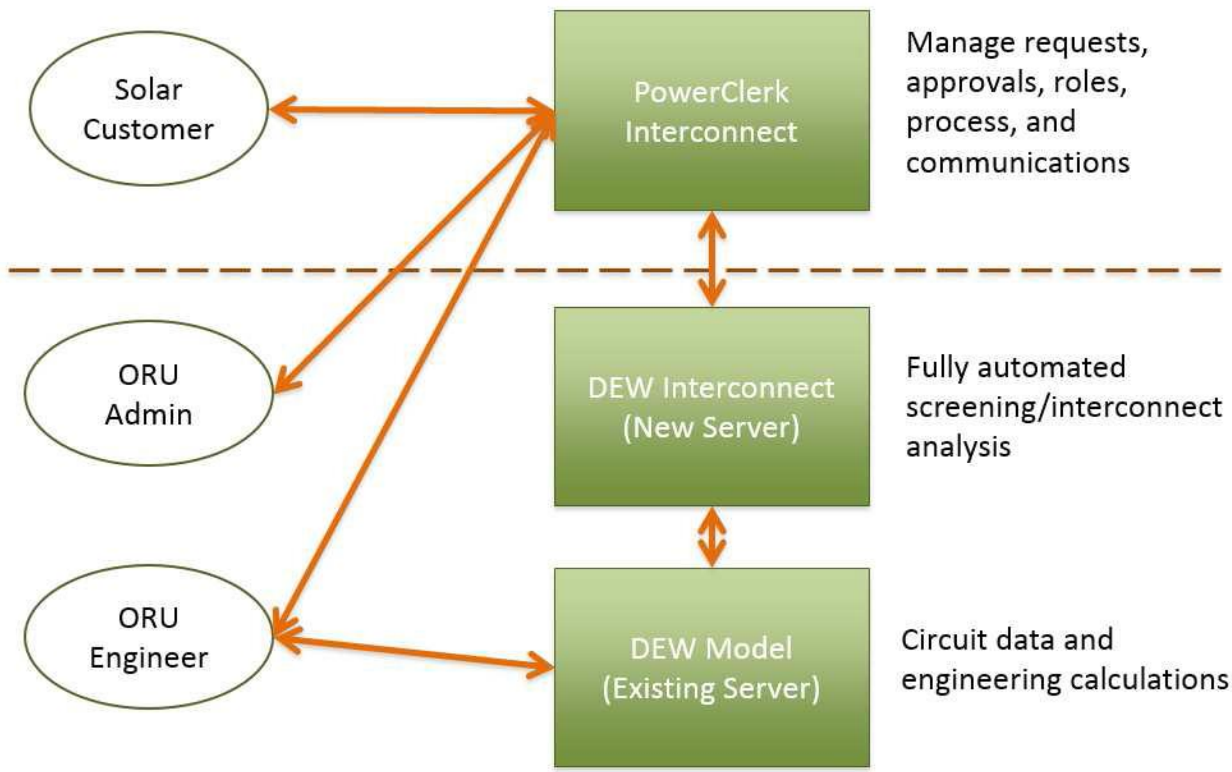


Gaps 2, 3, and 5 will be closed leveraging the Electric Power Transmission and Distribution ("EPTD") Smart Grid Program PON 3026 from NYSERDA to work with Electrical Distribution Design and CPR on a project with the objective of building a seamless DER Interconnection Assessment Application that consists of the CPR PowerClerk front-end integrated to DEW /ISM. Essentially, leveraging existing functionality from both products will provide a consistent, well documented, automated processes and analysis tools for streamlining interconnection application management and review. This project kicked-off in the first quarter of 2016 and will have a thirty-six month duration.

The proposed solution is to integrate existing industry-recognized software solutions for streamlined DER interconnections and distribution circuit analysis by CPR and EDD. The result will be a seamless end-to-end process for queuing, tracking, and managing DER interconnection requests; for quickly and transparently analyzing and responding to those requests; and for integrating DER into the engineering and operating models at O&R. Figure 2-2 illustrates the expected process flow.

Figure 2-2

Integrated Application / Queue Management and Analysis Process



Customers or solar providers will input DER Interconnection Requests into the PowerClerk software, which will manage the queue and related workflow. Upon receipt of a request from PowerClerk, DEW/ISM will automatically run interconnection screens based on O&R acceptance criteria. When a criteria violation occurs, the request will be forwarded for engineering review to assess the violations and plan corrective actions using DEW/ISM. All DER in the queue, regardless of approval state will be available in the DEW/ISM model, enabling engineers and operators to have a complete view of DER on the O&R system.

CPR will implement the PowerClerk Interconnect software as a service for O&R. EDD will implement a new instance of DEW/ISM at O&R that is dedicated to process interconnection requests. EDD/CPR will configure system interfaces so that requests entered into PowerClerk will automatically flow to DEW/ISM. The project team will configure the workflow process to manage an interconnection request from initiation through resolution. The technical evaluation process will likely involve three steps:

1. **Initial Technical Screen:** An automated simple screen checking location, size and existing PV in and near the requested location;
2. **Supplemental Review:** An automated, more detailed screen with power flow and step change analysis run on the feeder that includes analyzing all existing PV plus the proposed new PV site against O&R criteria based on IEEE 1547; and
3. **Interconnection Requirements Study:** A semi-automated detailed analysis performed by an engineer that includes identifying mitigation strategies to reduce/eliminate criteria violations when a request fails the automated screens.

The CPR PowerClerk workflow engine will be configured to move requests through the various steps in the process. Using processes defined by O&R, notifications will be automatically sent to appropriate persons involved in the end-to-end process including: customers, solar developers, administrators, engineers, and other stakeholders.

The solution proposed in this project will enable O&R to interface with customers for the purpose of tracking all interconnection requests in the queue. The workflow in the solution will track a request through all stages in the process. The process will be configured to align with client specified evaluation a criterion that is built around the industry standard IEEE 1547 publication interconnection requirements.

All DER attached to the system or proposed for attaching to the system will be managed in the database as well as be included in the ISM model of the distribution feeders. Having the data modeled for currently interconnected devices and the potential projects in the PowerClerk queue will assist in enabling the planning process to not only model and review existing DG and queued interconnections but allow the opportunity to forecast DG growth on the system based upon rates of applications received as well as actual installs.

Utilizing PowerClerk software will enable the planners to review projects interconnected on the system as well as within the queue. The data can also incorporate growths of DERs in certain areas of the system by incorporating actually growth rates based upon the size and type of DG interconnects and applications received. Once AMI technology is fully deployed, actual solar performance and irradiance data can be included in forecasting models to further enhance tools used in the planning and modeling process. The improvements to the interconnection process described in this section are estimated to include approximately $992K in capital costs and $225K in O&M costs for O&R over the next three years with additional costs expected beyond three years.

Stakeholder Input on Information Offered

O&R's Technology Engineering group has been in continual contact with DER providers that have interconnection applications in the O&R DG interconnection queue as the latest revisions to the SIR were developed. Most recently O&R offered to meet individually throughout 2016 with DER providers to discuss any potential substation backfeeding issues, CESIR updates as well as new requirements and timelines included in the most recent SIR Order. In these meetings the Company also solicited additional input as to the additional information that the DER providers would find useful. O&R

also has hosted several calls with the developers to better understand the financial impacts of interconnecting a solar project and to seek feedback on the O&R interconnection process. In many cases DER providers commented that O&R's Distributed Generation Interconnection Circuit Map was extremely helpful. Multiple DER providers accepted O&R's invitation and met with the Company. Members of the Technology Engineering organization also participated in the May 13, 2016 Con Edison – O&R Stakeholder Summit to provide additional information to DER providers. O&R has been and will continue to be engaged in utility industry conferences and discussions with entities such as EPRI Technical Working Groups for DER Integration and Power Quality, Smart Electric Power Alliance ("SEPA"), and the Centre for Energy Advancement through Technological Innovation ("CEATI") International Power Quality Groups.

Initial Distributed System Implementation Plan

Chapter 3 – Advanced Metering Infrastructure

AMI Rollout Plans

The Electric Rate Plan Order provides for the introduction of an AMI system in O&R's service territory. The Company will begin implementing an AMI system to, among other things, facilitate the Commission's REV policies and goals, reduce operating costs, accelerate identification of customer outages and improve overall outage response and efficiency. Per the Electric Rate Plan Order, O&R plans to deploy an AMI system beginning in Rockland County. O&R will be seeking additional approval to expand into Orange and Sullivan Counties to cover the Company's entire New York service territory, in its next rate case filing currently planned for late fall 2016. The part of the AMI project most visible to customers will be the installation of new AMI-enabled electric meters and new AMI communications modules for gas meters. As a transformative effort, the project will require a significant Company effort to implement the new processes, applications, technologies and integrations needed to fully enable the functions and features of the AMI system. In addition, high quality customer and stakeholder engagement and organizational change management will be essential to project success.

During 2015, the Company began preparations for the roll-out of AMI meters in 2017. Preparations included: finalizing the detailed business case analyses for the project; selecting the necessary equipment, software, and services; and, developing the AMI Business Implementation Plan. Starting in 2016, the back-office infrastructure will be designed, configured, tested and brought on-line to support the initial AMI capabilities. This infrastructure development requires approximately twelve months and is needed before the first meters can be installed. Collectively, this infrastructure enables the foundational aspect of the project upon which even more advanced capabilities can be developed to support customer program enhancements and operational improvements.

Starting in early 2017 when all of the new back-office infrastructure systems are in place and tested, the Company's focus will shift from the internal architecture to deploying assets in the field. The field assets consist mainly of communications devices, electric meters, and gas modules. A Meter Installation Vendor ("MIV") along with Company field forces and a separate Communications Installation Vendor ("CIV") will perform the installations. At this time, the Company is planning to install the communications infrastructure and meters over a four-year period (2017-2019 in Rockland County and 2018-2020 in Orange and Sullivan counties). The Company will first install communications and meters to the Pomona area in order to advance the ongoing NWA project. Business transformation activities and stakeholder/customer outreach and education has begun in advance of the field deployment and will continue throughout the deployment period. Plans for sequencing and timing the deployment across the service territory are being refined and an optimized deployment design will be completed by October 31, 2016.

With the appropriate data systems and web presentment in place, customers will have the opportunity to leverage the interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions. For example, a customer's energy consumption patterns might indicate that the customer would benefit by replacing an aging refrigerator or by installing a battery or solar array. When integrated into the digital energy marketplace contemplated under REV, such data will become invaluable to both customers and distributed energy resource providers as they bundle various products and services together to meet unique customer needs and provide solutions at scale.

Orange & Rockland

The AMI communications network and AMI meters deployed through this project will provide the foundation for implementing several of the policy objectives stipulated by the Commission in the REV proceeding. AMI will help achieve key REV objectives by improving system visibility, enhancing controls, and supporting advanced analytics. Specifically, AMI capabilities will make it possible for the Company to align with REV guidance by:

- **Helping customers better manage and reduce their energy costs:** Customers will have access to their interval electricity usage data, the granularity and visibility of which will increase their ability to adjust their consumption patterns to reduce their electricity bill. As a result, customers may choose to participate in new time-based rates and demand response programs offered by the Company.
- **Enabling market processes:** AMI is fundamental to the future development of market systems that can leverage actual customer usage data rather than models based on estimated usage. For example, AMI will measure the inflows and outflows of energy from customer premises on an interval basis so that customer purchases from different sources, as well as the sale of customer generated energy, may be accurately billed. The NYISO is currently putting together plans for a new Behind-the-Meter Net Generation tariff that will allow net generators to sell capacity into the NYISO market. If the NYISO customers are paid like generators, they may require five minute or less interval meter data. AMI can provide the necessary revenue grade metering information to support this initiative with strict adherence to the confidentiality, integrity and availability of this data.
- **Improving system efficiency and resiliency:** The ability of AMI communications and AMI meters to better monitor the Company's distribution system and performance of DER equipment can enhance quality of service and performance by enabling customer programs and technologies that may efficiently reduce demand and increase renewable generation. Real time monitoring of DER is essential to the DSP to track DER performance and capabilities both to make same day operational decisions and for near- term forecasts and scenario decisions.
- **Improving Industry Standards Compliance:** AMI utilizes telecommunications standards which will lower the cost of integration and development for many future REV-driven programs and plans across the utility enterprise. Standards-based communications will allow for greater security and improved management of the meter device system, while standards for communication data structures will improve integration with other systems. Specifically, AMI's back office information systems (Meter Data Management and the AMI Control System) recognize standard integration protocols, including web standards (i.e., OpenADR, IEC-CIM, MultiSpeak) which may be used to develop demand response, responsive DERs, maintenance management, outage management, and customer service system integrations.
- **Reducing Greenhouse Gas Emissions:** AMI will reduce the number of vehicles on the road for meter reading and repair functions. Customers may also conserve electricity (and thereby reduce generator emissions) through increased awareness or by participating in time-based rate and demand response programs enabled by AMI.
- **Supporting Flexibility in Rate Design:** AMI is foundational to supporting demand charges as well as other new rate designs to provide customers with price signals that better reflect the actual costs their usage imposes on the system and, correspondingly provide the information necessary to more effectively manage their electricity and gas bills.
- **Enabling Third Party Access to Customers' Energy Data:** With the appropriate data systems in place AMI can make customer electricity usage data available, per customer consent and security

requirements, to third party providers who can provide additional services for customers. O&R's AMI project will directly support REV and the Commission's Track Two Order by providing the data that can be made available to third parties, for a fee, to enable and support customer behavior change, as well as the tools necessary for the market to engage and drive solutions to scale.

Descriptions and estimates of five major investment/cost elements associated with the AMI implementation and on-going support are outlined below. Costs are defined by general area. A summary of the 20-year cumulative nominal values for each of these cost categories is included.

Table 3-1

AMI Investment/Cost Summary ($ in millions)

Cost Category	Description	Capital Investment: 20 Years	On-going O&M: 20 Years	Total Expenditure: 20 Years
AMI Meters	Physical AMI Meter (and supporting labor) to be installed at each premise/location	$56	N/A Accounted for in Ongoing Operations	$56
AMI Communications	AMI Network Infrastructure to support communications from the AMI meters to "head end"	$7	$3	$10
IT Platform	IT platform/systems to enable and support AMI system	$18	$5	$23
Labor & Project Management	Management of project during deployment, implementation	$17	N/A	$17
Ongoing Operations	On-going AMI Operations	N/A	$18	$18
Total Costs		***$98***	***$26***	***$124***

The Electric Rate Plan Order stated that:

> *"when the Commission acts on the Company's DSIP filing, the Commission may further consider the implementation of AMI, including deciding to modify or halt the Company's implementation of its proposed AMI system. In the event of a determination by the Commission to stop or modify the AMI system, all AMI project costs prudently incurred by the Company up to project cancellation, shall be recoverable by the Company. In such an event, recovery will not be provided for costs such as those for acquiring and/or installing any software, hardware or*

equipment that is ultimately not needed or cannot meet the required needs as determined at the time the Commission issues its final DSIP Order or earlier." [52]

In the DSIP Guidance Order the Commission stated:

> *"The deployment of AMI or equivalent advanced metering functionality will be an important contribution to enabling utilities to assume the role of the DSP. AMI will provide information that affords customers the opportunity to participate in demand response and energy efficiency programs, as well as innovative rate structures, allowing them to better manage electricity consumption and bills and drive overall system efficiencies. Additionally, AMI will facilitate customer access to value-added products and services provided by third parties including DER providers and ESCOs."* [53]

The Company believes its current AMI Plan is consistent with the Commission's intentions and expects to move forward with the purchasing of the necessary AMI equipment.

Customer Engagement Plan

In November 2015, Con Edison filed its AMI Business Plan as part of its current electric rate plan.[54] On March 17, 2016, the PSC issued an order approving Con Edison's AMI Business Plan subject to a conditions,[55] including that Con Edison file a detailed customer engagement plan by July 29, 2016. O&R is developing an AMI Customer Engagement plan in conjunction with Con Edison to provide for the continuing engagement of customers and third parties, and will file on July 29, 2016. Innovative rate structures to allow customers to take advantage of new capabilities, are also being developed jointly with Con Edison, and will be filed on July 29, 2016. O&R will be seeking recovery of the incremental costs associated with the Customer Engagement Plan and development of Innovative rate structures in its upcoming electric base rate case.

The Company has already begun stakeholder collaboration through meetings to discuss the AMI customer engagement plan. The objective is to drive collaboration amongst the group in areas such as customer education, Green Button Connect, innovative rate design, cost savings and revenue opportunities and data privacy. The first meeting was held on June 2, 2016 and provided external stakeholders an overview of the Customer Engagement Plan filing and key areas of collaboration. The goal of the following two meetings, one of which took place on June 14, 2016 and the final is scheduled for July 15, 2016, is to drive collaboration around draft proposals in these topic areas. The ultimate goal of the collaborative effort is to engage external stakeholders in determining how to best empower customers with knowledge and access to AMI benefits, as well as the ongoing engagement of customers and third parties.

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[52] Electric Rate Plan Order, Attachment A, P. 21.
[53] REV Proceeding, DSIP Order, p. 58.
[54] Con Edison 2015 Electric Rate Case, Con Edison AMI Business Plan.
[55] Con Edison 2015 Electric Rate Case, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, (issued March 17, 2016).

Benefit Cost Analysis

An updated Benefit Cost Analysis consistent with the PSC's current BCA framework is also being developed along with Con Edison and will be filed on July 29, 2016.

Proposed AMI Metrics

The Company has developed metrics to track certain aspects of the projected benefits from AMI deployment. The proposed metrics address a wide range of projected benefits the Company forecasts will be achieved and that it discusses in detail in its AMI Business Plan (Appendix B). The table below outlines the metrics and the proposed reporting schedule that would enable the Commission to monitor the success of the AMI project. Measuring these successes will help to quantify the cost reduction benefits discussed in the Business Plan. For example, the Company estimates that through the course of the AMI project, O&M savings will be realized due to the reduction in manual meter reading labor as identified in Business Plan. Although it is useful to track progress during implementation, benefits of AMI cannot be fully realized until implementation is complete, which is projected to be by year end 2020. In addition, incremental benefits may not be directly proportional with each phase of implementation. That is, twenty percent AMI deployment does not mean twenty percent of the benefits will be realized. Nor may such benefits be achievable immediately following such deployment, as there would be some reasonable transition, or "ramp-up" period, associated with each projected benefit.

The Company envisions reporting on the metrics on a regular and recurring basis pursuant to the reporting timeframes included in the attached schedule, varying with the type of benefit being tracked, the usefulness of the information in relation to the time period over which it is being tracked and reported, the amount of analysis involved and the amount of time needed to gather meaningful information for each metric. For some metrics, it is anticipated that it will take six to eight weeks following the end of each period to analyze the data and prepare a report. In others, there will be available progress data that is useful and reported on a more frequent basis. In order to best manage its resources, the Company proposes quarterly reports for data not requiring data gathering and analysis and semi-annual or annual reports for those metrics that require the Company to undertake more involved data gathering and analyses.

Table 3-2

O&R Proposed AMI Metrics

Category	Service / Function	Metric	Description	Goal	Report Start Date (At end of quarter specified)	Update Frequency	Notes
Customer Engagement	DCX Portal	**Customers using the AMI Portal**	% of customers with AMI meters who log into portal to view usage information each quarter.	TBD after one full year of AMI deployment	4Q2018	Quarterly	A benchmark will be established in the first year to track how many customers logged into the portal to view their energy usage.

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Category	Service / Function	Metric	Description	Goal	Report Start Date (At end of quarter specified)	Update Frequency	Notes
		Customers identified to receive energy saving messaging - All (Including Low Income)	% of customers identified to receive messages regarding their energy savings tools, personalized usage and or savings tips	A percentage of customers that will be identified to receive messages will be established by end of 2Q2017. (Identifying all customers is cost prohibitive. Analytics will be utilized to identify customers to communicate to)	2Q2018	Semiannual	The Company is determining the feasibility of tracking the number of customers who use the online portal once they receive their specific message for energy savings to identify energy usage since the analytics dashboards will not be available until 2018
	Awareness / Education	**Near Real Time Data**	Number of customers who have access to near real time data via the web after AMI meter installation	Starting at end of 4Q2018, 99% of meters deployed will be presented with near real time data	4Q2018	Semi annual	This reporting will begin in December 2018; the Company will not be implementing near real time data until the second phase of the AMI project (third quarter of 2018)
	Awareness / Education	**Customer Knowledge of AMI**	Awareness survey related to AMI benefits and features	Survey to be conducted prior to establishing a baseline goal. Subsequent surveys to improve knowledge on periodic basis after goal is established	4Q2017	Semi annual	The Company will perform an initial survey that will be used to determine the initial customer awareness by March 2017. The survey will be a random sample that is representative of the Company's service territory
	Awareness / Education	**Targeted Energy Forum Presentations**	Number of presentations provided; Target 2 per year	2 per year	30-Apr-18	Annual	Schedule and present two energy forums within the service territory per year
	Green Button Connect My Data	**Green Button Connect My Data**	Track number of customers who use GBC to share their energy usage information with third parties	Number of customers with an AMI meter using GBC per quarter	30-Apr-18	Quarterly	Track the number of customer who use GBC per quarter
	TOU (Time of Use) and TVP (Time Variable Pricing) tariff	**TOU (Time of Use) and TVP (Time Variable Pricing) tariff**	Track the number of AMI customers enrolled in the innovative rate pilot programs	Number of customer with an AMI meter enrolled in new rate pilot programs	4Q2018	Quarterly	Track the number of customers enrolled in innovative rate pilot programs per quarter

Orange & Rockland

Category	Service / Function	Metric	Description	Goal	Report Start Date (At end of quarter specified)	Update Frequency	Notes
Billing	Billing	**Estimated Bills - AMI accounts**	% of accounts with bills which are estimated	Less than 1.5 % of bills rendered every 6 months for customers with an AMI meter will be estimated	30-Jun-18	Semiannual	
Outage Management	O&M Cost Reduction	**Emergency response labor reduction**	Number of single outages for a large storm 50,000 or more outages) that were determined remotely via AMI eliminating the need to send a crew or call to confirm power restoration	TBD once AMI is fully deployed across the New York Service Territory	4Q2018	Annual	The Company will be reporting this metric when the new Outage Management System is fully integrated with AMI at the end of 2018
	Power Quality	**Proactive power quality issue identification**	Number of power quality issues identified through the use of AMI data	TBD once AMI is fully deployed across the New York Service Territory	30-Apr-18	Annual	The Company will report annually on the volume of PQ issues identified via AMI data
	False Outages	**Number of false outages resolved through AMI**	Number of false outages that were found through AMI that Company did not have to send a crew or call to confirm	TBD once AMI is fully deployed across the New York Service Territory	4Q2018	Annual	The Company will be reporting this metric when the new Outage Management System is fully integrated with AMI at the end of 2018
System Operation and Environmental Benefits	Meter Reading Costs	**Reduction in manual meter operations costs**	Track avoided meter operations O&M costs and report	In accordance with O&M savings filed in AMI Business Plan	30-Apr-18	Annual	Data will be provided every April for the year prior
	Environmental benefits resulting from less vehicle usage	**Reduction in vehicle fuel consumption and vehicle emissions**	Reduction in vehicle emissions due to reduction in manual meter reading	This goal will be aligned with the information provided in the AMI Business Plan on tons of carbon avoided	30-Apr-18	Annual	Orange and Rockland expects to eliminate approximately 4.75 metric tons of vehicle emissions (carbon dioxide equivalent) related to meter operations per vehicle per year

Category	Service / Function	Metric	Description	Goal	Report Start Date (At end of quarter specified)	Update Frequency	Notes
	Conservation Voltage Optimization (CVO)- KWh savings	**Quantify kWh savings attributed to CVO**	Quantify kWh savings attributed to CVO	In accordance with savings identified in AMI Business Plan	30-Apr-18	Annual	Data will be provided every April for the year prior
	Conservation Voltage Optimization (CVO)- Environmental benefits	**Environmental benefits due to CVO**	Provide total fuel consumption savings and corresponding emissions reductions	This goal will be aligned with the information provided in the AMI Business Plan on tons of carbon avoided	30-Apr-18	Annual	Data will be provided every April for the year prior
Meter Deployment	Deployment	**AMI Meters Deployed per month**	Number of Meters Deployed per month	TBD - the final meter deployment schedule is still begin finalized	4Q2017	Semiannual	The Company will report this metric twice per year in January and July describing the actual number of meter deployed compared to the forecasted number of meters to be deployed in the prior six months

Third Party Integration

Customer owned equipment can easily be integrated into the AMI communications network. O&R has selected Silver Springs Network ("SSN") as the AMI vendor. SSN has a foundational concept built into its business model of interoperability. SSN has numerous partners and vendor relationships where third-party manufacturers have built devices that can connect to the communications network.

There are two ways in which a utility can grow the ecosystem of devices participating in the network, and Silver Spring fully supports both approaches. First, with a core competency in integrating the Silver Spring Network Interface Controller ("NIC") into third-party devices, Silver Spring has embraced standards to drive the speed and efficiency of these integrations to enable more devices to embed the Silver Spring NIC at manufacturing time. Examples of standards used in integration include C12.19, DLMS/COSEM, DNP3, and CoAP. The other approach is to allow third-party devices to connect to the network via interoperable standards. Silver Spring is growing its industry leading ecosystem via this approach as well by engaging deeply in interoperability alliances such as Wi-SUN. Furthermore, a robust partner network already exists, where Silver Spring has integrated and tested 3rd party products, and certified them as compatible with the SSN network.[56]

All Silver Spring Gen4 and Gen5 wireless mesh products have implemented 802.15.4g and are 'Wi-SUN ready' now. Silver Spring has the industry's first Wi-SUN PHY certified products, where certification covers both conformance (correct implementation to the standard) and interoperability (wireless interoperation with other conforming products). Silver Spring additionally expects to be the first networking provider to have full Wi-SUN FAN certification, as Silver Spring's implementation is the most mature. Interoperability testing is performed between devices from multiple vendors, and Silver Spring is awaiting parallel implementations to become sufficiently complete so that interoperability may be tested.

While details of Wi-SUN testing methodology are confidential to Wi-SUN members, Silver Spring can share that it is generically verifying conformance to PHY specifications from IEEE 802.15.4g and MAC specifications from IEEE 802.15.4 and TIA TR-51. Silver Spring is also verifying PHY and MAC interoperability amongst products from multiple contributing organizations.

[56] http://www.silverspringnet.com/partners/

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Chapter 4 – Customer Data

Customer Data

The Commission acknowledged in its Track One Order, that the success of REV depends on the ability and willingness of customers to engage in DER programs with third-party providers. Customers' ability to engage in these programs is, in part, predicated on providing customers and third parties with relevant, useful, and actionable data and information.

Making customer data available, and providing third parties with access to that data via a customer-driven authorization process, is a central element of O&R's role as a DSP provider. As the DSP is developed and the REV marketplace grows, it is the Company's expectation that multiple types of third parties will need access to customer data in order to participate in the distributed market. O&R's near-term initiatives to improve access to customer data, described below, will enable the Company to provide useful data to customers and authorized third parties via tools that are secure, easy to use, and based on industry standards and best practices.

O&R believes that customer control over the authorization and dissemination of information to third parties is essential to maintaining customers' trust. Customers should make an affirmative choice to provide their data and should be educated on what that affirmative choice means for the disclosure of their data so that any release of customer data is done with their full knowledge and consent. Additional information on O&R's approach to data privacy and security is provided at the end of this chapter.

Usage Data Provided to Customers

O&R currently provides data to customers through four key channels: their bill, their *My Account* Portal, the Customer Care Portal and the public website ORU.COM. The O&*R My Account* portal provides the customer with access to manage and analyze their usage and account. The *My Account* portal provides the customer with numerous self-help account options and requires a username and password. The username and password can be set up by the customer on the ORU.COM website or by contacting a Customer Service Representative who will validate that they are working with the customer of record for that individual account. If a customer has multiple accounts, they can be joined under one username and password for the customer's convenience. The customer can access their *My Account* portal via desktop, computer, tablet or telephone as O&R utilizes mobile web capabilities and a Phone App accessible by iPhones and Android telephone technology. The portal allows customers to:

- Pay their bill;
- Review their account status;
- Utilize Green Button Download;
- Change their profile;
- Manage multiple accounts under their authority;
- Arrange for payment or collection agreements;
- Register for electric outage notifications via text;
- Stop service on their account;
- Sign up for Automatic Bill Payment;
- Utilize a home energy calculator; and

- Review their price to compare when shopping for third-party suppliers.

O&R also has developed a Customer Care Portal which allows Full Service Mandatory Hourly Pricing Customers with usage over 300 kW to review their interval data (in hourly or fifteen minute intervals) on a twenty four hour lag and perform various modeling exercises with their interval data.

The Company's AMI program will provide more granular consumption data for both gas and electric services, with gas consumption available hourly, residential electric consumption available in fifteen minute intervals and commercial electric consumption data available in five minute intervals. As explained below, O&R will provide customers with tools for increased visibility to their electric and gas consumption patterns will give customers the capability and empowerment to make better energy usage decisions and potentially lower their energy costs.

Customer Data and Engagement

The Commission acknowledged in its Track One Order that the success of REV depends on the ability and willingness of customers to engage in DER programs with third-party providers. Customers' ability to engage in these programs is, in part, predicated on providing customers and third parties with relevant, useful, and actionable data and information.

The Company takes protection of customer information, including personal information provided by the customer as well as usage data, very seriously. These principles are reflected in the Company's approach to each of the following initiatives. Additional information on O&R's approach to data privacy and security is provided at the end of this section.

Digital Customer Experience

In tandem with the AMI roll-out, the Company will enhance the ability of customers and third parties to obtain and utilize customer data as part of its Digital Customer Experience program. This program is designed to deliver an improved experience across all digital touch points. This redesign will cover www.oru.com, the O&R mobile website, the My Account portal, Customer Care, and the mobile app. All of the Company's customer-facing information channels will be consolidated and accessible through a single sign-on process. To preserve flexibility as the DSP is developed; the DCX program will rely on a robust technology platform which will be scalable and adaptable for future needs.

The O&R DCX program will be rolled out jointly with its affiliated company, Con Edison, in phases starting in 2016 through 2020, coinciding with the Company's AMI rollout with a total estimated O&R project cost of $4.0M in capital and $3.0M in O&M expenses over the next five years, with additional expenses expected beyond five years.

Green Button Connect Implementation Plan

O&R, in coordination with Con Edison, is proposing to implement a data sharing tool that uses Green Button Connect My Data standard protocols to transmit data to authorized third parties. GBC is a nationwide protocol, based on modern technical principles (*e.g.*, representative state transfer application program interfaces ("REST APIs"), Oauth 2.0 authorization protocols, XML). These protocols provide a process for customer authorization, data transfer, and data format for the exchange of data. Customers can utilize the GBC protocol to grant access to a specific third party on a historical basis, an ongoing basis, or a temporary basis. Once a customer provides proper authorization, the exchange of data with the third party is fully automated via the standard GBC API. Data processed according to GBC standards does not include any PII.

The Company is proposing to implement GBC for three key reasons. Using a nationwide standard protocol will support adoption by third parties that operate in multiple jurisdictions and are capable of receiving data in the GBC format. It is also consistent with, and complements, the Company's new DCX platforms. And, most importantly, the GBC transfer process is secure and customer-driven.

As previously stated, GBC will be implemented in phases beginning with providing customers with their usage data. Other aspects of customer profile information create added complexity and cost and it is unclear at this time what additional customer data that customers, third parties, or the Commission has determined to be necessary, relevant, useful, actionable, and cost-effective. Therefore, the Company will focus on developing protocols for transfer of customer-specific interval usage data first, with the anticipation of expanding the available data set after further assessment of data needs, including, but not limited to, consideration of the results of the Company's REV demonstration projects.

The Commission's March 17, 2016 Order,[57] in Con Edison's rate proceeding directed Con Edison to "develop a proposed implementation plan, budget and timeline for implementing Green Button Connect My Data so that customers' usage data is available from a central portal using Green Button Connect My Data." The AMI Order further states that "the proposed implementation plan shall be included in Con Edison's consumer engagement plan filing, which is due no later than July 29, 2016"[58]. O&R is developing it Green Button Connect requirements and architecture jointly with Con Edison and work plans are on the same schedule for efficiency and continuity across the companies. O&R's estimated project costs for rollout and maintenance of GBC are $1.4M in capital and $350K in O&M expenses over the next five years, with additional expenses expected beyond five years.

ESCO Data Access

Since 1998, investor-owned utilities have served as facilitators of the Retail Access market in New York State. In this role, the utilities have provided Energy Service Companies (ESCOs) with access to customer data in two main channels: Electronic Data Interchange ("EDI") transactions and a web interface that displays account-level information. At O&R, this web interface is referred to as the Retail Access Information System ("RAIS"). The EDI system provides much of the same information as the web interface, but is capable of processing large batch requests and provides additional transactional functionality required to administer the Retail Access market.

Currently, the New York Uniform Business Practices ("UBPs") govern the process by which ESCOs are granted access to customer data. Under the UBPs ESCOs are required to obtain a customer's consent to share their data, and retain documentation of that consent for two years. The UBPs require utilities to assume that a customer has consented to share their data if an authorized ESCO provides the utility with a customer account number. This same arrangement has been proposed to apply to all

[57] Con Edison 2015 Electric Rate, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, (issued March 17, 2016).

[58] Con Edison 2015 Electric Rate, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, (issued March 17, 2016), p. 41.

distributed energy resource providers in Case 15-M-0180[59], which would include Community DG Sponsors and other third parties.

The following table details some of the information that can be obtained by authorized third parties in the O&R RAIS portal, and EDI:

Table 4-1

Information Available on the RAIS Portal

Data Field	Channel
15 minute interval data	RAIS
Actual vs estimated read	EDI
Bill amount	EDI
Customer name	EDI, RAIS
ESCO status	EDI, RAIS
Hourly interval data	RAIS
Hourly meter indicator	EDI
ICAP tag	EDI, RAIS
Industrial code	EDI
ISO load zone	EDI, RAIS
Load profile ID	EDI
Meter number	EDI
Net meter status	EDI, RAIS
Next read date	RAIS
NYPA indicator	EDI
Percent residential	EDI
Recharge NY status	EDI
Service address	EDI, RAIS
Summary kWh history	EDI
Tax status	EDI
Bill Group schedule	EDI

EDI will continue to play an important transactional role in the New York Retail Access market, as indicated by the Commission in the Con Edison AMI Order[60], and therefore will continue to be supported by investor-owned utilities. Currently there is no established EDI transaction for interval data, so Con Edison and O&R are investigating options to make month-end AMI interval data available

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

[60] Con Edison 2015 Electric Rate Case , Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, (issued March 17, 2016), p. 42.

through EDI. Regarding the Commission's DSIP Guidance Order directive to provide information on its plans to "give ESCOs access to daily, hourly, and, eventually, close to real-time access to customer usage information, including budgets and timelines"[61] to fulfill this requirement, the Company plans to offer a new data exchange for ESCOs to access their customers' usage information, using as a foundation the same RESTful APIs developed for the GBC tool. This data exchange will provide ESCOs with an automated process to request and receive interval data that is more convenient than the current method of retrieving individual customer files from RAIS for each customer with interval data. Since the ESCO interval data exchange will rely on the same RESTful APIs developed for the GBC tool, the project will not incur incremental costs, and will proceed on the same timeline as the Company's GBC implementation.

Privacy and Security Requirements

The Company takes protection of customer information, including personal information provided by the customer as well as usage data, very seriously. The Company has a longstanding position that it does not share customer information with others without customer consent, except where required by PSC Order. The Company reserves the right to share, with its own agents and vendors, customer lists, and other customer information in order to market products or services to customers.

With respect to security of customer information, O&R recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program that is designed to protect Company computers, servers, business applications and data, and high value networks from unauthorized access and control from both external and internal threats. The Company also recognizes that the threat landscape constantly evolves and expands, and that it is critical to continuously improve our defense posture through investments in technology, improvements in our cybersecurity processes, and through collaboration with law enforcement, regulatory and industry resources.

Computer security will remain a major concern for the Company for both the short and long term. Malicious software and intrusions continue to become more sophisticated. We therefore must continuously improve our defenses. In addition to the cybersecurity elements described in this document, the Company is planning the following improvements in the near future:

- Expand the use of intrusion detection and prevention technologies
- Deploy the next generation of remote access technologies which take advantage of better authentication methods like Adaptive Authentication and Mobile Device Managers
- Improve employee awareness about cybersecurity through training and communications
- Continue to segment computer networks and users

Customer Engagement

In the area of Customer Engagement, O&R's core objective in developing the DSP are two-fold: first, to engage customers by providing them with information, education and tools to make informed

[61] REV Proceeding, DSIP Order, p. 62.

decisions about energy services; and second, to develop the capabilities and systems needed to facilitate customer activity in the distribution marketplace. To meet these objectives the Company has begun development of a multi-level strategy that incorporates and builds on existing initiatives and strategically expands the scope into new areas. The following section outlines the current state of the customer engagement efforts, and provides an initial set of plans to further enhance those efforts as DSP markets take shape.

Building on Existing Customer Engagement Activities

In order to successfully engage customers O&R recognizes that, at a minimum, it must sustain its ongoing efforts in the following areas:

- Providing quality customer service, as measured by PSC-mandated performance metrics, and complying with all regulations related to customer service
- Enhancing relationships with customers
- Focusing on understanding and anticipating customers' evolving needs and expectations

By maintaining the commitment to these core efforts the Company will maintain customer trust and sharpen its insights into what customers' value.

Enhancing Customer Relationships

Consistent with O&R's core values of service, honesty, concern, courtesy, excellence, and teamwork, the Company has a number of ongoing initiatives that focus on enhancing customer relationships. All O&R employees are required to participate in a 1-day training class to help improve their interactions with customers and better meet customer expectations. Online training is also available to reinforce successful communication techniques and customer focus. Focus on these topics is an ongoing effort, and most recently a Company-wide communication cascade was launched to drive a *Plus One* strategy for improving customer interactions.

Over the last several years the Company has rolled out a number of efforts to keep customers informed of when Company work may impact them. The Company uses telephone calls to notify customers of projects going on in their neighborhoods that may affect their service. Notifications are sent to customers to advise them in advance of tree trimming activity. The Company also monitors social media and responds to customer inquiries and posts information that provides real time updates of conditions in the field.

To improve performance related to customer appointments, a customer appointment performance metric has been implemented at O&R for Customer Meter Operations, Gas Operation and Electric Operations with a target of 95% of customer appointments kept on time for these organizations.

Leveraging Existing Tools and Resources to Increase Engagement

In recent years the Company has worked with stakeholders to develop online tools and resources that assist customers in making informed decisions about energy services. Following are some of the resources available to mass market customers on ORU.com:

- ESCO bill comparison tool for Retail Access customers to determine what their bills would have been if they were purchasing supply from the utility; and

- Home Energy Calculator that leverages actual billing data to analyze a customer's home energy use and the savings that can result from a variety of energy efficiency measures.

In addition to these tools, the O&R public website presents information about various programs and services available to customers, including the Company's portfolio of energy efficiency and demand management programs, outage information, and resources for certain customer segments such as low to moderate income customers. As described above, all of the Company's current digital resources and content will be refreshed and incorporated into the re-designed website as part of the DCX program. Content and tools will be organized so they are easy to find and explore.

Listening to Customers

O&R recognizes that in order to deliver an improved customer experience and make inroads in customer engagement, it must focus on understanding and anticipating the needs, priorities, and expectations of customers. To that end, O&R is redoubling its efforts to engage customers in an ongoing dialogue about the service that they receive from the Company, and ways to enhance their experience. Key initiatives include:

- Customer Service conducts a monthly transactional survey that measures how satisfied the customer's interaction was with the CSR and field representative. The survey focuses on the knowledge of the employee, length of time the customer waited to speak to a CSR, and how satisfied overall the customer was with the representative. The surveys are reviewed to identify training needs and areas for improvements;
- The Company maintains regular communication with customers through bill inserts, bill messages and the @Home publication enclosed in customers' bills. Elderly, blind and disabled; low income; and life sustaining equipment customers receive additional information to assist them throughout the year especially during the cold weather period; and
- Additionally, the Company will be incorporating new survey and feedback-gathering capabilities into recent investments in the customer service infrastructure. The new Call Center Enterprise Solution which is a state of the art telephony platform providing automated call distribution, IVR, media recording, dialer, reporting and speech analytics. Future enhancements will allow for immediate feedback via post-call customer surveys. Similarly, the DCX program will feature technology that allows customers to provide comments and feedback on all pages and after completing transactions. In both examples, timely customer input will allow for identification of areas that need improvement and drive enhancements.

Expanding Scope to Improve Customer Engagement

As O&R builds on existing customer engagement activities, it is also in the process of implementing new systems and developing new capabilities that will drive customer engagement as the market evolves. Examples of these activities, many of them introduced earlier in this Chapter, include creating new digital tools that help customers visualize energy usage information and use it to evaluate distributed energy opportunities, providing a customer-driven process for sharing energy usage data with authorized third parties, and testing an online marketplace that engages in-market consumers as they are shopping for household energy and energy-consuming products and services.

AMI, DCX & Green Button Connect

As described earlier in this Chapter O&R is poised to invest in AMI, the DCX program and Green Button Connect My Data to facilitate greater data access. These initiatives will also give customers, market participants and stakeholders an integrated suite of new tools that will enhance customer engagement.

The DCX program will enhance communication and interactions with customers and stakeholders by providing a simple, intuitive, and personalized experience anywhere, anytime, on any device. Leveraging AMI data, it will also provide improved analytical capabilities to better understand customer behavior and empower customers with tools to make informed decisions. The end result will be a low-effort, high-satisfaction digital customer experience that will drive increased customer adoption of digital channels.

By design, the DCX program will also support and complement efforts in the REV proceeding. It will provide seamless interfaces for customers participating in the Company's REV Demonstration Projects and later iterations of REV market development. It will also enable clear communications with participants in complex rates and programs.

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Initial Distributed System Implementation Plan

Chapter 5 - Distributed System Platform Technology Roadmap

Introduction

In conjunction with the myriad changes required for O&R to grow into the role of a DSP Provider, a number of foundational technology investments and enhancements will be required. The DSP Technology Roadmap examines the Company's current IT and communications capabilities, the near term DSP functionalities required, the gaps in meeting those requirements, and the plan to close those gaps in order to develop the DSP functionalities proposed over the next five year period and beyond.

These plans are an early conceptualization of the foundational and functional requirements that will be necessary to fully support the programmatic changes that are envisioned and outlined in this DSIP, and will be followed up on and adjusted as necessary in future DSIPs. They are subject to change and modification in subsequent DSIP filings as technology and circumstances develop in this evolving utility environment. The pace of the implementation of the DSP Technology Roadmap and required investments will be driven by a number of factors, some of which include the current state of the utility environment with respect to current system development and integration, data availability, actionable field device and sensor availability, communications infrastructure functionality and build out plans, the rate of DER penetration and the availability of resources required to implement each technology solution.

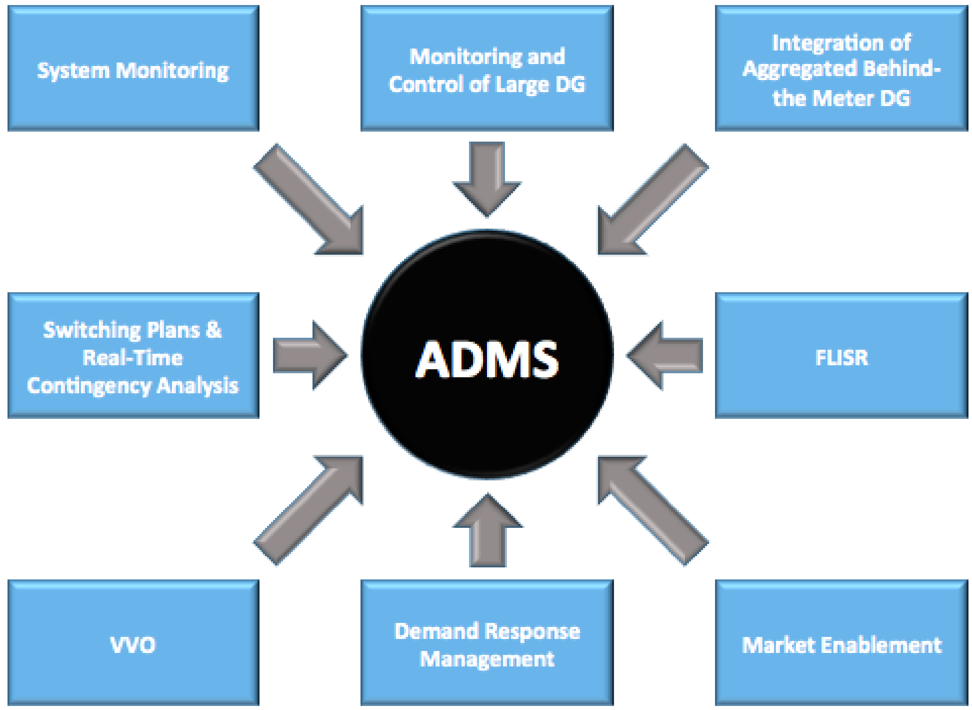
Approach to Developing the Technology Roadmap

O&R's approach to meeting the information technology system needs required for the DSP is predominantly model-based, and will require the implementation of new and sophisticated control systems and algorithms that will integrate with and leverage existing systems and related data. The foundation for the proposed state and what makes this possible to do with great accuracy is the Company's Integrated System Model, which combines system assets from the Geographic Information System, customer data, and system operational states and measurements. O&R has its entire distribution system accurately mapped with asset intelligence through verified three-phase field identification of devices and equipment, conductors, customers, and distributed generation. The ISM is the basis for the sophistical control model that will ultimately be realized through the development and implementation of an Advanced Distribution Management System.

An ADMS is the foundational platform that could be developed and integrated with other real-time systems and data sources, such as the Energy Management System, GIS, a Distribution SCADA system, Distribution Automation devices, substation equipment, AMI, customer data, DG, and the Outage Management System to enhance electric distribution system situational awareness, monitoring and control to improve reliability, resiliency and efficiency. ADMS is at the heart of how leading utilities presently are or are planning to monitor and control their distribution grids, and the Company expects to follow industry best practices in developing this technology infrastructure to facilitate REV objectives.

Figure 5-1

REV Functionalities Supported by ADMS



The initial technology investments will focus on building the necessary interfaces to engage customers, increase the volume and granularity of data, and enable greater DER penetration. The Company is continuously evaluating its technology needs, focusing on several key functional areas required to support DSP capabilities. These functions will be pursued in a phased and iterative approach, addressing the near term requirements of a DSP over the five year scope of this filing.

O&R has all of the necessary components for a complete ADMS solution as described below:

- A complete GIS with customer and asset connectivity, which updates an engineering model containing all customer load data, system data, and device configurations;
- SCADA is available for 98% of the Company's substations and an increasing number of circuits;
- An expanding and comprehensive distribution automation / smart grid program that has more than 250 devices deployed and will build out at a rate of nine circuit pairs per year with monitoring and control functionality;
- A robust radio frequency and communication infrastructure which can support distribution automation and facilitate ADMS command and control throughout the territory; and
- The pending deployment of an AMI program which will provide additional bell weather sensors as real time adjustments for calculated values in the state estimation and power flow results.

As shown in Figure 5-1, an ADMS is foundational to many of the functional requirements of REV. While planning for the changes to the transmission and distribution systems by attaching and enabling increasing DER penetration in more of the Company's service territory is at first a static and focused review and investigation, once it exists on the system it is vulnerable to changes. Using the ISM with DEW for planning purposes is the first step to safely, economically, and reliably engineer DER onto the electrical system. The model, SCADA, and applications will be applied in real time to measure and evaluate the actual behavior of the system including the impacts of DER. To add to the iterative process of planning and modifying the system will require tracking the changing behavior of the system over time through historical modelling, improved and expanded databases and advanced applications which identify vulnerabilities, contingencies, and power quality violations.

An ADMS will act in real time to coordinate the external interfaces to DERMS, DMS, VVO, and FLISR. ADMS will do this through its dynamic model of the distribution and transmission systems and SCADA. It will have a real time reference to the electrical system which will be the basis of analyzing changes relating to switching plans and contingency situations. An ADMS will be able to identify, monitor, and record data from abnormal system conditions resulting from planned and unplanned events that modify the design configuration of the electrical system.

Initial planning for the adequate incorporation of DER must be incorporated with a sophisticated real time ADMS that can provide monitoring, control and analysis for normal states, anticipated alternatives, unusual or abnormal states, and data collection with advanced analysis capabilities to re-engineer and re-configure the system in real time to plan for and effect changes necessary to operate a safe, reliable, and economical system.

Currently O&R is moving from a feasibility study, which evaluated the Company's readiness from a systems and data perspective, to a Scoping Study for an ADMS. The scoping study is required to describe the SCADA systems, data, communications infrastructure, GIS, customer connectivity, and modeling elements that combine into an ADMS. Assuming a positive BCA, a RFP could be produced from the Scoping Study that would define the applications/modules to be implemented. After that, the Company would be able to move into vendor selection and detailed implementation planning.

Functionality Needed to Support REV Implementation at O&R

REV objectives and evolving market needs will drive broad technology needs along the following lines:

- Integrating DER into forecasting and planning in order to target appropriate investment and potentially defer capital investment through appropriate utilization of suitability screening criteria and the BCA Handbook.
- Sharing system information in order to aid providers in developing DER in beneficial locations and configurations.
- Achieving increased visibility through improved technologies, automation and communications across the system in order to better plan for and operate the high DER penetration grid.
- Operating the dynamic two-way grid in a manner that encourages DER deployment, takes advantages of the opportunities DER provides and is able to handle the challenges increased DER Penetration will likely present.

- Collecting and sharing much more granular customer data through AMI in order to empower customers in regard to their energy usage to provide greater flexibility and opportunities to lower their bills.

More specifically, key functionalities needed in support of REV are described below.

1. Distribution System Planning – Functionality and supporting models, tools and systems that will enhance the Company's abilities to plan, forecast and manage available distributed energy resources in order to integrate DER into the electric distribution system. This section also includes the necessary tools and data requirements to identify and display locations where DER will be most beneficial to the distribution system.
2. Distribution Grid Operations – Functionality that provides greater visibility and potentially control and dispatch capability as DER penetration increases. Systems, models and tools that will assist control room operators in dispatching and managing DER, optimizing volt-VAR control, and controlling Distribution Automation devices in real time to maintain safety, reliability and appropriate operating parameters.
3. Sharing Customer Data – Functionality and systems for the acquisition and secure sharing of customer data with customers, third parties, and ESCOs.

Distribution System Planning

In order to effectively plan and operate the distribution grid, O&R needs to be able to accurately forecast both traditional loads and the sort and long term impacts of DER on the system. These forecasts form the basis for the electric system planning process the Company performs on an annual basis to identify the upgrades and improvements necessary to ensure the safe and reliable operation of the electric delivery system.

Forecasting

Accurate forecasting of electric demand is a critical foundation for system planning. System and substation-level peak demand data are generated and analyzed by O&R (in conjunction with Con Edison) on an annual basis for design planning. In all instances, gathering granular, reliable DER data at the substation and circuit level will be critical to developing accurate future forecasts that will drive the identification of operating risks and solutions required to manage and address such risk.

Table 5-1

Forecasting Technology Needs

Functional Category	REV Functionality	Current State	Future State	O&R Functionality Gap	System Needs
Forecasting	System peak demand	- Capability exists system-wide - Excel spreadsheet (forecasting templates) - EE and DR are integrated at the system level - Current forecasting is inclusive of most types of DER for both demand and energy forecasts	**Immediate (2017-2019):** - More frequent peak demand forecasts to make decisions on NWA solutions **Long-term (2020+):** - Improved forecast accuracy and DEW modeling	**Immediate (2017-2019):** - Automation **Long-term (2020+):** - Integration with DEW	**Immediate (2017-2019):** - Enhanced toolset to handle additional data volume **Long-term (2020+):** - Eventually forecasting may be integrated into DEW
	Substation peak demand / load shape	- All substations can provide necessary readings with the exception of four (one of which will retire) - No historical configuration data is currently tracked at circuit level - No forecasting at substation level for DR and EE - Location tracking for EE resources problematic - Configuration-dependent; manual process	**Immediate (2017-2019):** - Feeder peak / minimum load demand - Modeling for each DER resource' impact at circuit level **Long-term (2020+):** - Improved data accuracy (particularly for distribution losses)	**Immediate (2017-2019):** - Link between PowerClerk and the forecasting tool - Integration of historic and current configuration data - Automation **Long-term (2020+):** - Full integration with AMI to increase fidelity at feeder level	**Immediate (2017-2019):** - Working on a query to match to configuration - Add-on to the forecasting tool to integrate PowerClerk data **Long-term (2020+):** - Eventually forecasting may be integrated into DEW - AMI

Current State

Currently, O&R uses model-centric systems and data to assist in assessing current and forecasted state with respect to its design standards. With the model-centric approach, the same root Integrated System Model is used for planning, design, economic evaluation, and training, and as part of the future state will be utilized to perform real-time analysis and real-time control. Distribution planners use the ISM and DEW software, to model the T&D system. The model is derived by integrating data from multiple sources to create a base configuration model, which maintains the transmission, substation and distribution assets, historical measurements, and connectivity. The ISM uses DEW software, which directly calculates power flows.

A bottom up system peak demand forecasting at O&R is performed for the entire system and includes Energy Efficiency and Demand Response information at the system level. Forecasting is inclusive of applicable DER for both demand and energy forecasts.

At the substation level, peak demand and load shape forecasts do not include forecasts for DR and EE. It is currently difficult to track the specific locations of EE achievements, and DR capacity is only called for by the NYISO at this time. Therefore, it is unknown when the DR will be called. As the Company launches new DR programs, it is anticipated that their locational impact will be known and included in future forecasts.

O&R uses sophisticated planning tools to model the T&D system and identify required upgrades. The integration of DER into the system will increase the data required to accurately model the system. O&R will leverage the increasing amounts of data that are produced by automation/smart grid devices, AMI, and DER outputs to improve the load basis and overall planning process.

Future State

In the near future, O&R projects the need for more granular substation/bank/circuit data and peak demand forecasts to fully account for DER factors in demand growth, which will enable improved decisions on NWA solutions and support the potential deferral of capital projects. In addition, as advanced technology platforms, such as AMI and advanced automation technology and smart grid are implemented throughout the service territory, an increased and improved level of granular data will be available that will feed improved forecasts and DEW modeling. Ultimately, O&R anticipates forecasting will be integrated into DEW, but it is certain that improved forecasting methodologies, models and tools will be necessary to properly evolve the forecasting process.

O&R also envisions the ability to model the impacts of each DER at the circuit level (and sub-circuit segment level), which will enable the Company to better integrate DER data into its forecasts. In the longer term (post-2020), O&R expects continuing increases in forecast fidelity.

Technology Gaps and System Needs

The current functionality gaps include solutions for forecast automation and integration with other systems or new systems to improve the forecasting process. Additional applications and increased point collection from sensors and distribution automation devices into the eDNA database historian will require improved systems and additional resources to manage the data and make it relevant to forecasting systems. This will require additional development of eDNA and DEW, in addition to the infrastructure needed to handle increased amounts of data storage and communications bandwidth.

Integration of historic and current circuit configuration data is another key functionality that will have to be developed in order to determine and forecast DER impact on the system. O&R is currently working on developing a process to track and capture system configuration information at the appropriate level of granularity. In the long term, full integration with AMI and enhanced monitoring and control for larger size DER/DG units will be critical to increasing the fidelity of DER performance data at the feeder level.

In summary, the implementation of enhanced forecasting tools is dependent on the availability of the increased collection of data points on the system through AMI, enhanced field device technology, and expanded and reliable/redundant communications. In conjunction with the AMI rollout, the Company will consider options for automating DER data feeds into an improved forecasting process that will required improved methodologies, models and tools. Initially, the costs will involve developing a customized solution to augment the current Excel tool. However, expected increases in data volumes will likely precipitate the need for more comprehensive solutions, along with additional storage and communication capacity for transmitting data. O&R will continue to refine needs and will develop cost estimates when the scope of required solutions is clearly defined.

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Table 5-2

Planning Technology Needs

Functional Category	REV Functionality	Current State	Future State	O&R Functionality Gap	System Needs
Planning	Integration of DER into circuit analysis	- DEW planning tool - Daily data updates - Data stored on a shared drive, bring into SQL database - Currently implementing DSM tracking database for the 8760 data	**Immediate (2017-2019):** - Information based on segment; circuit / bank level - Database needs to feed into DEW **Long-term (2020+):** Same	**Immediate (2017-2019):** -Automation **Long-term (2020+):** Same	**Immediate (2017-2019):** - Enhancement of E3/Navigant Tool - DEW - DER assessment tool: EPRI is working on a tool with CYME and other software vendors on a commercial release of a similar product as well **Long-term (2020+):** Same
	Integration of BCA into planning process	- Estimates done by project manager at controls level - Excel spreadsheets	**Immediate (2017-2019):** - Enhancement or integration of additional data/information into DEW **Long-term (2020+):** - Automation	**Immediate (2017-2019):** - Integration of project cost and other financial data **Long-term (2020+):** - Automated link to the estimating tool	**Immediate (2017-2019):** - Manual data feeds - Enhancement of E3/Navigant Tool **Long-term (2020+):** - Automated data feeds
	Determination of areas that can benefit from DER / NWA	- Spreadsheet by E3 (projects over $5M; any distribution projects over $1M)	**Immediate (2017-2019):** - Increased precision and granularity **Long-term (2020+):** Same	**Immediate (2017-2019):** - A methodology and a toolset for including DR capacity as a "resource" **Long-term (2020+):** Same	**Immediate (2017-2019):** - Enhancement of E3/Navigant Tool **Long-term (2020+):** Same
	Integration of DER into contingency analysis	- Receiving data on large PVs, DGs, demand reduction (DSM), automatic RECO distribution crossings, final stations without readings, as well as enhanced station readings	**Immediate (2017-2019):** - Information based on segment; circuit / bank level - Database (DR / EE) needs to feed into DEW **Long-term (2020+):** Same	**Immediate (2017-2019):** - Enhancement or integration of additional data/information into DEW **Long-term (2020+):** Same	**Immediate (2017-2019):** - A solution to link PowerClerk with a seamless DER Interconnection Assessment Application - AMI **Long-term (2020+):** Same

Current State

The ISM and DEW software are used to model the T&D system. The model is derived by integrating data from multiple sources described below. The DEW software and ISM are used to run power flows for different loading/operating conditions. Power flow analysis is the basis for engineering and operating decisions. DEW and ISM include transmission, substation and distribution components, customer loads, system measurements, and the ability to analyze them in real time. Mapping data or component status data is updated in DEW daily while customer and system data is updated monthly.

DER assessment is one of the main tools that is used in DEW for generation impact analysis. This tool performs a series of power flow analyses associated with loss and restoration of user-selected generation types, operating at rated conditions, and load conditions evaluated at both minimum and maximum for a selected circuit. The tool conducts flicker analysis and interfaces to National Renewable Energy Lab and Clean Power Research to incorporate historical and forecasted solar generation data.

O&R has been strategically installing sensors throughout its service territory in order to provide additional data points for forecasting, planning, and fault sensing purposes. These sensors are installed in areas where gaps currently exist in data coverage as well as in potential trouble spots. The sensors record amps, voltage, and conductor temperature. Approximately 200 sensors have been installed in O&R's service territory in NY.

There is currently no direct linkage between capital project planning tools and the financial data for project costs that are necessary when performing benefit cost analysis. Project cost estimates are developed by project managers and are typically performed using spreadsheets or proprietary cost estimating tools. The identification of areas that could benefit from DER / NWA is presently performed using a spreadsheet application for major infrastructure projects over $5M and any distribution projects over $1M. The Company's current process is manually intensive, and while it is comprehensive, it is primarily cost, suitability and condition assessment based, and does not include sophisticated load flow modeling of DER and DG impacts and capabilities.

Future System Needs

The desired future state for the ISM for planning is to continue to improve the granularity of data that contributes to the load estimation routines in DEW. This will be accomplished through metering of large PV/DG systems to better understand their hourly and seasonal contributions to the grid for planning/forecasting and later with AMI for smaller systems. Integration of DER into the process will be further aided by including locational information indicating circuit and substation bank, as well as information contained in the DR/EE database as inputs into DEW. Effective integration of DER information into the planning process requires the ability for the Company to automate the data flow into DEW. It will be critical to ensure that circuit data is based on the normal configuration of the circuit and verification that the circuit is not in a contingency condition. The incorporation of DER data will require further enhancements to the Company's existing screening application, as well as a solution to link PowerClerk with a seamless DER Interconnection Assessment Application. There is also an immediate need for a methodology and a toolset to include DR capacity as a "resource" for system planning purposes.

The Company will need to develop a solution that will integrate information from DEW, DR/EE database information, DER data collected, and cost estimates (both capital and operational). O&R will further utilize the enhanced screening model and tool in accordance with the new BCA framework to weigh DER options against traditional utility solutions for the purposes of meeting the system planning criteria. Further enhancement to this process and modeling tool could then be developed to perform a similar analysis to determine if DER is a solution for circuits under contingency conditions.

Hosting Capacity

Hosting capacity varies across the service territory and includes location-dependent, seasonally dependent, circuit-specific, and time-varying characteristics depending upon the location on the circuit. Refresh rates also need to be considered as approved and queued DG interconnections change the landscape for hosting capacity on a frequent and dynamic basis. This creates unique challenges for the Company in providing granular data reflecting the dynamic nature of hosting capacity to developers.

Table 5-3
Hosting Capacity Technology Needs

Functional Category	REV Functionality	Current State	Future State	O&R Functionality Gap	System Needs
Hosting Capacity	Initial determination	- Manual SIR-based process - time- and resource-dependent - Minimum load data available for all circuits with the exception of four substations (one of which will retire) - No historical circuit configuration data is currently tracked at substation level - Level of granularity of currently available data may not be sufficient to support developer decision making (i.e., voltage differeces along circuit length)	**Immediate (2017-2019):** - Initial hosting capacity determination through established process (methodology to be determined by the supplemental DSIP) - Modeling for each DER resource' impact at circuit level - Overlay with maps **Long-term (2020+):** Same	**Immediate (2017-2019):** - Automation **Long-term (2020+):** Same	**Immediate (2017-2019):** - Add-on solution to integrate configuration data from GIS (NRG) - Integration with GIS (DER / Hosting Capacity layers) **Long-term (2020+):** Same
	Periodic updates	N/A	**Immediate (2017-2019):** - Update to shared hosting capacity on a monthly basis **Long-term (2020+):** Same	**Immediate (2017-2019):** - Integration of current configuration data -Process for periodic updates **Long-term (2020+):** Same	**Immediate (2017-2019):** - Add-on solution to integrate configuration data from NRG **Long-term (2020+):** Same

Current State

An acceptable statewide methodology for determining hosting capacity will developed by the JU through the Supplemental DSIP process. Minimum load data is one of the key components in determining hosting capacity. Minimum load data is currently available for all but four substations throughout the O&R service territory. In practice, hosting capacity of specific circuits is highly dependent on system configuration, which often changes.

As a first step, the Company has developed a “Red Zone” map that displays general areas/circuits where the cost to interconnect more than 1MW will be higher due to low minimal daytime load, aggregated Distributed Generation already interconnected, smaller conductors (wire size), operating voltage, and/or the number of applications in the queue on the circuit exceeding daytime load. While the map does not currently display hosting capacity, this approach will provide adequate distribution indicators as an interim step to provide guidance to developers showing where there will be higher costs for interconnecting when siting DG resources. This map will be retired as hosting capacity methodology is determined at the state level and improved data sharing requirements and methodologies are determined through the stakeholder collaboration process.

Future State and System Needs

The Company envisions the eventual development and maintenance of an outward facing system data map that would include hosting capacity. This map will likely include circuits color coded based on their hosting capacity. The map will also incorporate clickable embedded information, and while the exact makeup of that information is still being determined, it is likely to include at a minimum operating voltage and phasing. Periodic updates of the hosting capacity calculation and the map will have to be conducted, and ideally will be automated to reflect the dynamic nature of interconnections and system changes.

Due to cyber security concerns, the Company is determining the best approach to monitor and control access to hosting capacity data and other system data provided. The solution will be developed after review of industry best practices and evaluation of potential security concerns.

Distribution Grid Operations

As the penetration of DER increases across the Company's service territory, the requirements, opportunities, impacts, and challenges generated by DER will expand. Establishing the appropriate level of visibility, monitoring, and control will be critical to maintaining a safe and reliable grid and realizing the most value to customers and the system from DER that is connected. Capitalizing on the opportunities presented by DER, such as dispatchability of large scale DER on peak days or for certain contingencies, aggregation of behind the meter DER to provide load reduction and facilitate NWAs, or the ability to adjust/control DER to provide Volt/VAR support when needed, will require significant investments in a new integrated ADMS platform and expanding distribution automation and communication enhancements.

An ADMS will require the integration of data and information from numerous sources as described previously in this section. ADMS applications can provide the contingency analysis and system state estimation necessary to operate the distribution and transmission systems safely and reliably. Over time, it is envisioned an ADMS will have algorithms with learning ability capable of ascertaining normal behavior of the distribution and transmission systems, monitoring changing behavior and events, and signaling operators in real time regarding abnormal occurrences with recommendations and corrective action steps to restore and maintain reliability and acceptable operating parameters.

Monitoring and Control

Real time monitoring of DER will be essential for the Company to perform as the DSP to track DER performance and capabilities both to make same day operational decisions and for near-term forecasts and scenario decisions. As the amount of information that is being gathered grows, the need for a system that will aggregate, analyze, validate, and display the information to the operator will become a necessity. Information will be required to move between systems on a common information model as it becomes increasingly integrated with data sources, historical measurements, and advanced applications.

Table 5-4
Monitoring and Control Technology Needs

Functional Category	REV Functionality	Current State	Future State	O&R Functionality Gap	System Needs
Monitoring & Control	System monitoring	- Alarm index / events tagging done in SCADA - Digital switching system through GIS - No power quality, frequency monitoring at the feeder level	**Immediate (2017-2019):** - Ability to monitor power quality and frequency at the level of granularity necessary to enable integration of DER **Long-term (2020+):** - More granular weather / cloud cover forecasts	**Immediate (2017-2019):** - Power flow state estimation **Long-term (2020+):** - Tools to integrate clowd cover forecasts	**Immediate (2017-2019):** - 1st set of ADMS modules (timing still TBD pending scoping study) - AMI **Long-term (2020+):** - Full ADMS implementation (timing still TBD pending scoping study)
	Monitoring and control of large DG	- Ability to curtail for PV only, reclose at point of interconnect - Control over breakers for emergencies	**Immediate (2017-2019):** - Ability to curtail DG from the Control Center in times of contingency **Long-term (2020+):** - Ability to dynamically dispatch and curtail DG	**Immediate (2017-2019):** - Integrated power flow - State estimating **Long-term (2020+):** - Radio frequency available to render the increased volume of information	**Immediate (2017-2019):** - 1st set of ADMS modules (timing still TBD pending scoping study) - AMI **Long-term (2020+):** - Full ADMS implementation (timing still TBD pending scoping study)
	Monitoring and aggregation / dispatch of small DG	No	**Immediate (2017-2019):** - Ability to curtail DG from the Control Center in times of contingency **Long-term (2020+):** - Ability to dynamically dispatch and curtail certain DER (e.g., storage solutions)	**Immediate (2017-2019):** - Integrated power flow - State estimating **Long-term (2020+):** - Radio frequency available to render the increased volume of information	**Immediate (2017-2019):** - 1st set of ADMS modules (timing still TBD pending scoping study) - AMI **Long-term (2020+):** - Full ADMS implementation (timing still TBD pending scoping study)
	Switching plans and real-time contingency analysis	Demand planners and operations / control room make switching decisions. No automation	**Immediate (2017-2019):** - Switching plans and real-time contingency analysis **Long-term (2020+):** - More automation of controls - Additional infrastructure to provide more flexibility	**Immediate (2017-2019):** - Automation of controls **Long-term (2020+):** - Same capabilities expanded throughout service territory	**Immediate (2017-2019):** - 1st set of ADMS modules (timing still TBD pending scoping study) **Long-term (2020+):** - Full ADMS implementation (timing still TBD pending scoping study) - Radio capacity to handle increased data volume
	FLISR (Fault location, isolation and service restoration)	- No centralized logic	**Immediate (2017-2019):** -FLISR **Long-term (2020+):** Same	**Immediate (2017-2019):** - FLISR functionality **Long-term (2020+):** Same	**Immediate (2017-2019):** - 1st set of ADMS modules (timing still TBD pending scoping study) - AMI **Long-term (2020+):** - Full ADMS implementation (timing still TBD pending scoping study)
	Demand Response management	- Current DR and EE customers have advanced metering - Manual DR / EE customer notification (phone call / email)	**Immediate (2017-2019):** None **Long-term (2020+):** - Automated, real-time DR	**Immediate (2017-2019):** None **Long-term (2020+):** - Real-time / instant customer notifications	**Immediate (2017-2019):** None **Long-term (2020+):** - DR Module in ADMS or an add-on solution
	Live line clearance (planned and emergency)	- DER impact on the process and resulting technology needs are not clear	**Immediate (2017-2019):** - Manual process for older devices - Automation for newer devices **Long-term (2020+):** - Automated process	**Immediate (2017-2019):** - Potential process / procedure changes due to integration of DER **Long-term (2020+):** - Automation	**Immediate (2017-2019):** - Clear impacts and a new processes and procedures (as needed) **Long-term (2020+):** - Full ADMS implementation (timing still TBD pending scoping study)

Current State

Current system infrastructure will only partially meet the monitoring and control needs of the system as DER penetration increases. Alarm index and events tagging are currently done in SCADA at the substation circuit source. Current and voltage measurements are available through O&R's SCADA system, which covers 98% of the Company's substations, however, there is no power quality or frequency monitoring at the circuit level. A DSCADA system currently monitors and controls Distribution Automation equipment, including reclosers, motor operated air break switches, capacitors, and regulators, but coverage at this sub-circuit level is presently at less than 10% of the entire system.

The Company's ability to monitor and control large DG is limited to curtailing larger PV sources only, with reclosers at the point of interconnect. Switching plans and real-time contingency analyses are conducted by distribution planners and system operators, though the process is entirely manual. There is presently no centralized logic or technical capability for automated FLISR (Fault location, isolation and service restoration). Although some current DR and EE customers have advanced metering, there is presently no automation of aggregation or program management in this area. All DR notifications are currently done via personal phone calls or email.

As the penetration level of DG on the system increases, revised safety protocols are being adopted to address the continued safety of the line worker. Unintentional islanding of DG is a safety concern that requires continual evaluation and potential changes to the standards that govern the installation of larger DG. The resulting changes may precipitate a need for additional technological solutions to ensure worker safety. However, potential process and technology changes are not well understood at this point.

Future State

In the future, as DER penetration grows, the Company will need to expand its ability to monitor and control DERs on its system. In particular, O&R envisions requiring the ability to curtail or change operating parameters and states for large DG on the distribution system. While it is not clear whether aggregation of behind-the-meter will be accomplished by the Company or a third party, there will have to be mechanisms, and potentially tools to monitor and interface with aggregated behind-the-meter DG. Additionally, there will be need to dynamically interface with, control or modify operating parameters for certain types of DER (*e.g.*, storage solutions), particularly as they are implemented as part of NWAs.

With increased DER penetration on the system, automation will be necessary for such key system functions as switching plans and real-time contingency analysis, demand response, and, ultimately, live line clearance management. In the case of live line clearance, potential process or procedure changes due to integration of DER will need to be examined first to determine the desired future state functionality required.

Implementation Approach

The ADMS functionality described previously can provide a system that will increase the visibility into the distribution system by taking inputs from field sensors and meters through AMI in addition to DA. It will have System Modeling consistent with the planning ISM, which will reflect real-time configuration of the Distribution and Transmission Systems, including substation device settings. Some of the applications that would be available as a result of mapping, modeling, and Distribution Automation, Substation Automation, and SCADA coverage are listed below:

- Switching – Switch Plans and contingency analysis including curtailment criteria;
- State Estimator – Integrated System Model with Load Flow based on SCADA measurements;
- Relay Protection devices and settings – Model the capacity and behavior of equipment;
- Reliability Analysis;
- Demand Management Tracking;
- Demand Management Analytics;
- Data Reliability and Quality Control;
- Contingency Analysis;
- Fault Location Isolation and Service Restoration;
- Demand Response Management;
- Volt / VAR Optimization; and
- Distributed Energy Resource Management System.

An ADMS will benefit from the nearly complete SCADA coverage of substation and circuits in the EMS system. Along with the Distribution SCADA system and continuing Distribution Automation build–out, an ADMS will be able to take advantage of the coordinated loop schemes and switching segmentation available with SCADA operable MOABs and reclosers to incorporate FLISR, and through control of capacitors, load tap changing transformer controls, voltage regulators, and potentially smart inverters to incorporate VVO. O&R's potential project costs for an expected three year development and deployment of an ADMS are estimated to be $13.0 million in capital costs and $1.2M in O&M expenses annually beginning in the fourth year. It should be noted that estimates for any timelines and costs associated with a potential ADMS development and deployment are likely to be adjusted as a result of the ADMS scoping study currently taking place at the Company.

While modeling analysis and ADMS control are important to DSP operation, the supporting communications infrastructure is just as critical, if not more so, and will need to be improved and diversified. Constantly increasing data demands will overwhelm the low bandwidth radio capacity and require alternatives in mesh radio and cellular communications. The Company has convened an internal team to assess its current communications capabilities and determine gaps and future functionality that will be required. In addition, a Messaging Bus consisting of Protocol translators, Data Access Protocols, the Common Information Model for open translations, and Publish/Subscribe Protocols will be necessary to move data and information between systems and advanced applications.

Interconnection

A streamlined interconnection process and tools are critical to facilitate the integration of DERs in O&R's service territory.

Table 5-5

Interconnection Technology Needs

Functional Category	REV Functionality	Current State	Future State	O&R Functionality Gap	System Needs
Interconnection	Online application tool and portal with automated status communications	Initial functionality established (PowerClerk)	**Immediate (2017-2019):** - Further automation - accepting and processing applications, sending automatic communications, setting project deadlines and running reports **Long-term (2020+):** Same	**Immediate (2017-2019):** - Automation **Long-term (2020+):** Same	**Immediate (2017-2019):** - Configure PowerClerk - Interconnection Portal to automate submission of applications for interconnection and O&R responses **Long-term (2020+):** Same
	Automated technical review (preliminary and supplemental)	Beginning development	**Immediate (2017-2019):** - Integration w/ planning tools/process and automated screens **Long-term (2020+):** Same	**Immediate (2017-2019):** - Link between PowerClerk and DEW / ISM tool **Long-term (2020+):** Same	**Immediate (2017-2019):** - A solution linking PowerClerk with a seamless DER Interconnection Assessment Application **Long-term (2020+):** Same
	Queue management	Established w/ further development required	**Immediate (2017-2019):** - Time and date stamping of applications to be used as source of record **Long-term (2020+):** Same	**Immediate (2017-2019):** - Tracking automation **Long-term (2020+):** Same	**Immediate (2017-2019):** - A solution linking PowerClerk with a seamless DER Interconnection Assessment Application **Long-term (2020+):** Same
	Integration into planning process	Being developed	**Immediate (2017-2019):** - Output from interconnection process included in forecasting and planning tools (DEW / ISM) **Long-term (2020+):** Same	**Immediate (2017-2019):** - Link between PowerClerk and DEW/ISM tool **Long-term (2020+):** - Further input from SCADA and AMI reading of DER output back into planning process	**Immediate (2017-2019):** - A solution linking PowerClerk with a seamless DER Interconnection Assessment Application - AMI **Long-term (2020+):** Same
	Integration with GIS	Smart tagging of DER in NRG currently done manually. Initial symbology has been developed in NRG	**Immediate (2017-2019):** - Output of interconnection process integrated into GIS w/ nameplate information **Long-term (2020+):** - Actual performance data, gathered by AMI and SCADA, integrated into GIS information regarding interconnected DER - Output of inteconnection process integrated with operational and planning tools	**Immediate (2017-2019):** - More robust symbology for DER, harmonized across O&R and ConEd systems **Long-term (2020+):** - Further input from SCADA and AMI reading of DER output back into planning process	**Immediate (2017-2019):** - Enhanced handling of DER and associated data within GIS system - AMI **Long-term (2020+):** Same

Current State

O&R enhanced its online portal to facilitate timely DER interconnection[62] by purchasing Clean Power Research's PowerClerk Interconnect software for accepting and processing applications. PowerClerk Interconnect is built upon the PowerClerk Incentives platform, the industry-leading software platform for renewable energy incentive processing. A hosted, web-based application, PowerClerk Incentives is used today to process about 70% of the solar (PV) incentive applications (by volume) in the U.S. It is also used to manage other technologies including solar hot water, wind and small hydro. The portal allows customers to log in, enter application information, attach supporting documents, and electronically submit the application. Nearly 100% of O&R's applications are received through this portal.

Smart tagging of DER locations within O&R's GIS began in December 2015. With the DG type, location, and output mapped, the Company can perform detailed analysis of the impacts of DER currently connected in addition to areas where DER interconnection would benefit the system. The project to map all 3000+ DER currently approved and interconnected on the system was completed in January 2016.

In an effort to improve communications with the development community on areas where interconnection will be more costly, an interactive map was developed ahead of the hosting capacity discussions at the state level. The map is hosted on the O&R Solar and DG site.[63] This interactive map indicates general areas/circuits where the cost to interconnect greater than 1 MW will be higher due to factors such as low minimal daytime load, aggregated DG already interconnected, smaller conductor (wire size), operating voltage and/or the number of applications in the queue on the circuit exceeding daytime load. This interim map was developed prior to hosting capacity methodology being established by the JU and hosting capacity maps being developed in the state. As hosting capacity maps become available, this map will be replaced.

Technology Gaps and System Needs

In Track One of REV implementation, using the SIR as a framework, the PSC's February 26, 2015 Order[64] provides that each utility must establish the following interconnection functionality while working toward a consistent statewide look and feel for the interconnection portal. O&R is currently focusing on filling the gaps in its current portal functionality.

Many of the functionality gaps will be filled and functionality improved by leveraging the Electric Power Transmission and Distribution Smart Grid Program PON 3026 from NYSERDA to work with Electrical Distribution Design and the purchase of Clean Power Research's PowerClerk software.

O&R has begun to address gaps identified in the September 2015 report prepared by EPRI[65] for NYSERDA and was heavily involved in the efforts to amend the New York State Standardized

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62 www.oru.com/distributedgeneration
63 *Id.*
64 REV Proceeding, Track One Order.
65 Electric Power Research Institute, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, Final Report, September 2015

Interconnection Requirements finalized on March 18, 2016.[66] The interconnection portal will continue to be refined to meet requirements laid out in the Track One order and as documented in this DSIP.

Implementation

O&R recently received a newly awarded grant from NYSERDA to work with EDD and CPR on a project with the objective of building a DER Interconnection Assessment Application that consists of the CPR PowerClerk front-end integrated to the DEW/ISM back-end. The proposed solution is to integrate existing industry-recognized software solutions for streamlined DER interconnections and distribution circuit analysis by CPR and EDD. The result will be an end-to-end process for queuing/tracking/managing DER interconnection requests; for quickly/transparently analyzing and responding to those requests; and for integrating DER into the engineering and operating models at ORU.

Customers and solar providers will input DER Interconnection Requests into the PowerClerk software, which will manage the queue and related workflow. Upon receipt of a request from PowerClerk, DEW/ISM will automatically run interconnection screens based on ORU acceptance criteria. When a criteria violation occurs, the request will be forwarded to the appropriate ORU engineer to review the violations and plan corrective actions using DEW software and the ISM. All DER in the queue, regardless of approval state will be available in the DEW/ISM, enabling engineers and operators to have a complete view of potential DER on the ORU system. A further description of enhancements to the interconnection portal can be found in the Interconnection Processes section of the Distributed Grid Operations Chapter of this DSIP.

VVO

Volt/VAR Optimization represents a unique opportunity to operate the grid more efficiently. The capabilities that fall under the VVO umbrella include peak demand management through voltage reduction, continuous voltage optimization to deliver specified voltage more efficiently, and optimizing VARs to improve power factors throughout the load cycle. In order to achieve improved levels of efficiency toward optimization throughout the load cycle, O&R will be required to coordinate, through an ADMS platform, the real time operation of its automated voltage and VAR supporting devices with third-party DER/DG equipment with real-time monitoring and SCADA communications that provide distribution status to the ICS and system operators.

[66] CASE 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying Standardized Interconnection *Requirements* (issued March 18, 2016).

Table 5-6

VVO Technology Needs

Functional	REV	Current State	Future State	O&R Functionality Gap	System Needs
VVO	Real-time VVO	- System set up for peak year round - Statewide voltage reduction capability if required by NYISO - Monitoring and voltage supporting infrastructure on existing equipment limited - LTCs connected back to EMS system; can see voltage change, but some information missing - Working towards SCADA capacitor banks	**Immediate (2017-2019):** - VVO limited based on ADMS implementation timelines and the availability of infrastructure (new substations only) -Limited communication bandwidth **Long-term (2020+):** - Real-time Integrated Volt / Var Control System (IVVC) using SCADA controls through ADMS	**Immediate (2017-2019):** - Only newly-built substations may have monitoring and voltage support equipment - Consider cost-benefit analyses when evaluating retrofits -Existing communication infrastructure may not be sufficient to handle additional data points. **Long-term (2020+):** - Monitoring and voltage supporting equipment deployed on the entire system and a tool to manage and control the voltage support equipment -Deployment of the necessary monitoring and communications and automated VVO controlled through ADMS	**Immediate (2017-2019):** - Inventory of the current monitoring and voltage regulation capabilities at each substation / circuit and development of a standard for all new installations / upgrades -Inventory of the current communication system(s) that will be used to support VVO. **Long-term (2020+):** - ADMS (timing still TBD pending scoping study) - Integration of On-Load Tap Changers (OLTC) into ADMS system - Voltage support system-wide: CVO along with automated local controller set points on its substation LTCs, distribution capacitors, and distribution regulators with the availability of remote manual LTC control -Implement new communication design for new substations and distribution equipment and upgrade communication infrastructure as needed for existing equipment.

Current State

O&R is already implementing Volt/VAR control to maintain certain levels of efficiency by operating the system through automated local controller set points on its substation LTCs, distribution capacitors, and distribution regulators through remote manual LTC control by its System Operators. Watt and VAR readings for the majority of the Company's substation banks are provided through the SCADA system. The Company's substation distribution circuit meter data does not provide Watt and VAR readings through the SCADA system that would be required for VVO. These measurements are required for VVO applications to make real-time system adjustments. The tap changer controls on substation transformers where they are available are not all based on newer technology that can be accessed and controlled through remote interface.

Monitoring and voltage supporting infrastructure on existing equipment is limited. Voltage, power quality, and reliability data are currently not available at the circuit level. Although LTCs are connected back to the EMS and thus can see voltage changes, only newly-built substations may have the required monitoring and voltage support equipment. Currently, there are 79 transformer banks on the O&R system. The Company retains five years of transformer bank data, which consists of the following data points: amp readings for 12 banks, voltage readings for 66 banks, and MW/VAR readings for 74 banks. There are 220 circuits serving NY customers on the O&R system. The Company currently records amp readings for 207 circuit circuits via the SCADA network. Additionally, O&R receives MW/VAR readings for 2 circuits based on the advanced RTUs and relays in the stations.

Future State

In the future, the Company envisions a phased approach to VVO through the deployment of various VVO supporting equipment, the incorporation of AMI, and the development of an ADMS. In the near term, VVO will likely be limited based on ADMS implementation timelines and the availability of infrastructure. As such, VVO capabilities are to be implemented at new substations first.

The Company envisions a move towards a real-time Integrated Volt/VAR Control System utilizing SCADA control through an ADMS, which utilizes the ISM and advanced applications to achieve system wide VVO. In the long-term, third-party DER VVO solutions may be considered once the technology is developed and successful pilot programs have been completed and evaluated.

Technology Gaps and System Needs

Implementing VVO to achieve system-wide efficiencies requires monitoring and voltage supporting equipment to be deployed on the entire system. A tool to manage and control the voltage support equipment will be also needed. The preferred near-term solution is to implement elements of VVO along with automated local controller set points on substation LTCs, distribution capacitors, and distribution regulators with the availability of remote manual LTC control. In the long term, the Company envisions deployment of the necessary monitoring and communications to enable automated VVO controlled through an ADMS.

Additional data requirements such as Watts and VARs to the information currently being transmitted through SCADA will require substantial system and equipment changes and enhancements. Additionally, not all relays have the ability to provide Watts and VARs. Furthermore, LTCs need to be integrated into an ADMS system, and communication protocols for remote set points need to be established. Some of the LTC controls may need to be upgraded or changed to enable set point control.

DER providers may require VAR metering and meter upgrades to provide necessary input data at the point of generation. In addition, the enablement of third-party VVO provided by DER will depend on the availability of smart inverters with the ability to support system voltage and VAR needs per phase. Inverters that have an intermittent source (*i.e.*, PV or wind) will need to have battery storage or some other means to ensure reliable dispatch. The inverters will also need a communication channel to communicate with the utility. Standard utility protocols, such as DNP3 (level 1-4), 61850, Secured ICCP, or MODBUS will need to be made available.

Implementation

The systems that need to be brought online for distribution control and efficiency will depend on the data gathered from electric system measurements and control settings. In order to remotely adjust LTC settings, upgraded equipment will be necessary in many instances. O&R will conduct an inventory of all substation breaker relays and transformer load tap changer control types to determine if the existing equipment can be used for VVO. This effort is expected to be completed in 2017. Once this inventory is complete, work can begin on developing an upgrade plan for all units that do not meet the requirements for VVO function. O&R will also need to install remote control capability of transformer LTC settings that will work in conjunction with an ADMS system and VVO controller. As the electric distribution system transforms from a radial system to a bidirectional one with the growing forecasted DG penetration, high-speed data will be needed to monitor the power quality of the circuits as backfeed and fluctuating voltage conditions will become more common.

Available technologies will be evaluated to develop requirements for third-party technologies capable of providing VVO support. The evaluation process will identify the systems, protocols, secure communications, and metering that may be required for third-party technology interactions, as well as the need for a DERMS to monitor and potentially manage and control third-party VVO equipment. The impact interacting with third-party systems on cyber security must also be evaluated. If compromised, these systems could have an adverse effect on the grid. The evaluation will also review the impact on the ability of the Line Workers to safely work on the live distribution system with third-party equipment. Once a complete inventory of distribution breaker relays and LTC controls are complete, the Company can develop a cost to upgrade. Finally, pilot programs to validate third-party technology that can support VVO functionality accurately and reliably for electric customers will be considered. A market model would need to be created before any third parties could provide VVO services.

When the substation relay and LTC control inventory, described above, is complete, a cost estimate can be developed for VVO related equipment upgrades and the resultant ongoing O&M charges. The Company will then develop a plan for resource requirements to build out VVO functionality and resource requirements to maintain the new system. Next, an evaluation will be completed on the impact on data bandwidth, cyber security, communication infrastructure, identify required upgrades to LTC controls and other substation equipment such as protection systems, field forces for maintenance, and new cyber secure communications for DER. It is anticipated that VVO will demand more operations from substation transformers, distribution capacitors and voltage regulators, which will require additional maintenance activities and will shorten the life of the equipment. Therefore, additional operational cost of the units will be considered as part of the overall benefit / cost analysis to implement that would be completed once all of this information is ascertained.

Customer Data Sharing

Increased DER penetration in conjunction with market evolution expected under REV will have a significant impact on the technology infrastructure required to share data with customers and third parties. Customers will have access to their interval electricity usage data, the granularity and visibility of which will increase their ability to adjust their consumption patterns to reduce their electricity bill. As a result, customers may choose to participate in new time-based rates and demand response programs offered by the Company. Provision of the data to third parties, for a fee, will enable and support customer behavior change, as well as the tools necessary for the market to engage and drive solutions to scale.

While it is O&R's view that the migration to a 'transactive' energy market will be a lengthy implementation (and potentially outside the five-year view of this DSIP), the Company is making foundational investments to move toward this vision. The transactive energy market will require significant monitoring and control of both utility and DER assets, as well as the ability to share granular customer data with all market participants in near-real time.

Table 5-7
Customer Data Technology Needs

Functional Category	REV Functionality	Current State	Future State	O&R Functionality Gap	System Needs
Customer Data Sharing	Individual customer access and sharing of data	- Customers can access their monthly bill through My Account Portal; Green Button Download; Their Monthly Bill wich is via US Mail or eBill; MHP Customers can access interval data via Customer Care	**Immediate (2017-2019):** - Ability for customers to access their own interval data and share it automatically with authorized third parties **Long-term (2020+):** Same	**Immediate (2017-2019):** - Collection of most residential customer interval data. The ability to access and share interval data **Long-term (2020+):** - Collectoin of customer interval data at some locations	**Immediate (2017-2019):** - AMI - Green Button Connect - Digital Customer Experience (DCX) **Long-term (2020+):** Same
	Providing customer data to ESCOs	- Data provided to ESCOs through EDI	**Immediate (2017-2019):** - ESCO access to customer interval usage data via GBC **Long-term (2020+):** - ESCO access to near real-time customer usage data	**Immediate (2017-2019):** - Collection of most residential customer interval data - Architecture to share near real-time data w/ ESCOs **Long-term (2020+):** - Collection of customer interval data at some locations - Architecture to share near real-time data w/ ESCOs	**Immediate (2017-2019):** - AMI - Green Button Connect - Digital Customer Experience (DCX) **Long-term (2020+):** Same

Current State

Currently, individual customers can access their monthly bill (including historic usage data) through My Account Portal, including Green Button Download. Most customers, with the exception of very large customers, do not have interval data. There is no capability for them to directly share information with the third parties of their choosing. Individual customer usage data is provided by O&R to ESCOs through an EDI, at ESCO's request. To be able to request individual customer information, ESCOs are required to obtain customer's consent for a specific account number. Upon processing the request, O&R provides data to ESCOs via email.

Future State

Going forward, to support potential market participants' decision-making process, customers and ESCOs will need to see and be able to act upon more granular use data. In the future, the Company expects to provide them with this ability through the development of the Green Button Connect My Data. O&R envisions customers having the ability to access their own interval data and share it automatically with authorized third parties. From their end, ESCOs will have access to user data. O&R will limit automatic access to ESCOs that have been pre-approved to access GBC. In the longer-term, ESCOs will be able to access data close to real-time, potentially for a fee.

Technology Gaps and System Needs

The Company's current technology infrastructure does not provide the functionality envisioned for the future. Immediate gaps (i.e., gaps to meeting functionality needs identified for 2017-2019) include the collection of most residential customer interval data through AMI. With deployment starting in 2017, AMI will provide a foundation of information and communications capabilities that will enable the Company's customers to become informed and engaged energy consumers. Operating in concert with the DCX solution (described below), AMI will provide customers with the information necessary to help them manage their energy usage and manage costs.

Implementation

To provide customers with the ability to access and share data, O&R is establishing a new program, Digital Customer Experience. The DCX project will consolidate current data channels into a single point of access through a redesigned *My Account* web portal. As part of this enhancement and to accommodate the anticipated increased need for customers to share usage information*, My Account* will feature the Green Button Connect My Data tool. This application is a tool for customers to share their usage information with selected vendors in a national standard protocol that is currently being used by other utilities around the country. The initial rollout of GBC will feature interval usage with the anticipation of expanding the available data sets through a reassessment of data needs as markets grow.

The Customer Care portal will contain links to Green Button Connect / DCX tools, enabling a single sign in process. The DCX project will provide customers with the following information, tools and analytics:

- A simple intuitive view of their current and historical meter usage, including detailed interval data when AMI meters are installed throughout the O&R service territory;
- The ability to overlay additional data in graphical formats, including weather, price, billing data, as well as comparisons to data;
- The ability to download the usage in various forms, including the Green Button format;
- Personalized insights and actions in the form of energy saving tips and action plans powered by the DCX analytics capabilities;
- The ability to disaggregate their energy consumption, gas and electric, to determine how their energy is being utilized;
- Points and rewards programs encouraging customers to take specific actions (*e.g.*, enrolling in e-Bill or completing a home energy analysis);
- Proactive alerts associated with projected billing, home energy use and thresholds the customer can set and augment based upon their consumption or projected cost;
- Rate comparison functionality to help customers choose among time of use or other variable rate designs;
- Customer education reports providing insights about impacts of seasonal change on energy usage or the local system reliability, and more;
- Specific portal functionality for commercial and large industrial customers; and
- Provide customers the ability to schedule the automatic delivery of energy usage reports on an ongoing electronic basis.

The Company also plans, if ordered, to provide ESCOs access to interval usage information by utilizing the same interval data exchange platform, GBC. ESCOs do not currently receive interval data form O&R, so GBC would be the vehicle for them to get the data. ESCOs will have the ability to automatically request and receive customer interval data without market interruption and still utilize EDI for all other ESCO transactions. The enhanced data availability will enable third parties to develop customized energy products and services. The architecture required to share near real-time data with ESCOs has not been developed, either. As the DSP functionality evolves, it will be critical to ensure access to data at all customer locations and to transition to dynamic, near-real time data transmission to ESCOs. The DCX program will be rolled out in phases starting in Q1 2017 through Q2 2019, coinciding with the Company's AMI rollout.

Infrastructure and Supporting System Needs

As the Company develops the technology solutions required in support of the REV implementation, it will continue to evaluate the following key elements of the enabling infrastructure, as they may require upgrades:

Communication Infrastructure

The communications infrastructure is a key component of any solution to support operations in command and control as well as situational awareness and data based decision analysis. Communication requirements are multi-layered, location dependent, and consist of redundant and diverse technologies to deliver reliable data. The communication infrastructure and composition must act as the bridge for delivering timely, reliable, and secure data from and to the field in order to facilitate accurate, effective, and efficient management of the system.

With the influx of data automation and requirements anticipated to support a successful DSIP environment, a high-speed robust IT infrastructure must be part of the equation. The data networks that need to be considered include those falling under NERC CIP, High Value Networks (“HVN”), Virtual Private Networks (“VPN”) to cloud computing resources, along with trusted and untrusted networks. Each network poses unique cybersecurity, capacity and reliability challenges. The IT infrastructure is made up in two parts; the Wide Area Network (“WAN”) and the Local Area Network (“LAN”). Together, these systems support critical data requirements which play a vital role in securing Company data. These networks need to be kept current in order to secure mission critical data used to analyze and diagnose events at the edge of the monitored network as well as to raise event flags for operations to react to and rectify abnormal situations.

Current State

The communications infrastructure currently in place, utilizes multiple technologies including Company owned and leased fiber strands, private microwave and radio links, along with Telephone Company leased circuits. The LANs within the corporate environment have been kept current and provide secure and reliable data connectivity at all Company faculties. The corporate LAN however would need to grow, alongside with any future automation and communications infrastructure expansion plans.

The high-speed fiber infrastructure is a hybrid of Company owned transmission Optical Ground Wire (“OPGW”) and leased fiber from the public carriers. Several of the Company OPGW facilities do not have connectivity back to the corporate data presence and is used exclusively as a reliable source for protective relaying. The secured corporate high-speed fiber infrastructure is primarily made up of leased fiber spans. The locations which utilize corporate high-speed fiber consist primarily of employee office facilities and some key substations.

The corporate microwave and radio network is comprised of 14 tower facilities located throughout New York and New Jersey. The Company utilizes Federal Communications Commission (“FCC”) licensed 6 GHz and 11 GHz spectrum across its private microwave network. The microwave network offers a highly secure and reliable means of communications for mission critical voice and data, even throughout the worst of weather or other emergency events. Although highly reliable, the microwave and radio network does lack the bandwidth capacity of fiber optic networks. As such, it is viewed as a primary solution for mission critical low-speed circuits and as a backup to the corporate fiber backbone.

The Company's private radio system consist of six 220 MHz (12.5) data channels and six Low Band voice only, mobile communication channels. These systems have reached their capacity for field communications and cannot be expanded.

Future State

With the rapid growth of field automation and requirements for securing data for real-time analytics, focus on expanding the IT communications infrastructure is vital. The Company will need to ensure that field and customer data be secured through trusted sources and transported across reliable networks. In order to accomplish this, the corporate infrastructure will need to grow and expand in order to meet major automation initiatives.

High-speed data collection and transport facilities will need to be established throughout the service territory, with Company substations playing a key design role. The OPGW infrastructure will need to be extended to provide a high-speed backhaul capabilities. As monitored data increases, the communications infrastructure will need to encompass both primary and alternate data centers. Host systems will need to be developed and implemented to reach out to the edges of the system creating a network management environment to ensure reliable transmissions of data. The transition to real-time, automated distribution management will require high bandwidth speeds and a robust redundancy design. In addition, as third-party inverters start interacting with the O&R distribution system, the current infrastructure will not be able to handle the additional data requirements.

The Company is in the design phase of expanding the IT fiber infrastructure to key substations and facilities. Infrastructure expansion projects have been ongoing, however needs to be escalated in order to meet the rapid deployment plans for new technologies. In previous years, the Company focused on expanding its fiber backbone to 1 to 2 facilities per year. In order to meet the future automation initiatives, this goal will need to be increased to 4 to 5 sites per year, over the next several years. Microwave systems will also be evaluated as a viable means of diversity at critical data facilities.

The future IT infrastructure will not only need to consist of high-speed fiber optic/microwave backbones, but also will need to support increased data demands of intelligent field devices for real time data gathering. The Company has begun engineering studies on wireless radio frequency ("RF") networks in order to identify RF spectrum that could act as a viable means for providing increased bandwidth for last-mile data devices throughout its service territory. Successful DSIP efforts will require future infrastructure designs to be robust, highly reliable and diverse from the host computing equipment to last mile smart devices.

These projects collectively will improve communications reliability, resiliency, and network capacity for mission critical SCADA/DSCADA/ADMS as well as provide a necessary highway for transporting corporate security/video surveillance and DSIP corporate data networking. The high-capacity fiber network will increase bandwidth at key facilities and add reliability to critical communication systems. It also contributes to a communications highway for technologies that support customer restoration following outages.

The Company has created a core, cross departmental team to focus on the design considerations discussed in this section, such as identifying RF spectrum, expansion of fiber networks, implementation concerns, and redundancy options. A key goal of the team is to support the future state of the communication infrastructure that would accommodate DSP needs. The Company acknowledges a need to identify the costs associated with a future communication infrastructure state during the design and study phase. Allocations of the total cost will be included in upcoming and future year rate cases.

Cyber Security

Cyber security architecture must be able to support the increasing command and control real-time system with communications in milliseconds. As access to and sharing of data becomes necessary to facilitate industry changes, cyber security and customer data privacy are increasingly important. VPN, encryption, and other solutions will have to be implemented to protect both the distribution grid and customer data privacy. It will be critical that the Company retain control over ever growing volumes of data generated as the full-scale REV functionality takes shape.

Table 5-8

DSP Technology Roadmap High Level System Needs Overview

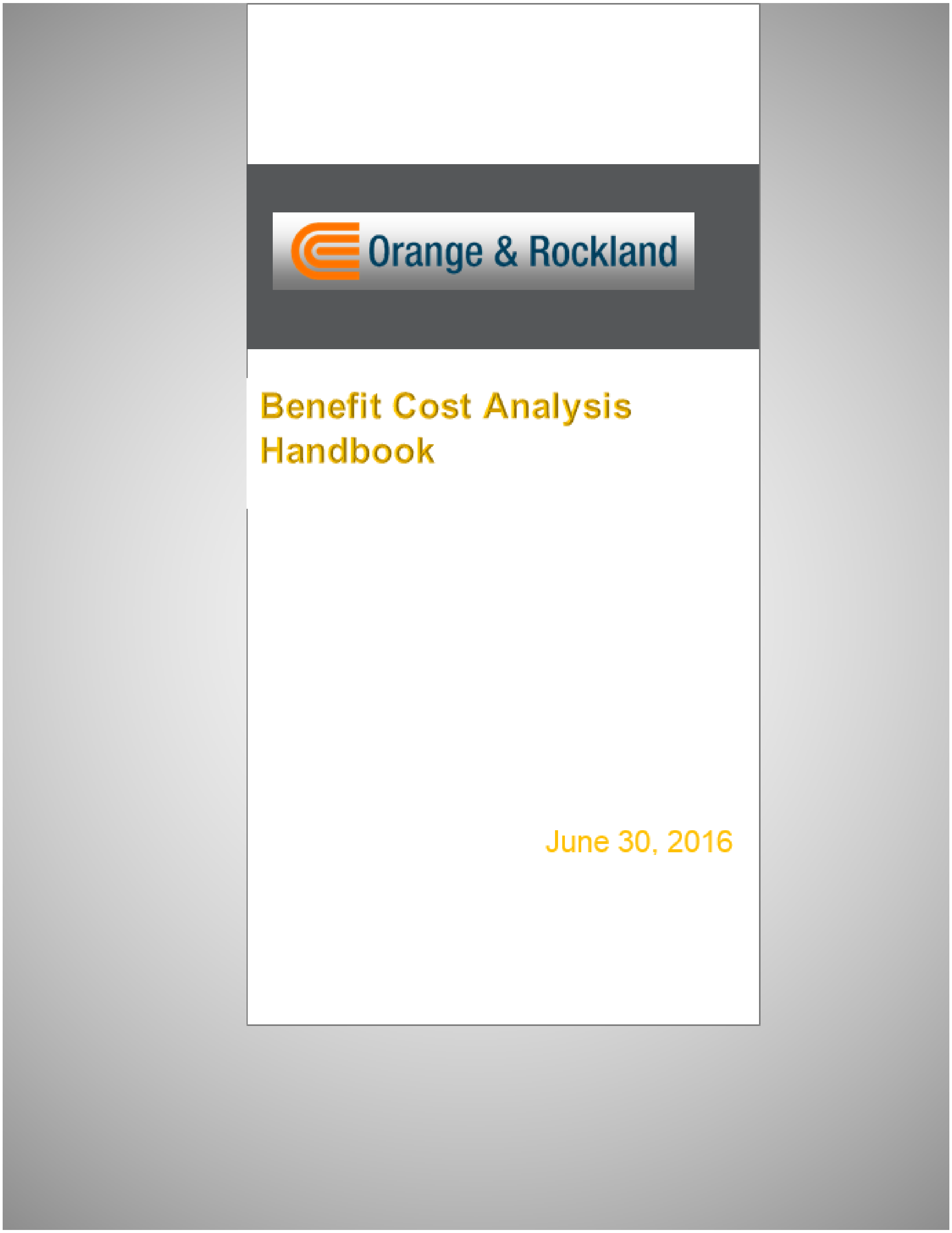
Functional Category		Immediate System Needs (2017-2019):	Long-Term System Needs (2020+):
Ditribution Planning	*Forecasting*	- Enhanced toolset to handle additional DER data volume - Add-on to the forecasting tool to integrate PowerClerk data	- Potential integration of DER data directly into DEW
	Planning	- Enhancement of E3/Navigant Tool - DER assessment tool for DEW	- Automated data feeds into BCA analyses
	Hosting Capacity	- Add-on solution to integrate configuration data from GIS (NRG) - Integration with GIS (DER / Hosting Capacity layers)	To Be Determined
Grid Operations	*Interconnection*	- Interconnection Portal to automate submission of applications for interconnection and O&R responses - Reconfiguration of the PowerClerk software - A solution linking PowerClerk with a seamless DER Interconnection Assessment Application - Enhanced handling of DER and associated data within GIS system	To Be Determined
	Monitoring & Control	- 1st set of ADMS modules (timing still TBD pending scoping study) - AMI	- Full ADMS implementation (timing still TBD pending scoping study) - Radio capacity to handle increased data volume - DR Module in ADMS or an add-on solution
	VVO	To Be Determined	- ADMS with VVO module (timing still TBD pending scoping study) - Integration of On-Load Tap Changers (OLTC) into ADMS system
Sharing Customer Data	*Customer Data Sharing*	- Green Button Connect - Digital Customer Experience (DCX)	To Be Determined
Infrastructure and Supporting Systems	*Communication Infrastructure*	- Substation Local Area Networks - Optical Grounding Wire Infrastructure	- Increased bandwidth and flexibility on communications infrastructure
	Advanced Metering Infrastructure	- Meter Data Management System - AMI network infrastructure - AMI meter deployment (Rockland County)	- AMI Meter Deployment (Orange and Sullivan County)

Orange & Rockland

ORANGE AND ROCKLAND UTILITIES, INC.

Initial Distributed System Implementation Plan

Appendix A – O&R Benefit Cost Analysis Handbook



Orange & Rockland

Benefit Cost Analysis Handbook

June 30, 2016

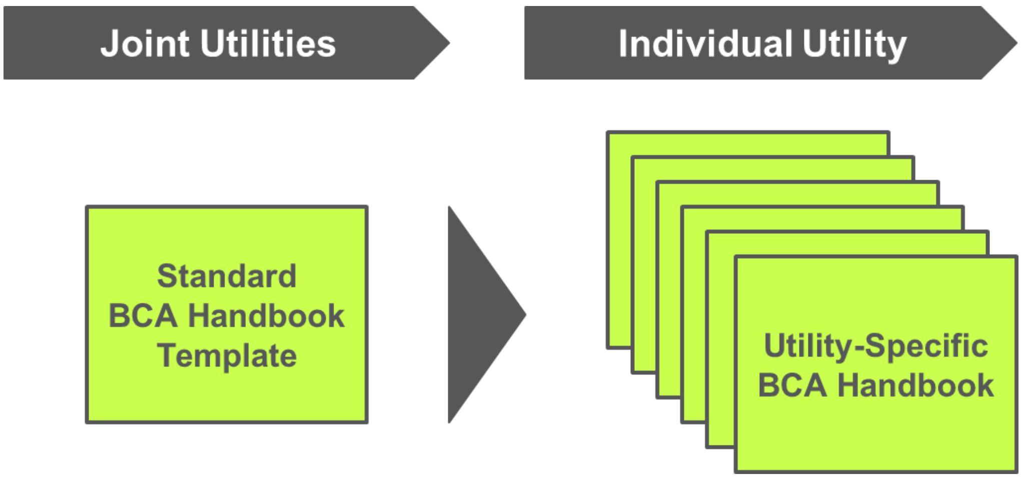
Version History

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	Orange & Rockland BCA Handbook - v1.0	06/30/16	Orange & Rockland	First Issue

Background

A Standard BCA Handbook Template was developed in collaboration with the New York Joint Utilities to provide consistent and transparent statewide methodologies that calculate the benefits and costs of potential projects and investments. Its purpose is to serve as a common basis for each utility's BCA Handbook. Figure 1-1 summarizes the relationship between the Standard BCA Handbook Template and the corresponding utility-specific BCA Handbooks.

Figure 0-1. Relationship between Standard BCA Handbook Template and Individual Utility BCA Handbooks



Source: Navigant

The BCA Handbooks include the key assumptions, scope, and approach for a BCA. They present applicable BCA methodologies and describe how to calculate individual benefits and costs as well as how to apply the necessary cost-effectiveness tests identified in the *BCA Order*. The BCA Handbooks also presents general BCA considerations and notable issues regarding data collection required for project and investment benefits assessments. Definitions and equations for each benefit and cost are provided along with key parameters and sources.

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Table of Contents

Acronyms and Abbreviations

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here at the front of the Handbook for ease of reference.

AC	Alternating Current
AGCC	Avoided Generation Capacity Costs
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost framework structure presented initially in the "Staff White Paper on Benefit-Cost Analysis" and finalized in the *BCA Order*.
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
C&I	Commercial and Industrial
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP Guidance Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
ICAP	Installed Capacity
JU	Joint Utilities (Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation)
kV	Kilovolt
LBMP	Locational Based Marginal Prices
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt
MWh	Megawatt Hour
NPV	Net Present Value
NO_x	Nitrogen Oxides
NWA	Non-Wires Alternatives
NYC	New York City
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PV	Photovoltaic
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision
RGGI	Regional Greenhouse Gas Initiative

RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model (National Renewable Energy Laboratory)
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SENY	Southeast New York (Ancillary Services Pricing Region)
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	Utility Cost Test

1. Introduction

The State of New York Public Service Commission (NYPSC) directed the Joint Utilities (JU)[67] to develop and file Benefit-Cost Analysis (BCA) Handbooks by June 30, 2016 as a requirement of the Order Establishing the Benefit-Cost Analysis Framework (*BCA Order)*.[68] The BCA Framework included in Appendix C of the *BCA Order* is incorporated into the BCA Handbooks. These handbooks are to be filed contemporaneously with each utility's initial Distributed System Implementation Plan (DSIP) filing and with each subsequent DSIP, scheduled to be filed every other year.[69]

The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The *BCA Order* requires that benefit-cost analysis be applied to the following four categories of utility expenditure:[70]

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection[71]
3. Procurement of DER through tariffs[72]
4. Energy efficiency programs

The BCA Handbook provides methods and assumptions that may be used to inform BCA for each of these four types of expenditure.

The *BCA Order* also includes a list of principles for the BCA Framework that are reflected in the BCA Handbook.[73] BCA should:

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.

[67] For the purpose of this document, Joint Utilities includes Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation.
[68] *BCA Order*: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).
[69] DSIP Guidance Order, pg. 64: "shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018."
[70] *BCA Order*, pg. 1-2.
[71] Also known as non-wires alternatives (NWA).
[72] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).
[73] *BCA Order*, pg. 2.

5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

1.1 Application of the BCA Handbook

The BCA Handbook provides a common methodology to be applied in BCA across investment projects and portfolios. Version 1 of the BCA Handbook is meant to inform investments in DSP capabilities or the procurement of DERs through tariffs, and to be specifically applicable to procurement of DERs through competitive selections (i.e. non-wire alternatives) and/or energy efficiency programs. Common input assumptions and sources that are applicable statewide (e.g., information publicly provided by the New York Independent System Operator (NYISO) or by Department of Public Service (DPS) Staff directly in the *BCA Order*) and utility-specific inputs (e.g., marginal cost of service and losses) that may be commonly applicable to a variety of project-specific BCAs are provided within. Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

Table 1-1 lists the statewide data and sources to be used for BCA and referenced in this Handbook. Source references are included in the footnotes below.

Table 1-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[74]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model[75]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[76]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[77]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[78]
Allowance Prices (SO_2, and NO_x)	NYISO: CARIS Phase 2[79]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[80]

[74] The 2016 Load & Capacity Data report is available in the Planning Data and Reference Docs folder at: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

[75] The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: http://www.dps.ny.gov. The filename is BCA Att A Jan 2016.xlsm.

[76] The finalized annual and hourly zonal LBMPs from 2016 CARIS Phase 2 will be available by December 2016 on the NYISO website in the CARIS Study Outputs folder within the Economic Planning Studies folder at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. Until such time that the finalized 2016 CARIS 2 data is published, the utilities will work with DPS Staff to determine the appropriate values to use for the September ETIP filing and otherwise.

[77] Historical ancillary service costs are available on the NYISO website at: http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp. The values to apply are described in Section 4.1.5.

[78] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[79] The allowance price assumptions for the 2016 CARIS Phase 2 study will be available on the NYISO website in the CARIS Input Assumptions folder within Economic Planning Studies at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. Until such time that the finalized 2016 CARIS 2 data is published, the utilities will work with DPS Staff to determine the appropriate values to be used in any BCA filings.

[80] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table 1-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table 1-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	ORU Rate Case 14-E-0493
Losses	ORU Electric Loss Report for Case 08-E-0751
Marginal Cost of Service	ORU Rate Case 14-E-0493 Exhibit DAC-E3
Reliability Statistics	DPS: Electric Service Reliability Reports[81]

The New York general and utility-specific assumptions that are included in this first version of the BCA Handbook (as listed in Table 1-1 and Table 1-2) are typically values by zone or utility system averages. In subsequent versions, application of the BCA Handbook may be enhanced by including more granular data, for example with respect to location (e.g., zone, substation, or circuit) or time (e.g., seasonal, monthly, or hourly).

The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.

1.2 BCA Handbook Version

This BCA Handbook v1.0 provides techniques for quantifying the benefits and costs identified in the *BCA Order*. The BCA Handbook will be updated every two years and filed with the DSIP.[82] Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.3 Structure of the Handbook

The four remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

[82] DSIP Guidance Order, pg. 64: "shall file subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018."

Section 2. General Methodological Considerations describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.

Section 3. Relevant Cost-Effectiveness Tests defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure (RIM). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.

Section 4. Benefits and Costs Methodology provides detailed definitions, calculation methods, and general considerations for each benefit and cost.

Section 5. Characterization of DER profiles discusses which benefits and costs are likely to apply to different types of DER, and provides examples for a sample selection of DERs.

Appendix A. Utility-Specific Assumptions includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

2. General Methodological Considerations

This section describes key issues and challenges that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in Section 4.

2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Doubling-counting can be avoided by (1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and 2) clear definition and differentiation between the benefits and costs included in the analysis.

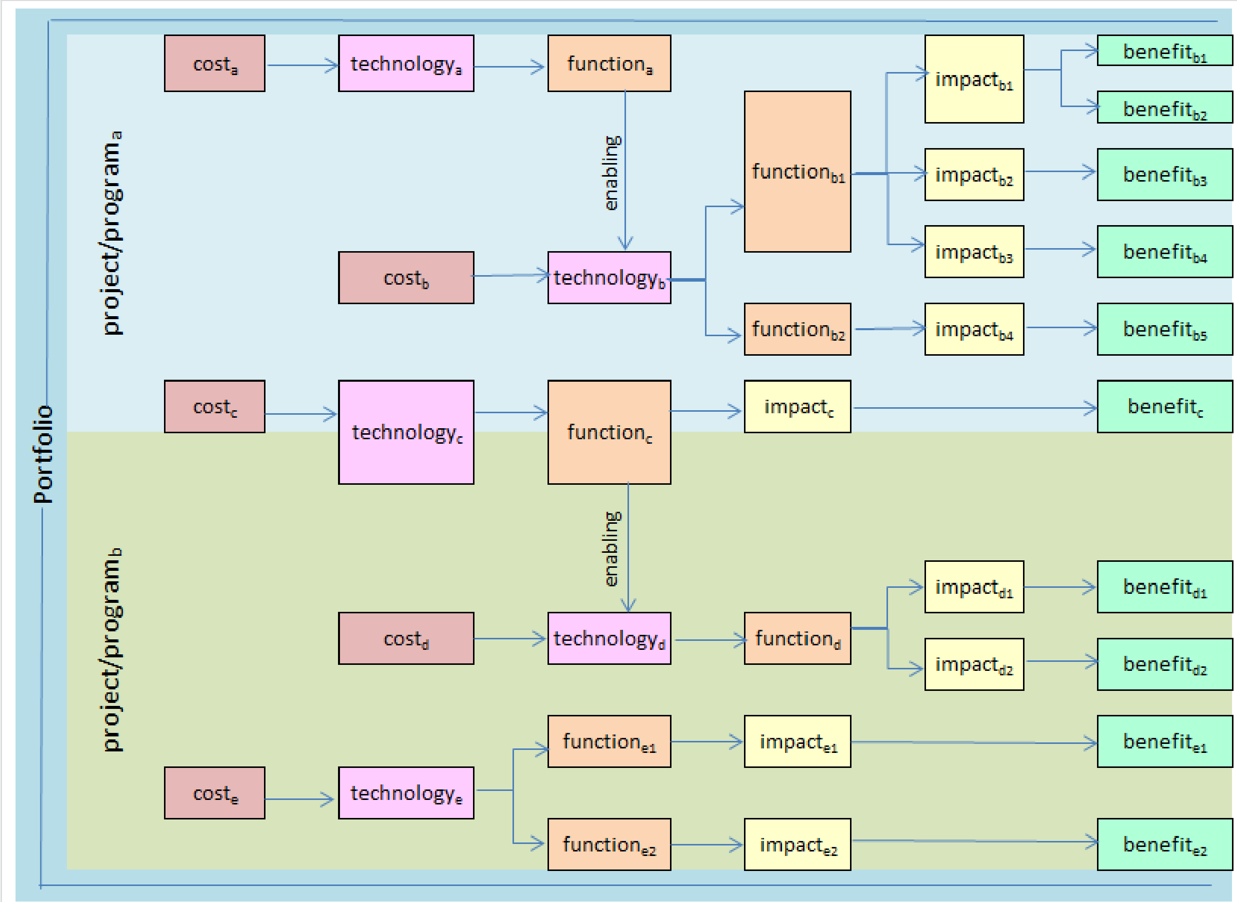
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

2.1.1 Accounting of Benefits and Costs Across Multiple Value Streams

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology also provides one or more functions that result in quantified impacts, which are valued as monetized benefits.

Figure 2-1 is an illustrative example of value streams that may be associated with a portfolio of projects or programs.

Figure 2-1. Illustrative Example of Value Streams that May be Associated with a Portfolio of Projects or Programs



Source: National Grid

Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies (e.g. technology$_b$ in Figure 2-1). Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function (e.g. technology$_c$ in Figure 2-1). It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Benefits and costs should also be allocated properly across different projects within a portfolio. This may present challenges especially in the case of enabling technologies. For example, the investment in $technology_c$ in Figure 2-1 is included as part of $project/program_a$. Some direct benefits from this technology are realized for $project/program_a$, however $technology_c$ also enables $technology_d$ that is included as part of $project/program_b$. In this example, the costs of $technology_c$ and the directly resulting benefit should be accounted for in $project/program_a$, and the cost for $technology_d$ and the resulting incremental benefits should be accounted for in $project/program_b$.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Overtime, investments made as part of previous projects or portfolios may also enable or enhance new projects. The *BCA Order* states that utility BCA shall consider incremental T&D costs "to the extent that the characteristics of a project cause additional costs to be incurred."[83]

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility's distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. If there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder. As another example, the incremental improvement on reliability indices may diminish as more automated switching projects are in place.

2.1.2 Benefit Definitions and Differentiation

A key consideration identified in performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

[83] *BCA Order*, Appendix C pg. 18.

As discussed in Section 3, the *BCA Order* identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section 4. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided LBMP, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided LBMP benefits may be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Sections 2.1.2.1 and 2.1.2.2 below define the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided LBMP, and differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits. Sections 2.1.2.1 and 2.1.2.2 also provide differentiation between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

Table 2-1 provides a list of potentially overlapping AGCC, and Avoided LBMP benefits.

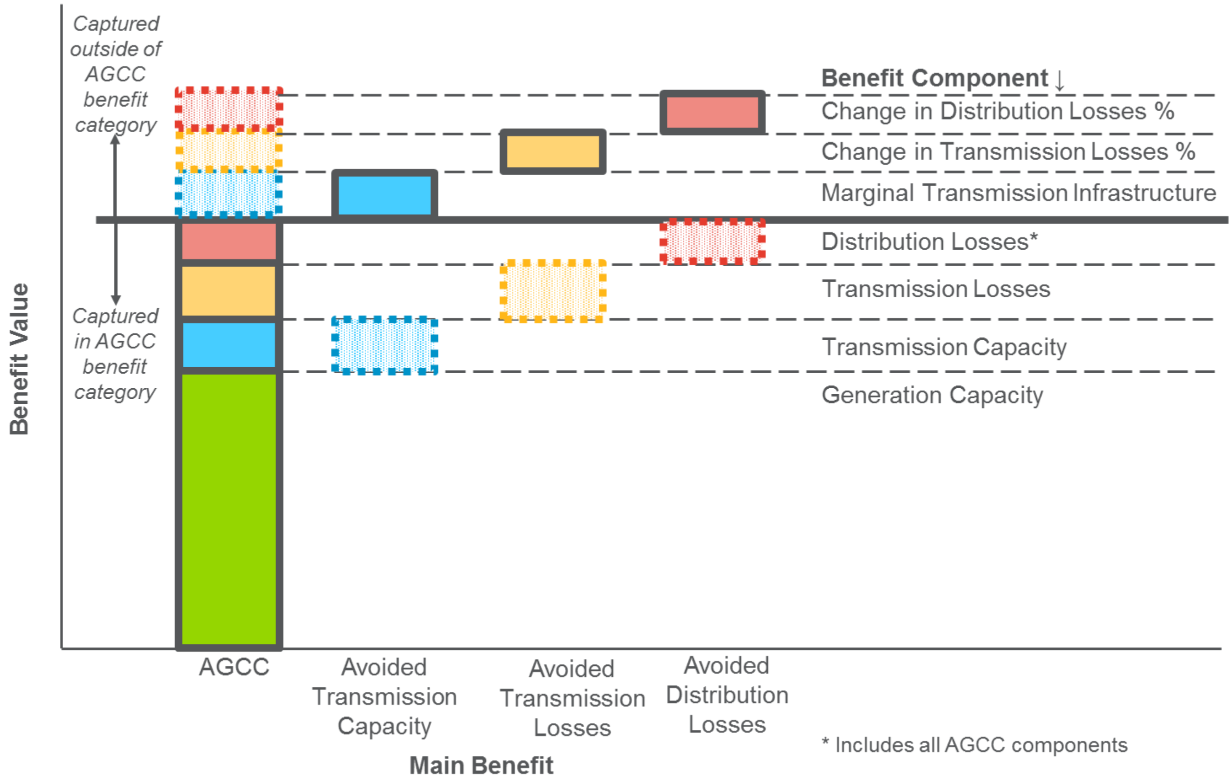
Table 2-1. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	• Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses
Avoided LBMP	• Net Avoided CO_2 • Net Avoided SO_2 and NO_x • Avoided Transmission Losses • Avoided Transmission Capacity • Avoided Distribution Losses

2.1.2.1 Benefits Overlapping with Avoided Generation Capacity Costs

Figure 2-2 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure 2-2. Benefits Potentially Overlapping with Avoided Generation Capacity Costs (Illustrative)



Source: Navigant

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission losses.[84] Additionally, distribution losses can affect the calculation of AGCC, depending on the project location on the system.[85] The AGCC calculation accounts for these distribution losses.

[84] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

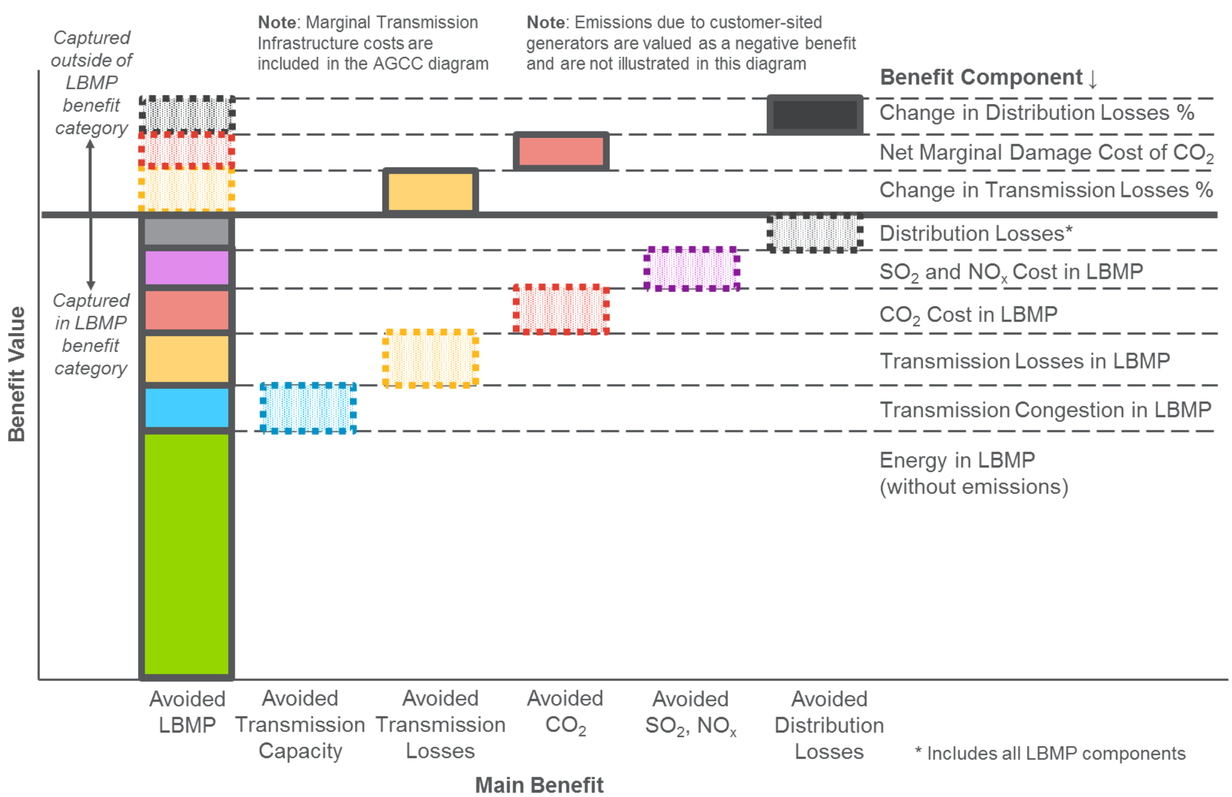
[85] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

If a project changes the electrical topology and therefore changes the transmission loss percent itself, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

2.1.2.2 Benefits Overlapping with Avoided LBMP

Figure 2-3 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

Figure 2-3. Benefits Potentially Overlapping with Avoided LBMP Benefit (Illustrative)



Source: Navigant

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit, but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided LBMP benefit include costs for factors beyond simple energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided LBMP benefit:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the LBMP

- Transmission-level loss costs which are embedded in the LBMP
- Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the LBMP

Additionally, distribution losses can affect LBMP purchases, depending on the project location on the system, and should gross up the calculated LBMP benefits.[86] To the extent a project changes the electrical topology and changes the distribution loss percent itself, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, the variable losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity of energy and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[87] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from “loss percent”. The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section 4 follow the same notation to represent various locations on the system:

[86] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the LBMP purchases due to higher losses.
[87] In the BCA equations outlined in Section 4 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

- "r" subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[88]
- "i" subscript represents the interface of the distribution and transmission systems.
- "b" subscript represents the bulk system which is the level at which the values for AGCC and LBMP are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{\mathrm{b}\rightarrow\mathrm{r}}$ would represent the loss percent between the bulk system ("b") and the retail delivery or connection point ("r"). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. Because benefits of grid modernization projects accrue over many years, baselines must be valid across the same time horizon. This introduces a few points that merit consideration:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO's CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-

[88] Transmission in this context refers to the distribution utility's sub-transmission and internal transmission.

contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.

- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may take place independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment, expected system performance, or both. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions underlying the existing baseline.

2.4 Normalizing Impacts

In addition to establishing an appropriate baseline, normalizing impact data presents similar challenges. This is particularly true for distribution-level projects, where system performance is significantly affected by external conditions beyond that which occurs on the distribution system. For instance, quantifying the impact of technology investment on reliability indices would require the baseline data to be representative of expected feeder reliability performance. This is a challenging task, as historical data would require weather adjustments and contemporaneous data would be drawn from different, but similar, feeders.

A distribution feeder may go through changes that could influence feeder performance independent of the technologies implemented. For instance, planned outages due to routine maintenance activities or outages due to damages from a major storm could impact reliability indices and changes in the mix of customer load type (e.g., residential vs. commercial and industrial), which may impact feeder peak load.

2.5 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[89]

[89] *BCA Order*, pg. 2

2.6 Granularity of Data for Analysis

The most accurate assumptions to use for assessing a BCA would leverage suitable location or temporal information. When the more granular data is not available, an appropriate annual average or system average maybe used, if applicable in reflecting the expected savings from use of DER.

More granular locational or temporal assumptions are always preferred to more accurately capture the savings from use of a resource. However, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where their use is required.

2.7 Performing Sensitivity Analysis

The *BCA Order* indicates the BCA Handbook shall include "description of the sensitivity analysis that will be applied to key assumptions."[90] As Section 4 presents, there is a discussion of each of the benefits and costs, and a sensitivity analysis can be performed by changing selected parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided LBMP or AGCC.

A sensitivity of LBMP, $/MWh, could be assessed by adjusting the LBMP by +/-10%.

In addition to adjusting the values of an individual parameter as a sensitivity, the applicability of certain benefits and costs would be considered as a sensitivity analysis of the cost-effectiveness tests. For example, inclusion of the Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.[91]

[90] *BCA Order*, Appendix C, pg. 31.

[91] *BCA Order*, pg. 25 ("The evaluation would then be conducted showing separately the impacts both with and without the wholesale market price effect.")

3. Relevant Cost-Effectiveness Tests

The *BCA Order* states that the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 3-1.

Table 3-1. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The *BCA Order* positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and ratepayers. Some projects may not provide benefits to the utility and ratepayers, even if it is beneficial to society as a whole. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that the impact is of a "magnitude that is unacceptable".[92]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 2 General Methodological Considerations.

[92] *BCA Order*, pg. 13.

Table 3-2 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test.

Table 3-2. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
Benefit				
4.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
4.1.2	Avoided LBMP‡	✓	✓	✓
4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
4.1.5	Avoided Ancillary Services*	✓	✓	✓
4.1.6	Wholesale Market Price Impacts**		✓	✓
4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
4.2.2	Avoided O&M	✓	✓	✓
4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
4.3.1	Net Avoided Restoration Costs	✓	✓	✓
4.3.2	Net Avoided Outage Costs	✓		
4.4.1	Net Avoided CO_2‡	✓		
4.4.2	Net Avoided SO_2 and NO_x‡	✓		
4.4.3	Avoided Water Impacts	✓		
4.4.4	Avoided Land Impacts	✓		
4.4.5	Net Non-Energy Benefits***	✓	✓	✓
Cost				
4.5.1	Program Administration Costs	✓	✓	✓
4.5.2	Added Ancillary Service Costs*		✓	✓
4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
4.5.4	Participant DER Cost	✓		
4.5.5	Lost Utility Revenue			✓
4.5.6	Shareholder Incentives		✓	✓
4.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 2 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 2.1.2.1 for discussion of potential overlaps in accounting for these benefits.
** The amount of DER is not the driver of the size of NYISO's Ancillary Services markets since a change in load will not result in a reduction in the NYISO requirements for Regulation and Reserves as the requirements for these services are set periodically by NYISO to maintain frequency and to cover the loss of the largest supply element(s) on the bulk power system. Therefore, there is no impact within the SCT as the overall Ancillary Services requirement remains unchanged. DER has potential to provide new*

distribution-level ancillary service. However, it is uncertain whether such service can be cost-effectively provided.
*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefits in each year of the analysis period (i.e., how much will it change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 4.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

A majority of the benefits included in the *BCA Order* can be evaluated under the SCT because their impact can be applied to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants in the *BCA Order*:

> "Wholesale markets already adjust to changes in demand and supply resources, and any resource cost savings that result are reflected in the SCT. Any price suppression over and above those market adjustments is essentially a transfer payment -- simply a shift of monetary gains and losses from one group of economic constituents to another. No efficiency gain results if, for example, generators are paid more or less while consumers experience equal and offsetting impacts. Therefore, the price suppression benefit is not properly included in the SCT beyond the savings already reflected there."[93]

3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

[93] *BCA Order*, pg. 24

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4. Benefits and Costs Methodology

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and general considerations.

There are four types of benefits which are further explained in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

Additionally, there are four types of costs that are also considered in the BCA Framework and explained in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

In this version of the Handbook, for energy, operational, and reliability-related benefits and costs,[94] it is assumed that impacts generate benefits/costs in the same year as the impact. In other words, there is no time delay between impacts and benefits/costs. However, for capacity and infrastructure benefits

[94] Energy, operational, and reliability-related benefits and costs include: Avoided LBMP, the energy component of Avoided Transmission Losses, Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation), the energy portion of

Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO2, Net Avoided SO2 and NOx, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, Shareholder Incentives, and Net Non-Energy Costs.

and costs,[95] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2016, the AGCC benefit would not be realized until 2017.

4.1 Bulk System Benefits

4.1.1 Avoided Generation Capacity Costs

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[96] It is assumed that the benefit is realized in the year following the peak load reduction impact.

4.1.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2015 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

Equation 4-1. Avoided Generation Capacity Costs

$$\text{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{Z,Y,r}}{1\text{-Loss\%}_{Z,Y,b\rightarrow r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

The indices of the parameters in Equation 4-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

[95] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity portion of the

Wholesale Market Price Impact, Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

[96] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

$\Delta\text{PeakLoad}_{Z,Y,r}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\text{Loss}\%_{Z,b\rightarrow r}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\text{SystemCoincidenceFactor}_{Z,Y}$ **(dimensionless)** captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\text{DeratingFactor}_{Z,Y}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$\text{AGCC}_{Z,Y,b}$ ($/MW-yr) represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

4.1.1.2 General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast.[97] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several

[97] 2015 CARIS Phase 1 Study Appendix. http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2015_CARIS_Final_Appendices_FINAL.pdf

localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[98] for more details on ICAP.

AGCC benefits are calculated using a static forecast of AGCC prices provided by Staff. Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section 4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (i.e. $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

4.1.2 Avoided LBMPs

Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP). The three components of the LBMP (i.e., energy, congestion, and losses) are all included in this benefit. See Section 2.1.2.1 for details on how the methodology avoids double counting between this benefit and others.

98 http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

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4.1.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-2 presents the benefit equation for Avoided LBMP:

Equation 4-2. Avoided LBMP

$$\text{Benefit}_Y = \sum_Z \sum_P \frac{\Delta\text{Energy}_{Z,P,Y,r}}{1 - \text{Loss\%}_{Z,b\to r}} * \text{LBMP}_{Z,P,Y,b}$$

The indices of the parameters in

Equation 4-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\mathbf{Energy}_{Z,P,Y,r}$ **(ΔMWh)** is the difference in energy purchased at the retail delivery or connection point ("r") before and after project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $Loss\%_{Z,b\to r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathbf{Loss\%}_{Z,b\to r}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\mathbf{LBMP}_{Z,P,Y,b}$ **($/MWh)** is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS Phase 2 planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

4.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that is valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the LBMP and the AGCC prices. Because static forecasts of LBMPs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

4.1.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation 4-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{C}} \frac{\Delta\mathrm{PeakLoad}_{\mathrm{Y,r}}}{\mathrm{Loss\%}_{\mathrm{Y,b\rightarrow r}}} * \mathrm{TransCoincidentFactor}_{\mathrm{C,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalTransCost}_{\mathrm{C,Y,b}}$$

The indices[99] of the parameters in

Equation 4-3 include:

- C = constraint on an element of transmission system[100]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta\mathrm{PeakLoad}_{\mathrm{Y,r}}}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\boldsymbol{\mathrm{Loss\%}_{\mathrm{Y,b\rightarrow r}}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2.

$\boldsymbol{\mathrm{TransCoincidentFactor}_{\mathrm{C,Y}}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

[99] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[100] If system-wide marginal costs are used, this is not an applicable subscript.

$\mathbf{DeratingFactor_Y}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\mathbf{MarginalTransCost_{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3. Orange & Rockland anticipates commissioning a new marginal cost study to capture recent work experience, to separately breakout the O&M component to support new capital projects and to present the results on a more granular basis where appropriate. When completed, the results of this new study will be integrated into the Handbook and will be applied prospectively.

4.1.3.2 General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study.

Some transmission capacity costs are already embedded in both LBMP and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in LBMP and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in significant over- or under-valuation of the benefits or costs and may result in no savings in utility costs for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table A-3 include both capital and O&M, and cannot be split between the two benefits. Therefore care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section 4.2.2.

4.1.4 Avoided Transmission Losses

Avoided Transmission Losses is the benefit that is realized when a project changes the topology of the transmission system and results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided LBMP and Avoided Generation Capacity benefits as described above in Sections 4.1.2 and 4.1.1. In actuality, both the LBMP and AGCC would adjust to a change in system losses in future years; however, the static forecast used in this methodology does not capture these effects.

4.1.4.1 Benefit Equation, Variables, and Subscripts

Equation 4-4 presents the benefit equation for Avoided Transmission Losses:

Equation 4-4. Avoided Transmission Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i} = \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\rightarrow i,\mathrm{post}}$$

The indices[101] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[102])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\mathbf{SystemEnergy_{Z,Y+1,b}}$ **(MWh)** is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b"), which includes transmission and distribution losses. Note that total system energy is used for this input, not the project-specific energy, because this benefit is only included in the BCA when the system topology is changed resulting in a change in the transmission loss percent, which affects all load in the relevant area.

$\mathbf{LBMP_{Z,Y+1,b}}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To

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[101] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[102] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) \$/MWh.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in transmission losses percent, which affects all load in the relevant zone.

$\mathbf{AGCC_{Z,Y,b}}$ **(\$/MW-yr)** represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level"[103] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of \$/kW-mo, which must be converted to \$/MW-yr to match the peak load impact in MW. To convert units, the summer and winter \$/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to \$/MW-yr.

$\mathbf{\Delta Loss\%_{Z,Y,b \to i}}$ **(Δ%)** is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,b \to i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,b \to i,post}}$ **(%)** is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

[103] "Transmission level" represents the bulk system level ("b").

4.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to selected DERs that are willing and qualify to provide ancillary services to NYISO. NYISO could purchase ancillary services from these DERs in lieu of conventional generators at a lower cost without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO. This value will be zero for nearly all cases and by exception would a value be included as part of the UCT and RIM.

As a load modifier, DER causes a reduction in load however, it will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are periodically set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to communicate with and effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services unless and until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

4.1.5.1 Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of this benefit is project specific.

Frequency Regulation

Equation 4-5 presents the benefit equation for frequency regulation:

Equation 4-5. Frequency Regulation

$$\mathrm{Benefit_Y} = \mathrm{Capacity_Y} * \mathrm{n} * (\mathrm{CapPrice_Y} + \mathrm{MovePrice_Y} * \mathrm{RMM_Y})$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project. The amount is difficult to forecast.

$\mathbf{n}$ **(hr)** is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$\mathbf{MovePrice_Y}$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

$\mathbf{RMM_Y}$ **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 4-6 presents the benefit equation for spinning reserves:

Equation 4-6. Spinning Reserves

$$\text{Benefit}_Y = \text{Capacity}_Y * \text{n} * \text{CapPrice}_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$\textbf{Capacity}_{\mathbf{Y}}$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project. The amount is difficult to forecast.

$\mathbf{n}$ **(hr)**: is the number of hours in a year that the resource is expected to provide the service.

$\textbf{CapPrice}_{\mathbf{Y}}$ **($/MW·hr)** is the average hourly spinning reserve capacity price. Default value uses the two-year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

NYISO in late 2015 changed the number of regions for Ancillary Services from two to three and two-year historical data is not available for all three regions. Thus, assume that EAST and SENY are equal to the historical data for EAST. The corresponding NYISO zones for EAST are F – K, and the corresponding zones for WEST are A – E.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period. To avoid the complication of the change in regions, the two-year historical average is based on November 1, 2013 through October 31, 2015.

The NYISO Ancillary Services Manual suggests that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.

The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.

4.1.6 Wholesale Market Price Impact

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., LBMP) and capacity (i.e., AGCC) due to a measure, project, or portfolio. LBMP impacts will be provided by Staff and are determined using the first year of the most recent CARIS 2 database to calculate the static impact on wholesale LBMP of a 1% change in the level of load that must be met.[104] LBMP impact will be calculated for each NYISO zone. AGCC price impacts are characterized using Staff's ICAP Spreadsheet Model.

2.1.2.2 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

Equation 4-7. Wholesale Market Price Impact

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{Z}} (1 - \mathrm{Hedging\%} \quad) * (\Delta\mathrm{LBMPImpact}_{\mathrm{Z,Y+1,b}} * \frac{\Delta\mathrm{Energy}_{\mathrm{Z,Y+1,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Z,b\to r}}} + \Delta\mathrm{AGCC}_{\mathrm{Z,Y,b}} * \mathrm{ProjectedAvailableCapacity}_{\mathrm{Z,Y,b}})$$

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K[105])
- Y = Year
- b = Bulk System

$\mathbf{Hedging\%}$ **(%)** is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. For BCA calculations the utilities have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

[104] *BCA Order*, Appendix C, pg. 8.
[105] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

$\mathbf{\Delta LBMPImpact_{Z,Y+1,b}}$ **(Δ$/MWh)** is the change in average annual LBMP at the bulk system ("b") before and after the project(s). This will be provided by DPS Staff.

$\mathbf{\Delta Energy_{Z,Y+1,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{Z,b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table A-2.

$\mathbf{WholesaleEnergy_{Z,Y,b}}$ **(MWh)** is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This must represent the energy at the LBMP.

$\mathbf{\Delta AGCC_{Z,Y,b}}$ **(Δ$/MW-yr)** is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[106] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\mathbf{ProjectedAvailableCapacity_{Z,Y,b}}$ **(MW)** is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

4.1.6.1 General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. LBMP market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS 2 database to calculate the static impact on LBMP of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT, but would be included in RIM and UCT as a sensitivity.

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[106] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

It is assumed that Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand, quickly reducing the benefit.[107]. It is also assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact, and the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact

4.2 Distribution System Benefits

4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

Benefit Equation, Variables, and Subscripts

Equation 4-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation 4-8. Avoided Distribution Capacity Infrastructure

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{V}} \sum_{\mathrm{C}} \frac{\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b \to r}}} * \mathrm{DistCoincidentFactor}_{\mathrm{C,V,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalDistCost}_{\mathrm{C,V,Y,b}}$$

[107] The one year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015

The indices of the parameters in

Equation 4-8 include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[108]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathbf{\Delta PeakLoad_{Y,r}}$ **(ΔMW)** is the nameplate demand reduction of the project at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2. This parameter is used to adjust the $\Delta \mathrm{PeakLoad_{Y,r}}$ parameter to the bulk system level.

$\mathbf{DistCoincidentFactor_{C,V,Y}}$ **(dimensionless)** captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system. This input is project specific.

$\mathbf{DeratingFactor_{Y}}$ **(dimensionless)** is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system. This input is project specific.

$\mathbf{MarginalDistCost_{C,V,Y,b}}$ **($/MW-yr)** is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited

[108] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3.

4.2.1.1 General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used when and wherever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure need may result in significant over- or under-valuation of the benefits or costs, and may result in no savings in utility costs for customers. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DERs could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. These values are provided in Table A-3.

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the constraint is relieved and benefits should not be realized from that point forward.

The marginal cost of distribution capacity values provided in Table A-3 include both capital and O&M, and cannot be split between the two benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section 4.2.2.

4.2.2 Avoided O&M

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. This benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. At this time, for most DER projects this benefit will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

4.2.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-9 presents the benefit equation for Avoided O&M Costs:

Equation 4-9. Avoided O&M

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{AT}} \Delta\mathrm{Expenses}_{\mathrm{AT,Y}}$$

The indices of the parameters in Equation 4-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\mathbf{\Delta Expenses_{AT,Y}}$ **(Δ$)**: Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

4.2.2.2 General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be zero for most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely. Labor and crew rates can be sourced using the utility's activity-based costing system or work management system, if that information is available.

4.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project changes distribution system losses, resulting in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%).

4.2.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-10 presents the benefit equation for Avoided Distribution Losses:

Equation 4-10. Avoided Distribution Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,i\rightarrow r} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r} = \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{post}}$$

The indices[109] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[110])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathrm{SystemEnergy}_{Z,Y,b}$ (MWh) is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, not the project-specific energy, because this benefit is only quantified when the distribution loss percent value is changed, which affects all load in the relevant part of the distribution system.

$\mathrm{LBMP}_{Z,Y,b}$ (\$/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an

[109] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[110] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\mathrm{Loss\%_{Z,b\rightarrow r}}$ parameter. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent, which affects all load in the relevant part of the distribution system.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system level ("b") based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\mathbf{\Delta Loss\%_{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

4.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses in the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses. Because losses data is usually only available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the time delay of benefits relative to the impacts.

4.3 Reliability/Resiliency Benefits

4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, since utilities are required to repair the cause of an outage regardless of whether the DER allows the customer to operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault or system damage. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of specific programs or specific projects are identified below. Use of methodology depends on the type of investment/technology under analysis. Equation 4-11 will generally apply to non-DER investments that allow the utility to save time and other expenses dispatching restoration crews. Equation 4-12 will generally apply to DER investments that are able to provide functionally equivalent reliability as an alternative to the traditional utility investment.

4.3.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-11 presents the benefit equation for Net Avoided Restoration Costs associated with non-DER investments:

Equation 4-11. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = -\Delta\mathrm{CrewTime_Y} * \mathrm{CrewCost_Y} + \Delta\mathrm{Expenses_Y}$$

$$\textit{Where,}$$

$$\Delta\mathrm{CrewTime_Y} = \#\mathrm{Interruptions_{base,Y}} * (\mathrm{CAIDI_{base,Y}} - \mathrm{CAIDI_{post,Y}} * (1 - \%\mathrm{ChangeSAIFI_Y}))$$

$$\%\mathrm{ChangeSAIFI_Y} = \frac{\mathrm{SAIFI_{base,Y}} - \mathrm{SAIFI_{post,Y}}}{\mathrm{SAIFI_{base,Y}}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for non-DER projects/programs that are applicable across a total system basis. More targeted data should be substituted for localized, geographic specific projects that exhibit localized impacts. Other reliability metrics will need to be developed to more suitably quantify reliability or resiliency benefits and costs associated with localized projects or programs. Once developed, the localized restoration cost metric will be applied and included in this handbook.

There is no subscript to represent the type of outage in Equation 4-11 because it assumes an average restoration crew cost that does not change based on the type of outage. The ability to reduce outages would be dependent on the outage type.

$\boldsymbol{\Delta\mathrm{CrewTime_Y}}$ **(Δhours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. This data is project and/or program specific. A positive value represents a reduction in crew time

$\boldsymbol{\mathrm{CrewCost_Y}}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration

$\Delta\mathbf{Expenses_{Y}}$ **(Δ\$)** are the average expenses (e.g. equipment replacement) associated with outage restoration.

$\#\mathbf{Interruptions_{base,Y}}$ **(int/yr)** are the baseline (i.e., pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI excluding major storms is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\%\mathbf{ChangeSAIFI_{Y}}$ **(Δ%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average and excludes major storms. It is available from the annual Electric Service Reliability Reports. Generally, this parameter is system-wide value. In localized project/program specific cases,, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

Equation 4-12. Net Avoided Restoration Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = \mathrm{MarginalCost}_{\mathrm{R,Y}}$$

The indices of the parameters in Equation 4-12 are applicable to DER installations and include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\mathrm{MarginalDistCost}_{\mathrm{R,Y}}$ ($/yr): Marginal cost of the reliability investment. This value is very project- and location- and a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent reliability as compared to the reliability provided by the traditional distribution reliability investment that would have otherwise been constructed and placed in service; If the DER does not defer or avoid a traditional reliability investment, this benefit does not apply. When an individual or portfolio of DER is able to defer a distribution reliability investment, the value of the avoided restoration cost is already reflected in the Avoided Distribution Capacity Infrastructure benefit calculation. Care must be taken to avoid double counting.

4.3.1.2 General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline, not based on outside factors such as weather. The changes to these parameters should consider the appropriate context of the project, for example, impact to one feeder or impact to a portion of the distribution system. The baseline values should match the portion of the system impacted. In addition, one should consider the types of outage event and how the project may or may not address each type of outage event to inform the magnitude of impact.

In addition to being project-specific, the calculation of avoided restoration costs is dependent on projection of the impact of specific investments affecting the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. Application of this benefit would be considered only for investments with validated reliability results.

4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

4.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-13 presents the benefit equation for Net Avoided Outage Costs:

Equation 4-13. Net Avoided Outage Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{C}} \mathrm{ValueOfService}_{\mathrm{C,Y,r}} * \mathrm{AverageDemand}_{\mathrm{C,Y,r}} * \Delta\mathrm{SAIDI}_{\mathrm{Y}}$$

Where,

$$\Delta\mathrm{SAIDI}_{\mathrm{Y}} = \mathrm{SAIFI}_{\mathrm{base,Y}} * \mathrm{CAIDI}_{\mathrm{base,Y}} - \mathrm{SAIFI}_{\mathrm{post,Y}} * \mathrm{CAIDI}_{\mathrm{post,Y}}$$

The indices of the parameters in Equation 4-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\mathrm{ValueOfService}_{\mathrm{C,Y,r}}$ ($/kWh) is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathrm{AvgDemand}_{\mathrm{C,Y,r}}$ (kW) is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\Delta \mathbf{SAIDI_{Y}}$ **(∆hr/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[111] Baseline system average reliability metrics can be found in the Company's annual Electric Service Reliability Reports **Error! Reference source not found.**. A positive value represents a reduction in SAIDI.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

4.3.2.2 General Considerations

The value of the avoided outage cost benefit is to be customer-specific, customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

[111] SAIDI = SAIFI * CAIDI

For this version of the BCA Handbook, the outage cost can be estimated by assuming that the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

At this time, the Standard Interconnection Requirements do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

4.4 External Benefits

4.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[112] or the increase of CO_2 from onsite generation. The CARIS Phase 2 forecast of LBMP contains a cost of carbon based on the Regional Greenhouse Gas Initiative (RGGI). Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the LBMP. This adder is based on the United States Environmental Protection Agency damage cost estimates for a 3% real discount rate. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs is the full marginal damage cost less the cost of carbon embedded in the LBMP.

4.4.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-14 presents the benefit equation for Net Avoided CO_2:

Equation 4-14. Net Avoided CO_2

$$\mathrm{Benefit_Y} = \mathrm{CO2Cost\Delta LBMP_Y} - \mathrm{CO2Cost\Delta OnsiteEmissions_Y}$$

Where,

$$\mathrm{CO2Cost\Delta LBMP_Y} = \left(\frac{\Delta\mathrm{Energy_{Y,r}}}{1 - \mathrm{Loss\%_{Y,b\rightarrow r}}} + \Delta\mathrm{Energy_{TransLosses,Y}} + \Delta\mathrm{Energy_{DistLosses,Y}}\right) * \mathrm{NetMarginalDamageCost_Y}$$

[112] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

$$\Delta \text{Energy}_{\text{TransLosses,Y}} = \text{SystemEnergy}_{\text{Y,b}} * \Delta \text{Loss\%}_{\text{Y,b}\rightarrow\text{i}}$$

$$\Delta \text{Energy}_{\text{DistLosses,Y}} = \text{SystemEnergy}_{\text{Y,b}} * \Delta \text{Loss\%}_{\text{Y,i}\rightarrow\text{r}}$$

$$\Delta \text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i}} = \text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i,baseline}} - \text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i,post}}$$

$$\Delta \text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r}} = \text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r,baseline}} - \text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r,post}}$$

$$\text{CO2Cost}\Delta\text{OnsiteEmissions}_{\text{Y}} = \Delta\text{OnsiteEnergy}_{\text{Y}} * \text{CO2Intensity}_{\text{Y}} * \text{SocialCostCO2}_{\text{Y}}$$

The indices of the parameters in Equation 4-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\mathbf{CO2Cost\Delta LBMP_Y}$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided LBMP benefit. The incremental value of CO_2 is captured in this benefit, and is valued at the net marginal cost of CO_2, as described below.

$\mathbf{CO2Cost\Delta OnsiteEmissions_Y}$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\mathbf{\Delta Energy_{Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table A-2.

$\Delta\mathbf{Energy}_{\mathbf{TransLosses,Y}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\Delta\mathbf{Energy}_{\mathbf{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section 4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathbf{NetMarginalDamageCost}_{\mathbf{Y}}$ **(\$/MWh)** is the "adder" Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of LBMP from CARIS. The LBMP forecast from CARIS includes the cost of carbon based on the RGGI, but does include the SCC from the U.S. EPA.

$\mathbf{\Delta Loss\%}_{\mathbf{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%}_{\mathbf{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%}_{\mathbf{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent post-project, which is found in Table A-2.

$\mathbf{\Delta Loss\%}_{\mathbf{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%}_{\mathbf{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent post-project, which is found in Table A-2.

$\mathbf{\Delta OnsiteEnergy_Y}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathbf{CO2Intensity_Y}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation. Note that there is a difference between metric tons and short tons[113].

$\mathbf{SocialCostCO2_Y}$ **($ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in carbon dioxide emissions. Annual values are provided by EPA, and are also located in Table A of Attachment B of the BCA Order. Per the BCA Order, the values associated with a 3% real discount rate shall be used. Note that Table A provides values in 2011 dollars; these values must be converted to nominal values prior to using the equation above.

4.4.1.2 General Considerations

The equation above represents two sources of emissions based on: (1) a change in LBMP purchases, which is valued at the $/MWh adder (i.e., $NetMarginalDamageCost_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power [CHP]), which is valued at the social cost of carbon from EPA.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided LBMP benefit. The LBMP impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in LBMP due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The methodology outlined in this section to value Avoided CO_2 may change. The *BCA Order* indicates "utilities shall rely on the costs to comply with New York's Clean Energy Standard once those costs are known."[114]

[113] 1 metric ton = 1.10231 short tons
[114] *BCA Order*, Appendix C, 16.

4.4.2 Net Avoided SO_2 and NO_x

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

4.4.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation 4-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{p}} \mathrm{OnsiteEmissionsFlag}_{\mathrm{Y}} * \mathrm{OnsiteEnergy}_{\mathrm{Y,r}} * \mathrm{PollutantIntensity}_{\mathrm{p,Y}} * \mathrm{SocialCostPollutant}_{\mathrm{p,Y}}$$

The indices of the parameters in Equation 4-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag_Y}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW is implemented as a result of the project.

$\mathbf{OnsiteEnergy_{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

$\mathbf{PollutantIntensity_{p,Y}}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$\mathbf{SocialCostPollutant_{p,Y}}$ **($/ton)** is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2

4.4.2.2 General Considerations

LBMPs already include the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: "Annual NO_x" and "Ozone NO_x." Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

4.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

4.5 Costs Analysis

4.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

4.5.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-16 presents the cost equation for Program Administration Costs:

Equation 4-16. Program Administration Costs

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta\mathrm{ProgramAdminCost}_{\mathrm{M,Y}}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

$\boldsymbol{\Delta\mathrm{ProgramAdminCost}_{\mathrm{M,Y}}}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

4.5.1.2 General Considerations

Program Administration Costs are program- and project-specific, therefore without a better understanding of the details it is not possible to estimate in advance the Project Administration Cost. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

4.5.2 Added Ancillary Service Costs

Added Ancillary Service Costs occur when DER causes additional ancillary service cost on the system. These costs shall be considered and monetized in a similar manner to the method described in the 4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

4.5.3 Incremental Transmission & Distribution and DSP Costs

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional T&D infrastructure costs caused shall be considered and monetized in a similar manner to the method described in Section 4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. These factors make estimating a value of incremental T&D costs in advance without project-specific information difficult.

Depending on the nature of a specific DER project the incremental costs could be borne by the interconnecting facility or shared among all ratepayers. For instance, a utility may need to make further investment in their T&D infrastructure, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

4.5.4 Participant DER Cost

Participant DER Cost includes the equipment and participation costs assumed by DER providers which need to be considered when evaluating the societal costs of a project or program. For the purpose of performing the BCA, Participant DER costs are applied net of rebates and incentives which have been accounted for under Program Administration costs.

The Participant DER Costs includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment, balance of system and labor for the installation. Operating costs include ongoing maintenance expenses.

This section provides four examples of DER technologies with illustrative cost information based on assumptions that will ultimately vary given the facts and circumstances specific to each DER application:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – reciprocal engine (100 kW)
- Demand Response (DR) – controllable thermostat
- Energy Efficiency (EE) – commercial lighting

All cost numbers presented herein should be considered illustrative estimates only. These represent the full costs of the DER and do not account for or net out any rebates or incentives. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from, each of which have different combinations of cost and efficiency.
- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the state
- **Available rebates and incentives:** Include federal, state, and/or utility funding.

The Commission noted in the February 2015 Track 1 Order that the approach employed to obtain DER will evolve over time, "The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach."[115]

The acquisition of most DERs in the near term will be through competitive solicitations rather than the establishment of tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation[116]. Company competitive solicitations for DERs will require the disclosure of costs by the bidders, including but not limited to capital, installation, marketing, administrative, fixed and variable O&M, lost opportunity and/or behavioral incentive costs. The Company will use the submitted costs in the project/program/portfolio BCA evaluation. Additionally, the Company will employ this information to develop and update its technology specific benchmark costs as they evolve over time..

For illustrative purposes, examples for a small subset of DER technologies are provided below.

4.5.4.1 Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table 4-1 for the intermittent solar PV example are derived based on information provided in the E3's NEM Study for New York ("E3 Report").[117] In this study, E3 used cost data provided by NYSERDA based on solar PV systems

[115] At 33
[116] BCA Order ,Appendix C p 18
[117] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

that were installed in NY from 2003 to 2015. This is just one example of evaluating the potential cost of solar PV technology. The Company would need to incorporate service territory specific information when developing its technology benchmarks. For a project-specific cost analysis, actual estimated project costs would be used.

Table 4-1. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[118]	4,430
Fixed Operating Cost ($/kW)	15

Note: These costs would change as DER project-specific data is considered.

1. **Capital and Installation Cost:** Based on E3's estimate for NYSERDA of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4 kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.
2. **Fixed Operating Cost:** E3's estimate for NYSERDA of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

4.5.4.2 CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. For this illustration cost parameter values were obtained from the EPA's Catalog of CHP Technologies[119] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can affect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural-gas fired CHP system. All these elements would need to be reviewed and incorporated to develop the Company's service territory technology specific benchmarks.

[118] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.
[119] EPA CHP Report available at: https://www.epa.gov/chp/catalog-chp-technologies

Table 4-2. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [120]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[121]

4.5.4.3 DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell. The Company would need to incorporate its service territory specific information when developing its DR technology benchmarks.

Table 4-3. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$225[122]

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature.
2. **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

[120] EPA CHP Report. pg. 2-15.
[121] EPA CHP Report. pg. 2-17.
[122] Based on O&R's Marketplace experience

4.5.4.4 EE Example

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting. Lighting cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed.

Table 4-4. EE Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/Unit)	$80

Note: This illustration would change as projects and locations are considered.

1. **Installed Capital Cost:** Based on Navigant Consulting's review of manufacturer information and energy efficiency evaluation reports. The Company would need to incorporate its service territory specific information when developing its EE technology benchmarks.

4.5.5 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue shortfalls due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other ratepayers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

4.5.6 Shareholder Incentives

Shareholder Incentives include the annual costs to ratepayers of utility shareholder incentives that are tied to the projects or programs being evaluated.

Shareholder incentives are project or program specific and should be evaluated as such.

4.5.7 Net Non-Energy Costs

A suggested methodology for determining this benefit is not included in this version of the Handbook. In cases where non-energy impacts are attributable to the specific project or program, they may be assessed qualitatively. Net Non-Energy Costs may be applicable to any of the cost-effectiveness tests defined in the *BCA Order* depending on the specific project and non-energy impact.

5. Characterization of DER profiles

This section discusses the characterization of DERs using several examples, and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are: *intermittent*, *baseload*, *dispatchable* and *load reduction*. There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table 5-1 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook.

Table 5-1. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies that have been selected as examples are shown in Table 5-2. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table 5.2.

Table 5-2. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER is capable of enabling a different set of benefits and incurs a different set of costs, as illustrated in Table 5-3.

Table 5-3. General applicability for each DER to contribute to each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
Benefits					
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided LBMP	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	●	●	●	●
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
Costs					
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Shareholder Incentives	●	●	●	●
23	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section 4, each quantifiable benefit typically has two types of parameters. The defined benefits established to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), however key parameters assess the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). In other words, the amount of the underlying value that is captured by the DER resource is driven by the key parameters. Table 5-4 identifies the parameters which are necessary to characterize DER benefits. As described in Section 4, several benefits potentially applicable to DER require further investigation to estimate and quantify the impacts, and project-specific information before they can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table 5-4. Key parameter for quantifying how DER may contribute to each benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	**SystemCoincidenceFactor**
2	Avoided LBMP	**∆Energy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**∆Energy (annual)** **∆AGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[123]
12	Net Avoided CO_2	**CO_2Intensity** (limited to CHP)
13	Net Avoided SO_2 and NO_x	**PollutantIntensity** (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

[123] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table 5-5 further describes the key parameters identified in Table 5-4.

Table 5-5. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[124] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[125]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
ΔEnergy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ΔEnergy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the ΔEnergy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[126]

[124] This parameter is also used to calculate the Wholesale Market Price Impact benefit.

[125] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided LBMP and AGCC. This transmission coincidence factor is applicable for the Avoided Transmission Capacity Infrastructure and Related O&M benefit, which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs and Avoided LBMPs benefits.

[126] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit.

5.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

5.1.1 Bulk System

According to the NYISO, the bulk system peak generally occurs during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM. Table 5-6 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes.

Table 5-6. NYCA Peak Dates and Times

Year	Date of Peak	Time of Peak
2011	7/22/2011	Hour Ending 5 PM
2012	7/17/2012	Hour Ending 3 PM
2013	7/19/2013	Hour Ending 6 PM
2014	9/2/2014	Hour Ending 5 PM
2015	7/29/2015	Hour Ending 5 PM

5.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. The main benefit is the deferred utility capital investment. Additionally, benefits of a reduced transmission peak are captured in Avoided LBMP and AGCC benefits.

5.1.3 Distribution

The distribution peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood. The distribution system peak may differ or may coincide with the NYCA system peak and/or the transmission peak. System-wide averages have been historically acceptable to use for some investment portfolios such as Energy Efficiency where the programs are broad based, and where system-wide averages are provided in the Technical Resource Manual (TRM), which assumes a historical coincidence for the NYCA peak. Going forward, for investments that are more targeted in nature, a more localized coincidence factor is likely to be appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be very low or zero if no constrained element is relieved (e.g., an increase in capacity in that location is not required, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

5.2 Estimating Coincidence Factors

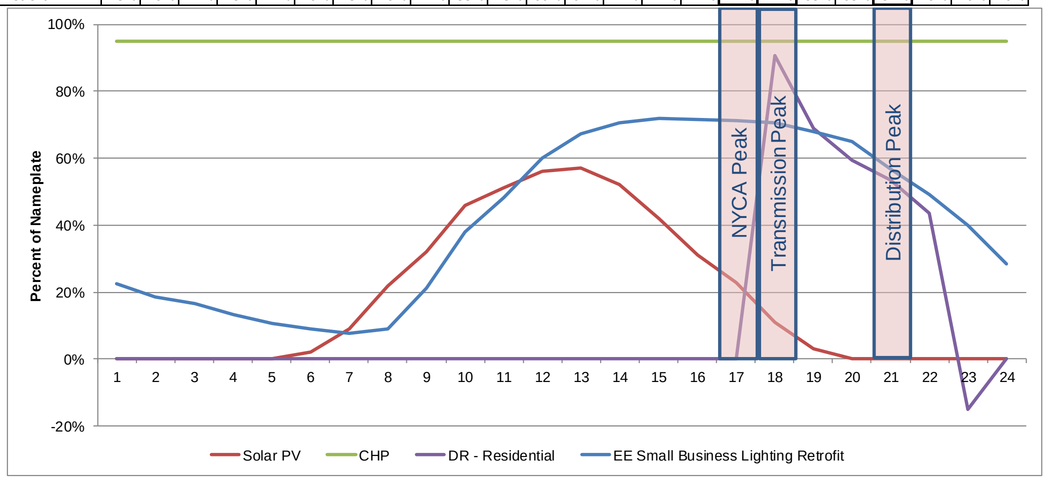
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and significant time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a 'typical day', or using a subset of hours that are appropriate for that specific DER.

Figure 5-1 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the NYCA Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource.

Figure 5-1. Illustrative Example of Coincidence Factors

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

Individual DER example technologies have been selected as examples and are discussed below.[127]

The values for the DER illustrative examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in E3's NEM Study for New York ("E3 Report")[128] based on a simulation of a large number of solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

[127] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DERs, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DERs and distribution system information is less generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWAs it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DERs, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, economic energy delivery. The BCA handbook incorporates derating factors in various benefit calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it is not included.

[128] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

5.3 Solar PV Example

Solar PV is selected to depict an **intermittent** DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions, were obtained from the E3 Report.

5.3.1 Example System Description

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on NYCA system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding NYCA system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

5.3.2 Benefit Parameters

The benefit parameters in Table 5-7 for the intermittent solar PV example are based on information provided in the E3 Report.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted-averages based on electricity delivered by utility are provided in Table 5-7. These values are illustrative estimates that may be refined as more data becomes available. To calculate project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (LBMP) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Table 5-7. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
∆Energy (time-differentiated)	Hourly

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC, that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[129] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section 4.1.1).
2. **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
3. **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[130] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
4. **∆Energy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly LBMPs.

5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

5.4.1 Example System Description

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance.

[129] NYISO ICAP Manual 4, June 2016 – Summer Unforced Capacity Percentage – Solar (Fixed Tilt Arrays) – pg. 4-23
[130] E3 Report, "Based on E3's NEM Ratepayer Impacts Evaluation in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed." PDF pg. 49.

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[131]

5.4.2 Benefit Parameters

Benefit parameters for the baseload CHP example are a combination of assumptions on system use and system characteristics.

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, with the exception of downtime for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[132]

The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[133] "CHP Technology," "Fuel," "Unit Capacity" and "Operation" were the four inputs required. Based on the example, a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors.

[131] https://www.epa.gov/chp/catalog-chp-technologies
[132] EPA CHP Report. pg. 2-20.
[133] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.

Table 5-8. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_x/MWh)	0.001
ΔEnergy (time-differentiated)	Annual average

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.1).
5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.2). There are no SO_2 emissions from burning natural gas.
6. **ΔEnergy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

5.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it is reduces demand on request from the system operator or utility.[134] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g., <100 hrs) and limited hours per call. The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

The coincidence factors shown below are based on experience and metering in Con Edison's Direct Load Control Program.[135] This DR example is specifically for a DR event called for five hours between the hours of 5pm and 10pm. The coincidence factors can and will change based on when DR event is called, customer response (e.g. overrides), device availability, load availability, and other project and technology- specific factors. Care should be taken to consider all these factors when determining appropriate coincidence factors for projects and portfolios.

The value of reduced energy use attributable to the DR asset can be calculated using the average LBMP of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2 hour events, 4 hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

5.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above. Coincidence factors might differ based on the call windows of the DR resource being evaluated.

Table 5-9. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.0
TransCoincidenceFactor	0.91
DistCoincidenceFactor	0.53
ΔEnergy (time-differentiated)	Average of highest 100 hours

Note: This illustration would change as specific projects and locations are considered.

[134] Some DR programs may be "dispatched" or scheduled by third-party aggregators.
[135] Specifically from the July 15 – 19, 2013 heat wave

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.0, based on Con Edison's Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the system peak.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.91, based on Con Edison's Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the transmission peak.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.53, based on Con Edison's Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the distribution peak.
4. **∆Energy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings can be estimated based on the *average* demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time-differentiated LBMP.

5.6 Energy Efficiency Example

Energy efficient lighting depicts a **load-reducing** DER where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology.

5.6.1 Example System Description

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial small business setting. The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing modifier because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of , small business-setting lighting system assumes that the coincidence factor is calculated during operational hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks. The illustrative values presented below are based on a recent Con Edison metering study.

5.6.2 Benefit Parameters

The benefit parameters described here are based on Con Edison experience with small commercial lighting projects.

Table 5-10. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	0.71
TransCoincidenceFactor	0.71
DistCoincidenceFactor	0.57
ΔEnergy (time-differentiated)	~9 am to ~10 pm weekdays

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the system peak.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the transmission peak..
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.57 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the distribution peak.
4. **ΔEnergy (time-differentiated):** This value is calculated using the lighting hours per year, divided by the total hours in a year (8,760). This time period is subject to building operation, which, in this exampleis assumed between 9 am and 10 pm, 6 days a week, 50 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

APPENDIX A. Utility-Specific Assumptions

This section includes utility-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 4.

The discount rate is set by the utility cost of capital, which is included in Table A-1.

Table A-1. Utility Weighted Average Cost of Capital

Regulated Rate of Return
7.1% for 2016, 7.06% for 2017
Source: ORU Rate Case 14-E-0493

The variable loss percent is used to account for losses occurring upstream from the load impact. Both the fixed and variable loss percent values may be affected by certain projects which alter the topography of the transmission and/or distribution systems. Utility-specific system annual average loss data is shown in Table A-2. Loss percentages come from utility-specific loss studies. The average loss percent and peak loss percent are assumed to be equal.

Table A-2. Utility Loss Data

System	Variable Loss Percent	Fixed Loss Percent
Transmission	1.3%	.4%
Primary Distribution	1.08%	0%
Secondary Distribution (with transformers)	.89%	.97%
Source: ORU study for NY PSC Case 08-E-0751		

Utility-specific system average marginal costs of service are found in Table A-3

Table A-3. Utility System Average Marginal Costs of Service

Year			
2016	11.76	32.92	17.14
2017	20.82	31.13	17.65
2018	33.14	24.21	18.18
2019	37.87	30.70	18.72
2020	17.53	48.57	19.29
2021	18.06	38.26	19.87
2022	18.60	39.44	20.46
2023	19.16	31.70	21.08
2024	19.73	28.19	21.71
2025	20.33	52.25	22.36
2026	20.94	82.11	23.03
2027	21.56	30.71	23.72
2028	22.21	29.28	24.43
2029	22.88	32.32	25.16
2030	23.56	65.49	25.92
2031	24.27	66.65	26.70
2032	25.00	64.51	27.50

Source: ORU Exhibit DAC-E3 for Rate Case 14-E-0493

Initial Distributed System Implementation Plan

Appendix B – O&R AMI Business Plan

Advanced Metering Infrastructure Business Plan

June 30, 2016

June 30, 2016

In accordance with the Advanced Metering Infrastructure (AMI) Collaborative provisions of the Joint Proposal approved by the Public Service Commission (Commission) in its Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan, issued October 16, 2015, in Cases 14-E-0493 and 14-G-0494, Orange and Rockland Utilities, Inc. (the Company) is pleased to submit its AMI Business Plan (the Plan). As stipulated in the Joint Proposal, the Plan includes a benefit cost analysis (BCA) for the proposed AMI investment.

As part of the Joint Proposal, the Company agreed to make a number of technical presentations to the Department of Public Service staff (Staff) and other interested parties regarding its AMI Business Plan. The first technical presentation took place on June 24, 2015. During this presentation, Staff and interested parties provided feedback and suggestions, some of which were incorporated into the business plan that the Company submitted to the Commission on July 2, 2015. The Company briefed a second technical presentation to the Staff on October 7, 2015. Certain of the feedback and suggestions received following the second presentation were incorporated into the update of the AMI Business Plan provided on November 19, 2015. Since that time the Company considered the merits of further enhancements and updates to its AMI Business Plan. Additionally, the Distributed Systems Implementation Platform (DSIP) Guidance document required utilities to file updated AMI business Plans with their DSIP on June 30, 2016. The revised costs, benefits and schedule for those enhancements and updates will be presented in this latest edition of the business plan.

Sincerely,

Keith Scerbo, Director

Orange & Rockland

AMI Business Plan

Table of Contents

1 Introduction

Orange and Rockland Utilities, Inc. (Orange and Rockland, O&R, or the Company) plans to deploy an Advanced Metering Infrastructure (AMI) system across the Rockland County part of its service territory as phase one of a Company-wide AMI deployment. Phase two will deploy AMI in the Company's service areas in Orange and Sullivan Counties. The part of the AMI project most visible to customers will be the installation of new AMI-enabled electric meters and new AMI communications modules for gas meters. As a transformative project, the project will require a significant Company effort to implement the new processes, applications, technologies and integrations needed to fully enable the functions and features of the AMI system. In addition, high quality customer and stakeholder engagement and organizational change management will be essential to project success.

During 2015, the Company prepared for starting the AMI implementation in 2017. Preparations included: finalizing the detailed business case analyses for the project; selecting the necessary equipment, software, and services; and, developing the AMI Business Implementation Plan Starting in 2016, the back-office infrastructure will be designed, configured, tested and brought on-line to support the initial AMI capabilities. This infrastructure development requires approximately twelve months and is needed before the first meters can be installed. Collectively, this infrastructure enables the foundational aspect of the project upon which even more advanced capabilities can be developed to support customer program enhancements and operational improvements.

Starting in early 2017 when all of the new back-office infrastructure systems are in place and tested, the Company's focus will shift from the internal architecture to deploying assets in the field. The field assets consist mainly of communications devices, electric meters, and gas modules. A Meter Installation Vendor (MIV) along with Company field forces and a separate Communications Installation Vendor (CIV) will perform the installations. At this time, the Company is planning to install the communications infrastructure and meters over a four year period across the New York Service Territory. The Company will first install communications and meters to the Pomona area of Rockland County in order to advance Reforming the Energy Vision (REV) demonstration projects.[136] Business transformation activities and stakeholder outreach and education will begin before field deployment and will continue throughout the deployment period. Plans for sequencing and timing the deployment across the service territory will be refined over the course of the next few months with a complete and optimized deployment design by October 31, 2016.

[136] 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 (issued February 26, 2015).

2 AMI Project Goals

Through implementation of the planned AMI Project, Orange and Rockland will deliver significant business, customer, and societal benefits that can be summarized as follows:

- Increase Operational Efficiency and Performance;
- Enhance Customer Service;
- Enable Customer Engagement;
- Provide a Foundation for REV; and
- Reduce Greenhouse Gas Emissions.

These benefits are discussed in detail in the following subsections and elsewhere in this document.

2.1 Increase Operational Efficiency and Performance

As demonstrated by successful AMI implementations at comparable electric and gas utilities, Orange and Rockland expects the planned AMI Project to produce measureable operational benefits in the following areas:

- Meter Reading;
- Metering;
- Field Services;
- Call Center;
- Outage Management;
- Meter Accuracy and Irregular Meter Condition (IMC);
- Revenue Protection;
- Inactive Meter/Unoccupied Premises; and
- Other Operations Benefits.

These tangible benefits, which provide the foundation for the project's financial business case, are described in detail in the business case portion of this document (Section 6.2, Operational Benefits).

2.2 Enhance Customer Service

Along with producing tangible operational benefits, the AMI project will drive improvements in the convenience, speed, and quality of the services that the Company provides to all of its customers – both during routine business activities and during outage situations.

Convenience: Examples of enhanced customer convenience include eliminating the need for manual reading of indoor meters and, within practical limits, offering customers flexible billing date options that better fit their financial circumstances.

Speed: The AMI's planned real-time data collection and electric service switching capabilities will increase the speed of customer services associated with handling customer calls and with activating and deactivating electric service.

Quality: The AMI's ability to reliably collect accurate billing data from electric and gas meters will greatly reduce the number of estimated bills and the customer disputes regarding those bills.

Outage Detection and Restoration: The AMI meters will detect the loss and restoration of electric power and will provide this information in real-time to Orange and Rockland's outage management system, augmenting the traditional outage notifications provided by customer calls and Supervisory Control and Data Acquisition (SCADA) systems. This will enable the Company to identify outages more quickly and facilitate efficient restoration activities. This is particularly crucial during storm restoration as it enables operators to efficiently dispatch the right type of repair crews to the impacted areas, provide more accurate estimated restoration times by understanding areas of "nested damage", and reduce outage times for all affected customers.

2.3 Enable Customer Engagement

The planned AMI will provide a foundation of information and communications capabilities that will enable the Company's customers to become informed and engaged energy consumers. Operating in concert with an advanced web portal, the AMI will provide customers with the information and controls necessary to help them manage their energy usage, control costs, and help the environment.

Digital Customer Experience (DCX): In a separate program, Orange and Rockland and Consolidated Edison Company of New York, Inc. (Con Edison) are jointly designing and implementing a new advanced web portal that will leverage state of the art digital technologies to enhance customer engagement and communication. The new portal will deliver an enhanced customer interface that will meet the customer needs of today and readily adapt to the needs of tomorrow. Specifically, the portal will employ AMI data to provide customers with:

- a simple, intuitive method to view graphical presentations of their current and historical energy consumption data;
- the ability to download energy consumption data in various forms, including the national standard Green Button[137] format (Green Button Download and Green Button Connect);
- the ability to overlay their graphical energy consumption views with weather, price, cost, and other related data;
- analytics and data presentment that will facilitate comparison of a customer's energy consumption with consumption by similar customers;
- analytics and data presentment that provide customer-specific energy insights and savings tips as well as personalized action plans for conserving energy and saving money;
- the ability to disaggregate their energy consumption (i.e., understand what is driving their usage patterns) to determine how their energy is being used;
- proactive alerts associated with projected billing, home energy use, and customer-set thresholds (energy use or projected costs); and

[137] http://energy.gov/data/green-button

- the ability to schedule the ongoing delivery of energy consumption reports.

The new portal's functions will be optimized for use on common device types (*e.g.*, mobile phones, tablets, and personal computers) and will be tailored to effectively serve the needs of each distinct customer segment (residential, small business, large commercial/industrial, and low income). For example, Figure 1, below, shows an automatically communicated usage alert that could be particularly useful for low income customers.

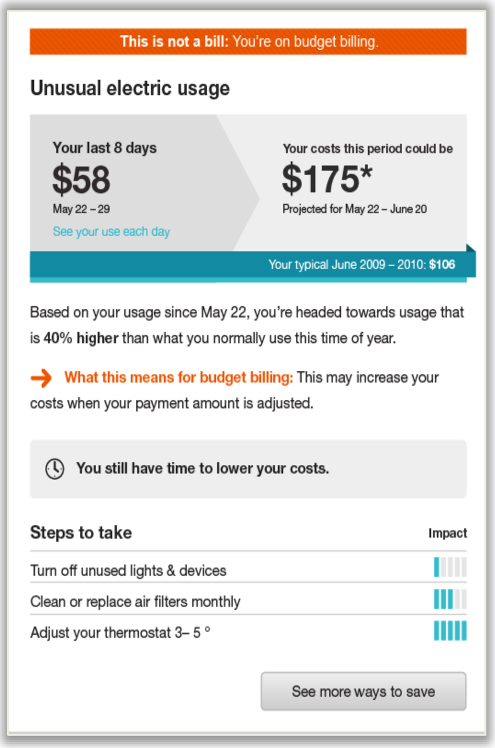


Figure 1: Proactive Consumption Alert under Consideration for DCX

To better serve customers and provide a consistent multi-channel experience, Customer Call Center employees will be able to access the customer portal and view the same information that the customers see. In addition, the portal will be integrated with the Company's main website, providing customers with seamless access using a single sign-on process. Finally, the information and functions provided by the new portal will be aligned with the Company's planned REV demonstration projects; providing a seamless, integrated experience for customers participating in these demonstration projects.

In alignment with the Company's AMI implementation plan, customers with AMI meters installed in 2017 will have access to their energy consumption data from the prior day. Starting in mid-2018, customers will have near-real-time access to their energy consumption data. As customer's AMI meters are installed, the Company will employ various methods to inform customers about the valuable new information and services that have become available to them. For example, Figure 2, below, shows an example of portal-related information that can be communicated to customers via several methods.

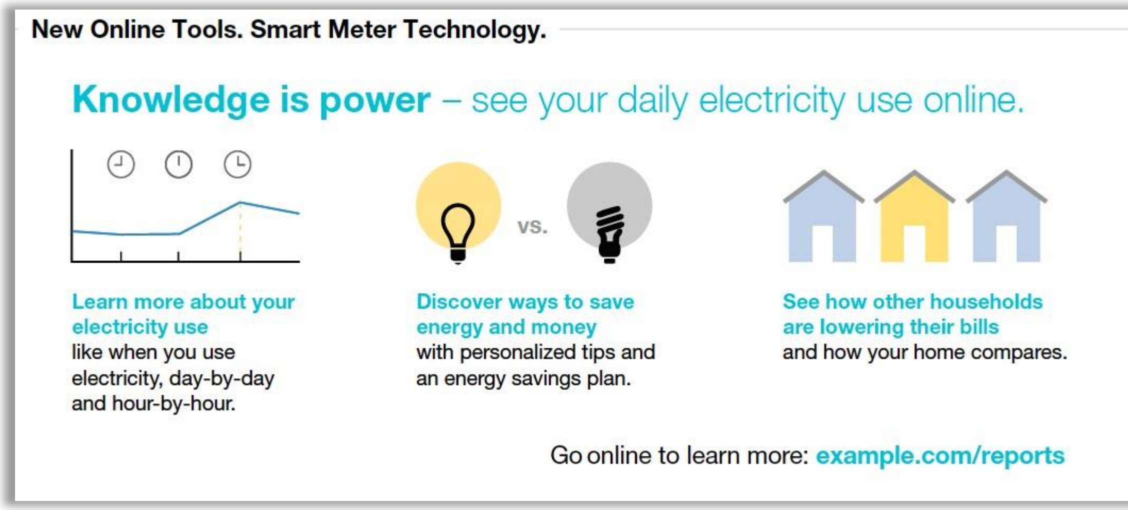


Figure 2: Portal Education Messaging Under Consideration for DCX

Figure 3, below, summarizes the range of advanced functions that the Company plans to provide through the new customer engagement portal.

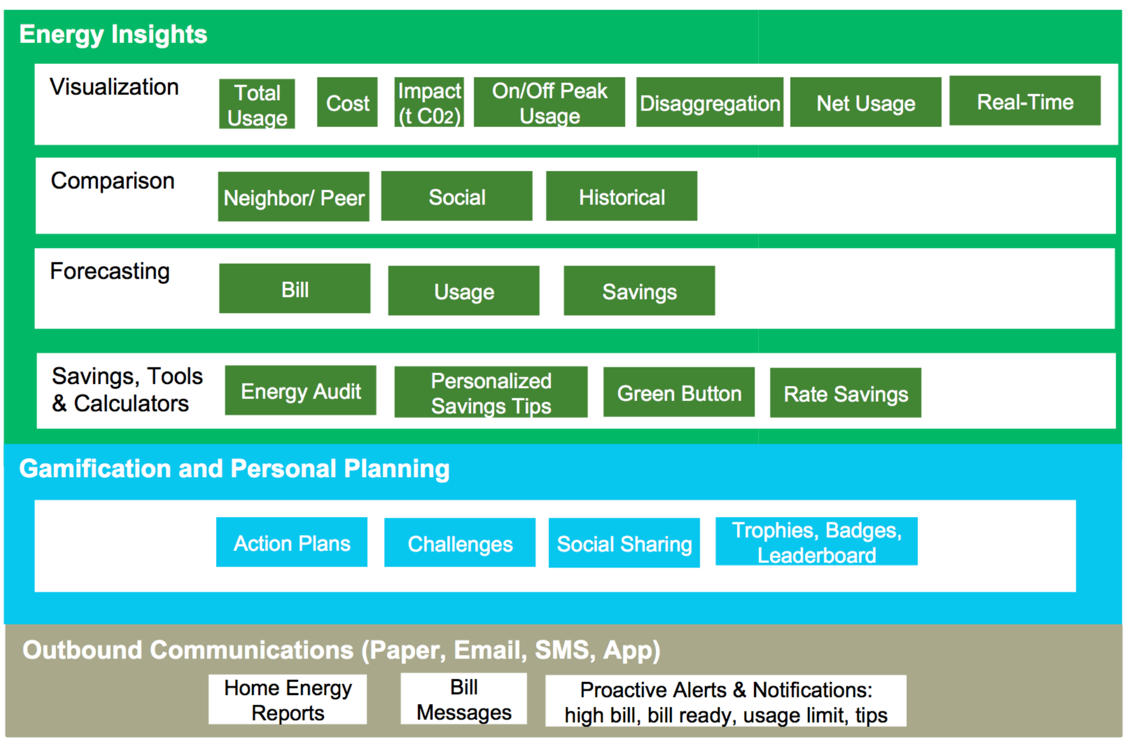


Figure 3: Summary of Planned Customer Portal Functions

As the AMI and DCX projects progress, O&R will continue to monitor market trends and evaluate other customer products and services in areas that include the following:

- Enhanced data driven tools to manage use and costs (*e.g.*, gamification);
- Further enhancements to Demand Response (DR) programs;
- Integration of Distributed Energy Resources (DER) such as solar and storage;
- Plug-in Hybrid Electric Vehicles (PHEV);
- Smart homes/smart appliances; and
- Voluntary prepayment programs.

2.4 Provide a Foundation for REV

Under the "Reforming the Energy Vision" (REV) strategy, the New York Public Service Commission (Commission) is actively spurring clean energy innovation, bringing new investments into the State and improving consumer choice and affordability. The planned AMI project will enable Orange and Rockland to fulfill the REV objectives of providing products, technology, and incentives for customers to actively participate in energy markets, control energy use, and take control of their monthly bill.

With the appropriate data systems and web presentment in place, customers will have the opportunity to leverage the interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions. For example, a customer's energy consumption patterns might indicate that the customer would benefit by replacing an aging refrigerator or by installing a battery or solar array. When integrated into the digital energy marketplace contemplated under the REV, such data will become invaluable to both customers and distributed energy resource providers as they bundle various products and services together to meet unique customer needs and provide solutions at scale.

The AMI communications network and AMI meters deployed through this project will provide the foundation for implementing several of the policy objectives stipulated by the Commission in the REV proceeding. AMI will help achieve key REV objectives by improving system visibility, enhancing controls, and supporting advanced analytics. Specifically, AMI capabilities will make it possible for the Company to align with REV guidance by:

- **Helping customers better manage and reduce their energy costs:** Customers will have access to their interval electricity usage data, the granularity and visibility of which will increase their ability to adjust their consumption patterns to reduce their electricity bill. As a result, customers may choose to participate in new time-based rates and demand response programs offered by the Company.
- **Enabling market processes:** AMI is fundamental to the future development of market systems that can leverage actual customer usage data rather than models based on estimated usage. For example, AMI will measure the inflows and outflows of energy from customer premises on an interval basis so that customer purchases from different sources, as well as the sale of customer

generated energy, may be accurately billed. The NYISO is currently putting together plans for a new Behind-the-Meter Net Generation tariff that will allow net generators to sell capacity into the NYISO market. If the NYISO customers are paid like generators, they may require five minute or less interval meter data. AMI can provide the necessary revenue grade metering information to support this initiative with strict adherence to the confidentiality, integrity and availability of this data.

- **Improving system efficiency and resiliency:** The ability of AMI communications and AMI meters to better monitor the Company's distribution system and performance of DER equipment can enhance quality of service and performance by enabling customer programs and technologies that may efficiently reduce demand and increase renewable generation. Real time monitoring of DER resources is essential to the DSP to track DER performance and capabilities both to make same day operational decisions and for near- term forecasts and scenario decisions.
- **Improving Industry Standards Compliance:** AMI utilizes telecommunications standards which will lower the cost of integration and development for many future REV-driven programs and plans across the utility enterprise. Standards based communications will allow for greater security and improved management of the meter device system, while standards for communication data structures will improve integration with other systems. Specifically, AMI's back office information systems (Meter Data Management and the AMI Control System) recognize standard integration protocols, including web standards (i.e., OpenADR, IEC-CIM, MultiSpeak) which may be used to develop demand response, responsive DERs, maintenance management, outage management, and customer service system integrations.
- **Reducing Greenhouse Gas Emissions:** See Section 2.5 below. AMI will reduce the number of vehicles on the road for meter reading and repair functions. Customers may also conserve electricity (and thereby reduce generator emissions) through increased awareness or by participating in time-based rate and demand response programs enabled by AMI.
- **Supporting Flexibility in Rate Design:** AMI is foundational to supporting demand charges as well as other new and innovative rate designs to provide customers with price signals that better reflect the actual costs their usage imposes on the system and, correspondingly provide the information necessary to more effectively manage their electricity and gas bills.
- **Enabling Third Party Access to Customers' Energy Data:** With the appropriate data systems in place AMI can make customer electricity usage data available, per customer consent and security requirements, to third party providers who can provide additional services for customers. O&R's AMI project will directly support REV and the Staff White Paper on Utility Business Models (Track Two) by providing the data that can be made available to third-parties, for a fee, to enable and support customer behavior change, as well as the tools necessary for the market to engage and drive solutions to scale.

2.5 Reduce Greenhouse Gas Emissions

The planned AMI system will facilitate reductions of greenhouse gas emissions in the following three ways:

- through Conservation Voltage Optimization (CVO);
- by facilitating consumer behavior changes (*e.g.*, expanded Demand Response Programs);
- and, by reducing vehicle emissions resulting from significantly reduced vehicle miles for:
    - meter reading;
    - service turn on/off and transfer;
    - responses to false outage service calls; and
    - efficiencies in service restoration following storms.

Conservation Voltage Optimization: AMI increases the amount of information available to grid operators and planners, enabling Orange and Rockland to better control voltage across the system, leading to a reduction in overall energy consumption. As a result, the Company is able to reduce the amount of power purchased and consumed, reducing the amount of electricity generated and the associated carbon emissions.

Changing Consumer Behaviors: Residential and commercial/industrial customers will have expanded access to products and service offerings that encourage energy efficiency. Each of these will result in environmental benefits that have not been calculated as part of this business plan but nonetheless are expected to be significant.

Reducing Company Vehicle Emissions: Remote meter reading and remote connect/disconnect will enable the Company to eliminate thirty (18 in Rockland County & 12 in Orange and Sullivan County) meter reading vehicles over time. Reduced personal vehicle mileage for meter operations will also save approximately 21,500 gallons of gasoline annually. Consequently, Orange and Rockland expects to eliminate approximately 142.5 metric tons of vehicle emissions (carbon dioxide equivalent) related to meter operations. In addition, Orange and Rockland anticipates a savings in vehicle miles travelled due to reduced false outage service calls, as well as more efficient service restoration following storms.

3 U.S. AMI Overview

Many utilities have completed AMI projects in the U.S. and elsewhere. The Department of Energy's (DOE) Smart Grid Investment Grant (SGIG) program spurred a surge in AMI implementations that led to significant maturation of AMI vendors, technologies, and practices. According to the Edison Foundation Institute for Electric Innovation (IEI), as of July 2014, over 50 million AMI meters had been deployed in the U.S., covering over 43 percent of U.S. homes. Figure 4 below shows the extent of AMI meter deployments by state that are completed, underway, or planned by 2015.

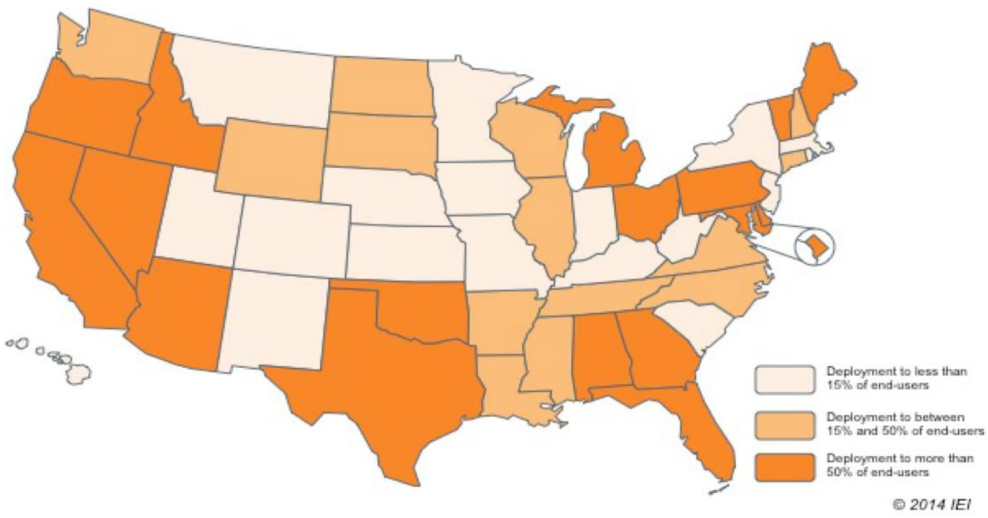


Figure 4: Expected AMI Meter Deployments by State by 2015[138]

Since many peer investor-owned utilities have already implemented AMI, O&R is in a position to understand and leverage the lessons learned by those utilities for the benefit of the O&R AMI project. To that end, O&R along with Con Edison conducted benchmarking interviews with six peer utilities of similar size, with similar AMI project scopes, and with similar environments. The discussions focused on the following four topical areas: (1) project background and business case; (2) system, hardware and security; (3) meter installation; and (4) customer engagement and organizational change. Insights gained through those discussions have been incorporated throughout this business plan.

[138] Institute for Electric Innovation; September 2014. Map does not include automatic meter reading installations. Source: http://www.edisonfoundation.net/iei/Documents/IEI_SmartMeterUpdate_0914.pdf

4 AMI Rate Case Filing Background

The Commission's Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan, issued October 16, 2015 in Cases 14-E-0493 and 14-G-0494, provides for the introduction of an AMI system in the Company's service territory. The Company will begin implementing an AMI system to, among other things, facilitate the Commission's REV policies and goals, reduce operating costs, accelerate identification of customer outages and improve overall outage response and efficiency. The Company will implement Phase One of its AMI deployment in Rockland County. Total funding for both Phase One and Phase Two AMI deployment, as proposed by the Company, is $98 million. .

The Company will manage cost variations with the ability to seek recovery in future rate cases for actual costs that exceed the funding level, including additional costs due to increases in scope to address the Market Design and Platform Technology ("MDPT") Final Report, the Commission's order on the Company's initial Distributed System Implementation Plan ("DSIP"). Recovery of the funding level is tied to completion of Phase One within five years of the Commission's issuance of a final DSIP Order with consideration for operational/weather emergencies and other external impacts. As the AMI implementation progresses, the Company will semi-annually prepare and submit to the Commission an AMI project status report that describes the progress of the project in terms of the objectives and benchmarks set forth in this AMI Business Plan.

The Company's DSIP filing is currently due in June, 2016. When the Commission acts on the Company's DSIP filing, the Commission may further consider the implementation of AMI, including deciding to modify or halt the Company's implementation of its proposed AMI system. In the event of a determination by the Commission to stop or modify the AMI system, all AMI project costs prudently incurred by the Company up to project cancellation, shall be recoverable by the Company. In such an event, recovery will not be provided for costs such as those for acquiring and/or installing any software, hardware or equipment that is ultimately not needed or cannot meet the required needs as determined at the time the Commission issues its final DSIP Order or earlier.

5 AMI Project Overview

AMI provides time-stamped measurement, status and event data from intelligent, communications-enabled meters and other end point devices. The AMI project is hardware intensive and involves replacement of meters or modules at every endpoint. Due to this large hardware component, the AMI meters and network are expected to be the largest capital expenditure for this project.

Each AMI implementation has three major components: the meters (and associated communication modules); a communication network; and a headend system that controls the communications and operation of the devices in the field.

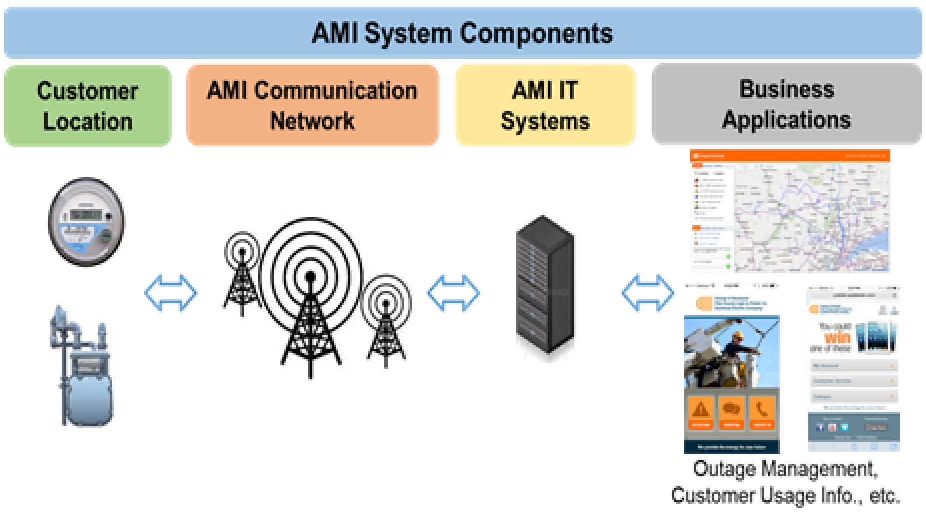


Figure 5: AMI System Components

The AMI project will span many areas of the Company and will introduce fundamental changes to the Company's business operations, field operations, customer service and staffing. Although complex, the O&R project will be implemented in the following three phases:

1) AMI Planning;
2) Pre-Deployment Activities; and
3) Deployment Activities.

5.1 AMI Planning

Orange and Rockland's AMI planning effort comprises work in five main areas: required AMI capabilities; the business case for AMI; the technical architecture; the implementation plan; and Customer Engagement. In each of these areas, the work starts with the original project scope as set forth in the direct testimony of the AMI Panel in the Company's current rate cases (see Section 1.2, titled "AMI Rate Case Background"). This project scope was to support additional AMI requirements identified through the AMI Collaborative process (contingent on Commission approval). Throughout its planning effort, Orange and Rockland applied its existing resources (technologies and people) wherever it was feasible and productive to do so.

5.1.1 AMI Capabilities

AMI planning begins with defining the Company's business objectives and then identifying and characterizing the AMI capabilities needed to support those objectives. Required AMI capabilities generally fall within the following functional categories and must be characterized in terms of function, scale, and performance:

- Meter attributes - measurements, events, service switching, processes, management;
- Communications - meters, customer premise devices, distribution automation;
- Data - logging, collection, management, processing, presentment; and
- Integrations - billing, customer service, outage management, asset management, work management, distribution management, web portals, customer devices, third party systems.

As presented in the Company's 2014 AMI rate case presentation, Orange and Rockland's original business objectives for AMI apply to residential and commercial electric and gas metering in Rockland County as a Phase One with Orange and Sullivan Counties as a Phase Two. The focus was primarily on improving the efficiency of operations associated with meter reading, customer service, outage management; acquiring information for system planning; and, providing a platform for enabling Energy Efficiency (EE) and Demand Response (DR) programs. The AMI capabilities needed for supporting those objectives were basic and their associated costs and benefits are evaluated in the original business case analysis. However, based on subsequent and on-going interactions with Staff and the O&R AMI collaborative, Orange and Rockland is now expanding its AMI objectives to include additional technologies and strategies for enabling extensive customer engagement and market animation in the distribution grid in support of REV.

With regard to promoting customer engagement, the integrated AMI solution must be capable of frequent, quick, secure, reliable and moderately complex messaging and control interactions with customers and/or their devices (i.e., smart phones, thermostats, EV chargers, intelligent inverters, home energy management gateways). In addition, the integrated AMI solution will need to have the data collection, processing and data presentment capabilities required for supporting complex rate designs involving variable pricing for energy and demand.

Regarding support for market animation in the distribution grid, the integrated AMI solution must be capable of frequent, quick, secure, reliable and moderately complex messaging and control interactions with various distribution sensors and control devices, distributed energy resources, grid operators, field personnel and various applications supporting system operations. Over the last six months Orange and Rockland has reviewed its AMI plans and is providing in this latest version of the AMI business case, the impacts to the cost, benefits and schedule of collaborative requested additions.

5.1.2 AMI Business Case

Orange and Rockland's original AMI business case, detailed in Section 6 of this AMI Business Plan, was developed and presented as part of the AMI Panel's direct testimony in the Company's most recent electric and gas rate cases. The business case assesses the costs and tangible financial benefits for Phase One of the Company's AMI plan; a deployment in Rockland County that supports basic functional capabilities involving specific direct integrations with other Company systems.

5.1.3 Technical Architecture

The technical architecture for the AMI solution encompasses all of the hardware and software needed to deliver planned AMI capabilities to Orange and Rockland's business processes. Along with the principal AMI components (meters, field area network, headend system), the solution will employ parts of the Company's information systems and communications network and information technology infrastructures (including security assets) and will require integrations with other Company business/operations applications.

Orange and Rockland is developing its AMI technical architecture with assistance provided by technology consultants from IBM. The development process involves a combination of research, workshops and analyses focused on the business and technical dimensions of the current and "to-be" environments. As mentioned previously, the technical architecture will utilize existing resources and processes whenever it is feasible and productive.

5.1.4 Implementation Plan

As the capability requirements, business case and technical architecture progress toward completion, Orange and Rockland will develop an AMI implementation plan that integrates all the various tracks of the project into a cohesive and coordinated endeavor. The first part of the planning effort described below in Section 5.2, Pre-Deployment Activities, will focus on establishing system, organization, and customer readiness before the first advanced meter is deployed in the field. The second part of the plan, described below in Section 5.3, Deployment Activities, will address the technical, business, and customer service activities that must occur in concert with the actual mass deployment of the advanced meters. When the implementation plan is completed the costs, timing, resourcing and outcomes of the planned project activities will be fully aligned with the planned AMI capabilities, the business case, and the technical architecture.

A high level schedule for the project activities is shown below in Figure 6. Orange and Rockland originally planned to begin deploying the AMI communications network and AMI meters in Rockland County in 2016; however, a number of business and technical considerations have led the Company to move its initial network and meter deployments to 2017. The Company plans to complete the AMI deployment in the New York Service Territory in 2020. A master schedule is being finalized to incorporate all facets of the project, including particulars internal to the Company as well as those of third parties such as equipment vendors and other service providers.

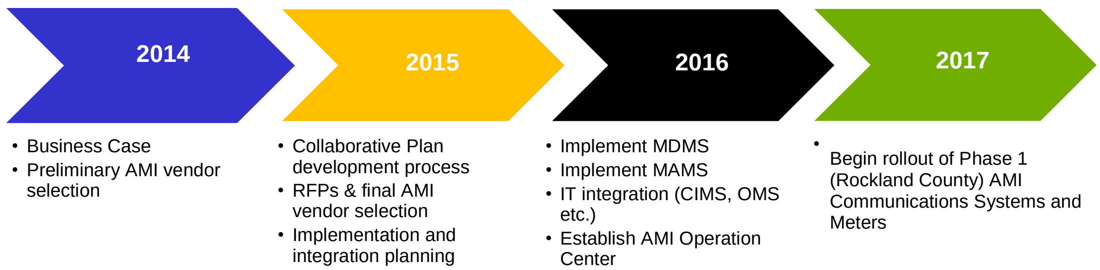


Figure 6: High Level Implementation Schedule

5.2 Pre-Deployment Activities

The project activities described in the following subsections will develop the system, organization and customer readiness that must be established before the first advanced meters are deployed at customers' premises.

5.2.1 Select and Procure Technology and Services

Orange and Rockland's AMI implementation will combine existing assets and services, such as the existing customer system and outage management system, with new technologies and services acquired from a variety of vendors. The Company reviewed and evaluated its opportunities for using existing assets and services. The capabilities and costs of new technologies and services, that might or will be needed, were investigated through a competitive procurement process that Orange and Rockland performed jointly with its affiliate, Con Edison. The vendors' proposals have enabled the Company to select the existing or new technologies and services that most cost-effectively deliver the planned AMI capabilities.

5.2.1.1 AMI Technology

The AMI technology includes AMI-enabled electric meters, AMI communications modules for gas meters, and the communications network and the "headend" system that monitors and controls communications with all of the meters and modules. Aside from the legacy Itron MV-90 system that collects meter data from its large commercial and industrial customers (a total of 338 meters), Orange and Rockland has no existing AMI assets; consequently, the Company's plan requires selection and purchase of a new AMI solution. To that end, Orange and Rockland and its affiliate, Con Edison, jointly prepared and issued a request for AMI proposals. The Request for Proposals (RFP) was issued to four AMI vendors on May 15, 2015.

The vendors' proposals, received on July 3, 2015, provided the Companies with the information needed to fully investigate the advantages and disadvantages of AMI solutions that communicate via mesh radio technologies in comparison with an AMI solution that communicates via a point-to-multipoint radio technology[139]. As part of their investigation, Orange and Rockland and Con Edison asked the vendors to submit proposals for several scenarios involving different deployment areas and different levels of system capacity/performance. This provided Orange and Rockland and Con Edison with the flexibility to minimize costs and maximize the services available from their respective AMI solutions. The deployment scenarios for Orange and Rockland included the entire service area. The capacity/performance scenarios have allowed the Company to assess the costs and benefits of providing near real-time energy consumption data to many, or all, of its electric customers. Following a thorough review of the technical and economic aspects of each proposed solution, Orange and Rockland has selected a mesh radio based AMI solution. The AMI solution that the Company will employ is offered and supported by Silver Spring Networks.

5.2.1.2 Meter Data Management System (MDMS)

The large majority of AMI projects include implementation of a MDMS. Serving as the central repository of meter data for the utility enterprise, the MDMS provides complete and valid data to other systems in the format and frequency they require. The MDMS reduces the ongoing operation and maintenance costs of information technology by streamlining and consolidating meter-related data (measurements, events, status, attributes) that would otherwise be distributed across several legacy data systems. The MDMS is also the integration hub where multiple systems can access validated meter data; consequently, the means and methods for system integration will significantly influence a utility's MDMS solution plan.

Orange and Rockland's initial AMI system plan was prepared in association with the Company's electric and gas base rate case filing of 2014 and included minimal use of the existing MDMS. Due to the functional objectives envisioned at that time, the solution plan called for storing interval data in the MDMS for customer presentment only. The existing customer information system (with minor modifications) was to be used along with features of the AMI headend system to support basic meter data management requirements. Now, in light of its ongoing interactions with Department of Public Service Staff and the AMI Collaborative, the Company sees a need for implementing a MDMS that will support advanced meter data management requirements associated with complex rates, data presentment, extensive customer engagement, and market animation in the distribution grid.

Orange and Rockland has evaluated an opportunity to use the existing MDMS that manages and processes the interval meter data from the Company's large commercial and industrial customers. The system is currently used as the repository for the interval meter data that the Company presents to its large commercial and industrial customers through its Customer Care web portal. However, based on extensive research, the cost to upgrade the hardware and infrastructure to support near real time data makes this option unrealistic.

[139] The AMI system costs used in Orange and Rockland's original business case and 2014 rate case filing were based on less demanding requirements and an AMI solution that communicates via point-to-multipoint radio technology.

Orange and Rockland, with its affiliate, Con Edison, participated in a joint solicitation for a new MDMS. The RFP for the MDMS was issued to prospective vendors on June 23, 2015. The vendors' proposals were received on August 3, 2015. Orange and Rockland completed its proposal evaluations and has selected an MDMS vendor. The MDMS solution that the Company will employ is offered and supported by Omnetric.

5.2.1.3 Meter Asset Management System (MAMS)

Successful AMI projects commonly implement and employ a MAMS for managing the inventory and asset lifecycle of the utility's meters, meter communication modules, other AMI end-point devices, various customer premise devices and the components comprising the AMI field area networks. In so doing, the MAMS is used for coordinating and documenting the purchase, receipt, acceptance, stocking, transfer, configuration, testing, installation, maintenance, optimization, removal, retirement and disposal of the managed assets. The MAMS functions are essential both during and after AMI deployment.

A MAMS was not included in the initial AMI system plan that was prepared in association with Orange and Rockland's electric and gas base rate case filing of 2014. Instead, given the project objectives targeted at that time, the initial solution plan used an existing meter inventory management system (the Gas and Electric Meter System, or GEMS) as well as a collection of other existing information systems (with minor modifications) to support identified asset management functions.

Since formulating its initial AMI plan, Orange and Rockland has determined that the scope, complexity and importance of AMI asset management will warrant implementation of a complete MAMS solution. To that end, Orange and Rockland and its affiliate, Con Edison, jointly prepared and issued a request for MAMS proposals. The MAMS RFP was issued to prospective vendors on June 1, 2015. The vendors' proposals were received on July 17, 2015. Orange and Rockland completed its proposal evaluations and has selected the meter asset management Vendor. The MAMS solution the Company will employ is offered and supported by TESCO.

5.2.1.4 Meter and Communication Installation Services

AMI projects are commonly supported by Meter Installation Vendors (MIV) and Communications Installation Vendors (CIV) who specialize in rapid, large scale deployment of AMI-enabled electric meters, AMI communication modules for gas meters and the equipment associated with the AMI field area network. When used, a MIV/CIV is usually responsible for equipment inventory, storage and staging processes and will acquire local resources like a rental vehicle fleet and temporary workers to accomplish the deployment.

Orange and Rockland's original AMI implementation plan, developed in association with the Company's electric and gas base rate case filing of 2014, deploys AMI to 116,000 electric meters and 91,000 gas meters in Rockland County, spread out over a period of five years.

Orange and Rockland, in this latest AMI implementation plan, plans to use vendor-provided installation services in concert with Company personnel as a way to effectively manage the AMI deployment. The Company, jointly with its affiliate, Con Edison prepared and issued a request for MIV & CIV proposals.

The joint RFPs for MIV and CIV were issued on September 14, 2015. The installation vendors' proposals were received in late October, 2015. The Company selected Smart Grid Solutions as its meter installation vendor and is still evaluating RFP responses for communications installation work.

5.2.1.5 System Integration Services

AMI projects are commonly supported by third party system integrators who specialize in developing, testing and implementing the complex integration solutions required for a highly functional AMI. The integration effort touches almost every component of the AMI environment and can involve thousands of distinct interactions among those components.

The scope, complexity and duration of Orange and Rockland's integration effort will be substantially affected by the scope and complexity of the AMI solution and the number of interfacing legacy IT systems. Orange and Rockland's original AMI implementation plan involved having in-house resources develop, test and implement a relatively finite number of interactions among a few systems. However, discussions around supporting REV and effectively developing customer engagement have generated requirements for a highly functional AMI system and indicated a need for much more extensive and complex integration across several more systems.

Orange and Rockland now plans to use a third party system integrator with the capabilities needed to properly integrate a highly functional AMI solution. The selection occurred through a vendor solicitation that the Company conducted jointly with its affiliate, Con Edison. The joint RFP for system integration services was issued on August 31, 2015. The system integrators' proposals were received on October 9, 2015. Orange and Rockland selected IBM as its system integrator.

5.2.2 Build the Initial Network and Computing Environments

Starting in 2016, anticipating Commission approval of the Company's DSIP[140], Orange and Rockland will design, configure, install, integrate, test, and commission the computer and network environments needed for initial activation of the AMI solution. This effort is expected to take twelve months and will be needed before the first meters can be installed.

5.2.2.1 Application Platforms

Each new and distinct application system in the AMI solution (AMI headend system, MDMS, MAMS) will require multiple independent environments for test, training (where applicable), disaster recovery and production.

5.2.2.2 Network Infrastructure

Initial activation of the AMI will require end-to-end network connectivity between the AMI headend system and each AMI meter and communications module deployed. The AMI network infrastructure will comprise multiple field area networks, which provide connectivity with meters and other endpoint

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[140] Orange and Rockland will file its DSIP in June, 2016. Following its review of the Company's DSIP, the Commission might decide to either modify or cease the Company's AMI implementation. Provisions for the Company recovering costs incurred prior to such modification or cessation are discussed in Section 4, *AMI Rate Case Background*.

devices, and a wide area network (commonly referred to as a "backhaul" network) that connects the AMI headend system with the field area networks. Where practical and appropriate, the backhaul network will utilize parts of the Company's enterprise network infrastructure. Significantly, the meters, field area networks, and backhaul network will employ compatible, standards-based technologies (such as IPv6, IEEE 802.15.4g, ANSI C12.22, ZigBee, and SNMP) that can accommodate communications with and among third party devices and systems that comply with those same standards.

5.2.2.3 Integration

Effective integration of the component systems will be critical to the success of the AMI implementation. System interfaces must be ready to support all required inter-system interactions prior to initial activation of the AMI solution. Orange and Rockland's original AMI implementation plan provided for specific interactions among a few systems – the AMI headend system, the Customer Information and Billing System (CIMS), the Outage Management System and an internally-developed meter data repository. Based on the need to support REV and provide for customer engagement the requirements for more extensive AMI capabilities require a much more extensive integration across several more systems.

5.2.2.4 Security

Strong means and methods for securing the AMI data and functions will be designed into the solution (rather than added on) and must be fully operational prior to installation of the first AMI meter. Security measures will include end-to-end data encryption, rigorous access controls and the monitoring of security-related events and alerts from all parts of the AMI solution. Management of AMI security will be incorporated with the systems, policies and practices that make up Orange and Rockland's enterprise security management framework.

5.2.2.5 Testing

A systematic test program consisting of multiple phases of testing will be established to verify that the system's hardware, software and interfaces function and perform as planned. One key performance measurement objective will be to verify the capabilities of the communications and application systems in response to a meter reporting power interruptions during various power outage scenarios. How the system handles the simultaneous delivery of a large number of messages will allow the Company to model a "throughput profile" and establish technical procedures to manage such events.

5.2.3 Plan and Begin Business Transformation

Productive use of AMI will require planning and implementation of significant organizational and process changes prior to initial use of the system. Organizational readiness will be critical to the project's success.

Orange and Rockland has begun its process analysis and planning effort and has identified and characterized the necessary changes in all parts of the business that will be affected by, or will have an effect on, AMI deployment and/or operation. The Company is examining and documenting its existing organization and processes. Knowledge of the current state is used to verify the completeness in the new process and organization designs that are now in development. The new organization and process designs will fully leverage the capabilities of both the new AMI-related systems and the Company's legacy systems.

Beginning well ahead of AMI "light up", implementation of the new/modified processes and organization changes will be guided by a detailed change management plan that describes and schedules the necessary stakeholder communications, training, provisioning and re-deployment activities. Significant changes will occur in the areas of meter operations, billing, customer service, outage management, information systems, telecommunications and work management.

Creation and provisioning of an AMI Operations organization will be a key part of the transformation. This team will monitor and manage the daily operation of the AMI project, will be responsible for resolving system problems and will act as the AMI "point of contact" for the rest of the Company.

5.2.4 Plan and Begin Customer Outreach and Education

Effective and detailed customer outreach and education will be critical to the success of the AMI project. To that end, Orange and Rockland is in the beginning stages of developing a comprehensive customer engagement plan that will be designed to achieve high levels of customer contact, understanding, acceptance and satisfaction. The customer engagement plan will incorporate insights gained from customer inputs, discussions with other utilities, and research into industry best practices. The Order Adopting Distributed System Implementation Plan Guidance (Case 14-M-0101) requires each utility to provide "a thorough customer engagement plan" which "includes a robust customer outreach and education program". O&R is working collaboratively with Consolidated Edison and a vendor to develop the Customer Engagement plan. The plan, although not ready at the time of this filing, will be ready, in conjunction with Consolidated Edison, on July 29, 2016. O&R does expect additional funding will be required to manage and implement the customer engagement plan and file the forecasted costs in July as well with an update in its November rate filing.

Well before initiating AMI deployment, the Company will provide customers, employees, and other stakeholders with timely communications. The information provided will clearly and thoroughly explain the nature of the project, the Company's goals, what the customers will experience during the deployment, the ways that the project will affect customers' services, and how customers can contact the Company with their questions and concerns. Figure 7 below illustrates the overall customer engagement sequence leading up to, during and following the completion of meter installations. Note that communications materials (*e.g.*, website, FAQs) will be developed and available well before the start of installation. This same sequence will be followed for all meter installation areas throughout the project lifecycle.

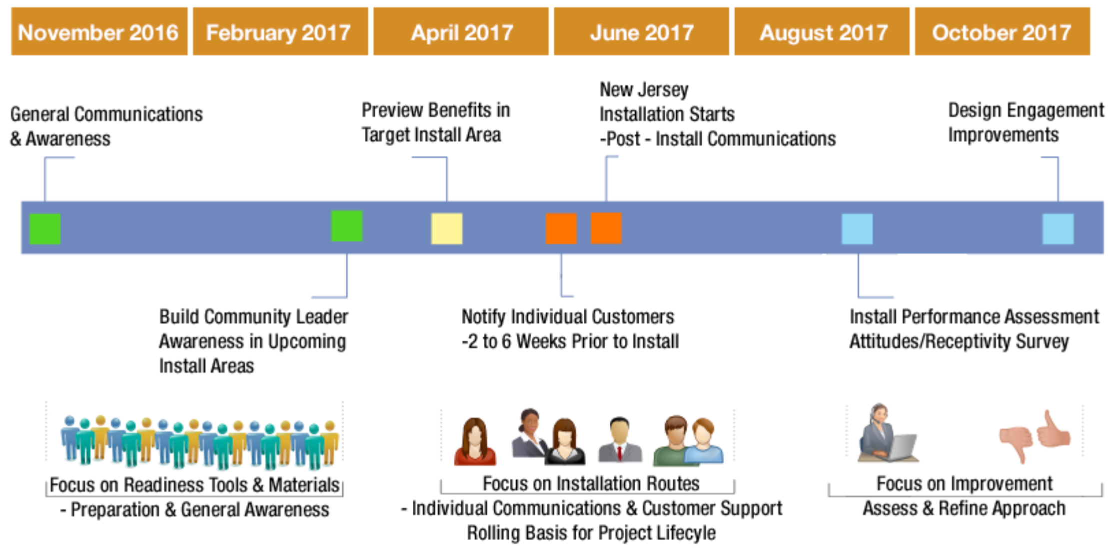


Figure 7: Customer Engagement Sequence to Support AMI Meter Installation

The Company's means and methods for customer outreach and education will include: one-on-one interactions with Customer Service and Field Representatives, print media, electronic and social media, public relations campaigns, cross-marketing with other programs, event sponsorship and participation, and experiential education. These activities will be refined and sequenced as the Company gains better understanding of effectiveness and customer preferences. Those preferences will be identified during the collaborative effort of the customer engagement plan which will include customer surveys. Finally, the Company's employees will be provided training so that they consistently communicate project-related information that will engage our customers.

Messaging regarding the benefits of the project will focus on core benefits, such as customers' ability to manage their energy use and costs, energy efficiency/environmental improvements, enhanced customer service, and increased reliability. Figure 8 below shows an example of a draft infographic that summarizes customer benefits that will be enabled by AMI meters.

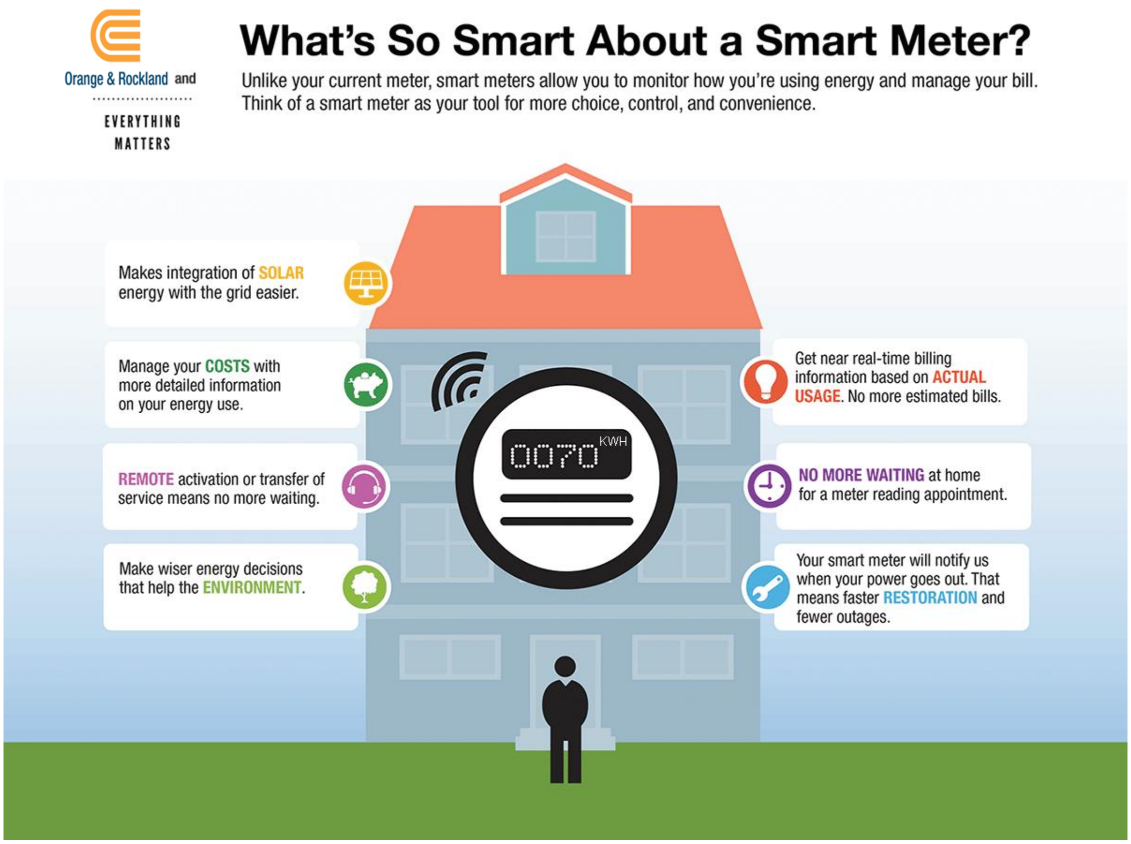


Figure 8: Draft AMI Infographic

Notably, AMI project experiences across the country have revealed a consistent set of stakeholder concerns for a small percentage of customers. These concerns can be broadly categorized as rate impacts, privacy, health, and safety. Orange and Rockland will provide factual, up-front information to address such concerns. In addition, the Company plans to offer customers the option to decline installation of an AMI meter at their premises. Customers who decline a fully functioning AMI meter will be notified of their selection along with the fee they will be charged to cover the Company's cost of reading the meter manually every month. This communication will include instructions for communicating questions or changing to a fully functioning AMI meter. Orange and Rockland, based on the most recently approved electric and gas rate cases, has an AMI opt-out tariff.

5.3 Deployment Activities

Orange and Rockland will begin deploying AMI meters only when the planned pre-deployment activities (described above in Section 1.5) have established appropriate levels of system and organization readiness. Once the deployment commences, the focus will shift to:

- Promoting successful and timely meter installations;
- Achieving and maintaining satisfactory system performance;

- Transitioning to new/modified business processes; and
- Managing continued customer outreach and education.

5.3.1 Manage Meter Installations

Orange and Rockland's original meter deployment plan, developed in association with the Company's 2014 electric and gas base rate case filing, installs 116,000 electric meters and 91,000 gas meter modules over a period of five years. The Company has decided, in this latest AMI Business Plan that the meter deployment can be accomplished in four years across the entire New York Service territory and will be completed with a combination of in-house and vendor-provided installation services.

During the length of the deployment period, the Company will rigorously monitor and manage the meter installations so that meters are successfully installed and activated. This means that the project managers must orchestrate several parallel streams of activity associated with equipment availability, installer availability, system readiness, organization readiness and customer communications. This also means that procedures and resources must be in place to address the wide variety of issues that can affect the installation effort.

5.3.2 Manage System Availability and Performance

Throughout the deployment period, the Project Management Team, the AMI Operations organization and other supporting resources will work closely so that all parts of the AMI solution are available when and where needed and are performing in accordance with well-defined requirements. A variety of tools and processes (both existing and new) will enable system performance monitoring and effective coordination of installation activities with system availability. As the scale of the deployment progresses toward completion, special attention will be given to repeatedly verifying that all aspects of system performance meet or exceed the Company's specified requirements.

5.3.3 Continue Business Transformation

The planned sequence of process and organization changes will start before meter deployment begins and will continue up to completion of the full deployment. During the deployment period, the Company will manage a variety of changes in those areas that are affected by, or have an effect on, the deployment effort and/or the transition to using and managing the AMI. As the scale of the deployment progresses, the project managers will work closely with the appropriate Company management personnel so that the necessary transition activities are scheduled, implemented and validated in sync with the requirements of the deployment and with the availability of AMI capabilities.

5.3.4 Continue Customer Outreach and Education

Effective customer outreach and education will be a critical project success factor throughout the life of the project. During the meter deployment period, Orange and Rockland will employ a variety of communications channels and methods to effectively monitor and manage customers' awareness, questions, concerns, expectations, and satisfaction. The Company understands that it will be especially important to provide customers with clear, complete and useful information several times before meter installation, at the time of meter installation and several times after meter installation. For low income customers, additional attention is required to build awareness and understanding. O&R will build on its existing outreach practices to provide the necessary engagement opportunities for low income customers. The Company will also implement the procedures and resources needed to effectively address the wide variety of customer-related issues that can affect AMI deployment and use.

5.4 Cybersecurity Plan

The Company recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program. This program is designed to protect Company computers, servers, business applications and data, and high value networks from unauthorized access and control from both external and internal threats. We also recognize that the threat landscape constantly evolves and expands and that it is critical to continuously improve our defense posture through investments in technology, improvements in our cybersecurity processes and through collaboration with law enforcement, regulatory and industry resources. The customer engagement plan will provide for a data privacy review based on cyber security standards.

The Company's cybersecurity program is built on the following foundational principles:

- Cybersecurity should be based on a comprehensive risk assessment, including increased focus around the security tenets (Confidentiality, Availability, and Integrity) that apply to the items being protected;
- Cybersecurity is designed into all computing and communications elements used by the Company and our customers;
- Computing networks are segmented so that high value networks such as control centers are separated from the corporate information network;
- The Company's cybersecurity defense posture is layered, eliminating dependence on any one defense;
- Regular vulnerability assessments and penetration tests are conducted by independent third party experts;
- Access privileges to computing and communications assets are limited based on "least privilege needed"; and
- Redundancy and diversity are built for all components to reduce impact and affect recovery.

With malicious software and intrusions continuing to become more sophisticated, computer security will remain a major Company concern for both the short- and long-term. The actors are changing and increasingly have the skills to employ stealth techniques over time that attempt to evade and disable current detection mechanisms. They methodically attempt to exploit vulnerabilities in access controls and software products using slow, persistent attacks to compromise weaknesses, a technique referred to as Advanced Persistent Threat.

To protect against these evolving threats, we plan to soon implement the following cybersecurity improvements:

- Expand use of intrusion detection and prevention technologies;
- Expand use of next generation web and database firewall technologies;
- Expand use of correlation and big data analytic technologies;

- Deploy the next generation of remote access technologies which take advantage of better authentication methods like Adaptive Authentication and Mobile Device Managers; and
- Improve employee awareness about cybersecurity through regular training and communication.

The Company has defined and implemented a formal cybersecurity policy using International Standardization Organization (ISO) Standard 27002 as a reference model. The foundation of ISO 27002 is to protect the confidentiality, integrity, and availability of systems and data through a process to regularly evaluate all aspects of the program, including review of policies, standards, and procedures in addition to the actual implementation of technical controls. These objectives support the Company's goal to provide reliable electric and gas service to businesses, government agencies, and consumers.

Cybersecurity for business applications begins with corporate governance that establishes requirements for application information security and control. Cybersecurity governance is elucidated through corporate policies and instructions that contain the specific requirements that business owners and application developers must meet for software development and business application security. These corporate policies and other supporting procedures provide the framework for application software development and support, including asset classification, protection of sensitive information, control of information exchanges with business partners and other external organizations, business application access controls, user access management, and disaster recovery.

Business application assets are protected by security controls, including those designed for information in databases and accessible through software applications, built into the applications during system design and implementation through the use of a Software Development Life Cycle (SDLC) process. Following, are key governing principles of the SDLC process applied to new systems:

- The architecture of procured systems is reviewed to provide proper design and incorporation of security controls;
- Application software is developed with secured coding principles;
- Role-based access controls are implemented throughout a system.
- Data is never to be pushed into "High Trust" from "Low Trust" networks; consequently, systems must be designed so that data is pulled from "High Trust" to "Lower Trust" networks;
- External data exchanges are encrypted to protect information transmitted between business applications and external organizations; and
- Authentication techniques must be applied to both users and interacting system components.

New corporate initiatives include the use of devices (AMI meters, distributed generation systems, etc.) not deployed within the Corporate Network. These devices potentially increases cyber security risk to the Company as they are outside the company's physical security controls. Accordingly, all external devices and systems are designed in a manner to protect the integrity of the network and data being returned to company managed systems. Key principles used for all physically uncontrolled devices include all previously discussed controls and the following:

- Each device must be identified during the manufacturing process as a device intended for the Company's system;

- Transmissions of data from external devices must be carried by dedicated, encrypted networks on which those devices are authenticated;
- All external data must be collected and temporarily stored in a "Low Trust" zone until it is securely pulled into a "High Trust" zone in the corporate environment;
- Management systems must authenticate with external devices before interacting with those devices;
- Local operation and manipulation of an external device's functions must be temporarily authorized and authenticated by the device's corresponding security management system;
- All local operation and manipulation of an external device's functions must be permanently logged; and
- Attempts to locally operate or manipulate an external device's functions without proper authentication and authorization must be immediately annunciated and permanently logged.

6 Business Case

6.1 Executive Summary

O&R's original AMI business case was developed as part of the Company's 2014 electric and gas base rate case filing. The business case assesses the costs and tangible financial benefits for a phase one AMI deployment in Rockland County only, with Orange and Sullivan Counties being deployed in a phase two project. The originally defined scope focused on implementing AMI capabilities for the following functions:

- Automated meter reading for register and interval billed accounts;
- Meter outage notifications and other alerts;
- On demand remote meter requests (service switch operation, voltage checks, instantaneous reads);
- Ability for customers to have access to meter usage data and use of that data for Energy Efficiency (EE) and Demand Response (DR) programs; and
- Transmission and storage of select data for use in system planning and engineering.

For this original scope, one-time project costs were estimated at $43.3 million for the AMI implementation with cumulative recurring O&M expenses of $17.6 million for the 20-year period. Net depreciation costs were estimated at $43.0 million for the 20-year period which includes the depreciation of the AMI program capital costs, the amortization of outmoded meter asset costs and an offset of depreciation savings from deferred capital expenses. Quantified benefits originally identified for the AMI program were primarily focused on operational savings and total $143 million over a 20-year period.

For the revised scope generated from the AMI collaborative, and AMI deployment across the entire New York service territory one-time project costs are estimated at $98.0 million for the AMI implementation with cumulative recurring O&M expenses of $26.0 million for the 20-year period. Net depreciation costs are estimated at $98.0 million for the 20-year period which includes the depreciation of the AMI program capital costs, the amortization of outmoded meter asset costs and an offset of depreciation savings from deferred capital expenses. With additional benefits generated from the collaborative the quantified benefits identified for the AMI program total $229 million over a 20-year period.

A summary financial view of the costs and benefits for all of O&R's New York service territory AMI deployment is shown below in Table 1. Total benefits over the 20-year period exceed total expenses resulting in a positive business case with an estimated investment payback of 9.0 years.

Table 1: Financial Highlights and Summary ($ in millions)

Business Case Financial View	**All NY Estimate**
Capital Project for AMI System	$98

A. Costs (20 Year Total Costs)	
O&M Expense for AMI System	$26
Net Capital Depreciation Expense for AMI System	$77
Amortization of Stranded Assets	$21
Sub-Total (does not include Capital Project costs)	$124
B. AMI Benefits (20 Year Total Benefits)	
AMI Cost Reduction Benefits	$170
Customer and Societal Benefits	$59
Sub-Total	*$229*
C. Total (20 Year Net Total)	
Benefits Less Costs	*$105*
Utility Simple Payback Period	*9.0 years*
Total Meters	*362,117*
Capital Cost Per Meter	*$270.63*

6.2 Operational Benefits

This current business case assesses a set of benefits which provide value to the customers. Many of the Company benefits are built from analyses of corresponding business process changes.

The currently planned AMI capabilities will enable cost saving benefits in the operational areas and business processes listed below and described in the following sub-sections:

- Meter Reading;

- Metering;
- Field Services;
- Call Center;
- Outage Management;
- Meter Accuracy and Irregular Meter Condition (IMC);
- Revenue Protection;
- Conservation Voltage Optimization;
- Inactive Meter/Unoccupied Premises; and
- Other Operations Benefits;

6.2.1 Meter Reading

Meter Reading

Costs associated with the manual retrieval, collection and collation of the meter billing reads will be either eliminated or reduced. Meter readings and the subsequent transferring of the data will occur remotely rather than through a manual process. Cost reductions will include, but are not limited to the following:

- Meter Reading Labor;
- Vehicle, Fuel, and Maintenance;
- Uniforms and Safety Shoes; and
- Handheld Meter Reading Devices.

Employee Safety

Due to the nature of their work, Meter Readers have significant exposure to safety issues and conditions that may result in and/or vehicle accidents. The reduction of the Meter Reading workforce reduces overall exposure to workers compensation, employee medical and legal costs and to customer property claims resulting from employee accidents.

6.2.2 Metering

High Bill Testing

With increased usage data available to Call Center personnel and customers, the number of high bill field tests will be substantially reduced.

Customer Load Research

Load research activities are used for rate design, utility commission rate case requirements, and internal data gathering. These activities traditionally have required expensive solid-state data recorders that must be connected via phone lines or manually retrieved. With AMI, an existing meter can be remotely configured to record measurement data in shorter intervals that are appropriate for load research and engineering studies. This will facilitate easier and less expensive gathering of load research data. In the future, this will involve a system change only and will not require a field visit. Customers can be added or deleted from the load research effort as required. The savings associated with this item include the deferred cost of the procurement and maintenance of the data recorders, the cost of the labor to collect the data, and the large amount of current data processing to put the data into usable format.

Meter Standardization and Reprogramming Costs

Advanced meter data will be obtained directly from the AMI system and would eliminate the need for complex, higher cost solid-state TOU or demand meters that are currently used to capture commercial TOU/ Mandatory Day Ahead Hourly Pricing (MDHP) information. Additional savings can be realized with reduced communication costs for new MDHP customers as well as the costs avoided by the elimination of field visits to reprogram meters when required. Reprogramming meters remotely also enables more customers to easily be added to such programs.

Immediate Identification of Stopped/Dead Meters

Currently, the discovery of stopped or dead meters occurs during monthly meter read activity. With AMI, the daily collection of meter data will allow the Company to quickly discover and replace stopped meters resulting in better customer service. The billable service that would have otherwise gone unmeasured for some extended period of time can instead be properly measured and billed. No estimate or negotiation with the customer need occur. Furthermore, the data collected from the AMI meter will allow for more analysis to take place in the office, thus reducing the need for field visits in some instances.

Electric Meter Deferred Capital Replacement Costs

The Company has a large population of electro-mechanical meters that, as a result of age or service issues, must be gradually replaced over time. The AMI project claims the deferred cost of replacing those electric meters over the next 20 years as a benefit since all of those meters will be replaced as part of the AMI project.

6.2.3 Field Services

Move In/Move Out

AMI will have the ability to provide on-request meter reads. This can be used to obtain initial or closing reads as customer accounts are opened or closed. Customer service representatives (CSR's) can provide for remote reading of the meter(s) while the customer is on the phone without a need for a field visit or a callback. A new account can be set up or final bill can be generated within a matter of minutes. In the event of a final bill, the departing customer can be provided with an estimate of the total owed and payment options during the call resulting in improved collection.

Reduced Collection Time

Each AMI-enabled electric meter will be equipped with an integral service switch which can be remotely operated to either connect or disconnect a customer's electric service; thus eliminating the time and expense of manually installing and removing boots from the meter. Field personnel must attempt to make customer contact when performing a collection stop, however when appropriate, the ability to remotely disconnect the service will make the turn-off process more efficient. Moreover, the ability to remotely reconnect a customer's electric service will allow for rapid restoration of service following receipt of payment.

Meter Re-reads

Meter re-reads are required due to manual read errors, billing disputes or estimated reads. Since the AMI technology allows for on-demand retrieval of meter readings, the need to send a Meter Reader to the field to retrieve an additional read will be eliminated in most cases. Since re-reads are out of normal route sequence and are solitary rather than batch in nature, off-cycle reads can carry significantly higher costs than normal billing reads.

Fire Cuts

In some cases of fire at customer premises, power to the premises is cut by Company personnel who must travel to the premises and physically remove the electric meter from its socket. With AMI, the Company can much more quickly and safely cut the electric service by remotely operating the AMI meter's integral service switch. While safety is enhanced by the immediate disconnect of power, we will still dispatch a crew so as to provide for the full and complete safety of the responding emergency personnel and to handle the needs of the Incident Commander including restoration requirements, primary disconnect, wire removal, etc.

Field Investigations

The Company currently sends Meter Technicians to the field to investigate a variety of issues. Some examples include: electromechanical demand meters with demand reset issues; reported cloudy globes on meters; probing issues for TOU meters. The AMI program will eliminate electromechanical meters through replacement with new meters, and the AMI systems ability to remotely acquire and then analyze meter data will allow the Company to reduce significantly the number of field investigation work orders.

6.2.4 Call Center

Estimated Reads

Estimated meter readings are used as necessary for billing when the billing reading is not available. The missing readings may be the result of prohibitive weather, unavailability of meter reader resources, inaccessible meters, or other sporadic conditions. The availability of remotely obtained, accurate meter reads via AMI will eliminate the majority of estimated readings.

Customer Accounting

An adjustment to a previously issued bill is required when the utility detects a billing error. AMI will decrease the number of billing adjustments by eliminating the need for re-reads and increasing billing data accuracy. Currently, billing adjustments are expensive due to the cost of obtaining a re-read, performing a back office investigation, manually updating of the CIS system, and re-issuing the corrected bills. Quick resolution of such customer concerns is a value added for the Company's customers, as is the avoided cost for such adjustments.

Customer Calls

A reduction in estimated bills will result in the reduction of associated customer calls. In addition, other calls may be resolved without need for a call back due to the availability of AMI meter data to the Customer Service Representatives. Multiple customer calls due to outage events would also be reduced. These reductions will result in improved call-handling metrics, faster call processing, and better customer service levels.

6.2.5 Outage Management

The AMI system will significantly improve outage identification and restoration efforts which will benefit customers as well as provide for cost savings. The Outage Management benefits realized through an AMI deployment include the following:

- AMI will reduce costs incurred for both Mutual Assistance and Company restoration crews during major storms. Crews will be dispatched more efficiently and released in a timely manner following verification of service restoration. Nested outages will be more visible and more easily rectified.
- The Company responds to a significant number of outage reports per year that are determined to be “false outages.” These “false outages” are not associated with the electric service being provided to the premises and instead require the services of an electrician to resolve an internal electrical problem. Currently, the Company dispatches personnel in response to false outage reports. With AMI, office personnel will be able to quickly check for power at the meter and prevent unwarranted field visits.
- In addition to false outages, the Company responds to customer complaints regarding high voltage, low voltage, and flickering lights. Many of these complaints will be avoided as a result of actions taken following analyses of AMI meter data. With the AMI’s improved monitoring and measurement capabilities, real power quality problems may often be identified and resolved before a customer detects an issue.
- By reducing the incidence of dispatching line crews to areas where different crews or no crews are required, line crews can respond more quickly to circumstances where other personnel are tied up. For example, site safety areas that require Company resources to monitor the location until it can be made safe. This should result in a reduction of site safety expenses.
- More effectively managed outages are expected to reduce the CAIDI (Customer Average Interruption Duration Index) metric, the average length of an outage experienced by a customer with no power.

6.2.6 Meter Accuracy and Irregular Meter Condition (IMC)

Meter Accuracy and Irregular Meter Condition (IMC) benefits are realized in two areas. First, the Company has nearly 71,000+ electro-mechanical meters in service in Rockland County. These meters typically under-register usage as they age. All of these meters will be replaced as AMI meters are deployed.

IMCs refer to errors in billing due to failed components, incorrect data entry, and other causes. The Company will improve identification and resolution of many of these types of operational issues as part of the AMI project due largely to:

- Audited meter installations at all locations; and
- Meter data analytics that will much more readily identify irregular metering conditions.

6.2.7 Revenue Protection

The AMI technology will allow for improved theft detection through the monitoring of meter tamper alerts and analyses of meter data. In addition, during the meter deployment phase of the project, tampering situations will be discovered as every premise will be inspected both before and during the meter change out. The daily information provided by an AMI system will enhance the timely detection and rectification of energy theft.

6.2.8 Conservation Voltage Optimization

AMI increases the amount of information available to grid operators and planners, enabling Orange and Rockland to better control voltage across the system, leading to a reduction in overall energy consumption. As a result, the Company is able to reduce the amount of power purchased and consumed, reducing the amount of electricity generated and the associated carbon emissions.

6.2.9 Inactive Meter/Unoccupied Premises

Another AMI-enabled program concerns inactive meter or unoccupied premises. Due to the Company's practice of performing soft-locks upon termination of service, there are a number of premises where electric service remains connected although the account is inactive. AMI will eliminate the potential for this condition by providing the capability to physically disconnect the electric service to vacant premises using remote service switching. As a result, the Company can eliminate these unbillable energy costs and therefore reduce the subsequent costs that are currently socialized across the customer base.

6.2.10 Other Operational Benefits

Billing improvements are anticipated based on expected increased billing accuracy, and fewer exceptions, resulting in fewer billing complaints. Specifically, this benefit is based on:

- less work related to billing exceptions;
- less work related to customer complaints for high/estimated bills; and
- automation of some manual billing processes.

6.2.11 Operational Benefits Summary

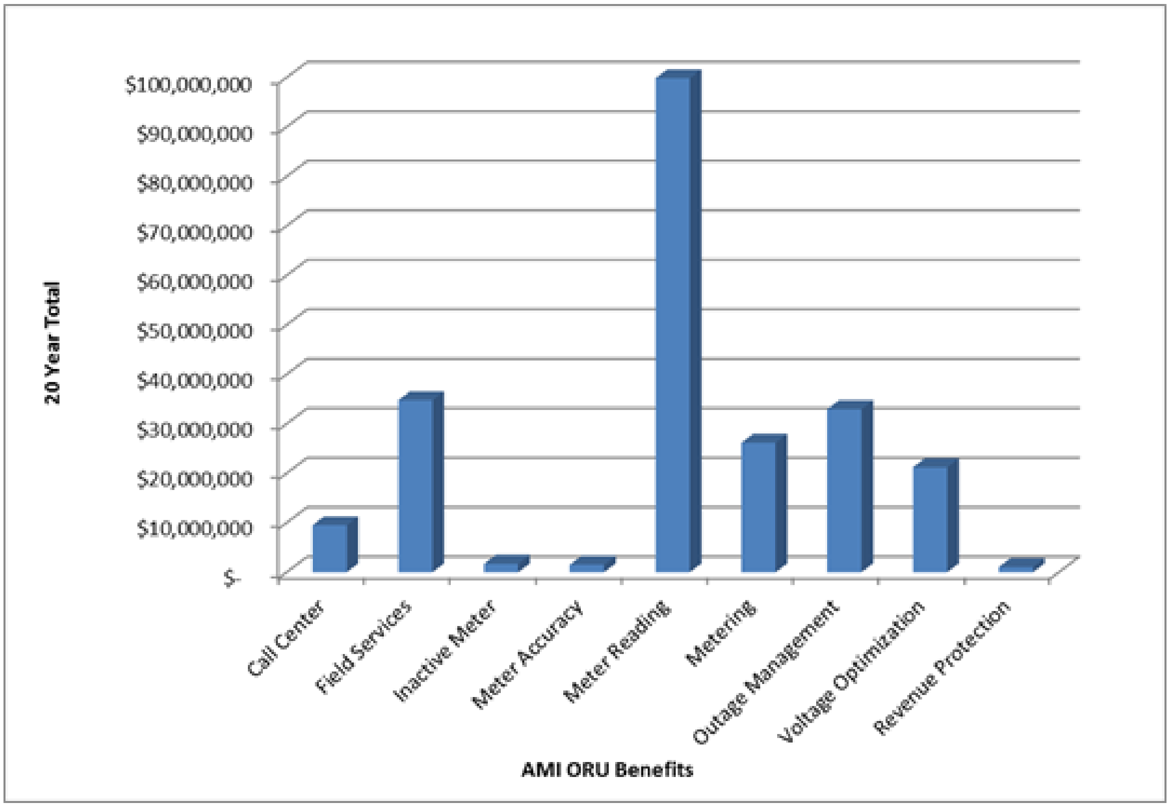
The business case benefits are summarized below in Table 2.

Table 2: Business Case Benefit Summary ($ in millions)

Benefit	Description	20 Year Cumulative Value
Meter Reading	Reduced labor costs and associated system and equipment costs for meter reading	$100
Metering	Deferred capital expense for existing meter replacements	$26
Field Services	Reduced operating costs for field work related to collections, connects, disconnects, cut-ins, re-reads, field tests, and investigations	$35
Call Center	Reduced call center inquiries, bill complaints, and cancel/rebills	$9
Meter Accuracy and Irregular Meter Condition (IMC)	Increased recovery of unaccounted for energy	$2
Outage Management	Reduced outage restoration and false dispatch costs	$33
Revenue Protection	Increased recovery of unaccounted for energy	$1
Conservation Voltage Optimization	Reduction of the amount of power purchased and consumed	$21
Inactive Meter/Unoccupied Premises	Reduced unbilled energy costs	$2
Total Benefits		***$229***

Notably, the primary benefits are driven from Meter Reading and Field Services. A comparison of the benefits is shown below in Figure 9.

Figure 9: Benefits Comparison



6.3 AMI Investment and Operating Costs

This business case includes descriptions and estimates of five major investment/cost elements associated with the AMI implementation and on-going support. Costs are defined by general area. A summary of the 20-year cumulative nominal values for each of these cost categories is listed in Table 3 as filed in the 2014 rate case for Rockland county New York and in Table 4 subsequently amended based on the AMI collaborative discussions including deployment across the entire New York service territory.

Table 3 – AMI Investment/Cost Summary ($ in millions)

Cost Category	Description	Capital Investment: 20 Years	On-going O&M: 20 Years	Total Expenditure: 20 Years
AMI Meters	Physical AMI Meter (and supporting labor) to be installed at each premise/location	$34	N/A Accounted for in Ongoing Operations	$34
AMI Communications	AMI Network Infrastructure to support communications from the AMI meters to "head end"	$4	$5	$9
IT Platform	IT platform/systems to enable and support AMI system	$3	$2	$5
Labor & Project Management	Management of project during deployment, implementation	$2	N/A	$2
Ongoing Operations	On-going AMI Operations	N/A	$11	$11
Total Costs		***$43***	***$18***	***$61***

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Table 4 – AMI Investment/Cost Summary ($ in millions)

Cost Category	Description	Capital Investment: 20 Years	On-going O&M: 20 Years	Total Expenditure: 20 Years
AMI Meters	Physical AMI Meter (and supporting labor) to be installed at each premise/location	$56	N/A Accounted for in Ongoing Operations	$56
AMI Communications	AMI Network Infrastructure to support communications from the AMI meters to "head end"	$7	$3	$10
IT Platform	IT platform/systems to enable and support AMI system	$18	$5	$23
Labor & Project Management	Management of project during deployment, implementation	$17	N/A	$17
Ongoing Operations	On-going AMI Operations	N/A	$18	$18
Total Costs		***$98***	***$26***	***$124***

6.3.1 Cost Model Assumptions and Limitations

The costs in this current business case are based on actual vendor prices from competitive bids. The deployment period for New York is modelled from 2017 to 2020.

6.3.2 Cost Structure Assumptions

The cost structure refers to the assumptions made concerning roles and responsibilities for the Company's resources and / or suppliers. These are summarized below in Table 5. Changes to these assumptions may impact the resulting cost estimates.

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Table 5 – Implementation Support Services Assumptions

Cost Area	Business Structure Assumption for Implementation and On-going Operations	Basis of Cost Estimate Used in the Cost-Benefit Analysis
Electric meters and gas modules, including hardware, ancillary equipment, shipping, handling, insurance, freight, testing, and warranty support	Vendor provided	Pricing from previous utility implementations and estimates provided to the Company by vendors
Initial core deployment meter installation work, including minor repair work, and call center appointment scheduling	O&R personnel provided and/or vendor resources	Pricing from previous utility implementations, consultation with other utilities, and estimates from vendors
RF Communication hardware and software requirements including warranty	Vendor provided	O&R Communications group experience and estimates from vendors
Lease costs for some number of third party sites to mount RF equipment	O&R to manage, locate premises, negotiate agreements, and install	O&R Communications group experience
AMI System Operations	O&R to establish new support group	Experience from other utilities. O&R estimates.
AMI System Software On-Going Maintenance	O&R AMI communication systems vendor to provide maintenance	Experience from other utilities. Vendor price estimates.
AMI RF communication System field Maintenance	O&R personnel provided	O&R Communications group experience
On-Going Meter Operations	O&R personnel provided	O&R business case estimates
AMI system training and on-site support	Vendor provided	Vendor estimates

Cost Area	Business Structure Assumption for Implementation and On-going Operations	Basis of Cost Estimate Used in the Cost-Benefit Analysis
IT systems integration work	O&R personnel and IT vendors provided	O&R IT estimates. Vendor price estimates
IT hardware environment to support AMI headend, MDMS, and middleware	Joint. Vendor to provide hardware. IT to install and operate.	O&R IT estimates
Project Management Office (PMO)	O&R personnel provided	O&R business planning
External communications	O&R personnel provided	O&R business case estimates

6.4 Business Case Analyses

6.4.1 Financial Analysis

This evaluation describes the Company's AMI deployment project considering a four-year effort to deploy the system throughout Rockland County service territory, beginning in 2016, based on the Business Plan described in Section 1. The Company's discovery and modeling process demonstrates that the AMI system drives large operational improvements and significant value to its customers. Automation reduces operational costs across many departments, including but not limited to: Meter Reading, Field Services, Call Center and Billing. The Company will also use the system to deliver benefits by: (a) reducing meter reading costs; (b) reducing the number of inactive accounts with electric consumption; (c) automating Connect/Disconnect; and (d) reducing revenue loss due to energy theft.

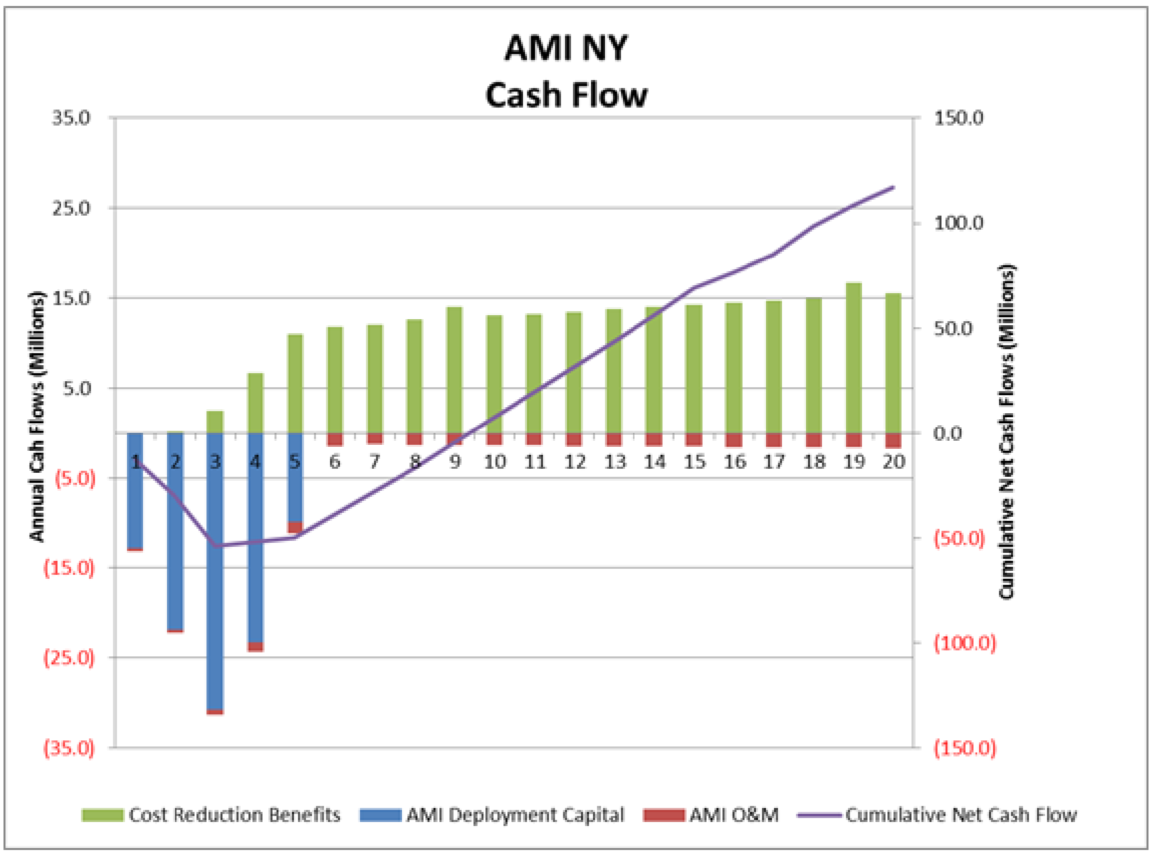
The overall results of the evaluation are positive. The Company finds that customers will realize significant service enhancements, and that the operational benefits financially justify a deployment of AMI. The Company will incur the following expenditures to achieve AMI deployment: AMI metering equipment, a wireless RF communications network, related IT management and network systems, implementation services and on-going operational expenses. Over the 20-year evaluation period, assuming a four-year project life with a three-year meter deployment scenario, the Company would expect to invest $98 million in capital and incur $26.0 million in operational costs to run the system.

Benefits over the 20-year evaluation period exceed spending, and result in an estimated return on investment in 9.0 years. Benefits generally result from improved operational efficiencies and customer benefits.

The AMI infrastructure contemplated is foundational to facilitating the enhanced delivery of various customer programs and utility best practices, including: demand response initiatives; net-metering of distributed energy resources; future distribution system asset monitoring; measurement and control; responsive load control opportunities; and numerous other possibilities. This business case does not speculate on the timing, scope, or financial impact of these AMI-dependent enhancements to utility programs and practices. Likewise the evaluation does not speculate on the impacts to the Company's other REV driven programs and plans.

The expenditure and benefit patterns of the AMI investment are represented in Figure 10.

Figure 10: Capital Investment and Ongoing Cost-Benefit Comparison



The business case financial summary and business case results are shown in **Table 6.**

Table 6 – Financial Results and Summary

Business Case Financial View	Current
A. Costs (20 Year Total Costs)	
O&M Expense for AMI System	$26
Net Capital Depreciation Expense for AMI System	$77
Amortization of Stranded Assets	$21
Sub-Total	***$124***
B. AMI Benefits (20 Year Total Benefits)	
AMI Cost Reduction Benefits	$170
Customer and Societal Benefits	$59
Sub-Total	***$229***
C. Total (20 Year Net Total)	
Benefits Less Costs	***$105***
Utility Simple Payback Period	***9.0 years***

6.4.2 Sensitivity Analysis

This current AMI Business Plan still provides for a sensitivity analysis, although with solidified vendors equipment and services costs resulting from competitive bid processes the analysis is much less valuable. The original AMI evaluation leverages findings, results, and lessons learned from AMI projects at other utilities as well as advice and information from consultants and vendors. Any analysis is incomplete without evaluating areas of uncertainty. There are many techniques available to perform such an analysis. In this report, a straightforward use of varying the input assumptions to determine output effects has been chosen.

Listed and described in Table 7 are the different data parameters for the purposes of the sensitivity analysis. The approach identifies the impact on the base case of independent changes of each of the seven variables addressed, meaning that with each sensitivity analysis performed, only a single parameter is changed. Performing the sensitivity analysis in this manner helps identify the isolated impact on the business case as a result of changing a single variable.

Table 7: Summary of Sensitivities and Rationale

Variable	Base Case Value	Sensitivity Analysis Assumption	Description and Rationale
Meter Installation	$35 per Install	$18 Favorable / $70 Unfavorable	Half / Double from Base Case
Module Installation	$40 per Install	$20 Favorable / $80 Unfavorable	Half / Double from Base Case
letwork Devices Insta	$3.2K per Install	$1.6K Favorable / $6.4K Unfavorable	Half / Double from Base Case
Meter Cost	$84 per Meter	$42 per meter Favorable / $168 p/m Unfavorable	Half / Double from Base Case
Gas Module	$50 per Module	$25 per module Favorable / $100 p/m Unfavorable	Half / Double from Base Case
Network Devices	$4K per Device	$2K Favorable / $8K Unfavorable	Half / Double from Base Case

Sensitivity Analysis Results

Table 8 and Table 9 present the impact to the base business case (four-year project) for Rockland County only in terms of changes to costs, benefits, and overall net customer impact. With regard to the cost components, the AMI electric meter, gas module, network infrastructure price, and installation costs are the key variables that may impact overall cost; the largest impact to the business case is the meter cost as meters are the largest component within the project and unfavorable negotiations will significantly impact our business case. However, as shown in the analysis below, the main components have a relatively small impact on the overall benefit over the 20-year review of the project.

Table 8: Sensitivity Analysis: Installations and System Integration > Entire O&R Service Territory

		Meter Installation		Module Installation		Network Device Installation	
		Favorable	Unfavorable	Favorable	Unfavorable	Favorable	Unfavorable
Business Case Component	**Costs & Benefits (20 Year)**	**$18 per unit**	**$70 per unit**	**$20 per unit**	**$80 per unit**	**$1,600 per unit**	**$6,400 per unit**
A. Costs (20 Year)							
Capital Investment for AMI System Project	$98	$93	$109	$95	$106	$97	$101
Re-occurring O&M Expense related to AMI System	$26	$26	$26	$26	$26	$26	$26
Sub-Total	***$124***	***$119***	***$135***	***$121***	***$132***	***$123***	***$127***
B. AMI Benefits (20 Year)							
AMI Operational Benefits	$170	$170	$170	$170	$170	$170	$170
AMI Corporate and Capital Benefits	$59	$59	$59	$59	$59	$59	$59
Sub-Total	***$229***	***$229***	***$229***	***$229***	***$229***	***$229***	***$229***
C. Total (20 Year Net)							
Benefits Less Costs	**$105**	**$110**	**$94**	**$108**	**$97**	**$106**	**$102**
Utility Simple Payback Period	**9.0**	**8.9**	**9.4**	**8.9**	**9.3**	**9.0**	**9.1**

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Table 9: Sensitivity Analysis: Meter, Module, Server, Storage Costs > Entire O&R Service Territory

		Meter Cost		Gas Module		Network Device	
		Favorable	Unfavorable	Favorable	Unfavorable	Favorable	Unfavorable
Business Case Component	**Costs & Benefits (20 Year)**	**$42 per Meter**	**$168 per Meter**	**$25 per Module**	**$100 per Module**	**$2K per Device**	**$8K per Device**
A. Costs (20 Year)							
Capital Investment for AMI System Project	$98	$87	$121	$94	$108	$97	$100
Re-occurring O&M Expense related to AMI System	$26	$26	$26	$26	$26	$26	$26
Sub-Total	***$124***	***$113***	***$147***	***$120***	***$134***	***$123***	***$126***
B. AMI Benefits (20 Year)							
AMI Operational Benefits	$170	$170	$170	$170	$170	$170	$170
AMI Corporate and Capital Benefits	$59	$59	$59	$59	$59	$59	$59
Sub-Total	***$229***	***$229***	***$229***	***$229***	***$229***	***$229***	***$229***
C. Total (20 Year Net)							
Benefits Less Costs	**$105**	**$116**	**$82**	**$109**	**$95**	**$106**	**$103**
Utility Simple Payback Period	**9.0**	**8.9**	**9.0**	**9.1**	**9.3**	**9.0**	**9.0**

6.5 Anticipating Project Scope and Business Case Revisions

Orange and Rockland developed a viable AMI business case as part of the Company's 2014 electric and gas base rate case filing. We have since then identified a number of new scope items needed to support expanded AMI capabilities identified through the AMI Collaborative process. Based on the completion of our joint RFP process with Con Edison, we are now incorporating those new scope items in our business case analysis. The following are the new scope additions:

- a new Meter Data Management System (MDMS);
- a new Meter Asset Management System (MAMS);
- AMI and MDMS capabilities needed to enable near real-time collection, processing and presentment of meter interval data;
- professional services from a System Integrator;
- contractor services for installing the AMI meters and modules; and
- contractor services for installing the AMI network equipment.

It is important to note that the cost and effort tied to O&R's Phase One AMI project will provide benefit to O&R's Phase Two AMI project. The average cost per meter in Phase Two is expected to be less than Phase One due to the effort around systems and IT infrastructure work that will be completed in Phase One. As indicated earlier this AMI Business Plan, industry standard approach is to deploy all systems and technology before meters are deployed. Since Rockland County is Phase One all Information Technology work will be complete before meters are deployed which provides the benefit to Orange and Sullivan Counties.

6.6 Potential Future Applications

The original AMI project scope did not include the hardware, software, and services needed to implement all possible AMI-enabled applications; however, the planned AMI will provide a solid foundation of metering, communications, and computing resources that will support adding the following future applications:

- **Demand Side Management Programs:** Orange and Rockland is considering a variety of new demand-oriented rate offerings such as Time-of-Use (TOU) rates, Critical Peak Pricing (CPP) and Critical Peak Rebates (CPR). Implementation of these types of rates would be readily supported by time-series AMI meter data and AMI-enabled customer messaging (i.e. price signals). Historically, the high cost of metering on an individual customer basis has been a major obstacle to customer participation in demand management programs. This is especially true for mass market consumers such as residential households and small commercial businesses. AMI makes it possible to offer customers affordable opportunities to better manage their energy costs and, in the process, improve the economic efficiency of the electricity system by choosing and responding to prices that more accurately reflect the cost of electricity supply and delivery. Some notable examples of AMI-enabled customer programs include Sacramento Municipal Utility District's "smart home" time-of-use rate, which helped reduce customer bills by 10-13%, and, Oklahoma Gas & Electric's demand response program, in which 99% of participating customers saved an average of $150 annually.

- **Distribution Automation**: When fully deployed, the AMI communications network will provide a ubiquitous capability for reliable, timely, and secure communications with and among intelligent distribution management devices such as capacitor controllers, motor-operated switches, reclosers, and transformer tap changers.
- **Methane Detection:** AMI-enabled methane sensors would enable rapid detection of, and response to, natural gas leaks.
- **Corrosion Potential Detection:** AMI-enabled voltage sensors could detect gas pipeline corrosion by measuring corrosion-induced potential at pipeline test points; thus enabling condition based monitoring (CBM) and substantially reducing truck rolls and labor for manual tests.
- **Stray Voltage Detection and Reporting:** AMI-enabled voltage sensors could measure stray voltage on street lights and utility structures.
- **Prepayment:** Prepayment, a customer payment method that helps customers manage their energy costs, is currently not permitted by regulation. The economic benefits and customer satisfaction associated with prepayment programs are well-documented in the industry literature. Further, studies have shown that prepayment programs can contribute significantly to energy efficiency and conservation.
- **Data Analytics:** The AMI solution will provide more than 31.9 million discrete measurements every day from the electric and gas meters. This abundance of data will provide O&R with the opportunity to apply analytical tools to:
    - reduce electric and gas system losses;
    - improve electric system reliability;
    - evaluate the impact of electric vehicles and distributed energy resources;
    - prevent overloading of the electric system;
    - evaluate options for system optimization;
    - design new services for its customers in support of distributed energy resources; and
    - provide tools that help electric and gas customers understand and manage their energy consumption.

7 Conclusion

The energy distribution system of the next 20 years will be formed by those utilities and service providers who are most capable of delivering next generation smart capabilities. Specifically, in New York, these providers must be able to support the evolving demands of the state's REV initiative. For example, those who provide Distributed System Platforms (DSPs) face a future in which they will have reliability-driven responsibilities to enable distributed markets, accommodate technology innovations, and engage third-party energy service providers. DSPs will play a critical role in developing products and services that will inform and connect energy systems and enable their benefits to society. The Company considers AMI a foundational component of this evolution, enabling precise measurement and potential control capabilities throughout the system. Without AMI, a utility may not fully facilitate the many service offerings, products and markets that are envisioned in the REV future. With AMI, the Company can best provide for the developing array of distributed resources and services, while continuing to provide for enhanced and cost effective reliability. Key in doing so is the input of Staff and other parties in the developing marketplace, as well as, the experience of others in the broader utility industry. This Business Plan reflects such input, as will the Company's developing services as a DSP provider.

AMI Supplement A: AMI System Requirements

New York Public Service Commission AMI Minimum Functional Requirements:

- AMI systems must be compliant with all applicable ANSI standards, Commission regulations and Federal standards, such as Federal Communications Commission regulations.
- AMI systems must provide net metering.
- AMI systems must provide for a visual read of consumption either at the meter or via an auxiliary device. The utility is responsible for providing customers with the auxiliary device if it is the only means of a visual read of consumption data.
- AMI systems must be able to provide time-stamped interval data with a minimum interval of no more than one hour.
- AMI meters must have sufficient on-board meter memory capability to ensure meter data is not lost in the event of an AMI system failure and that the previous and current billing period of billing data is stored on the meter.
- AMI systems must have the ability to provide customers direct, real-time access to electric meter data. The data access must be provided in an open non- proprietary format.
- AMI systems must have the ability to remotely read meters on-demand.
- At the point where the customer or the customer's agent interfaces with the AMI system, the data exchange must be in an open, standard, non-proprietary format.
- AMI systems must have two-way communications capability, including ability to reprogram the meter and add functionality remotely, without interfering with the operation of the meter.
- AMI systems must have the ability to send signals to customer equipment to trigger demand response functions and connect with a home area network (HAN) to provide direct or customer-activated load control.
- AMI systems must have the ability to identify, locate, and determine the extent of an outage, and have the ability to confirm that an individual customer has been restored.
- AMI systems must have the following security capabilities:
    - Identification - uniquely identify all authorized users of the system to support individual accountability;
    - Authentication – authenticate all users prior to initially allowing access;
    - Access Control - assign and enforce levels of privilege to users for restricting the use of resources, and deny access to users unless they are properly identified and authenticated;
    - Integrity – prevent unauthorized modification of data, and provide detection and notification of unauthorized actions;
    - Confidentiality - secure data stored, processed and transmitted by the system from unauthorized entities;
    - Non-repudiation - provide proof of transmission or reception of a communication between entities;
    - Availability – allow for the availability and accessibility of information stored, processed and transmitted by the system, as required;
    - Audit - provide an audit log for investigating any security-related event; and

- Security Administration – provide tools for managing all of the above tasks by a designated security administrator.

Orange and Rockland Functional and Performance Requirements

The Company has identified both functional and performance requirements for the AMI business case as outlined in the table below:

Table A.1: AMI Base System Specifications

Requirement	Base System Specification
Regulatory	Must comply with New York PSC Minimum Requirements for AMI
Electric Metering	Meters must support TOU rates, demand calculations, net metering, reactive power assessment, remote configuration, and downloadable firmware; must support remote service switch for residential meters; real time and scheduled reporting of alarms and alerts (*e.g.* outage information)
Gas Metering	Meters must support hourly interval data, CCF, for C&I meters - CCF Uncorrected, pressure, and temperature

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Table A.2: AMI Detailed Specifications

Requirement	Performance Scenario 1	Performance Scenario 2	Performance Scenario 3	Remarks
Electric Meter register reads (kW) Number of Commercial (C) meters - 30,000 Number of Residential (R) meters - 196,000	C - 5 min interval R - 15 min interval	C - 5 min interval R - 15 min interval	C - 5 min interval R - 15 min interval	Interval reads at these frequencies will support future TOU programs Note- meter interval configuration can be changed to shorter intervals from AMI headend
Electric Customer Data Presentment	100 % of meters (226,000 electric meters) to be displayed near real time (15 minute lag)	20% of meter reads (45,200 meters) displayed near real time (15 minute lag)	Data will be displayed on portal next day	Determination of selected option to be made following RFP's for Meters/ Communications system equipment and Installation
System Performance - Interval Reads	99.50%	99.50%	99.50%	For both gas and electric meters
System coverage	100%	100%	100%	For both gas and electric meters
Gas Meter register reads	Hourly gas interval reads	Hourly gas interval reads	Hourly gas interval reads	132,500 gas meters
Gas Customer Data Presentment	Data will be displayed on portal next day	Data will be displayed on portal next day	Data will be displayed on portal next day	

AMI Supplement B: Definition of Terms

Table B.1: Definition of Terms

Term	Definition
Advanced Metering Infrastructure	Advanced Metering Infrastructure (AMI) is the term denoting electricity and gas meters that measure and record usage data at a minimum in hourly intervals, and provide usage data to both consumers and energy companies at increased frequencies. AMI meters are "smart" and have additional interoperability features, such as 2-way metering, communications enablement with customer equipment, and other capabilities.
CAIDI	CAIDI refers to Customer Average Interruption Duration Index. CAIDI is a measure of duration that provides the average amount of time a customer is without power per interruption of service.
Conservation Voltage Optimization	Conservation Voltage Optimization (CVO) is a technique for improving the efficiency of the electrical grid by optimizing voltage on the circuits that run from substations to customers.
Demand Response	Demand response (DR) programs are incentive-based programs that encourage or direct electric power customers to temporarily reduce their demand for power at certain times in exchange for a reduction in their electricity bills or other incentive. Customer-controlled reductions in demand may involve actions such as curtailing load, operating onsite generation, or shifting electricity use to another time period.
Distribution System	Distribution system refers to the portion of the facilities of an electric system that is dedicated to delivering electric energy to an end-user, rather than transmission, which transports energy between bulk electrical system components.
Methane	Methane is a colorless, flammable, odorless hydrocarbon gas which is the major component of natural gas. As a component of natural gas, it is often monitored in closed spaces to alert distribution operators to potential leaks.

AMI Supplement C: List of Abbreviations

AMI	Advanced Metering Infrastructure
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CCF	One Hundred Cubic Feet
CIMS	Customer Information Management System
CIS	Customer Information System
CIV	Communications Installation Vendor
CSR	Customer Service Representatives
CVO	Conservation Voltage Optimization
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed Systems Implementation Plan
DSP	Distributed System Platform
EV	Electric Vehicle
HEFPA	Home Energy Fair Practice Act
IMC	Irregular Meter Condition
IT	Information Technology
MAMS	Meter Asset Management System
MDHP	Mandatory Day Ahead Hourly Pricing
MDMS	Meter Data Management System
MIV	Meter Installation Vendor
O&M	Operations and Maintenance
OMS	Outage Management System
PSC	Public Service Commission
REV	Reforming the Energy Vision

RF	Radio Frequency
RFP	Request for Proposal
TOU	Time of Use

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Appendix C – REV Demonstration Projects

REV Demonstration Projects

O&R, aligned with the REV Track One Order and the PSC's Memorandum and Resolution on Demonstration Projects,[141] December 12, 2014 has begun one REV Demonstration project, a residential customer marketplace, and is currently examining opportunities for additional demonstrations. The next focus area O&R intends to explore may involve testing the Platform Service Revenues potential for energy storage, as well as a time varying rate demonstration project as required in the 2015 Electric Rate Case.[142] In addition, the Company's Pomona Program, approved in the 2015 Electric Rate Case,[143] will provide opportunities to prove-out DSP Provider functionalities as well, potentially in conjunction with REV Demonstration projects.

Current REV Demonstration Projects

On July 1, 2015, O&R filed a demonstration plan[144] with the PSC for a Residential Customer Engagement and Marketplace Platform ("CEMP"). PSC Staff reviewed[145] the plan and determined that the proposed REV Demonstration project complied with the objectives set forth in Ordering Clause 4 of the Track One Order. On November, 20, 2015, O&R filed an implementation plan[146] with the PSC. The Company launched the CEMP in late January 2016.

O&R, in partnership with Simple Energy, is implementing the REV Demonstration project. The project is designed to establish, and then expand upon, a network of third party product and service partners accessible through the marketplace platform in order to increase customer awareness of their own energy consumption, provide opportunities for increased distribution and adoption of all forms of DER, and test new revenue streams for O&R and its partners. The Simple Energy CEMP is testing the following hypotheses:

- An O&R sponsored marketplace that matched specific DER and EE solutions to eligible customers will launch the adoption of DER products on the marketplace
- A marketplace sponsored by O&R will encourage customer participating in DER and EE offerings and generate new utility revenue opportunities through the engagement of third parties
- A combined marketplace that provides customers with DER and EE offerings, instantaneous and enhanced rebates , easy to use interactive tools and options, and access to recommended third-party services and installers will drive a rewarding customer experience leading to ongoing customer interactions

[141] Case 14-M-0101, *Memorandum and Resolution on Demonstration Projects*, December 12, 2014.
[142] Case 14-E0493, The Commission's Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan, (issued October 16, 2015).
[143] Case 14-E0493, The Commission's Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan, (issued October 16, 2015).
[144] NYPSC Case 14-M-0101, "OR DemoProject", July 1, 2015.
[145] NYPSC Case 14-M-0101, "REV Demonstration Staff Assessment_O&R Residential Marketplace", November 10, 2015.
[146] NYPSC Case 14-M-0101, "OR_REV_Demonstration_Project_Implementation_Plan_(REDACTED)", November 20, 2015.

The CEMP will be delivered via multiple digital channels – web, email, and mailed paper Energy Insight Reports – to engage and motivate designated customers in the places where they already spend their time. Simple Energy will design, configure, host and operate the Energy platform, including:

- Energy Insight Reports delivered via postal mail and email
- Energy Insights
- Energy Challenges
- Rewards
- Marketplace

The Program initially launched as a standalone Marketplace with integrated marketing encouraging all O&R customers to purchase energy saving products and services. In May 2016, the Customer Engagement Platform launched to support the marketplace by providing designated customers with Energy Insights Reports, Gamification and Rewards with the goal of driving behavioral energy efficiency through the MY ORU Advisor portion of the REV Demonstration project.

Figure C-1

My ORU Advisor Materials

In March and April 2016, the marketplace platform expanded its offerings and engagement with customers and trade allies. Ongoing activities will test customer adoption of DER products and inform decisions regarding a DSP through the ability of an online marketplace to generate new Platform Service

Revenues as outlined in the Track Two Order[147] and facilitate integrating DER on to the grid. This demonstration addresses both customer engagement and new utility revenue opportunities. The latest CEMP Quarterly Report was filed on May 2, 2016.[148]

Future REV Demonstration Projects

O&R continues to explore future REV Demonstration projects. To that end, on February 5th, 2016 Con Edison and O&R jointly released an RFI soliciting responses from third parties on delivering innovative energy storage solutions that provide value for key stakeholders, including our customers, our shareholders, and our project partners. The RFI also served as a first step in testing the hypothesis that the companies can derive significant PSRs from deploying energy storage on the electric system. Responses to the RFI are currently in the final stages of being evaluated with the intent of moving forward in developing an energy storage REV Demonstration project if possible.

In the second half of the 2016, O&R and Con Edison plan on releasing a second and third RFI regarding low to moderate income customers and the electrification of transportation, respectively. If the RFI process proves to be successful, the Companies may continue to utilize it beyond 2016. O&R also intends to fully engage with NYSERDA's REV Connect initiative in order to explore further opportunities for REV Demonstration projects. The Company has also begun to develop future demonstration projects as directed by PSC Orders. These include a demonstration project providing the opportunity to use alternate approaches to increasing hosting capacity and facilitate greater DER penetration to be filed in the Supplemental DSIP, as directed in the DSIP Guidance Order,[149] and a Smart Home Rate demonstration project to be filed by February 1, 2017, in accordance with the Track Two Order.[150]

O&R conducted a stakeholder engagement meeting regarding REV Demonstration projects on May 16, 2016. That meeting covered much of the material outlined above including an update on the status of the CEMP demonstration project, an overview of the O&R Con Edison demonstration RFI process, and a discussion of potential focus areas for future demonstration projects.

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[147] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking And Utility Revenue Model Policy Framework, (issued May 19, 2016), (pp. 12,19).
[148] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, "OR Demo Report Q1 2016 5.2.16 Updated", May 2, 2016.
[149] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Distributed System Implementation Plan Guidance, (issued April 20, 2016), (p. 45).
[150] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking And Utility Revenue Model Policy Framework, (issued May 19, 2016), (p. 156).

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Appendix D – DSP Organizational Considerations

O&R's transition to serve as the DSP requires a large number of changes to the Company's business model, processes and procedures, and the tools used to maintain the safe and reliable operation of the distribution system, the beginning stages of these changes are outlined in this Initial DSIP. The DSP will also bring change to the way the Company is organized, the functions carried out by various organizations, and the required resources and skillsets required to serve as the DSP. This appendix begins to outline some of the organizational considerations intrinsic to early DSP functionalities.

The three organizations at O&R that are most impacted and involved in early DSP functionalities and wider REV requirements are the Utility of the Future, Electrical Engineering, and Control Center and Substation Operations. Many DSP and REV requirements require incremental effort and in many cases coordination across organizations is required, as with NWAs.

Utility of the Future

The Utility of the Future ("UotF") organization was created in June 2015 to organize and proactively align the Company's approach to DER integration with the evolving energy distribution markets in New York. This new department has day-to-day REV initiative oversight and is responsible for framing the structure and developing the approach to REV at O&R. The group also helps to set and guide the Company's overall strategy in its approach to REV, in conjunction with Con Edison. UotF functions currently include Regulatory Management, NWAs, and Demonstration Projects. The UotF group's responsibilities and function will continue to evolve as DSP functionalities expand at O&R and REV proceeds.

Regulatory Management

The REV proceeding, along with the 12+ related proceedings, have generated a growing number of required regulatory filings and efforts. The O&R UotF group coordinates compliance with REV related regulatory requirements by identifying SMEs, coordinating between organizations, defining workflows and tasks, managing responses to regulatory requirements, gaining alignment with Con Edison, coordinating with the JU, and contributing to the development of responses/materials as appropriate. O&R's regulatory management efforts have thus far focused on DSIP development, JU engagement, Clean Energy Advisory Council ("CEAC") participation, and Track Two support.

DSIP Development

The UotF group conducts project management for DSIP development at O&R. For the initial DSIP this includes defining and interpreting the requirements outlined by the PSC, formulating strategic positions in conjunction with Con Edison, developing a project plan and timelines, identifying SMEs, supporting the development of content, overseeing stakeholder engagement, managing editing and the review cycle, coordinating content with Con Edison, packaging the final filing, and responding to any interrogatories or additional requirements post-filing. The UotF group also oversees O&R's contribution to the development of the Supplemental DSIP to include identifying SMEs, coordinating with the JU, supporting the development of content, helping to coordinate stakeholder engagement, informing O&R leadership on Supplemental DSIP content/progress, and directly managing any O&R specific requirements within the filing. Going forward UotF will continue to manage all aspects of DSIP development for each biennial filing.

JU Engagement

The UotF group coordinates all of O&Rs activities within the JU. This includes coordinating directly to develop positions, contributing to regulatory filings, identifying O&R SMEs to participate in various JU initiatives, and managing O&R's contribution to the Supplemental DSIP. As evidenced by the joint nature of the Supplemental DSIP, it is critical that a common approach is taken across the state to various issues addressed by REV, such as hosting capacity and BCA implementation. The JU serves as the forum for developing this commonality and the UotF group will continue to serve as O&Rs primary interface with the other New York utilities.

REV Track Two Requirements

On May 19, 2016 the NYPSC released the Order Adopting a Ratemaking and Utility Revenue Model Policy Framework ("Track Two Order")[151] outlining the tenants of a new utility regulatory model within the context of REV. The Track Two Order contains a number of requirements for the utilities to develop in upcoming rate cases or separate filings. The requirements include proposals for various Earning Adjustment Mechanisms ("EAM"), a progress report, proposed tariffs, and a REV demonstration proposal. As with the DSIPs, the UotF group will manage and coordinate responses to regulatory requirements outlined in the Track Two Order.

Rate Case Support

In addition to the DSIPs and other regulatory filings, many of the programs, tools, and resources required for O&R to serve as the DSP will be outlined in rate case filings. To that end, the UotF group will coordinate the documentation of those potential programs and needs within rate case filings. UotF will also coordinate the inclusion of all REV directed rate case requirements.

Clean Energy Advisory Council Participation

The UotF Director fills O&R's position on the CEAC Steering Committee. The CEAC's primary objective is to support innovation and collaboration leading to the development of the most impactful clean energy programs and to reduce cost and achieve scale for these resources, including an effective transition from current clean energy program offerings and on-going delivery thereafter. The Steering Committee meets a minimum of four times a year and is responsible for establishing priorities for the Council and developing a work plan identifying key areas of focus based on the responsibilities assigned to the Council by the Commission. The Steering Committee is also charged with establishing CEAC Working Groups to investigate areas of focus and priorities, as well as defining their scope and reviewing their progress. Finally, the CEAC Steering Committee will also produce written updates on not less than an annual basis on the progress of its work.

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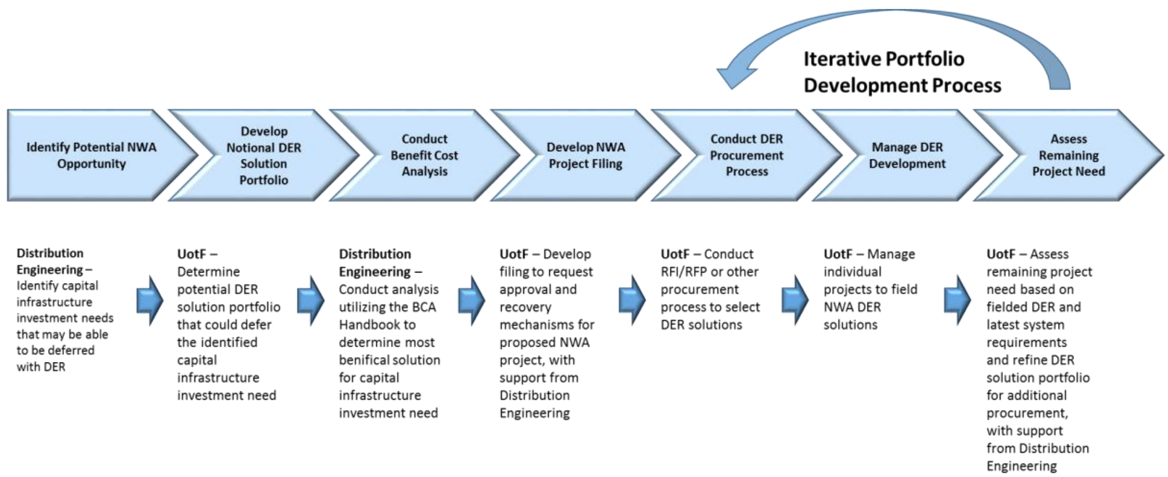
[151] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking And Utility Revenue Model Policy Framework, (issued May 19, 2016).

Non Wires Alternatives

The UotF group will oversee the development and administration of current and future NWA programs at O&R. Once NWA opportunities are identified and a benefit cost analysis is conducted by Engineering or other organizations as required (discussed further in this Appendix), the UotF group will take the lead on the development and administration of NWAs, with continued support from Engineering. The NWA lifecycle is displayed below.

Figure D-1

NWA Lifecycle



NWA Development

Once a potential NWA project is identified by Engineering, the UotF group will compile the notional DER solution portfolio that could, as an alternative, defer the capital infrastructure investment need. This DER solution portfolio will then be used in the benefit cost analysis, utilizing the BCA Handbook, conducted by Engineering and other organizations as required. Once a DER solution is determined to be favorable in deferring a capital infrastructure investment, in accordance with the BCA Framework, the Utility of the Future group, with support from Engineering, will prepare the filing proposing the NWA project. Following NWA approval, UotF will oversee DER procurement, utilizing RFI/RFPs or other procurement processes in order to analyze and select potential DER solutions. Once DER solutions have been fielded, the UotF group, with the support of Engineering, will assess the remaining need to effectively defer the capital infrastructure investment in order to refine the DER solution portfolio and conduct further DER procurement.

NWA Administration

In addition to developing NWA projects, the UotF group will oversee the development, implementation, and/or fielding of discrete DER solutions that are part of the broader solution. This could include a variety of activities from overseeing the implementation and budget for customer sided solutions to directly managing the fielding of a utility sided solution, in coordination with the appropriate O&R organizations.

Demonstration Projects

As with other REV initiatives, the UotF group oversees the development and administration of REV Demonstration projects. This includes the identification of focus areas for future demonstration projects, based on regulatory requirements and prioritization of REV related concepts to be tested. Once focus areas are identified, UotF will administer the RFI/RFP process to select vendors or third-party partners when appropriate. The UotF group will also support the development proposals, implementation plans, and other regulatory filings associated with demonstration projects. The ongoing administration of REV Demonstration projects will either be directly managed by the UotF group, or be assigned to appropriate group within O&R with ongoing oversight by UotF.

Electrical Engineering

Multiple groups within Electrical Engineering will take on or expand current functions to fulfill DSP roles. Engineering will support the forecasting of DER, identification and analysis around NWA projects, as well as other BCA activities. It will also play a role in the collection and sharing of system data, including hosting capacity. The Engineering group will develop the systems and functionality needed for O&R to serve as the DSP, to include ADMS and VVO, as well as oversee the interconnection process and support the sharing of system data.

Engineering

Forecasting of DER

As penetration of DER increases on the system, it will become ever more important to accurately forecast the impact of various DER types on the system. Information regarding different DER types will come from a variety of sources, require different analysis, and will impact the system in different ways. This is discussed further within the Distribution Planning chapter of this DSIP. Planners within the Distribution Engineering group will have to contribute additional effort and focus in order to incorporate the increased complexity DER brings to the bottom up forecasting process.

Non Wires Alternatives

Distribution Engineering will take the first step in the NWA development process by identifying planned capital infrastructure investment that could potentially be deferred by DER. This will be done through the project suitability process developed collaboratively by the JU and as part of the integrated planning process. Once potential NWAs are identified, Distribution Engineering will conduct a benefit cost analysis, with input from the UotF group to what the potential DER solution portfolio could be, to determine the most beneficial course of action for the potential project. Then as UotF takes the lead on development and administration of the NWA project going forward, the Engineering group will continue to support the development of the NWA filing and the subsequent iterative portfolio development process for the project, assessing the impact of DER solutions deployed and updating the remaining need going forward.

BCA Handbook Implementation

As introduced above, Engineering will conduct a benefit cost analysis on projects identified to have the potential to be solved or deferred with DER. This process will utilize and BCA Handbook and comply with guidance set out in the BCA Framework. The most direct application of the BCA Handbook will be for potential NWA projects, however there will likely be other investments in which the BCA Handbook will need to be applied to.

Hosting Capacity

The Engineering group will also be responsible for determining hosting capacity on the circuits within the Company's service territory. The definition and methodology to determine hosting capacity will be developed by the JU through the Supplemental DSIP process and filed in the Supplemental DSIP on November 1, 2016. Once the definition and methodology are established, hosting capacity by circuit will be determined by the Engineering group. This process will include an initial determination and then updates at an agreed upon interval. The information will likely also have to be formatted in order to be shared with DER developers and where appropriate included on the system data map the Company is currently developing.

System Data Collection/Sharing

In addition to hosting capacity, the Company is also developing a map in order to share useful and insightful system data with DER providers and other third parties. This map will include (by circuit) peak load, minimum load, voltage, amount of DG connected, and amount of DG currently in the queue. Engineering will be responsible for developing this information, in conjunction with the interconnection function, and formatting it in a manner that allows it to be incorporated into the system data map. This information will also have to be updated at a regular interval.

In order to O&R to serve as the DSP Provider, a number of foundational technology investments and enhancements are required. This plan is laid out in the DSP Technology Roadmap chapter of this Initial DSIP. Some of these investments in functionalities, namely ADMS and VVO, will be developed by the Engineering group.

ADMS Development

With respect to grid operations, an ADMS will serve as a platform to add the functionality required to provide real-time visibility and management of DER on the system. Engineering has already begun to explore the development of an ADMS and is currently moving from a feasibility study, which evaluated the Company's readiness from a systems and data perspective to a Scoping Study for an ADMS. Assuming a positive BCA, a RFP could be produced from the Scoping Study that will define the applications/modules to be implemented. After that, the Company anticipates moving into vendor selection and detailed implementation planning. It is presently anticipated that Engineering will serve as the lead for the entire development process. Additionally, once the initial ADMS platform is established, Engineering will explore and implement modules for various functions supported by the ADMS platform.

VVO Development

Within the VVO section of the Distribution Grid Operations chapter of this DSIP a phased approach to implementing VVO is outlined. Engineering will oversee the process to assess current voltage regulation capabilities and equipment on the system, coordinate the expansion of monitoring and control capabilities, and, if determined to have a positive BCA, develop system wide VVO.

The Engineering group is focused on emerging technologies and their impact/integration into the distribution system, such as Microgrids, EVs, and a variety of DG. The group also manages O&R's interconnection processes.

Interconnection Management

Engineering oversees all aspects of the interconnection process at O&R. This has included most recently, as described in the Interconnection Process section of the Distribution Grid Operations chapter of this DSIP, participation in the revision of the SIR and enhancement of O&R's interconnection portal to comply with REV Track One requirements. Engineering handles the reception, processing, and tracking of interconnection applications. For larger DG applications, the Engineering group also develops pre-application reports, initial screenings, and Coordinated Electric System Interconnection Reviews as required. Engineering will also maintain and manage the interconnection queue, prioritizing it based on guidance laid out by the SIR and other regulatory orders, and conduct analysis on the queue itself to provide information to system data map.

Control Center and Substation Operations

As penetration of DER increases on O&R's distribution system, the impact that DER on the system will have to be managed real-time by the Control Center and Substation Operations. Much of the near term DSP functionalities surrounding the management of DER on the system will be handled by the System Operations Group.

System Operations

The System Operations group, and the Control Center in particular will be the organization that carries out the DER monitoring and control functions as part of the DSP.

Real-time DER Management

The increase in DER penetration on the distribution system will present a number of opportunities and challenges, as outlined in the System Operations section of the Distribution Grid Operations section of this DSIP. Within the Control Center, monitoring, controlling, and dispatching DER is outside of the normal functions of the operators. This will likely eventually result in the need for new skillsets and resources to monitor, manage, and take advantage of the benefits provided by DER on the system. Micro-grids, CHP sites, battery storage, and reverse flow through substations are becoming more prevalent on the system and the coordination of these technologies with providers will require more attention than the operator can give. Additionally, in order to operate the more dynamic grid, increased technical skills will be needed within the Control Center to analyze sensor inputs, coordinate load shifting, and likely monitor and control certain DER that are having an impact upon the system. While many of these functions have the potential to be automated through an ADMS, an engineering background will be needed to fulfill functions including the monitoring, dispatch, control, and curtailment of large DER on the system as needed in order to mitigate system impacts. Additionally, there could potentially be an interface between the Control Center and third parties in order to monitor and control behind-the-meter aggregated DER.

NWA Execution

In addition to the monitoring and control of DER described above, the Control Center will also be responsible for the real-time deployment of NWA solutions. Depending on the nature of the need and solution, some portions of DER may need to be dispatched real-time, such as to meet a contingency need.

VVO Execution

Once full VVO capabilities are established, it will fall to the control room to provide management and oversight to automated system-wide VVO. This will likely be accomplished through the development of a VVO module within ADMS.

Initial Distributed System Implementation Plan

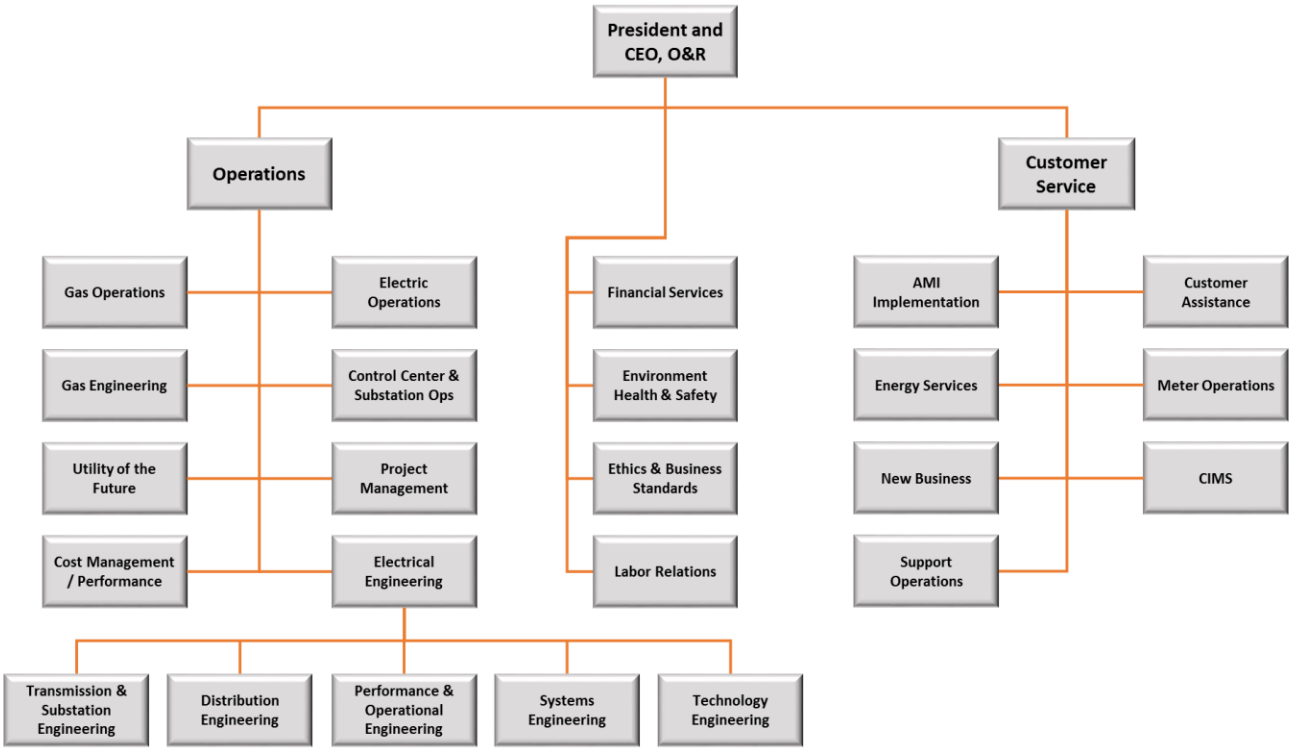
Appendix E – O&R Organizational Chart

O&R Organizational Chart

The organizational chart below displays the primary groups within O&R. Additional detail for the Electrical Engineering organization is included since multiple groups within are referenced directly in the DSIP.

Figure E-1

O&R Organizational Chart



ORANGE AND ROCKLAND UTILITIES, INC.

Initial Distributed System Implementation Plan

Appendix F – Forecast Capital Expenditures – Project List

The transmission and distribution capital budgets for the forward five-year period are included below. The figures below are derived from the 2016 budget. Forecast capital expenditures will continue to be refined through the 2017 budget process and filed in the upcoming base electric rate case. The potential approval of future NWA projects will also have an impact on future budget estimates.

Table F-1

Forecast Information Technology Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.20599642 - AMI Program - NY Electric	E - Distribution	3,644.45	6,230.40	6,230.40	6,230.07	3,089.94
Total:		**3,644.45**	**6,230.40**	**6,230.40**	**6,230.07**	**3,089.94**

Table F-2

Forecast Equipment Purchases Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.10106251 - Transformers - NY OH (Incl Contributions)	E - Distribution	1,337.71	1,303.68	1,313.17	1,340.61	1,340.61
PR.10106252 - Transformers - NY UG (Incl Contributions)	E - Distribution	2,536.20	2,518.02	2,556.61	2,608.26	2,608.26
PR.10106289 - Electric Meter Purchases - NY	E - Distribution	1,000.72	563.55	643.31	656.47	669.63
PR.10106292 - Electric Meter 1st Install Bkt - NY	E - Distribution	741.59	755.85	799.44	815.24	831.57
PR.21525656 - Spare 400MVA transformer 2	E - Transmission	3,011.00				
Total:		**8,627.21**	**5,141.10**	**5,312.53**	**5,420.59**	**5,450.07**

Table F-3

Forecast Safety/Security Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.20467629 - Subst Security Equip-Transmission	E - Transmission	3,945.49	3,451.77	1,986.19	1,505.64	
PR.20941119 - Existing Security Site LAN	E - Distribution	204.26				
PR.20941127 - Security Installs EL Sub	E - Distribution	977.34	434.82	249.20	235.48	240.06
Total:		**5,127.10**	**3,886.59**	**2,235.39**	**1,741.12**	**240.06**

Table F-4

Forecast Storm Hardening Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.20457790 - Storm Hardening OH TL - NY	E - Transmission		1,231.21	1,666.71	1,653.23	1,649.60
PR.20457923 - Storm Hardening UG Projects-NY	E - Distribution	2,463.12	2,603.76	2,409.88	2,480.27	2,477.87
PR.20468386 - Guinea Hill Road Backup	E - Distribution	561.73				
PR.20468880 - Orangeburg - Kings Highway (Rt 340 To Pip)	E - Distribution	688.31				
PR.20468882 - Orangeburg - Kings	E - Distribution		247.35			

Orange & Rockland

Project	Category	2016	2017	2018	2019	2020
Highway (Pip To Rt 303)						
PR.20468907 - Orangeburg - Route 303 Reconductor (50-4-13/54-3-13 Tie)	E - Distribution				280.45	
PR.21200092 - Storm Hardening OH TL - Trans Lines 55/56 and 551/561 Structure Re	E - Transmission	1,379.89				
PR.21522835 - Tuxedo Park - Storm Hardening	E - Distribution	309.35				
Total:		**5,402.40**	**4,082.33**	**4,076.59**	**4,413.95**	**4,127.48**

Table F-5

Forecast Risk Reduction Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.10002972 - Sterling Forest New 69kV Source L26 Tap	E - Transmission	4,098.20				
PR.10002963 - Substation Comm. Protection Bkt - NY	E - Transmission	47.07	56.33	64.36	47.85	27.55
PR.10001795 - Little Tor Substation UG Ckt Exits	E - Distribution		848.43	796.41		
PR.10002299 - Port Jervis Subst 2-35MVA Bank, 6 Ckts	E - Distribution	353.15	2,241.38	5,952.09	4,952.61	
PR.10002302 - Port Jervis Subst 2nd Bank U/G Ckt Exits	E - Distribution		43.68	790.19	696.82	
PR.10002539 - Little Tor Substation Transmission Tap	E - Transmission	18.88	478.86	522.46		
PR.10002542 - Little Tor Substation	E - Distribution	590.05	2,975.15	2,846.50		
PR.10003089 - T/L 702 Upgrade, Burns to Harings	E - Transmission	3,378.84	5,104.64			
PR.10075208 - Port Jervis Sub 69kV UG Intrastation Tie	E - Transmission		148.14	988.42	996.09	
PR.10106346 - Substation Department Blanket - NY	E - Transmission	165.65	166.54	166.54	166.54	164.54
PR.10106556 - W Nyack 2 50MVA Banks & Swchgr	E - Distribution			492.85	3,963.15	2,103.83
PR.10106557 - W Nyack UG Ckt Exit Relocation	E - Distribution			147.80	1,985.37	988.31
PR.10106576 - L6 to 69kV-Bullville to WHghts	E - Transmission	211.89	249.10	3,168.77	4,250.34	
PR.20457621 - Pearl River Upgrade To 69kV	E - Distribution			8.29	9.82	100.13
PR.20457714 - Burns 69kV Terminal	E - Transmission			8.29	10.04	96.64
PR.20468428 - West Nyack - Distribution Part 1	E - Distribution			320.11		
PR.20468429 - West Nyack - Distribution Part 2	E - Distribution			327.80		
PR.10002994 - TL 551 OPGW W Nyack to Snake Hill Rd	E - Transmission	3.11	504.33			
PR.10003000 - Line 562/563 CAT-1 Optical Ground Wire	E - Transmission	11.17	1,109.61			
PR.10075237 - Smart Grid Automation Resiliency Projects - NY	E - Smart Grid Distribution	1,078.73	2,925.19	2,925.91	2,983.58	2,979.83
PR.10075397 - Shoreline Protection Blanket	E - Transmission	240.82	239.60	236.60	237.30	236.86
PR.10106263 - E Dist Bkt -Sys Reliability NY	E - Distribution	10,761.84	8,416.26	8,860.74	8,446.16	11,944.58
PR.10106283 - U/G Rebuild Blanket (NY)	E - Distribution	1,847.49	1,819.05	1,846.60	1,882.96	1,915.98

Project	Category	2016	2017	2018	2019	2020
PR.10106285 - U/G Rehab Blanket (NY)	E - Distribution	270.62	274.30	277.98	283.78	283.78
PR.10106303 - Paving & Drainage Blanket - NY	E - Distribution	82.49	82.55	83.38	81.83	81.59
PR.10106306 - Transmission Relay Upgrade Bkt - NY	E - Transmission	600.52	598.63	593.83	589.73	604.56
PR.10106311 - Distribution Automation Blanket - NY	E - Distribution	1,506.39	1,495.51	1,512.17	1,481.73	1,479.72
PR.10106318 - Smart Grid Equipment Blanket	E - Smart Grid Distribution	76.44	75.79	75.75		
PR.10106339 - NY Incremental Reliability - Defective Poles Blanket	E - Distribution	1,793.72	1,805.99	1,793.72	1,793.72	1,793.68
PR.10106348 - Relay Department Blanket	E - Transmission	38.93	40.72	39.71	39.71	38.26
PR.10106554 - N Rockland 345kv Transmission	E - Transmission	483.50	1,566.45	1,065.55		
PR.10106572 - North Rockland-345kV Station	E - Transmission	1,391.66	12,584.17	3,721.63		
PR.10106574 - Line 111 Extension to PJ	E - Distribution			690.97	788.54	
PR.10106575 - West Nyack 138kV Yard	E - Transmission	286.80	992.16	5,949.60	3,962.16	
PR.20457710 - Line 50 69kV Upgrade	E - Transmission			8.29	10.04	50.87
PR.20457716 - West Nyack Trans Reconfig	E - Transmission				388.58	598.52
PR.20457719 - Line 12 Reconductor Shoemaker To Pocatello	E - Transmission					495.80
PR.20468414 - Nanuet - Convent Road (Center St To Railroad)	E - Distribution			773.97		
PR.20879842 - NYSERDA Cental Rockland Smart Grid Automation	E - Transmission	797.91				
PR.20945924 - Pine Island - County RT 1 to Pulaski Highway	E - Distribution				443.71	
PR.20969078 - Tower Leg Remediation	E - Distribution	178.09	374.77		336.63	332.67
PR.21487884 - Swinging Bridge UG Exit	E - Distribution				1,484.30	
PR.21487892 - Disturbance Monitoring Upgrades	E - Transmission	500.23				
PR.21487899 - Switchgear Upgrades	E - Distribution	487.39	487.82	487.32	503.79	502.81
PR.21487901 - RTU Upgrades	E - Transmission	197.58	197.64	197.53	195.29	194.80
PR.21487954 - Line 55/56 Structure Repl bkt	E - Transmission			977.10	999.67	1,026.29
PR.21487958 - Line 51 Upgrade	E - Transmission		1,184.29	990.65		
PR.21488085 - Monsey - Carlton Road (College to Blauvelt)	E - Distribution					655.22
PR.21488377 - Suffern NY - Spook Rock Road (between Viola & Grandview)	E - Distribution				522.23	
PR.21487847 - T/L 702/703 Fiber Underground	E - Transmission	241.65	5.00			
PR.21487887 - Line 67 Relay Replacements at West Haverstraw	E - Transmission	492.54	244.68			
PR.21487950 - Lines 55/56, Structure 28 and Lines 551/561, Structures 126 & 142	E - Transmission	983.56				
PR.21487951 - Lines 55/56, Structure 33 and Lines 551/56, Structures 48 &50	E - Transmission	-	985.09			
PR.20457752 - Deerpark-Transmission Tap	E - Transmission	207.74	1,883.67			
PR.20457768 - Deerpark-Circuit Exits	E - Distribution	736.88	2,503.05	3,061.78		
PR.20457948 - Deerpark Sub 69/34.5kV Bank	E - Distribution	3,853.71	4,717.38			
PR.21488222 - Monsey NY - Rt 59 (tenure to West Street)	E - Distribution	111.01				

Project	Category	2016	2017	2018	2019	2020
PR.21488380 - Tomkins Cove - Lakeview Conversion	E - Distribution				684.92	
PR.21488382 - Upper Nyack NY - Broadway (Castle Heights to Larchdale)	E - Distribution					895.91
PR.21488384 - Upper Nyack NY - Midland (Christian Herald to Larchdale)	E - Distribution					754.08
PR.21488388 - West Nyack NY - Greenbush Road (4kv conversion to 13.2kV)	E - Distribution				798.78	
PR.21513905 - Piermont - Rt 9w (Ash St)	E - Distribution					791.25
PR.21513924 - Grandview - Rt 9w - Part 2 (Old Mountain Road)	E - Distribution					793.71
PR.21513938 - CR 43-Mongaup River to CR 42	E - Distribution			628.53		
PR.21514500 - CR 43-Mongaup River to CR31 - Part 1	E - Distribution					359.10
PR.21514504 - CR 43-Mongaup River to CR31 - Part 2	E - Distribution					600.66
PR.21514510 - Granhamtown/Mt Orange - Greenville Tnpk to S. Centerville	E - Distribution	347.85				
PR.21514522 - Lower Road - CR1 to Step - Part 3	E - Distribution	302.93				
PR.21514525 - Lower Road - Garnerville Road to CR1 - Part 2	E - Distribution	517.41				
PR.21522112 - Chester - Black Meadow Road to Pine Hill Road Part 2	E - Distribution		397.91			
PR.21522119 - Chester - Black Meadow Road to Pine Hill Road Part1	E - Distribution		339.84			
PR.21522125 - Chester - Glenmere Road - Pine Hill Road to Route 17A	E - Distribution			562.10		
PR.21522137 - Chester - Pine Hill Road - Black Meadow Road tp Glenmere Road	E - Distribution		508.01	1.51		
PR.21522205 - Monroe - Lakes Road (conversion/tie) - Part 1	E - Distribution					496.89
PR.21522216 - Monroe - Lakes Road (conversion/tie) - Part 2	E - Distribution					611.08
PR.21522241 - Pulaski Highway - fill the Gap	E - Distribution				155.86	0.47
PR.21522264 - Tuxedo-Route 210/17A - Pole relocation	E - Distribution		446.39			
PR.21522274 - West Warwick - Blooms Corner (Ryerson to Walling)	E - Distribution	257.19				
PR.21522276 - West Warwick - Blooms Corner (Walling to Waterbury)	E - Distribution	291.32				
PR.21522818 - Brady Road/Long House Road - Part 2 (upgrade)	E - Distribution			356.25		
PR.21522820 - Liberty Corners - Newport Bridge to Pine Island Turnpike-mainline	E - Distribution		656.34			
PR.21522824 - Port Jervis - Grandview Ave (Park Ave to Main Street)	E - Distribution					220.75
PR.21522830 - Reservoir Road Conversion	E - Distribution					315.51
PR.21534133 - New Tie 27-4 & 27-3 West Haverstraw	E - Distribution		422.99			
Total:		**39,842.97**	**62,197.42**	**54,320.05**	**46,173.67**	**34,536.21**

Orange & Rockland

Table F-6

Forecast New Business Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.10106257 - E Dist Bkt - New Business NY	E - Distribution	4,799.19	4,179.26	4,992.47	5,024.05	6,293.36
PR.10106566 - Blue Lake Substation	E - Distribution	779.38				
PR.10106567 - Blue Lake UG Ckt Exits	E - Distribution	226.42				
PR.10106569 - Blue Lake Trans Reconfig	E - Transmission	206.40				
PR.21031986 - IBM Sterling Forest Substation	E - Distribution	2,232.23				
PR.21513343 - POMONA Project	E - Distribution				1,468.49	1,528.70
Total:		**8,243.63**	**4,179.26**	**4,992.47**	**6,492.54**	**7,822.06**

Table F-7

Forecast Replacement Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.10106340 - Oil Pump and Retire Blanket	E - Distribution	116.10	117.40	119.10	121.90	121.90
PR.10003005 - Ramapo Fire Suppression System Replacemt	E - Transmission	624.39				
PR.10075389 - Ramapo 138kV Yard Breaker Replacement	E - Transmission	937.22				
PR.10106380 - Pole Butt Removal Blanket	E - Distribution	32.10	32.10	32.10	32.00	32.00
PR.10106389 - Sale of Scrap Blanket	E - Distribution	(137.00)	(137.00)	(137.00)	(137.00)	(137.00)
PR.10106568 - Ramapo Bnks 1300/2300 Repl	E - Transmission			6,074.36	4,291.04	
PR.20457946 - West Nyack Breaker Upgrades	E - Transmission			498.08	524.79	
PR.20953200 - Burns Breaker Replacements	E - Transmission			998.39	998.59	
PR.21442603 - E Dist Bkt - Replacement NY	E - Distribution	2,783.41	2,143.95	2,288.40	2,183.07	3,093.56
PR.21487975 - Palisades Mall Swtich Repl	E - Distribution	397.36				
PR.21512974 - West Haverstraw 138kV Breaker Replacements	E - Transmission					985.91
Total:		**4,753.58**	**2,156.45**	**9,873.43**	**8,014.39**	**4,096.37**

Table F-8

Forecast Municipal Infrastructure Support Capital Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.10106260 - E Dist Bkt - Interference NY	E - Distribution	296.12	269.10	285.94	315.17	400.15
Total:		**296.12**	**269.10**	**285.94**	**315.17**	**400.15**

Table F-9

Forecast System Expansion Expenditures NY Only (T&D) by Project ($000.0s)

Project	Category	2016	2017	2018	2019	2020
PR.10002433 - West Warwick Substation	E - Distribution		47.06	226.46	491.65	3,965.34
PR.10002436 - UG Trans from ROW to West Warwick	E - Transmission				247.19	2,491.39
PR.10002971 - Sugarloaf to Shoemaker Corridor Study	E - Transmission	338.63				
PR.10075223 - Blooming Grove Bank Upgd & 2nd 35MVA Bk	E - Distribution			47.65	2,174.01	2,976.88
PR.10075224 - Blooming Grove U/G Circuit Exits	E - Distribution				102.72	1,479.76
PR.10075266 - West Warwick U/G Circuit Exits	E - Distribution				149.23	2,974.82
PR.10075390 - Blooming Grove Transmission Extention	E - Transmission				92.18	993.59
PR.10075393 - Sugarloaf 138kV - West Warwick	E - Transmission				182.34	788.69
PR.10106565 - Sugarloaf 138kV UG Bus Extnsn	E - Transmission				143.51	990.99
PR.10106573 - Sugarloaf to W Warwick OH	E - Transmission	116.63	807.18	988.75	218.11	2,973.69
PR.10106597 - Summit Ave - Montvale	E - Distribution	304.78				
PR.20457746 - Wurtsboro Substation Replacement	E - Distribution	662.64	2,848.86	4,804.46		
PR.20457751 - Wurtsboro UG Exits	E - Distribution	1,482.32	751.43	46.62		
PR.20468304 - West Warwick Part 2 - Ryerson Rd (Rt 94 To Blooms Corner)	E - Distribution	340.77				
PR.20468423 - Wesley Hills - (Summit Park To Sanitorium)	E - Distribution	895.29				
PR.20468426 - Pomona - Conklin Road (RT 45 To Buena Vista)	E - Distribution		679.93			
PR.20468427 - Pomona - Saw Mill Road (Conklin To Little Tor)	E - Distribution		816.40			
PR.20468501 - West Warwick Part 4 - Miller/Dekay (Sandfordville To Waterbury)	E - Distribution				863.01	
PR.20468509 - West Warwick Part 5 - Waterbury (Dekay To Blooms Corners)	E - Distribution			390.77		
PR.20468688 - West Warwick Part 9 (Newport Bridge - Blooms Corners To Amity)	E - Distribution			486.36		
PR.20468691 - West Warwick Dist Part 1 (Sanfordville -1A To Pi Tnpk-Double)	E - Distribution					459.36
PR.20468734 - Ledge Road-Spruce To Pine Grove	E - Distribution		737.03			
PR.20468745 - Kirbytown-Mt. Orange To Pocatello	E - Distribution					439.86
PR.20468842 - Wurtsboro Distribution Part 3	E - Distribution			246.78		
PR.20468956 - West Warwick Part 11 (Distillery-Pi Tnpk To West Ridge)	E - Distribution		301.11			
PR.20468957 - West Warwick Part 12 (West Ridge-Distillery To Old Ridge)	E - Distribution		345.18			
PR.20468958 - Pine Island - Pulaski Highway To Pine Island Station	E - Distribution				530.74	
PR.21487875 - Wurtsboro Transmission Tap	E - Transmission			47.60		

Orange & Rockland

Project	Category	2016	2017	2018	2019	2020
PR.21501388 - Monsey 50MVA Banks & Switchgear	E - Distribution				233.43	2,477.17
PR.21501392 - Monsey UG Circuit Exit Upgrades	E - Distribution					506.22
PR.21514529 - Wurtsboro - Masten Lake	E - Distribution				297.26	
PR.21514534 - Wurtsboro -Wurtsboro Hills	E - Distribution				544.90	
PR.21522838 - Wurtsboro - Convert 9-1-48	E - Distribution			435.20		
PR.21522842 - Wurtsboro - Convert 9-2-48	E - Distribution			232.66	0.57	
PR.21522843 - Wurtsboro -Yankee Lake	E - Distribution				520.06	
PR.20945818 - Monroe - Toby Place conversion	E - Distribution	142.64				
PR.20945917 - Pearl River - Oriole St (Orangeburg Rd to Blauvelt	E - Distribution	298.09				
PR.10002433 - West Warwick Substation	E - Distribution		47.06	226.46	491.65	3,965.34
PR.10002436 - UG Trans from ROW to West Warwick	E - Transmission				247.19	2,491.39
PR.10002971 - Sugarloaf to Shoemaker Corridor Study	E - Transmission	338.63				
Total:		**4,581.78**	**7,334.17**	**7,953.33**	**6,790.91**	**23,517.76**

Initial Distributed System Implementation Plan

Appendix G – Cybersecurity and Privacy Strategy Framework

The Company, Con Edison, Central Hudson Gas & Electric Corporation, and Niagara Mohawk d/b/a National Grid developed this framework. The Company applied concepts from this framework to develop its cybersecurity and privacy policies. New York State Electric and Gas Corporation and Rochester Gas & Electric Corporation have developed a corporate framework to be presented separately. All the utilities are still working to develop a future common position.

1. Executive Summary

The NY Reforming the Energy Vision (REV) Cybersecurity and Privacy Framework ("Framework") focuses on ensuring that adequate attention is given to cybersecurity and customer privacy challenges to address new and emerging threats introduced by the NY Reforming the Energy Vision (REV) order. This Framework provides a common language for understanding and managing cybersecurity risk. The Framework enables all NYS utilities to align their cybersecurity activities while considering individual utility business requirements, risk tolerances, and resources.

The Framework enables NYS utilities regardless of size, degree of cybersecurity risk, or cybersecurity sophistication to apply the principles and best practices of risk management to improving the security and resilience of critical infrastructure.

The Framework incorporates cybersecurity best practices and industry standards that are consistent with leading cybersecurity authorities, such as NERC, NIST, and other related agencies, that will help NYS utilities identify, implement, and improve cybersecurity practices. (See supplement 3.1). It creates a common language for addressing cybersecurity and privacy threats ("threats") to the NYS utility sector. The proposed framework is designed to evolve with changes in cybersecurity threats, processes, and technologies. This Framework envisions effective cybersecurity as a dynamic and evolving response to threats. As a result, NYS utilities that adopt this Framework would be better positioned to comply with any future cybersecurity and privacy regulations.

The Framework consists of six main parts:

1. **Information Security Management***:* This component provides for a set of cybersecurity policies and standards that would help govern each NYS utility to design, implement and maintain a coherent set of policies, processes, and systems to manage cyber related risks to its information assets , thus ensuring acceptable risk levels to the NYS REV objectives set aside in the vision;
2. **Risk Methodology***:* This component provides for a standardized approach to identifying assets, vulnerabilities, and threats and their impacts to provide a good assessment of cyber risk to a utility;
3. **Security Design Principles:** Security design principles (sometimes referred to as guiding principles or design principles) are fundamental security objectives that should be met during the development of any security architecture, and applied when the corresponding security controls are implemented
4. **Cybersecurity Capabilities to Manage Risk:** This component provides the necessary procedures, controls, and technologies within the organization to eliminate, reduce, or mitigate risk. This

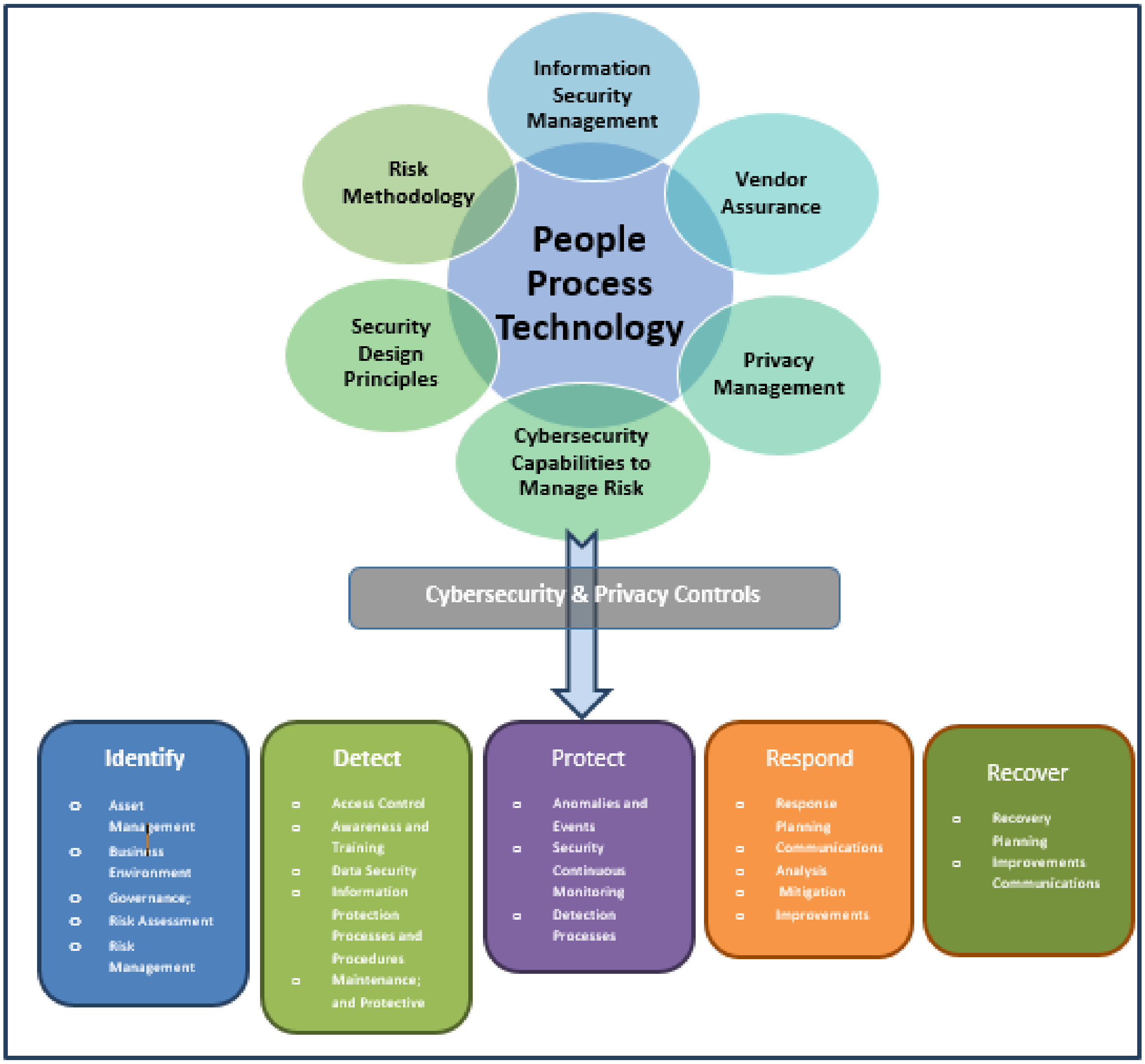
component will specifically identify the cybersecurity activities within the functional categories of: Identify, Protect, Detect, Respond, and Recover (see figure below).

5. **Privacy Management***:* This component provides for a privacy framework that is embedded within the overall strategic vision to protect company information as well as customers' privacy and comply with legal and regulatory requirements;
6. **Vendor Assurance**: This component provides procedures and policies for protecting against threats that can be introduced through the supply chain and to ensure an assurance program exists to continually monitor on a regular basis.

The Framework is meant to be initial guidance to NYS Utilities and their third party contractors and business partners that will be participating in the REV initiative and will be expanded to include further guidance of the minimum control objectives expected for participation that will be released as part of the NYS Order Adopting Distributed System Implementation Plan (NYS DSIP) Guidance Supplemental filing due on November 1, 2016.

2. The Framework

The Framework is focused on people, processes and technology as being the foundation for a comprehensive cybersecurity and privacy governance program. This enables every NYS utility to provide a consistent approach in establishing cybersecurity and privacy objectives, managing risks, and implementing relevant cybersecurity capabilities and controls.



2.1 Information Security Management

Each participating utility shall adopt a formal cybersecurity program and plan based on an accepted industry recognized framework to insure confidentiality, integrity, and availability of systems, information, and assets. This component will position each utility to comply with the NYS DSIP. Information Security Management is based on ISO/IEC 27001, which is an industry known standard providing requirements for an information security management system (ISMS) and is noted as an informative reference within the NIST Cybersecurity Framework.

Information Security Management requires that all businesses and operating companies within the regulated NYS utilities, including third party contractors and business partners, develop cybersecurity policies and standards that will properly mitigate the risks identified by each NYS utility as part of implementing a risk management strategy (described in more detail in Section 2.2 below). These cyberpolicies and standards exist to protect assets in use and to govern REV related projects and activities. Third party contractors and business partners must work with each NY Utility to ensure that they have adequate information security management practices, which is discussed in more detail in Section 2.6 below.

During the course of NY REV Grid modernization effort, any existing information security management policies or standards should be periodically reviewed, amended, and appropriately communicated to ensure the relevance and accuracy to any business or functional change via a risk-based approach.

2.1 Risk Methodology

Each participating NYS utility organization shall adopt a formal risk management program that identifies, acts on, and mitigates risks based on an industry approved risk methodology framework (approved list of frameworks in Supplement 3.1). The Risk Management Program includes policies, processes, and procedures that are defined, implemented as intended, and periodically reviewed. Consistent methods should be implemented to respond effectively to any change in risk to the respective utility. These methods must be in place to develop and refine the policies and standards mentioned above, and protect information based on data privacy, confidentiality, integrity, availability and critical infrastructure considerations in accordance with the law, regulations and internal data classification standards.

The risk management program shall incorporate and address risks related to each NYS Utility's REV program and each of the individual REV projects. As a result, the respective NYS Utility must have a process in place to identify threats and vulnerabilities, implement controls to mitigate risks, and manage residual risk accordingly to meet the respective utilities risk appetite for the REV program and individual projects. Finally, the NYS Utilities will need to align compliance objectives with regulatory, legal and statutory obligations and requirements and provide assurance and attestation of their effectiveness.

2.2 Security Design Principles

The foundation of any desired security architecture is a set of design principles intended to serve as a guidance when choosing the relevant cybersecurity controls (Section 2.5.1) that are leveraged to promote an adaptable architecture necessary to deliver a competitive advantage to the NYS utilities and their customers. These principles are based on the industry standard ISF (Information Security Forum) General Information Security Principles and they are:

1. **Balance Risk with Business value**: Security controls should be commensurate with the value of the information assets and vulnerability risk.
2. **Strive for simplicity:** Simplicity of security controls should result in better understanding and management of security controls, and the prompt resolution of security related issues.
3. **Obscurity is not Security:** The term "security through obscurity" is used to refer to the idea that a less well-known, less common, and thus less inviting target appears more secure statistically, even if it is not more secure technically. In many cases, it is not more secure, and it is often just a matter of time before attention is focused on that environment.
4. **Enforce Least Privilege:** Only the minimum possible privileges should be granted to a user, technology or a process for accessing an information asset.
5. **Promote Privacy:** Solutions should support privacy through prudent data collection, access and consent.
6. **Need to Know:** Access should be provided only to information that is necessary to perform a relevant business function
7. **Ensure Accountability and Traceability:** Information security accountability and responsibility must be clearly defined and acknowledged. Accountability must be enforced through traceability.
8. **Enable Continuous Protection of Information:** Information protection at all times is required to guarantee the Confidentiality, Integrity & Availability of information.
9. **Security is integral to System Design:** Security must be addressed at all stages of the solution life cycle .The security requirements of a system or application should be considered as part of its overall requirements (and not as an afterthought).
10. **Perform Defense in Depth:** This principle guides the selection of controls to ensure resilience against multiple vectors of attack, and to reduce the probability of a single-point of failure in the security of the architecture.

2.3 Cyber Security Capabilities to Manage Risk

The Framework will help deliver capabilities to manage threats and risks. Any of the industry recognized standards and best practices noted in Section 3.1 below may be utilized by each NYS Utility to identify and implement the detailed cybersecurity capabilities. For the purposes of the framework, the following capabilities which are based on the NIST Cybersecurity Framework, are Identify, Protect, Detect, Respond, and Recover and will enable the participating NYS Utilities to define policies, procedures, controls, and technology to address risks and threats.

- **Identify**: Develop the organizational understanding to manage cybersecurity risk to systems, assets, data, and capabilities. The activities in the Identify Function are foundational for effective use of the Framework. Understanding the business context, the resources that support critical functions, and the related cybersecurity risks, enables each utility to focus and prioritize its efforts, consistent with its risk management strategy and business needs. Examples include: Asset Management; Business Environment; Governance; Risk Assessment; and Risk Management Strategy.

- **Protect**: Develop and implement the appropriate safeguards to ensure delivery of critical infrastructure services. The Protect Function supports the ability to limit or contain the impact of a potential cybersecurity event. Examples include: Access Control; Awareness and Training; Data Security; Information Protection Processes and Procedures; Maintenance; and Protective Technology.
- **Detect**: Develop and implement the appropriate activities to identify the occurrence of a cybersecurity event. The Detect Function enables timely discovery of cybersecurity events. Examples include: Anomalies and Events; Security Continuous Monitoring; and Detection Processes.
- **Respond**: Develop and implement the appropriate activities to take action regarding a detected cybersecurity event. The Respond Function supports the ability to contain the impact of a potential cybersecurity event. Examples include: Response Planning; Communications; Analysis; Mitigation; and Improvements.
- **Recover**: Develop and implement the appropriate activities to maintain plans for resilience and to restore any capabilities or services that were impaired due to a cybersecurity event. The Recover Function supports timely recovery to normal operations to reduce the impact from a cybersecurity event. Examples include: Recovery Planning; Improvements; and Communications.

2.4.1 Cyber security & Privacy Controls

Cybersecurity and privacy controls provide a comprehensive range of measures for NYS utilities to protect their information systems and customer information. The controls should be designed, in a layered security approach to protect the confidentiality, integrity, and availability of systems and information. They involve aspects of policy, oversight, supervision, processes, or automated mechanisms implemented by information systems/devices that fall under an overarching cybersecurity plan and governance program. This program will have similarities amongst the NYS Utilities, but will also include differences, as it will be based on each utility's individual risk management process and associated security and privacy policies. Each NYS Utility will describe their individual program in further detail within their individual NYS DSIP and DSIP Supplemental Filings.

Though this framework is not meant to prescribe specific control measures, as it is intended to allow flexibility for each NYS Utility and their third party contractors and business partners. Any industry recognized standard and best practices noted in Section 3.1 below may be utilized by each NYS Utility to identify and implement the detailed control activities; however, for purposes of this Framework, the NIST Special Publication 800-53 Rev 4 Security and Privacy Controls for Federal Information Systems and Organizations ("NIST SP 800-53") guidance is depicted to identify those control topics or "family" as noted in the table below. This serves to assist the

NYS Utilities in providing greater flexibility and agility to defend against an ever changing threat landscape, along with the ability to implement a structured approach to tailor any provisions required to specific missions/business functions, environments of operation, and/or technologies based on the level of risk that is acceptable to the specific utility.

ID	Family	ID	Family
Security Control			
AC	Access Control	MP	Media Protection
AT	Awareness and Training	PE	Physical and Environmental Protection
AU	Audit and Accountability	PL	Planning
CA	Security Assessment and Authorization	PS	Personnel Security
CM	Configuration Management	RA	Risk Assessment
CP	Contingency Planning	SA	System and Services Acquisition
IA	Identification and Authentication	SC	System and Communications Protection
IR	Incident Response	SI	System and Information Integrity
MA	Maintenance	PM	Program Management
Privacy Control			
AP	Authority and Purpose	IP	Individual Participation and Redress
AR	Accountability, Audit, and Risk Management	SE	Security
DI	Data Quality and Integrity	TR	Transparency
DM	Data Minimization and Retention	UL	Use Limitation

Each NYS Utility and their third parties and business partners must design their REV security and privacy programs to address each of the above control family topics, based on risk assessments performed for each system or initiative.

Additional guidance on security and privacy controls will be developed as part of the NYS DSIP Supplement filing due November 1, 2016. This will allow for each of the NYS Utilities to begin the process of implementing this Framework and leveraging lessons learned in continuing to enhance it.

2.4 Privacy Management

Each NYS Utility shall have a governance structure in place that shall be responsible for ensuring data privacy compliance aligned with the NYS DSIP, NYS General Business Law § 899-aa(2), and an industry recognized framework(see Section 3.1) . This function also draws on resources from the utility's legal department to create a partnership to ensure that the people, processes, and technology are considered and embedded as part of an integrated approach to privacy compliance. Every NYS Utility shall ensure a designated data privacy team shall be responsible for developing a Data Privacy Strategy and deliver a Data Privacy Governance Program, which is fully aligned with the companies NYS REV effort.

In support of achieving the goals of the NYS REV initiative, each NYS Utility must develop and maintain their Data Privacy Governance Program with key personnel and committees at various levels of the organization that set, direct, and implement a privacy governance strategy that consists of a privacy risk methodology that identifies each NYS Utility's privacy threats and vulnerabilities, implement controls to mitigate risks, and manage residual risk accordingly to meet the respective utilities risk appetite. The Data Privacy Program will provide clear accountabilities through policy and supporting initiatives for delivering the company's key administrative, technical, and physical privacy and information security safeguards.

Similar to the information security principles noted in Section 2.3 above, the NYS Utility's Data Privacy Program should also consist of design principles to ensure credibility and promote continued customer confidence and goodwill. These principles are based on the Generally Accepted Privacy Principles (GAPP) that ensure the efficient and systematic control of collection, processing and disposition of personal information based on internationally recognized best practice. They are:

a. **Management**: The entity defines, documents, communicates, and assigns accountability for its privacy policies and procedures.
b. **Notice**: The entity provides notice about its privacy policies and procedures and identifies the purposes for which personal information is collected, used, retained, and disclosed.
c. **Choice and Consent**: The entity describes the choices available to the individual and obtains implicit or explicit consent with respect to the collection, use, and disclosure of personal information.
d. **Collection**: The entity collects personal information only for the purposes identified in the notice.
e. **Use, Retention and Disposal**: The entity limits the use of personal information to the purposes identified in the notice and for which the individual has provided implicit or explicit consent. The entity retains personal information for only as long as necessary to fulfill the stated purposes or as required by law or regulations and thereafter appropriately disposes of such information.
f. **Access**: The entity provides individuals with access to their personal information for review and update.
g. **Disclosure to third parties**: The entity discloses personal information to third parties only for the purposes identified in the notice and with the implicit or explicit consent of the individual.
h. **Security for Privacy**: The entity protects personal information against unauthorized access (both physical and logical).
i. **Quality**: The entity maintains accurate, complete and relevant personal information for the purposes identified in the notice.
j. **Monitoring and Enforcement**: The entity monitors compliance with its privacy policies and procedures and has procedures to address privacy related inquiries, complaints and disputes.

2.5 Vendor Assurance

Each NYS utility should protect against supply chain threats to information systems and assets as part of their information security strategy. Utilities should implement a standardized process for identifying, assessing, and mitigating security risks that can be introduced at the supply chain level. Individuals involved in the acquisition process should be educated on identifying and intercepting such risks. Examples of supply chain threat agents may include: foreign intelligence services, cyber criminals, insider threats, and industrial espionage.

Supply chain risk management should be developed as a multi-departmental engagement with respective responsibilities. The engagement should integrate strategies and goals on the corporate level, guidance and procedures on the business level, and policy implementations and constraints on the information systems level.

A comprehensive strategy for protecting against supply chain risks should include at a minimum:

- Performing due diligence and risk assessment of potential new vendors
- Validation of vendor security controls to ensure the design and operating effectiveness to mitigate the risks identified appropriately by the respective NYS utility.
- Periodic monitoring of the vendor contract and to ensure compliance to the NYS utility agreed terms and conditions
- Enforcing policy and procedure compliance
- Ensuring the protection of customer information at rest and in motion
- Providing methods for allowing customer opt-in prior to releasing any customer information unrelated to the normal delivery of energy
- Appropriate security terms within legal agreements with third parties that ensure that they have proper security and privacy controls to protect NY Utilities’ customer information

Supplement

3.1 Industry Standards and Best Practices

Cybersecurity Industry Standards and Guidelines leveraged to inform development of Cybersecurity and Privacy Joint Utility Framework

- NIST Cybersecurity Framework
- NISTIR 7628: Guidelines for Smart Grid Security
- NIST SP 800-53: Security and Privacy Controls for Federal Information Systems and Organizations
- NIST SP 800-30: Guide for Conducting Risk Assessments
- NIST SP 800-161: Supply Chain Risk Management Practices for Federal Information Systems and Organizations
- NIST 800-144: Guidelines on Security and Privacy in Public Cloud Computing
- NIST IR 8062: Privacy Risk Management for Federal Information Systems
- Fair Information Practice Principles (FIPPs)
- Electric Sector Cybersecurity Capability Maturity Model (ES-C2M2)
- DOE DataGuard Energy Data Privacy Program
- AICPA Generally Accepted Privacy Principles
- ISO/IEC 27001 Information Security Management
- ISO/IEC 27002 Code of Practice for Information Security Controls
- ISO/IEC 27005 Information Security Risk Management
- ISO/IEC 27018 Code of Practice for Protection of PII in Public Cloud
- ISO/IEC 29100 Privacy Framework
- ISO/IEC 29101 Privacy Architecture Framework
- ISO/IEC 29134 Privacy Impact Assessment
- DOE voluntary code of conduct
- Information Security Forum General Information Security Practices

3.2 Definitions

- **Access Control**: Access to assets and associated facilities is limited to authorized users, processes, or devices, and to authorized activities and transactions.
- **Analysis**: Analysis is conducted to ensure adequate response and support recovery activities.
- **Anomalies and Events**: Anomalous activity is detected in a timely manner and the potential impact of events is understood.

- **Asset Management**: The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.
- **Availability:** is generally considered the next most critical security requirement, although the time latency associated with availability can vary.
- **Awareness and Training**: The organization's personnel and partners are provided cybersecurity awareness education and are adequately trained to perform their information security-related duties and responsibilities consistent with related policies, procedures, and agreements.
- **Business Environment**: The organization's mission, objectives, stakeholders, and activities are understood and prioritized; this information is used to inform cybersecurity roles, responsibilities, and risk management decisions.
- **Communications (Recover)**: Restoration activities are coordinated with internal and external parties, such as coordinating centers, Internet Service Providers, owners of attacking systems, victims, other CSIRTs, and vendors.
- **Communications (Respond)**: Response activities are coordinated with internal and external stakeholders, as appropriate, to include external support from law enforcement agencies.
- **Confidentiality**: is generally the least critical for actual power system operations, although this is changing for some parts of the power system, as customer information is more easily available in cyber form: Privacy of customer information is the most important =general corporate information, such as human resources, internal decision-making, etc.
- **Cybersecurity**: is the protection required to ensure confidentiality, integrity and availability of the electronic information communication system.
- **Data Security**: Information and records (data) are managed consistent with the organization's risk strategy to protect the confidentiality, integrity, and availability of information.
- **Detection Processes**: Detection processes and procedures are maintained and tested to ensure timely and adequate awareness of anomalous events.
- **Governance**: The policies, procedures, and processes to manage and monitor the organization's regulatory, legal, risk, environmental, and operational requirements are understood and inform the management of cybersecurity risk.
- **Integrity**: is generally considered the most critical security requirement for power system operations, and includes assurance that:
    - Data has not been modified without authorization
    - Source of data is authenticated
    - Timestamp associated with the data is known and authenticated
    - Quality of data is known and authenticated
- **Improvements (Recover)**: Recovery planning and processes are improved by incorporating lessons learned into future activities.
- **Improvements (Respond)**: Organizational response activities are improved by incorporating lessons learned from current and previous detection/response activities.

- **Information Protection Processes and Procedures**: Security policies (that address purpose, scope, roles, responsibilities, management commitment, and coordination among organizational entities), processes, and procedures are maintained and used to manage protection of information systems and assets
- **Maintenance**: Maintenance and repairs of industrial control and information system components is performed consistent with policies and procedures.
- **Mitigation**: Activities are performed to prevent expansion of an event, mitigate its effects, and eradicate the incident.
- **Personal information**: Information that is about, or can be related to, an identifiable individual that a NYS Utility has a relationship with.
- **Privacy**: The rights and obligations of individuals and organizations with respect to the collection, use, retention, disclosure and disposal of personal information.
- **Protective Technology**: Technical security solutions are managed to ensure the security and resilience of systems and assets, consistent with related policies, procedures, and agreements
- **Recovery Planning**: Recovery processes and procedures are executed and maintained to ensure timely restoration of systems or assets affected by cybersecurity events.
- **Response Planning**: Response processes and procedures are executed and maintained, to ensure timely response to detected cybersecurity events.
- **Risk Assessment**: The organization understands the cybersecurity risk to organizational operations (including mission, functions, image, or reputation), organizational assets, and individuals.
- **Risk Management Strategy**: The organization's priorities, constraints, risk tolerances, and assumptions are established and used to support operational risk decisions.
- **Security Continuous Monitoring**: The information system and assets are monitored at discrete intervals to identify cybersecurity events and verify the effectiveness of protective measures

Initial Distributed System Implementation Plan

Appendix H – Acronyms

Acronym	Description
ACE	Alternative Cable Evaluation
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
BCA	Benefit Cost Analysis
BPS	Bulk Power System
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CEATI	Centre for Energy Advancement through Technological Innovation
CEI	Consolidated Edison, Inc.
CESIR	Coordinated Electric System Interconnection Review
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CIS	Customer Information System
CIV	Communications Installation Vendor
CPR	Clean Power Research
CSR	Commercial System Relief
CVO	Continuous or Conservation Voltage Optimization
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DCX	Digital Customer Experience
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DEW	Distribution Engineering Workstation
DG	Distributed Generation
DPS	Department of Public Service
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSIP	Distributed System Implementation Plan
DSM	Demand Side Management
DSP	Distributed System Platform
EAM	Earning Adjustment Mechanism
EDD	Electrical Distribution Design

Acronym	Description
EDI	Electronic Data Interchange
EE	Energy Efficiency
EEPS	Energy Efficiency Portfolio Standard
EMS	Energy Management System
EPRI	Electric Power Research Institute
EPTD	Electric Power Transmission and Distribution
ESCO	Energy Service Company
ETIP	Energy Efficiency Transition Implementation Plan
EV	Electric Vehicle
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
GBC	Green Button Connect My Data
GIS	Geographic Information System
HVN	High Value Network
ICS	Industrial Control System
I&M	Inspection and Maintenance
IOAP	Interconnection Online Application Portal
ISM	Integrated System Model
ISO	International Standard Organizaiton
IVVC	Integrated Volt VAR Control
JU	Joint Utilities
LAN	Local Area Network
LMP	Locational Marginal Price
LMP+D	Locational Marginal Price plus the Value of Distribution
LTC	Load Tap Changer
LTE	Long Term Emergency
MAD	Minimum Approach Distance
MDM	Mobile Device Manager
MDPT	Market Design and Platform Technology
MIV	Meter Installation Vendor
MOAB	Motor Operated Air Break

Acronym	Description
MVA	Mega Volt Ampere (Apparent Power)
MVAR	Mega Volt Ampere Reactive (Reactive Power)
MW	Megawatts
NDA	Non-Disclosure Agreement
NERC	North America Electric Reliability Criteria
NIC	Network Interface Controller
NPCC	Northeast Power Coordinating Council
NWA	Non Wires Alternatives
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSERDA	New York State Research and Development Authority
NYSRC	New York State Reliability Council
OMS	Outage Management System
O&M	Operations and Maintenance
OPGW	Optical Ground Wire
O&R	Orange and Rockland Utility
PII	Personally Identifiable Information
PQ	Power Quality
PSC	Public Service Commission
PSR	Platform Service Revenues
PV	Photovoltaic
RAIS	Retail Access Information System
RECO	Rockland Electric Company
REV	Reforming the Energy Vision
RF	Radio Frequency
RFI	Request for Information
RFP	Request for Proposal
RMS	Remote Monitoring System
RNA	Reliability Needs Assessment
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

Acronym	Description
SC	Service Classifications
SCADA	Supervisory Control and Data Acquisition
SCT	Societal Cost Test
SDLC	Software Development Life Cycle
SEPA	Smart Electric Power Association
SIR	Standardized Interconnection Requirements
SME	Subject Matter Expert
SSN	Silver Spring Networks
T&D	Transmission and Distribution
T&S	Transmission and Substation
TV	Temperature Variable
TVP	Time Varying Pricing
UBP	Uniform Business Practices
UFLS	Under-frequency Load Shedding
UTDT	Underground Transmission Design Tools
VPN	Virtual Private Network
VPP	Virtual Power Plant
VVC	Volt/VAR Control
VVO	Volt/VAR Optimization
WAN	Wide Area Network
WAP	Weather Adjusted Peak