Con Edison's DSIP presents its self-assessment and five-year view of the integration of Distributed Energy Resources into Planning, Operations, and Administration

Distributed System Implementation Plan (DSIP)

June 30, 2016

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I. Executive Summary

Consolidated Edison Company of New York, Inc. (the Company or Con Edison) is excited to be among the utilities at the forefront of the changing energy landscape, and to be committed to dramatically changing the way energy is produced and consumed in New York. It is with these goals in mind that Con Edison presents its Initial Distributed System Implementation Plan (DSIP). This five-year, self-assessment and strategic roadmap responds to the Order Adopting the DSIP Guidance,[1] and strives to take a larger look at the efforts the Company is undertaking to give customers more choice, control, and convenience and to remake the day-to-day planning and operation of the electric system. This DSIP outlines Con Edison's plan to efficiently integrate distributed energy resources (DER) and promote the Company's goals of customer engagement, reliability, and operational excellence. The DSIP also includes a plan for encouraging technological innovation and promoting a robust marketplace for DER. In addition, key planning information, including the electric demand and energy forecast, and capital budget, will be updated and shared with stakeholders in an effort to provide timely and actionable information with regard to potential market opportunities. The highlights of the DSIP include:

- Five-year roadmap to have integrated approximately 800 MW of DER by 2020
    - Builds on the robust growth of solar energy
    - Enables the steady growth of combined heat and power which enhances resiliency
    - Provides greater opportunity to benefit from the Company's successful Energy Efficiency and Demand Response programs
- Grid modernization investment plans in support of DER
    - Builds adaptability and increases grid edge monitoring so the grid benefits from increasing amounts of DER
    - Implements Advanced Metering Infrastructure (AMI) to provide the cyber secure backbone and metering information that will be critical to developing the new market place envisioned by the Commission
    - Seeks strategic transmission investments to enable large scale renewables (LSR)
- Multi-pronged plan to stimulate DER growth
    - Outlines opportunities, in the capital investment plan, for Non Wires Alternatives (NWA) including the ongoing Brooklyn Queens Demand Management (BQDM) project which targets 52 MW of NWA
    - Presents several new candidates for NWA solutions, potentially including Glendale (which is a 60 MW load transfer and installation of a substation transformer) and several projects at the distribution level

[1] Case 14-M-0101 *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Adopting Distributed System Implementation Plan Guidance (April 20, 2016).

    - Promotes innovation and inform future DSP investments, and potentially permanently reduce load through multiple demonstration projects, in addition to Targeted Demand Management (TDM) monies
- Elements of the Con Edison Distributed System Platform (DSP) already in place and available to stakeholders:
    - Current system and network forecasts are updated to reflect the increased role of DER
    - Presentation of phase 1 network hosting capacity maps available for most of Con Edison's service territory to inform stakeholders and initiate dialog
    - Presentation of network maximum and minimum load duration curves to share informative system data via website

Con Edison's initial DSIP moves the Public Service Commission's (PSC or the Commission) Reforming the Energy Vision (REV) initiatives forward and, along with the upcoming supplemental DSIP filing and ongoing stakeholder engagement, lays the broad foundation to meet the Company's larger goals of remaking the energy landscape in its territory.

II. Introduction

On February 26, 2015, the Commission issued its *Order Adopting Regulatory Policy Framework and Implementation Plan* (Track One Order)[2] in its Reforming the Energy Vision (REV) proceeding which details the regulatory framework and implementation plan for REV. This Initial DSIP filing is a thorough self-assessment of the Company's system and describes immediate opportunities that will further contribute to REV policies and goals. The DSIP 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 documents the Company's plans over a five-year period and will be updated every two years. Per the Commission's April 20, 2016 Order Adopting the DSIP Guidance (DSIP Order),[3] the Company will jointly file a Supplemental DSIP on November 1, 2016 with the Joint Utilities (JU),[4] to outline the joint plan for the tools, processes, and protocols required and a coordinated approach for deployment. These topics include probabilistic planning, system data sharing standards, further development of hosting capacity, and details of stakeholder engagement.

A. Alignment with Company Objectives

Con Edison's continuing efforts to modernize and strengthen its electrical distribution system, while creating opportunities for customers to take control of their energy use and bill, are aligned with New York's REV initiative. Con Edison supports the Public Service Commission's (PSC) REV and Clean Energy Standard (CES)[5] efforts and is collaborating with stakeholders, Department of Public Service Staff (DPS Staff), and the Commission. Leveraging the existing transmission and distribution infrastructure is critical to efficiently integrating intermittent and nascent technologies into the electric grid to benefit the environment, lower customer costs, and increase reliability and resilience. In addition, Con Edison's robust transmission system will enable LSR that will add to the portfolio of smaller scale DER integrated by the DSIP. Smart grid investments can also complement portfolios of Customer Sided Solutions (CSS), NWA, and traditional utility solutions as is being shown in BQDM.

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[2] 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).

[3] REV Proceeding, April 20, 2016 Order Adopting Distributed System Implementation Plan Guidance (DSIP Order). In the same proceeding, on October 15, 2015, the Staff Proposal Distributed System Implementation Plan Guidance (Staff DSIP Guidance) was issued and was followed by stakeholder comments, including those of the Joint Utilities (Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric and Gas Corporation, Niagara Mohawk d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation. In view of the timing of the Staff DSIP Guidance and DSIP Order, and the need to initiate preparation of the DSIP well before its due date, there may be non-material discrepancies between the DSIP and the DSIP Order.

[4] See note 3 above for the listing of the Joint Utilities.

[5] Case 15-E-0302, *In the Matter of the Implementation of a Large-Scale Renewable Program and Clean Energy Standard*, Order Expanding Scope of Proceeding and Seeking Comments (issued January 21, 2016).

B. Overview of Con Edison's Service Territory

Con Edison is privileged to power one of the most dynamic and exciting urban centers in the world.[6] Con Edison's electric system safely and reliably serves 3.4 million customers in the five boroughs of New York City and Westchester County[7] and is consistently recognized as one of the most reliable electric systems in the country.[8] The all-time system peak load of 13,322 MW, which occurred in 2013, comprises approximately 40 percent of New York State's peak demand in roughly 1 percent of the geographic footprint. Highlights of the Con Edison System include:

The electric system includes both underground and overhead systems. The underground network serves 86 percent of Con Edison's customers, while the overhead system supplies the remaining 14 percent. This is achieved via 62 area substations which supply 64 networks and 19 non-network load areas. Approximately 2,300 primary voltage distribution feeders supply network and non-network load.

Con Edison's electric underground distribution system is the largest underground, low-voltage network system in the world. The Con Edison distribution system includes approximately 251,500 manholes and service boxes, 25,000 conduit miles of duct, 95,800 miles of underground cable, and 41,200 underground transformers that further step the voltage down from 33kV, 27kV, 13kV, or 4kV to 120/208 volts to supply the low-voltage secondary distribution system.

The Company's electric underground network system uses second-contingency design meaning it is designed to sustain the loss of any two feeders in a network under peak load conditions without any feeder or transformer overloads or adverse impact on service to customers.

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[6] CECONY/O&R service territory gross metropolitan product was approximately 5 percent of U.S. GDP in 2015. Moody's Analytics, *Gross County Product, DataBuffet*, n.d., https://www.economy.com/databuffet/pro/beta/# (accessed 06 28, 2016); Wolters Kluwer, *Blue Chip Economic Indicators*, Monthly Report, New York: CCH Incorporated, Vol. 41, No. 4, April 10, 2016.

[7] Con Edison's electric service territory covers 604 square miles and is comprised of New York City, with the exception of the fifth ward (Rockaway Peninsula) in Queens, and approximately two thirds of Westchester County.

[8] PA Media Release 10/23/15: "PA Consulting Group awarded Con Edison its Outstanding System-Wide Reliability for the eighth year in a row for providing customers with system-wide reliability that is 85 percent better than the industry average. The award recognized that Con Edison incorporates planning criteria for outage contingencies that are more stringent most of the industry. This means that the average customer on Con Edison's system can expect an outage about once every ten years." *PA Consulting Group honors North American* utilities for excellence in reliability at the 2015 ReliabilityOne™ awards ceremony, October 23, 2015. http://www.paconsulting.com/introducing-pas-media-site/releases/pa-consulting-group-honours-north-american-utilities-for-reliability-excellence-at-2015-reliabilityone-awards-23-october-2015/

The Company's (non-network) electric overhead distribution system includes 168 autoloops; 219 unit substations; 13 multibank substations; approximately 198,400 poles; 50,800 overhead transformers; and approximately 34,200 miles of overhead wire including primary, secondary and service wire. The non-network system uses a first contingency design, meaning it is designed to sustain the loss of one feeder under peak load conditions without any feeder or transformer overloads or adverse impact on service to customers.

Con Edison's electric system design, particularly the larger network system, provides award-winning reliability and flexibility in addressing system needs. As the Company has learned with its growing experience with DER as well as analysis using its load flow models, the network system requires special consideration when integrating DERs as compared to non-network systems. For instance, the high load density and network design can absorb Distributed Generation (DG) interconnection more readily than non-network systems by spreading the power in multiple directions, but the efficacy of the relief provided by such DER is lessened for these same reasons. Thus, providing load relief at the distribution level is more challenging in network systems. As a result, depending on the load relief need and location, for an equivalent solution to be provided by DER on a network system, multiples of the need is required in nameplate DER (which is not the case for non-network systems). This raises the cost of the portfolio of DER solutions to meet load relief needs.

C. Con Edison's Experience with DER, REV, and Stakeholder Collaboration

Con Edison recognizes the value of DER through its experience with Energy Efficiency (EE) and Demand Response (DR) programs, solar projects, Combined Heat and Power (CHP), and the BQDM program. The BQDM program is the Company's biggest effort to date to meet an area's growing demand for energy through EE, DER, and DR instead of traditional infrastructure builds. The Company's experience with demonstration projects will also help provide more experience with innovative new energy technologies and customer strategies.

Con Edison is leveraging its expertise, collaboration with the JU, and stakeholder engagement sessions it has conducted to gain valuable insights and input of other parties. The collaboration with the JU will be critical to establishing shared operating tools and functionality for 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 algorithms, processes, and tools will be instrumental to defining the DSP.

The Company also proactively held a Stakeholder Kickoff with the Joint Utilities on February 29, 2016 and a Stakeholder Summit jointly with Orange and Rockland Utilities (O&R) on May 13, 2016, that covered the Initial DSIP content and solicited feedback on customer and system data sharing. The all-day sessions hosted 70 and 34 outside parties, respectively, and both were favorably rated by 90 percent of survey respondents. These have helped Con Edison engage with the stakeholders and have assisted in developing an understanding of key issues both from the utility and the stakeholder perspective. The February session was focused on the complexities of the Company's electric system

and the May session followed up by focusing on the DSIP filing and customer and system data sharing. Please see **Appendix C** for more details.

Con Edison is committed to engaging customers and providing them with more information and opportunities to control their energy usage. Through foundational investments like AMI, Green Button Connect (GBC), and the Digital Customer Experience (DCX), the Company will provide customers more granular and timely 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 potentially help generate more innovative solutions to improve the environment, increase the efficiency of the grid, and reduce the customer's costs.

Cybersecurity continues to be a top priority, and is all the more important with greater amounts of data and a dramatic increase in the number of devices connected to the system as well as the increasing automation of the distribution system. As the PSC stated in the Order Adopting DSIP Guidance, "The deployment of systems that support greater degrees of situational awareness and flexibility simultaneously, ironically offer the opportunity to make the 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 applying the latest tools and techniques to counter any emerging cybersecurity threats in order for both the safe and reliable operation of the distribution system and the protection of customer's Personally Identifiable Information (PII).

Con Edison has a steadfast commitment to delivering safe and reliable service. The Company believes it is important to proceed with integrating advanced technologies and testing new concepts in a way that maintains the high standards of delivery for customers. This is consistent with the Track One Order, which states, "The comprehensive, complex, and transformative nature of REV will require years of iterative planning and increasingly granular design determination."[10] In addition to the self-assessments conducted in the initial DSIP, the Company will outline near-term capability enhancements and discuss potential future needs as DER penetration increases. This document will also reference ongoing REV Demonstration projects and other programs and proceedings which will accelerate the Company's learning to maximize the value of the DSP.

D. DSIP Structure

The DSIP will define the Company's ongoing efforts to integrate DER. The DSIP is structured to be consistent with the now familiar format of the DSIP Order and the DSIP Guidance. This Initial DSIP is the result of a Company-wide collaboration. The Distribution System Planning chapter describes how the Company is evolving its planning processes to consider DER solutions. The Distribution Grid

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[9] REV Proceeding, Track One Order, p. 3.
[10] REV Proceeding, Track One Order, p. 120.

Operations chapter details how developing and adapting technologies will facilitate the integration of DER as a tool for operators. The Advanced Metering section outlines the Company's plans for AMI, and points to other forums where Company plans have or will be filed. The Customer Data chapter describes the current state of available customer data as well as the means and progress made for sharing information with authorized third parties. Finally, the DSP Information Technology (IT) System Roadmap will identify the anticipated functionality requirements of a DSP, an assessment of current Company systems, and gap analysis of near-term and long-term needs. Each chapter meets the specific requirements proposed in the DSIP Order. There are also several key appendices, which include the Benefit Cost Analysis (BCA) Handbook, a roadmap of systems to build a DSP, and other key tables and figures. Taken as a whole, this DSIP documents the efforts the Company has taken towards building the dynamic DSP that will continue to modernize the grid using the latest technological advancements, provide operational flexibility, and deliver customer excellence.

E. Distribution System Planning

The Company will address the current state of the forecasting and capital planning process, how DERs are integrated, and how the DSP will evolve to integrate greater amounts of DER. Con Edison already incorporates Demand Side Management (DSM) and other DER into its forecasting process and identifies locations where DER may help defer capital infrastructure investments (*e.g.,* BQDM). In addition to these capabilities, the Company will describe the processes it has developed to identify and display areas where DER would have more immediate delivery infrastructure avoidance value). In order to further its capabilities in incorporating DER, Con Edison will develop or enhance internal processes related to:

- Forecasting of DER
- Beneficial Locations for DER Deployment
- BCA Framework

Preliminary processes for each of these key DSP functions have been developed by internal working groups and through cross-Company collaboration between Con Edison and O&R.

1. Forecasting of DER

The forecasting of some types of DER, such as EE or DR, is a fairly mature process. In the fall of 2015, for the 2016 10-year peak load forecast, the projection of DG was refined to better account for the load reductions offered by these resources. DG included in the peak load forecasting process now include solar photovoltaic (PV), CHP and other large generators, and energy storage. The effect of DG on peak load reduction is assessed on the system as well as on a network by network basis. On a network-by-network basis, DG contribution to peak demand reduction can be measured using factors such as contingency design of the system, type of DG, coincidence with peak load, total number of DG(s) in the network, and the size(s) of the DG. The Company will continue to develop and improve the tools it has in order to produce forecasts well as incorporating and leveraging AMI data. Finally, DG also contributes energy reductions in the sales forecast.

The Company is providing forecasts of annual peak demand, historical peak day load shape, energy load forecasts at the system level, 8760 hour actual network load data and load shape at the network level. The Company's plan is to publish this information online for DER providers and other third parties through the Company's DG website, www.coned.com/dg.

Based on the forecast and review of current and future DER penetration, Con Edison has determined that it is likely the DSP will remain in the Stage 1 or Low Adoption portion of the S curve described in **Figure 1**. This means that the Company's approach should include smart grid investments that facilitate an increasing penetration of DER on the electric system. This curve also provides milestones that indicate when the DSP begin transitioning from stage 1 to stage 2 where more market level functions would begin developing. Based on current forecasts, these are likely to happen beyond the five-year scope of this DSIP. This forecast and understanding of the DER penetration stages has helped inform the DSIP strategy.

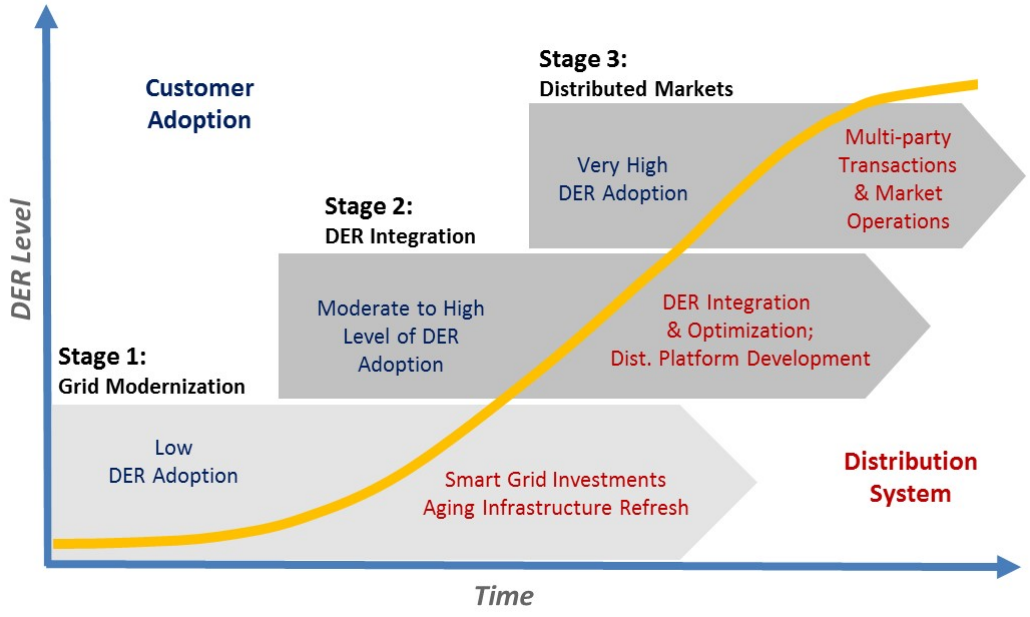

Figure 1 - DSP Functionality as Driven by DER Adoption[11]

2. Beneficial Locations for DER Deployment

As part of its integrated planning process, Con Edison already evaluates EE and DR in its capital planning. For example, Con Edison has focused on Tier 2 networks where it incents DR[12] during peak

[11] De Martini, Paul and Kristov, Lorenzo, Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight, Lawrence Berkeley National Laboratory, August 13, 2015.

hours or contingencies. More recently, the Company has evaluated DER as a solution to meet system expansion needs. Looking ahead, the Company will utilize suitability criteria to evaluate NWA alternatives that are candidates to replace traditional infrastructure needs and then compare the costs and benefits of the NWA solution to the traditional solution to select the best solution.

Additionally, providing methodology for determining hosting capacity and making that information available to third party DER providers are critical to direct capital investment to locations where the DER can most easily interconnect. The New York Standardized Interconnection Requirements (SIR) and the Electric Power Research Institute (EPRI) Gap Analysis[13] prepared in conjunction with the SIR serve as the starting point for the utility's assessment. The Company will begin publishing initial (*i.e.*, phase one) hosting capacity maps for the underground network at the time of this filing. The Company believes these are the first hosting capacity maps for an underground network system and the goal is to provide stakeholders with useful information and the opportunity to provide feedback on the maps early in the process. The JU-sponsored EPRI forum,[14] Supplemental DSIP process,[15] and the ongoing proceeding evaluating the Value of D[16] will inform the ultimate solution for determining and displaying hosting capacity.

Recent studies by economist Dr. Susan Tierney and EPRI to evaluate the value of DER in electric distribution systems (often referred to as LMP+D) help inform the Company's DSIP. The studies found that, in general, the value of D is relatively low in most areas of the electric distribution system. The studies point to areas where system expansion requires significant capital outlay as exceptions to this rule which matches the finding in BQDM and also directs the suitability criteria and capital plans. Additionally, it was found that the value of DER in a low voltage mesh network quickly lessens and dissipates as the distance from the DER to the point of need increases. This means that targeting DER at the feeder level or transformer level will be more challenging than targeting it at the Area Substation

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[12] Cases 07-E-0392 *et al*., *Tariff Amendments to Increase Participation in Rider U*, Memorandum Order (issued April 24, 2008). The PSC noted: "Staff also recommends using the Company's network reliability index as a basis for determining which networks would be eligible for Tier 2 participation. The network reliability index is used to determine the relative strength of each network by calculating the probability of failure of multiple associated feeders within a network over time as caused by individual component failures. The network reliability index is used to help the Company prioritize its conventional infrastructure investments." *Id*., pp. 7-8.

[13] Electric Power Research Institute (EPRI), *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, Final Report, Report Number 15-28 (EPRI Gap Analysis), September 2015.
[14] Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State. EPRI, Palo Alto, CA: 2016. 3002008848.
[15] REV Proceeding, Joint Utilities' Response to the PSC's Final DSIP Guidance Order (issued May 5, 2016).
[16] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources* (Value of D Proceeding), Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference (issued December 23, 2015).

level. Dr. Tierney's *The Value of "DER" to "D"*[17] and EPRI's *Time and Locational Value of DER*[18] included actual load flow modeling examples to see how DER can be used to meet system expansion needs. Their work highlights the challenges of resolving local constraints in low voltage meshed networks that are prominent across Con Edison's service territory. With that context, Con Edison's NWA proposals (including BQDM) focus mostly at the substation level where analysis indicates DER have the best ability to succeed. Nonetheless, the Company has also modified its feeder and transformer relief procedures to test NWA at this level and we propose an NWA candidate at the feeder level to continue exploring opportunities for NWA at more local levels.

3. BCA Handbook

Con Edison and its consultants, along with the JU, developed the initial BCA and have identified capital projects within the 10-year forecast to compare to NWA solutions. Projects will be identified for BCA and filtered through suitability criteria that are being developed through the JU stakeholder process. 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 and/or portfolios of DER solutions will be evaluated. The BCA Handbook must also consider the timeliness of solutions

The BCA handbook, included as **Appendix N**, will be further developed through the Value of DER proceeding.

4. Non-Wires Alternatives (NWA)

Con Edison has reviewed past capital investments and future capital forecasts and determined that, in general, NWA opportunities are most prevalent at the Area Substation level. In general, our analysis indicates that over 50 percent of the capital investment needed at the area substation may be appropriate for consideration. Con Edison was able to translate this area substation opportunity into NWA via the Brooklyn Queens Demand Management program (BQDM) described below. The Company is also looking to potentially expand this NWA opportunity to the Glendale project which would be a second phase to BQDM. In addition, Con Edison has also reviewed its feeder and transformer relief programs and while at this time analysis indicates there is less opportunity, in the near term, for NWA,

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[17] Tierney, Susan F., *The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability* (March 31, 2016). Dr. Tierney's white paper may be found in Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Comments of the Joint Utilities on an Interim Successor to Net Energy Metering (filed April 18, 2016)(JU Comments), Appendix B.

[18] Electric Power Research Institute, *Time and Local Value of DER: Methods and Applications*, Executive Summary for EPR Report 3002008410 (April 2016). This may be found in Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Comments of the Joint Utilities on an Interim Successor to Net Energy Metering (filed April 18, 2016)(JU Comments), Appendix C.

the Company has modified its feeder and transformer relief programs to offer some NWA opportunities in this arena also.

5. NWA: Brooklyn Queens Demand Management Program

Con Edison's BQDM project is an example of an NWA-related project already underway prior to the DSIP and REV filings and that will continue soliciting NWA solutions through 2018. BQDM uses a variety of solutions including NWAs and non-traditional utility solutions to address the area of greatest need for system expansion in three networks serving Brooklyn neighborhoods that have been exhibiting higher than normal growth rates. As the project evolves, it offers invaluable experience about how NWA solutions are helping to meet new and growing load needs. BQDM has already successfully secured 9MW of customer sided solutions (CSS) to meet summer 2016 needs and will continue adding CSS and utility sided solutions (USS) through 2018.

On December 12, 2014, the Commission approved the BQDM Plan.[19] The Company's forecasts indicated the sub-transmission infrastructure serving Brownsville area substations No. 1 and No. 2 will be 69 MW above the electric system's current capabilities to meet reliability requirements by 2018 over an extended 12 hour peak load day. Due to projected load growth in the networks, the capability shortfall increases to 107 MW by 2023. To meet this growth would have required construction of an area substation by 2017, sub-transmission feeders, and the expansion of a switching substation to provide adequate supply to the load area. Instead, the Company has planned a portfolio of 52 MW of non-traditional solutions, including 41 MW of customer-side solutions and 11 MW of non-traditional utility solutions, in addition to 17 MW of traditional utility solutions to enable the Company to defer building the substation to 2026. Construction costs for the land and equipment necessary to build the substation and sub-transmission feeders were estimated to be $1 billion. The most recent quarterly report filing in this program indicates the BQDM program has secured and contracted for 10.68 MW of load relief at the peak hour, using $23.9M of the $200 million budget.[20]

6. NWA Candidates under Review: Glendale and Others

Con Edison has identified several additional capital investment opportunities to review for NWA suitability and cost effectiveness. As part of this DSIP, Con Edison planners have begun reviewing these projects and will apply BCA tests to suitable projects. The candidates are:

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[19] Case 14-E-0302, *Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program* (BQDM Proceeding), Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).

[20] BQDM Proceeding, Q1 2016 BQDM Quarterly Report – Final (issued May 31, 2016), pp. 3-5.

Area Station Level Projects

- The Glendale Area Station project (Glendale): The traditional project installs a new transformer at the Glendale substation to facilitate a 60 MW load transfer (described in the distribution level projects below) and support the BQDM NWA. The Company believes there may be opportunity to defer the Glendale project beyond its 2019 date through NWA essentially making it an expansion of BQDM.
- West 65th St. No. 1: The traditional area substation projects involve either upgrading synchronous bus sections or installing cooling for both synchronous busses to provide greater capacity.

Distribution Level Projects

- Glendale Load Transfer Project (Glendale): This traditional project in support of the BQDM NWA involves the transfer of 60 MW of load from the overloaded Brooklyn network to a nearby Queens network with spare capacity. Along with the new transformer (described in the area station level projects above), the Company believes there is an opportunity to defer the Glendale load transfer beyond its 2019 date through NWA.
- Flushing Crossing Project: The traditional project addresses capacity constraints at six feeder crossings in the Flushing load pocket. The feeders cross multiple geographical obstructions, including the Grand Central Parkway and the Flushing River. Some of the crossing work is underway; therefore, the latter stages of the project are better candidates for NWA.
- Yorkville Crossing Project: The traditional solution is to utilize the full breaker capability of the station by bifurcating the feeder from the station to the load via a new duct system in order to decrease duct occupancy and increase the ratings of the feeders. As part of this plan, two new crossings must be created from the Bronx to Manhattan. Some of the crossing work is underway; therefore, the latter stages of the project are better candidates for NWA.
- Penn Network Feeder Relief: As a result of forecasted load growth due to the Hudson Yards Project, distribution feeders in the Penn Network will require additional reinforcement to maintain reliability to customers. This project will result in all Pennsylvania Network feeders operating within their capability and maintaining capacity for future load growth.

Distribution Programs

Feeder reinforcement projects in Columbus Circle, Williamsburg, and Hudson networks are proposed to meet anticipated feeder overloads. These projects will utilize newly modified procedure EO-2072 to expand the timeline for potential procurement of DER solutions.

7. Hosting Capacity

Con Edison and the other New York utilities have defined hosting capacity as the amount of DER that can be accommodated without adversely impacting power quality or reliability under current electric system configurations and without requiring infrastructure upgrades. Hosting capacity can be used to inform developers about favorable utility interconnection locations. Developing hosting

capacity algorithms requires a dual approach to accommodate both the network and non-network system designs. The Company will present the first view of hosting capacity in the larger network portion of the service territory in this DSIP. The hosting capacity for the non-network system, the design of which is common with the other JUs, will be further refined through technical conferences and presented as part of the Supplemental DSIP. The Company will continue to refine and expand upon the methodologies for hosting capacity and ultimately expects to tie the hosting capacity to the LMP+D efforts.

F. Distribution System Operations

1. DER Monitoring, Dispatch, and Control

Con Edison is committed to the continued safe and reliable operation of its system – a critical requirement for all customers. As the penetration of DER increases across the Company's service territory, the requirements, impacts, opportunities, and challenges generated by that DER will also grow. 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.

To that end, the Company believes it will be critically important to establish requirements for DER providers. These requirements would be consistent with DER contract obligations and interconnection requirements, and will be expanded, as necessary, to include maintenance and emergency outage protocols, real-time monitoring, and potentially control to maintain and manage. These evolving requirements should be developed jointly by all utilities, with input from stakeholders, and introduced within Case 15-M-1080, *Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products* or further explored through the Supplemental DSIP process.

Metering, particularly with the rollout of the AMI communications network, will provide system operators a link to information about the real-time performance of DER. In addition, there will be opportunities for added services through the ability to dispatch large scale DER on peak days, aggregate behind-the-meter DER to provide load reduction and facilitate NWAs, and/or the ability to provide Volt/VAR optimization (VVO) and other ancillary services when needed. Current and future REV Demonstration projects will inform further development of these opportunities and the business case surrounding them.

2. Physical and Cybersecurity

The Company recognizes that the increased flow of customer and system data will present cybersecurity risks that must be addressed. This need will only grow due to the increase in reliance on third-party DER, and the level of sensitive, complex, and critical information that will need to be communicated. The Company is committed to providing useful system and customer information while not exposing data that might increase risk and unintended consequences. Increasing risks must be met with thoughtful processes and responsive plans. In addition, the cyber secure backbone of the AMI communications network will facilitate more secure communications across the grid.

3. Interconnection Process

Con Edison is committed to enhancing the customer experience. As more customers use DER, their engagement with the Company will increase. The interconnection process is one of the ways that customers will first experience DER participation, so it is critical that this process be as customer-friendly and seamless as possible. Con Edison has been working to address areas identified by the EPRI Gap Analysis[21] for improvement through the New York State SIR process. In addition, the Company has created an interconnection application portal through www.coned.com/dg to further improve the customer experience.

4. DSP Structure

The Company established its Distributed Resource Integration (DRI) organization in July 2015 to more fully integrate and realize DER and REV opportunities today and build on its experience for the future. The DRI organization also brings the Company's policy, business, and technical experts together, allowing it to move forward rapidly on its energy future initiatives, which are aligned with REV. The organization is integrated across key planning, engineering, and operational functions as well as Customer Operations, Corporate Affairs (including Energy Policy and Regulatory Affairs), Accounting and Finance, and Law. The breadth of technical expertise and tighter coordination with utility planning and operations allow the Company to more effectively develop and implement DSP functions.

The DRI organization integrates the infrastructure planning, innovative technical options, energy efficiency, pilot programs, and strategic functions required to move towards the grid of the future. As shown in **Figure 2** below, the following organizations, which are responsible for various REV and REV-like initiatives, report to the Vice President DRI: Utility of the Future, Energy Efficiency, Distribution Planning (which includes the DSP Manager and the DG Ombudsman), Demonstration Projects, and the Project Management Office.

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[21] Electric Power Research Institute, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, Final Report, Report Number 15-28, Electric Power Research Institute, September 2015 (EPRI Gap Analysis).

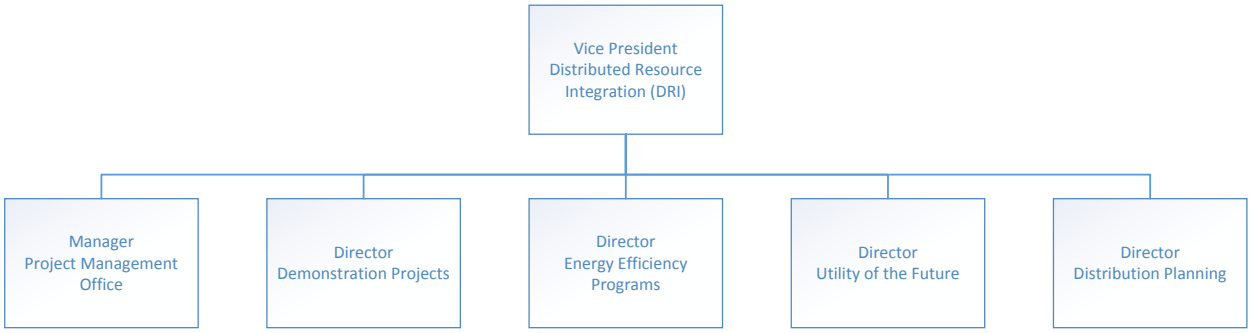

Figure 2- DRI Reporting Structure

The DSP itself will continue to mature as customer needs evolve and as learning from demonstration projects and other initiatives provide insight. The functionalities of the future DSP are currently being identified and developed through various demonstration projects, new planning processes, systems developments, NWA projects, evolving forecasting methodologies, and the existing EE/DR programs.

G. Advanced Metering

Con Edison has developed and filed a business case for the deployment of AMI and associated communications network. This plan was approved by the Commission on March 17, 2016,[22] and includes the rollout of approximately 3.6 million advanced electric meters. AMI will provide for two-way communication and the capability to monitor electric usage of all customers.[23] The robust communications network will allow for additional communications with specific DER components going forward and discussed in this plan. The Company is also developing a customer engagement plan addressing the conditions of approval to be filed on July 29, 2016.

H. Customer Data Sharing

Future business models and customer engagement with energy-related technologies will result in a growing need to provide data to help customers make informed decisions. These data-sharing requirements will raise privacy and cybersecurity concerns as noted above. Con Edison will continue to work through the DSIP and stakeholder engagement process to determine data sharing needs, including consideration of the value and appropriate means of sharing information.

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[22] 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*, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions (issued March 17, 2016) (AMI Order).

[23] Though it is expected to be a small percentage of the customer base, customers can opt-out of receiving an advanced meter.

The Company is committed to giving customers the information and tools to better manage energy use and lower bills. Con Edison's AMI initiative will provide customers with unprecedented access to their energy usage data so they can make more informed energy choices. Market participants can also benefit from customer data and engagement to identify cost-effective DER customer solutions to lower costs and increase reliability. Determining the level of data and granularity needed by market participants and customers will help determine customers' ability and willingness to engage in DER programs. The Company also needs to understand the costs associated with measuring, storing, managing, and communicating the data to customers and third parties as well as customer data security.

The Company's commitment to a better customer experience includes an enhancement of its digital services, called DCX, including the web, texting, e-mail, apps, and more. As part of DCX, the Company is developing GBC capabilities, which will allow customers to gain insight into their energy usage, and electronically authorize and automatically share data with third parties. In addition, the Company's REV Demonstration projects are testing customer engagement strategies, to gain insights into customer responses to energy usage information and their willingness to engage with third-party DER providers. The knowledge gained from DCX, coupled with AMI and REV Demonstration projects, will support on-going stakeholder engagement to determine what customer data is required and valuable.

As the Company refines customer data requirements and engagement, the security and privacy of customers and energy usage data becomes more important than ever. The Company is actively working to understand customer needs, through engagement, technical conferences, and surveys, while maintaining customer protections. In addition, the Company is also coordinating with the JU on a common cybersecurity and privacy framework that reflects best practices and is sufficiently robust to accommodate anticipated REV requirements.

As outlined in the JU Comments in response to the Technical Conferences Regarding Customer and Aggregated Energy Data Provision, "the success of REV depends on the ability and willingness of customers to engage in DER programs directly 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."[24] At the same time, the Company takes protection of customer information, including personal information provided by the customer and customer-specific usage data, very seriously. The Company does not and will not share customer information with other parties without customer consent, except where required by the PSC (such as with Sustainable Westchester as required by the PSC). The Company does not sell or otherwise share customer lists, and will not disclose customer-specific information to third parties that may want to market products or services to

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[24] REV Proceeding, Utility Comments in Response to November 3, 2015 Notice of Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues (filed January 13, 2016), p. 3.

customers. The Company may, however, work with third parties to engage customers in new ways, and may provide aggregated information with its own partners, taking care to specify how any customer-related date is to be handled consistent with regulatory requirements. Through the implementation of GBC and AMI, the Company expects to be able to securely and quickly provide granular usage data to authorized third parties.

As the Company refines customer data requirements and engagement, the security and privacy of customers and energy usage data becomes more important than ever. The Company is actively working to understand customer needs, through engagement, technical conferences, and surveys, while maintaining customer protections. AMI, DCX, and REV Demonstration projects all support customer privacy and data security protocols. In addition, the Company is also coordinating with the JU on a common cybersecurity 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.

I. DSP Technology Roadmap

In conjunction with the many changes required for Con Edison to develop as DSP Provider, a number of foundational technology investments are required. This plan is laid out in the DSP Technology Roadmap of this Initial DSIP. The DSP Technology Roadmap examines the Company's current IT and communications capabilities, the AMI and DCX initiatives, the near-term DSP functionalities required, the gaps in meeting those requirements, and how to close those gaps to achieve the DSP functionalities over the next five years. Broadly, these enhancements include tools to better analyze the impact of DER on forecasting as well as tools to integrate DER solutions and the BCA Handbook into the planning process. On the electric system, these needs include the infrastructure technology as well as architectural changes to coordinate the operation of DER with existing system assets to maintain safety and reliability. An example would be the advanced SCADA required to coordinate smart inverter operation with load tap changers and substation capacitors. The Company will rely on an advanced degree of distribution automation for maintaining safe and reliable operation in an environment of increasing DER penetration. The collection of additional system data will facilitate the Company's forecasting and planning processes as well as provide DER providers with information about locations where DER can provide the most benefit to the distribution system.

J. Related Ongoing Proceedings

1. Rate Case (Case 16-E-0060)

Con Edison filed an electric rate case requesting funding for elements to build the DSP. That proceeding is ongoing, and its outcome may impact the DSP, or specific projects and programs referenced in this document.

2. REV Demonstration Projects (Case 14-M-0101)

Demonstration projects allow the Company to gain insight into new concepts and business models. This will improve the integration of DER and test ideas and determine best practices. Con

Edison, in alignment with the REV Track One Order has begun three approved REV Demonstration projects, outlined below:

Connected Homes - In partnership with Opower, Inc., Enervee Corp., and Bridgevine, Inc., Connected Homes will engage customers through multiple channels to participate in DSM activities.

Building Efficiency Marketplace - In partnership with Retroficiency, Inc., the Marketplace will examine how interval meter data analytics help commercial customers take advantage of energy efficiency and demand response.

Clean Virtual Power Plant - In partnership with SunPower Corp. (Solar PV) and Sunverge Energy, LLC (battery storage), the project will examine how residential customers can participate as a DER and help increase resiliency and system capacity.

Energy Storage – A Request for Information (RFI) has been issued to test innovative business models for grid-scale energy storage and responses are currently under evaluation.

Future Demonstration Projects – The Company is in the process of soliciting more demonstration projects, and has developed a process to solicit innovative ideas with potential market partners. These projects will include developing innovative approaches to serving Low to Middle Income (LMI) customers, and the electrification of transportation.

The Company is committed to sharing lessons learned with the JU to inform the evolving DSP.

3. Community Choice Aggregation (Case 14-M-0224)

The Community Choice Aggregation proceeding will give customers more choice and control of their energy costs and is currently being piloted through a nonprofit organization, Sustainable Westchester. The proceeding will also inform the development of the DSP, as it will test an avenue for bringing DER choice directly to customers, and will require progress on cybersecurity and privacy issues related to the transmission of customer data.

4. Value of D (Case 15-E-0751)

The Value of D proceeding that was initiated at the end of 2015 is to determine how to more precisely value DER on a locational and temporal basis. This effort will inform compensation mechanisms for DER to move beyond net metering to a more refined LMP+D approach. This proceeding will develop through technical conferences and collaboratives to identify an interim approach to valuing DER for the Commission's review and decision by January 2017.

5. Large Scale Renewables/Clean Energy Standard (Case 15-E-0302)

The CES aims to achieve the goal of 50 percent renewable energy by 2030 and supports the development of new large-scale renewable generation in New York State. The effort also includes the development of a Renewable Energy Credit (REC) marketplace.

6. Track Two of the REV Proceeding (Case 14-M-0101)

The Track Two Order of the REV proceeding, issued on May 19, 2016, identifies a combination of rate making reforms to encourage a high level of penetration of DER while maintaining a sustainable business model for the utilities. The Track Two Order envisions the utilities receiving platform services revenues (PSR) for the operation or facilitation of markets for DER, as well as Earnings Adjustment Mechanisms (EAM) for achieving outcome-based results aligned with policy objectives.

7. Utility Code of Conduct (Case 15-M-0501) and Regulation and Oversight of DER Providers/Products (Case 15-M-0180)

The Utility Code of Conduct and Regulation and oversight of DER providers will outline the operating principles as the utility operators rely to a greater degree on DER in planning and operations. The DSP will be at the center of this relationship.

8. Management and Operations Audits of Con Edison and Orange and Rockland Utilities (Case 14-M-0001)

Consistent with the requirements of the DSIP Order and in response to a recommendation in this management audit, the Company developed a comprehensive and integrated electric distribution plan and incorporated it into this DSIP. This is discussed in greater detail in the Delivery Infrastructure and Capital Budget Plan Section and in **Appendix E**.

K. Evolution to a Transactive Energy Market

Con Edison is supporting early DER markets in several ways. The Company generally solicits DR resources and also pays a premium for DR in select networks where such resources are more needed by the Company. The Company also continues to promote Energy Efficiency programs, and is evolving those programs to more market based approaches, consistent with its Energy Efficiency Transition Implementation Plan (ETIP). Distributed solar generation continues to develop in Con Edison's territory, consistent with the Commission direction, and the Company is considering methods to evolve the business model and compensation mechanism for these resources, recognizing that current net metering methodology is not sustainable at higher levels of solar resource penetration. The Company, along with the other JUs, has partnered with three solar companies to form the Solar Progress Partnership. The partnership recently filed a proposal in the Value of D Proceeding discussed above to move from net metering to a LMP+D approach. Other forms of DG may receive credit through standby tariffs.

Con Edison is making foundational investments to move toward a more interactive and transaction based market for energy at the distribution/customer level. Such a transactive market will require significant monitoring and control of both utility and DER assets. The investments to facilitate such a market include AMI, distribution automation, DCX, GBC, and the supporting communications infrastructure. These are long-term endeavors that will bring value to customers as they are implemented by improving customer engagement and enhancing the reliability of the system.

III. Distribution System Planning

A. Introduction

Distribution system planning is a fundamental activity of the utility to provide reliable and cost-effective electric service to customers. As new technologies become available, the Distribution System Platform (DSP) will help integrate DER into the planning process and improve the grid's environmental footprint. The objective of the DSP is to integrate DERs as efficiently as possible, and in a manner that maintains or enhances grid reliability. This chapter addresses the current state of the forecasting and capital planning process, how DERs are integrated throughout, and how these processes will evolve to integrate greater amounts of DER.

The Company's distribution system planning efforts have always been centered on providing safe and reliable service to its customers. The results of these efforts are reflected in the electric reliability performance metrics,[25] where the Company has consistently been recognized for its high performance. The traditional solutions for distribution system needs have proven to be effective and efficient. As DER penetration levels increase, careful consideration needs to be given to the evaluation of solutions so as to not compromise safety, reliability, or cost of service to customers.

Con Edison has been at the forefront of integrated planning and has a mature forecasting process that includes DER consideration. DR and EE, in particular, have been forecasted as load modifiers for years. In addition, the Company has recently evolved the process by which it forecasts all forms of DG, including PV, CHP, and energy storage. The DERs 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 by a particular time. 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 rolls up these projects, among other categories of spending, into a yearly outlook.

By providing load relief in a specific locational area of need, at specific peak times, DERs offer an opportunity to defer some traditional investments, thereby realizing savings for both the utility and customers. Con Edison is demonstrating and testing this in the BQDM Program, a widely cited success story in which a substation and expansion project, totaling nearly $1B, are being deferred using a

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[25] Case 15-E-0179, *In the Matter of 2014 Electric Reliability Performance in New York State*, 2014 Electric Reliability Performance Report (filed June 22, 2015).

portfolio of customer-side solutions, and both non-traditional and traditional utility solutions (with a NWA cost of $200 million and an estimated total cost of $450M) from 2017 to 2026.

To build on the success to date of BQDM, Con Edison conducted a review of load relief projects across the system to identify where else DER can meet system needs. The tool to be used to determine cost effectiveness of solutions, both traditional and non-wire alternatives is the Benefit Cost Analysis (BCA) handbook, which uses a Societal Cost Test (SCT). To further direct DER deployment, the Company will provide an update on efforts to release a hosting capacity map, showing the areas where DERs should be able to interconnect under existing control configurations and without requiring infrastructure upgrades.

In total these efforts represent the Company's support of DER in every aspect of distribution system planning, from forecasting to implementing DER solutions as substitutes for traditional solutions, in a manner that maintains the safety and reliability of the grid. It is expected these processes will continue to evolve with greater DER penetration.

B. Forecast of Demand and Energy Growth

1. Forecast Methodologies

a) Long-Term Electric Peak Demand Forecast

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 temperature variable (TV)[26] design condition of 86°F. The method used to develop the weather adjusted peak (WAP) demand is regression analysis. An example of the regression used to determine the WAP demand can be found below.

[26] TV factor used for Service Area analysis is calculated as the average of the highest three-hour temperature (dry-bulb) and humidity (wet-bulb) readings each day, as registered at the National Weather Service stations at Central Park and LaGuardia Airport. Data for the two stations is averaged. The Maximum effective Wet-Dry Bulb temperature is the average of the three consecutive Wet/Dry hourly temperatures occurring between the hours of 9 AM and 9 PM yielding the highest Wet/Dry Average. Because heat buildup over a hot spell of a few days' duration significantly increases air conditioning use and stress on Con Edison'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. Fridays, weekends, and holidays are excluded from the TV calculation.

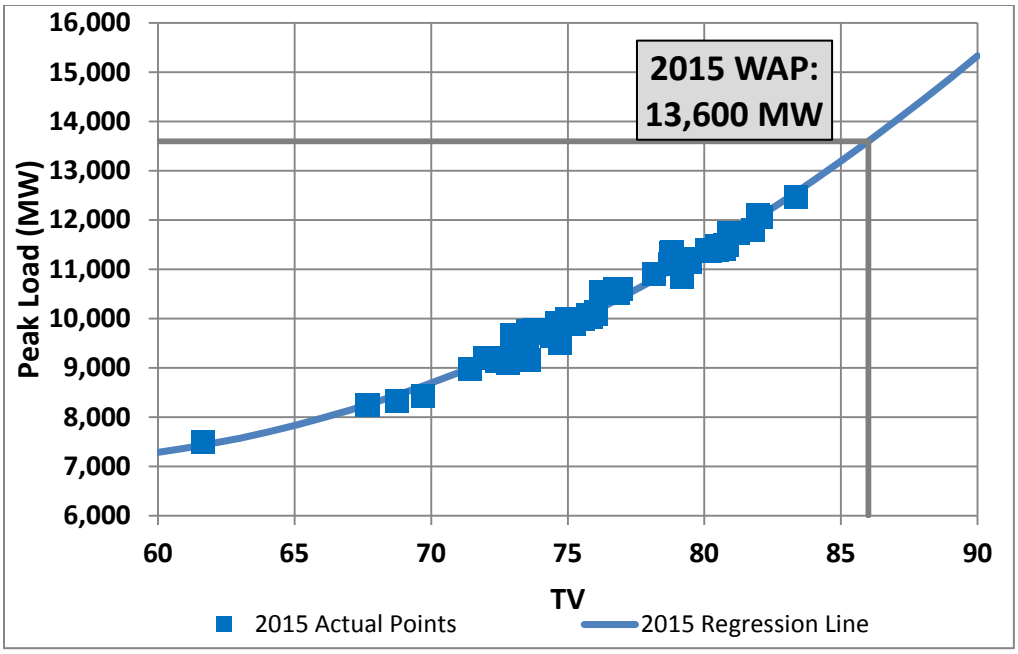


Figure 3 - Regression Analysis to Determine WAP Demand

The electric peak demand forecast is produced by adding incremental demand growth measured in Megawatts (MW) of key customer sectors: residential, commercial, and governmental. Along with sector demand growth, non-sector specific technology driven load growth is added. Residential and commercial sector demand growth is determined using top-down econometric models. The residential top-down econometric model considers number of households, saturation of air conditioning (A/C), household occupancy, and hourly use per unit of A/C to determine sector growth. The commercial top-down econometric model considers the number of customers by service classification, the price of electricity, and other macroeconomic measures to determine sector demand growth. Governmental sector demand growth is calculated by summing demand for new projects. Non-sector specific technology driven load growth includes growth from technology shifts, such as electric vehicles or conversions from steam to electric air-conditioning.

There are various DER measures that offset demand, such as EE, DR, DG, PV, and targeted load relief programs, collectively referred to as load modifiers. The Company has pursued self-directed and Energy Efficiency programs for years to reduce load, and has developed methodologies to measure and forecast the associated load modifiers. In a REV environment, it is expected that DER penetration will increase and that DER-specific forecasting methodologies will be evaluated and refined. The assumptions underlying each of these categories will be explained in further detail in the Available Resource Section.

The long-term Con Edison 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 Company work-plans to be developed prior to the start of the next summer season each year.

Figures 4 and 5 below conceptually show the process to produce a system peak forecast

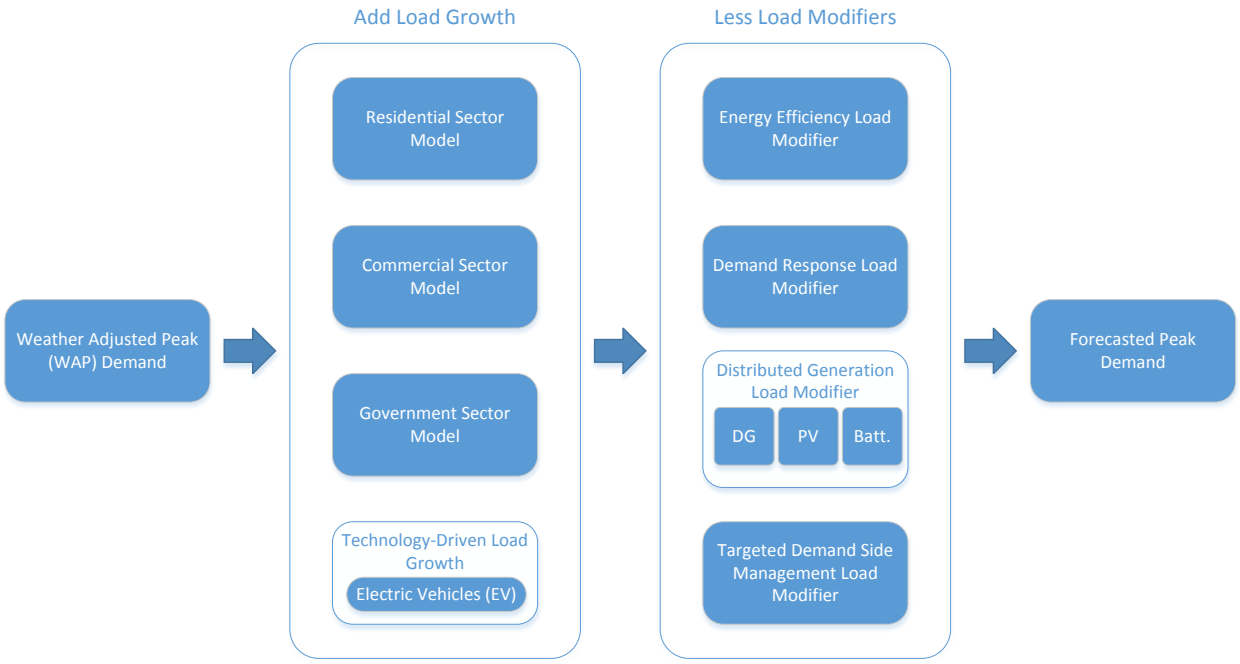


Figure 4 - Forecasting Process

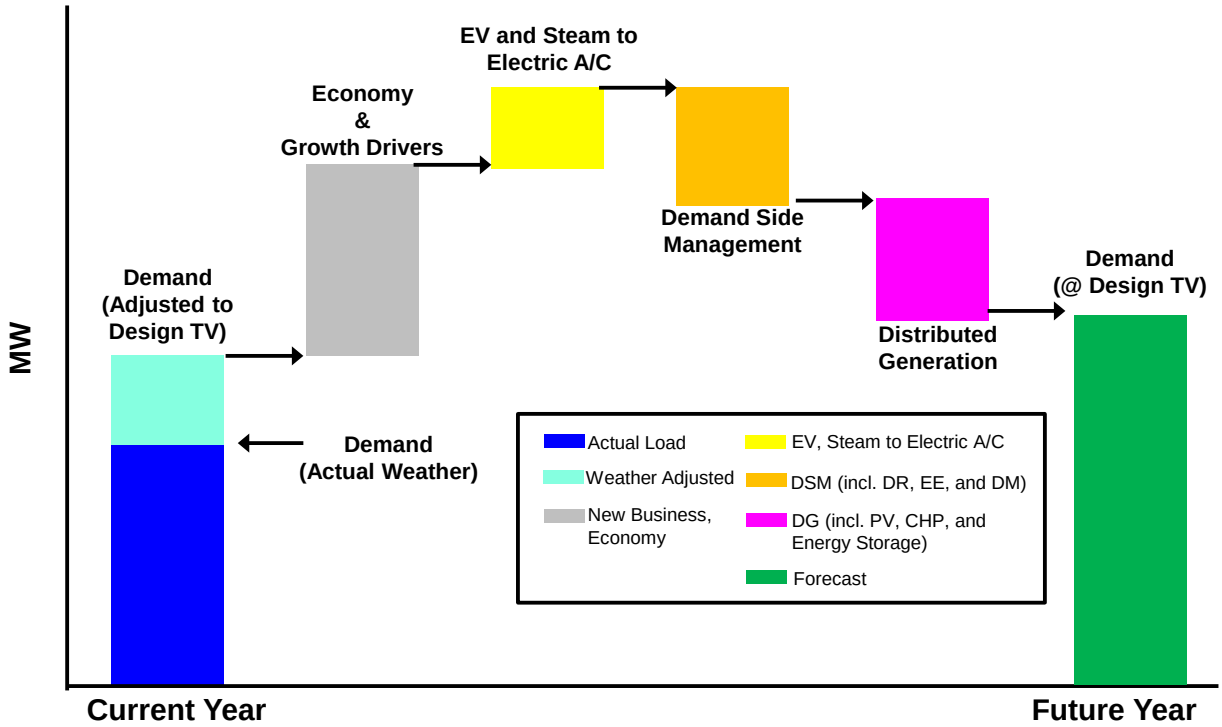


Figure 5 - Illustrative Process of Adjusting Forecasting (not to scale)

b) Five-Year System Coincident Peak Demand Forecast

Based on the above described forecast methodology, the five-year system coincident peak demand forecast presented in **Table 1** below, and the ten-year system coincident peak demand forecast is presented graphically in **Figure 6**. This forecast was published in October 2015. Included are detailed notes on each line item presented below:

2016 - Electric System Peak Demand Forecast (in Megawatts)

		2015	2016	2017	2018	2019	2020
1	**Updated System Forecast**	**13,600**	**13,781**	**13,942**	**14,048**	**14,124**	**14,164**
2	MW Growth:		181	161	106	76	40
3	% Growth:		1.30%	1.20%	0.80%	0.50%	0.30%
4	**Additional MW Growth (Incremental Rolling)**						
5	Electric Vehicles (EVs)		1	5	6	6	7
6	Steam A/C Conversion		11	22	33	43	54
7	**Load Modifiers (Incremental Rolling)**						
8	Photovoltaics/Solar (PVs)		-8	-29	-40	-51	-60
9	Distributed Generation (DG)		-22	-48	-85	-90	-91
10	Energy Storage		-2	-3	-3	-4	-4
11	**Coincident DSM (Incremental)**						
12	Con Edison EE		-22	-15	-19	-25	-25
13	NYSERDA EE		-5	-7	-8	-7	-7
14	NYPA		-7	-5	-5	-1	-1
15	BQDM		-6	-24	-6	13[27]	0
16	DMP		-36	-68	0	0	0
17	Demand Response		-32	-9	-8	-3	-3
18	Total Incremental DSM:		-109	-126	-46	-24	-36
19	Rolling Incremental DSM:		-109	-235	-281	-305	-341
20	**System Forecast less DSM, less DG, PVs and Batteries + EVs + Steam A/C**		**13,652**	**13,653**	**13,677**	**13,724**	**13,729**
21	MW Growth:		52	1	24	47	5
22	**Rounded System Forecast less DSM, less DR and PVs + EVs + Steam A/C**		**13,650**	**13,655**	**13,675**	**13,725**	**13,730**
23	MW Growth (Rounded):		50	5	20	50	5
24	% Growth:		*0.37%*	*0.04%*	*0.15%*	*0.37%*	*0.04%*

[27] The positive load modifier for BQDM in 2019 is the result of no longer contracting and calling upon certain non-permanent DER resources, as was done for years (2016-2018) of the BQDM program.

25	Note: 2015 Demand is Weather-Adjusted	

Table 1 - Electric System Peak Demand Forecast (in Megawatts)

System forecast line item descriptions:

Line 1: Updated System Forecast: The weather adjusted peak (WAP)

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

Line 3: Percentage Growth: Growth as a percentage of the base

Line 5: Electric Vehicles (EVs) – The incremental load growth associated with Electric Vehicle charging

Line 6: Steam A/C Conversion – The incremental load growth associated with customers converting steam chillers to electric air-conditioning

Line 8: Photovoltaics/Solar (PVs) – The cumulative effect of the solar units (PV) coincident with peak hour demand (see the Available Resources section of this DSIP for an in depth explanation of how the PV peak coincidence is determined)

Line 9: Distributed Generation (DG) – The peak load reduction associated with non-solar generators (*e.g.*, Combined Heat and Power (CHP), gas turbines, *etc.*)

Line 10: Energy Storage – The peak load reduction associated with appropriately rated batteries

Line 11: Coincident DSM (Incremental): Category heading for the below seven lines

Line 12: Con Edison EE: Annual incremental forecasted system coincident demand reductions from Con Edison's energy efficiency programs

Line 13: NYSERDA EE: Annual incremental forecasted system coincident demand reductions from NYSERDA's energy efficiency programs

Line 14: NYPA: Annual incremental forecasted system coincident demand reductions from NYPA energy efficiency/demand management projects

Line 15: BQDM: Annual incremental forecasted system coincident demand reductions from the Brooklyn Queens Demand Management Program

Line 16: DMP: Annual incremental forecasted system coincident demand reductions from the Con Edison/NYSERDA Demand Management Program

Line 17: Demand Response: Annual incremental forecasted system coincident demand reductions from Con Edison's commercial and residential demand response programs. It does not include NYISO DR.

Line 18: TOTAL Demand Side Management (DSM) - Annual sum of peak reduction programs

Line 19: Rolling Incremental DSM – Total sum of new (*i.e.,* not baked into the previous year's WAP) peak reduction programs, including the previous year's

Line 20: System Forecast less DSM, less DG, PVs and Batteries + EVs + Steam A/C – System forecast including all incremental growth and load modifiers

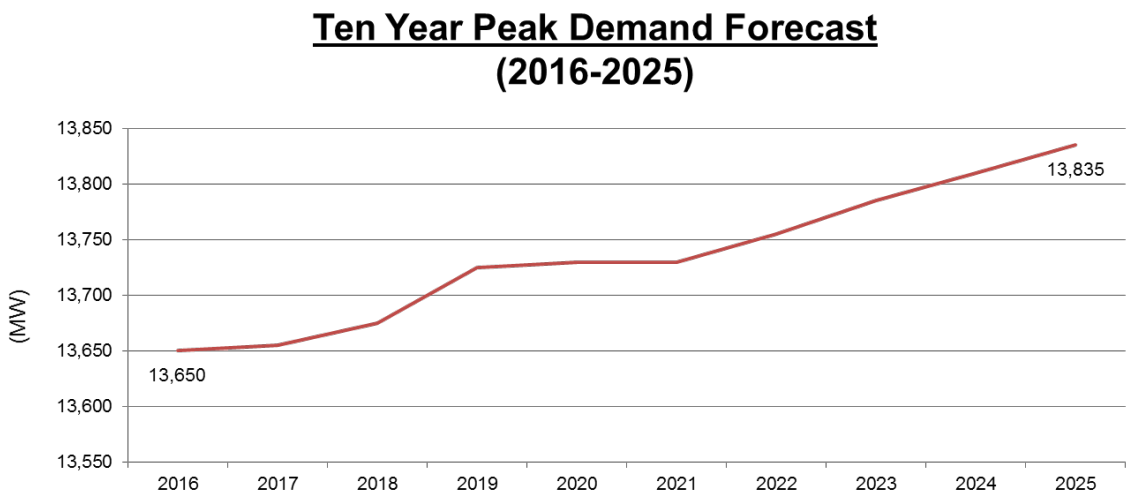
Line 21: MW Growth – Net growth; sector growth plus technology driven growth less DER load modifiers

Line 22: Rounded System Forecast less DSM, less DR and PVs + EVs + Steam A/C – System Forecast rounded to the nearest 5 MW

Line 23: MW Growth (Rounded): Net growth rounded to the nearest 5MW; sector growth plus technology driven growth less DER load modifiers

Line 24: Percentage Growth – Rounded MW Growth as a percentage of the rounded system forecast

Line 25: Note: 2015 Demand is Weather-Adjusted – see above description of the weather adjustment methodology and process.



CAGR:	
2016-2020 (5-Yr):	0.2%
2016-2025 (10-Yr):	0.2%

Figure 6 – Ten-Year System Coincident Peak Demand Forecast (2016 - 2025)

2. System Peak Day Load Shapes

Currently, Con Edison does not create and utilize electric system hourly load shape forecasts for the electric system peak day. The determination of the single electric system peak hour (system-wide and by network load area), generated by the Company's peak demand forecast methodology, sets the

design point for maintaining system reliability. Historically, an electric peak day hourly load shape forecast has not been included as a critical design and planning parameter because traditional assets offer fixed capability at all times. Given the dynamic nature of different types of DERs, the potential need for an electric peak day hourly load shape forecast will be determined as DER penetration increases.

Tracking the electric peak day hourly load shape over time will allow the Company to be vigilant of load shape related issues (*e.g.*, peak hour shifts, snap back, or the duck curve[28] seen in the California service territories). While certain DER solutions may reduce the system or network peak demand, overall system utilization may decline if energy reductions at off-peak times exceed the contribution to peak demand reduction. As part of the self-assessment requested in the DSIP guidance, the Company evaluated its DER forecast as well as prior year actual system and network load curves to determine if DER penetration levels necessitate the development of electric peak day hourly load shape forecasting capabilities. Photovoltaic generation is of particular concern as a contributor to a duck curve electric system peak day hourly load shape as the energy generation from solar wanes at the onset of the late afternoon/early evening system peak. The factors considered in the peak load evaluation were the load shapes of DER types (DR, PV, and DG), the absolute scale of DER penetration as a percentage of electric peak load, and it was judged that the impacts of a potential peak hour load shift were insignificant in the near term. As such, at the present, the Company believes the actual electric system and network load curves and DER forecasts are adequate for system planning and operations without an electric 8760 hourly load shape forecast. The Company will revisit this potential concern as the DSIP evolves.

[28] Duck curve refers to the graphic interpretation of the load shape when solar and wind generation is subtracted from load on an average day and its similarity to a sitting duck. Tweed, Katherine, *California's Fowl Problem: 10 Ways to Address the Renewable Duck Curve,* GreenTech Media, May 14, 2014.

For reference, the system load shape for the all-time system peak day of 2013 is included in **Figure 7** below:

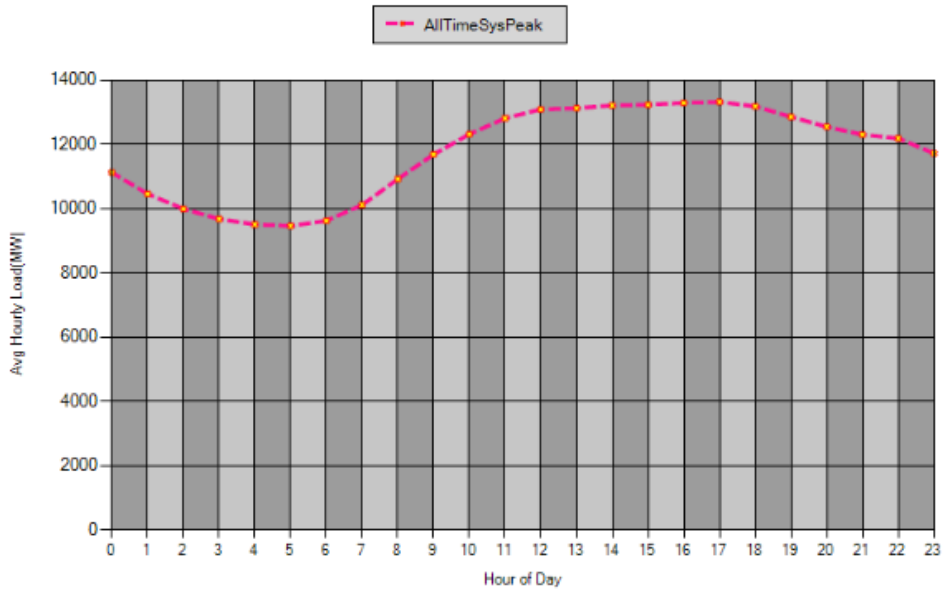


Figure 7 - Load Shape for All Time System Peak Day

3. Energy Forecast

The five-year system energy forecast, by service class, is found below as presented in the Company's 2016 Electric Rate Case.[29]

[29] Case 16-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, 09 - EIOP Exhibits (EIOP-01) – (EIOP-14) (filed January 29, 2016).

Electric Volume Forecast (GWh)		2016	2017	2018	2019	2020
Con Edison Service Classes	SC 1 - Residential	14,140	14,297	14,561	14,718	14,824
	SC 2 - Small Commercial	2,299	2,295	2,321	2,337	2,355
	SC 5 - Rail Road Platform & Stations Lighting	117	117	117	117	117
	SC 6 - NYC Private Street Lighting	9	9	9	9	9
	SC 8 - Master Metered Apartments	1,923	1,951	1,990	2,009	2,035
	SC 9 - Large Commercial	27,092	26,719	26,821	26,810	26,764
	SC 12 - Multiple Dwelling Space Heating	350	343	336	331	327
	Standby	224	226	226	256	280
Con Ed	**Total**	**46,154**	**45,957**	**46,381**	**46,587**	**46,711**
NYPA Service Classes	SC 62 - General Small	18	19	19	19	20
	SC 66 - Westchester Street Lighting	46	45	44	44	44
	SC 80 - NYC Street Lighting	187	178	174	174	174
	SC 91 – NYC Public Buildings	9,305	9,236	9,209	9,183	9,133
	KIAC	366	364	365	364	364
NYPA	**Total**	**9,922**	**9,842**	**9,811**	**9,784**	**9,735**
System	**Total**	**56,076**	**55,799**	**56,192**	**56,371**	**56,446**

Table 2 - Five Year System Energy Forecast

The delivery volume forecast is used to determine the revenue forecast. The send-out forecast is used by the Con Edison Energy Supply Panel to develop an energy supply cost forecast.

The electric delivery volume forecasts are based on various methodologies. The forecasts of delivery volumes for major service classifications (SCs) are based on econometric models, which will be discussed below. The forecasts of delivery volumes for the other SCs are performed on a deterministic or individual service class basis described further below.

Econometric models were used to forecast electric delivery volumes for SC 1 (Residential), SC 2 (Small Commercial), SC 5 (Rail Road Platform and Stations Lightings), SC 6 (New York City Private Street Lighting), SC 8 (Master Metered Apartments), SC 9 (Large Commercial), and SC 12 (Multiple Dwelling Space Heating). NYPA Service Classes are also included in the energy forecast by service class: SC 62 (General Small); SC 66 (Westchester Street Lighting); SC 80 (New York City Street Lighting); SC 91 (NYC Public Buildings); and KIAC (Kennedy International Airport Cogeneration). The modeling periods, the independent variables, and the model structure are described below.

- Modeling Period
  - The SC 12 econometric model is developed on a monthly basis, using data from October 1990 through September 2015. The other econometric models are developed on a

quarterly basis, using data from the fourth quarter of 1990 through the third quarter of 2015.

- Independent Variables
  - Three types of independent variables are employed – weather, dummy, and economic.
    - Weather variables, in terms of heating and cooling degree days, are included in all models to account for delivery variations due to differences in weather conditions.
    - Dummy variables are included in the SC 2, SC 9, and SC 12 models to account for structural breaks in the data. While dummy variables were used to address structural breaks, no large impact events have occurred since the Company's testimony in the 2013 Electric Rate Case[30] that needed to be included in the models.
    - Key economic variables included in the various models are as follows:
      - The SC 2 and SC 9 models include the number of customers in the class, real electric price of the class, and private non-manufacturing employment. In this and all future references to the private non-manufacturing employment variable, the reference is to the series that has not been seasonally adjusted.
      - The SC 1 model includes the real electric price of the class and real disposable income.
      - The SC 8 model includes the real electric price of the class.
      - The SC 12 model includes the number of customers in the class.

Model Structure

Each of the econometric models consists of two parts: the first part is a regression model, which correlates the delivery volume with the set of independent variables selected into the model; the second part is an autoregressive integrated moving average (ARIMA) model. The combined model is often referred to as an ARIMAX model in modeling literature, where the letter X stands for the set of independent variables included in the model. The ARIMA model can take many different forms, and each model has its own ARIMA structure, statistically determined according to the data pattern of each SC. Additionally, for two small service classifications (SC 5 -- Rail Road Platform and Stations Lightings and SC 6 -- New York City Private Street Lighting), the forecasts were done on a deterministic basis, because delivery volumes have not changed significantly. The delivery volume forecasts for the three groups of customers, who are on special rates under the Business Incentive Rate (BIR), Recharge New

[30] Case 13-E-0030, *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*, Forecasting Panel Testimony (filed January 25, 2013).

York (RNY), and Standby Service programs, are not based on econometric models. The forecast of delivery volumes for commercial customers receiving the Company's BIR under Rider J are done on a deterministic basis. The RNY forecast for the portion (below-the-allocation) that is exempt from the System Benefits Charge (SBC) and Renewable Portfolio Standard (RPS) charge was based on historical data. The Standby Service forecast was performed on an individual customer basis for the 56 existing and four projected new Standby Service customers.

The NYPA volumes were also developed by using econometric models on a deterministic basis.

For SC 66 (Westchester Street Lighting), and SC 80 (New York City Street Lighting), the forecast of delivery volume is performed on a deterministic basis based on recent billing data. The forecasts of delivery volume for large scale developments are based on data provided by Energy Services.

Econometric Models were used to forecast the power supplied by KIAC to JFK Airport, and the forecasts of delivery volumes for all other NYPA service classes.

The delivery volume forecast for Con Edison customers includes the following adjustments:

- Solar generation – to account for the projected delivery volumes associated with the installation of solar panels by customers who will then generate a portion or all of their energy requirements. See the Available Resources Section for more details.
- Standby service - to reflect the projected delivery volumes from customers who plan to convert a portion, or all, of their existing load to on-site generation and will become standby service customers. See Available Resources Section for more details.
- DSM Programs – to account for expected energy reductions resulting from energy efficiency and demand management programs. See Available Resources Section for more details.

4. Network Load Area Peak Demand Forecasts

Con Edison also prepares network load area level demand forecasts which roll up to the substation level. The network level is more granular than substation level; therefore, in some cases, Con Edison will present network forecasts in lieu of the requested substation level. The network-level forecasting process is similar to the system-level with some notable exceptions, such as using the project queue for sector load growth, keeping batteries as part of DG, and using independent network peak hours instead of the system's peak hour.

a) Network Independent Forecast Methodology

The Company also develops its long-term Network Independent Electric-Peak Demand forecast by using internally developed models. "Independent" is the key term in these forecasts, as the peak demand is determined for the peak hour of each network and typically differs from the system peak hour. Much like the system peak, each network's peak hour will inform infrastructure investment decisions. The load shapes of each network vary, and can peak at different times. Examples of

independent network load shapes will be discussed later in this section and can be seen in **Figures 9-11**. Determining the network peak demands is a useful point of information for DER providers, and will be provided in the pre-application report, as guided by the SIR. As with the system peak, Forecasting Services assesses the prior summer's actual daily peak demands and adjusts the overall season's peak demand for each network to a design condition based on a one-in-three probability of meeting or exceeding the design condition over 30 years. The method used to develop the WAP demand is regression analysis, performed on each network and radial area. See below for an example of regression output used to determine the WAP demand for a network representative of New York City.

Although the weather adjustment process is usually performed using the most recent actual demand experience in situations when there is an absence of data points across the TV spectrum and specifically at the top end of TV spectrum, additional years' experience may be looked at and pooled regressions may be looked into to narrow the range of estimated demand to the design criteria and determine the WAP value.

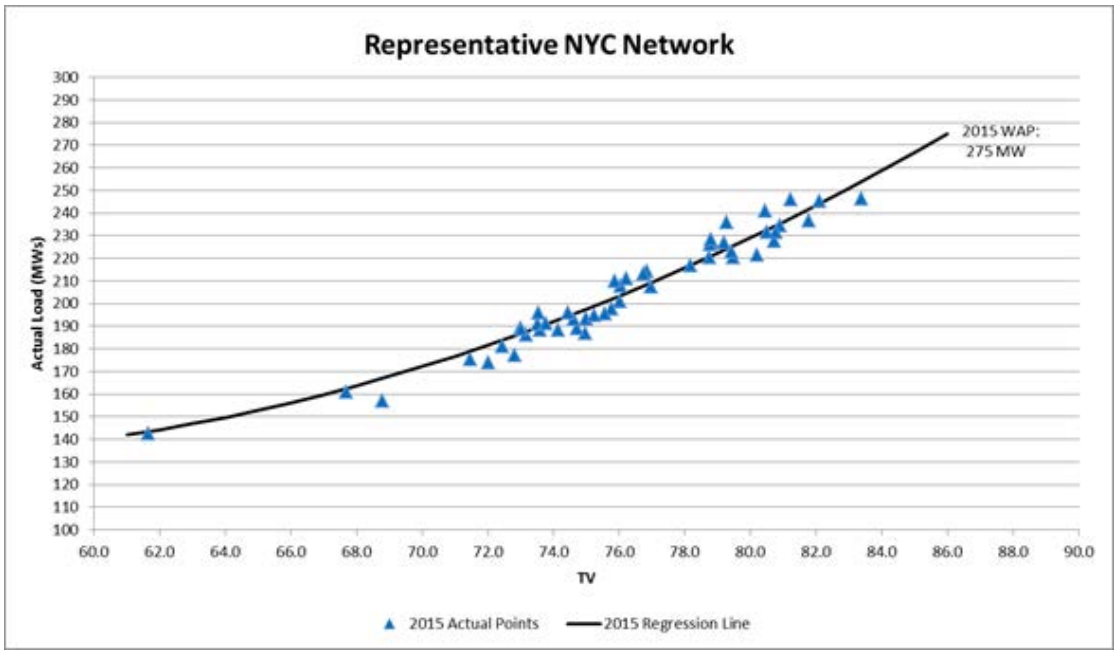


Figure 8 - Regression analysis to determine WAP for a representative NYC network

For the years that the Company has jobs in queue, a bottom-up approach is used. The bottom-up approach uses known information to forecast expected load. For the outer years that do not have jobs in the queue, the top-down strategy is used. A key distinction between the system and network forecast methodologies is that the network independent peak forecast utilizes both a top-down and bottom-up process for determining demand growth, while the system peak demand forecast uses a top-down approach for incremental demand growth. The bottom-up methodology is used in the network forecast because the macroeconomic factors used to determine the top-down growth cannot be finely parsed across the network and radial areas. The bottom-up process aggregates the net expected demand of new or expansion projects. Similar to the system demand forecast, the loads are modified to

account for other load growth (EV and Steam A/C to Electric A/C) and any applicable reductions for DER-related programs.

The long-term Network Load Area Independent Electric-Peak Demand Forecast (Network Independent Peak Forecast) is developed during the early fall to incorporate the most recent summer experience. The Network Independent Peak Forecast is developed in parallel with the System Forecast. However, the System Forecast is an input to the Network Peak Forecast and therefore the Network Peak Forecast cannot be finalized until the System Forecast is complete.

A representative sample of a Network Load Area Independent Electric Peak Demand Forecast is shown below in **Table 3**, with the respective lines explained below.

Representative NYC Network (MW)								
Line	Modifiers	2015	2016	2017	2018	2019	2020	2021
1	**Weather Adjusted Base**	275.00	280.00	286.00	292.00	297.00	299.00	299.00
2	MW Growth		5.00	6.00	6.00	5.00	2.00	0.00
3	% Growth		1.79%	2.10%	2.05%	1.68%	0.67%	0.00%
4	**Additional MW Growth (Incremental Rolling)**							
5	Electric Vehicles (EVs)		0.00	0.02	0.04	0.07	0.10	0.13
6	Steam A/C Conversion		0.00	0.00	0.00	0.00	0.00	0.00
7	**DER Load Modifiers (Incremental Rolling)**							
8	Photovoltaics/Solar (PV)		-0.01	-0.08	-0.14	-0.20	-0.26	-0.32
9	Distributed Generation (DG - incl. batteries)		0.00	0.00	0.00	0.00	0.00	0.00
11	**Independent DSM (Incremental Rolling)**							
12	Energy Efficiency (EE)		-0.23	-0.29	-0.55	-0.94	-1.33	-1.58
13	Demand Management Programs (DMP)		-0.10	-0.63	-0.63	-0.63	-0.63	-0.63
14	Demand Response (DR)		-3.70	-3.82	-3.92	-4.00	-4.07	-4.13
15	Total DSM:		-4.03	-4.74	-5.10	-5.57	-6.03	-6.34
16	**Network Forecast less DSM, less DG, PVs + EVs + Steam A/C**		276	281	287	291	293	292

Table 3 - Representative Network Forecast

Line	**Description**
1	2015 Value is the Weather Adjusted Peak (WAP), 2016-2021 is base network load based on all known construction projects
2	MW Growth – The incremental load growth of residential, commercial, and governmental sectors
3	Percentage Growth – Growth as a percentage of base
5	Electric Vehicles (EV) – The incremental load growth associated with Electric Vehicle charging
6	Steam A/C Conversion – The incremental load growth associated with customers converting steam chillers to electric air-conditioning
8	Photovoltaics/Solar (PV) – The peak load reduction associated with appropriately rated solar

	generation
9	Distributed Generation (DG) – The peak load reduction associated with non-solar generators and energy storage (*e.g.*, Combined Heat and Power (CHP), gas turbines, batteries, etc.)
12	Energy Efficiency (EE) – Network peak load reductions associated with Con Edison EE, NYSERDA EE, and NYPA EE programs
13	Demand Management Programs (DMP) – Network peak load reductions associated with DMP
14	Demand Response (DR) – Network peak load reductions associated with Con Edison DR programs. NYISO DR is not included
15	Total DSM – Annual sum of peak reduction programs
16	Network Forecast, less DSM, less DGs, less PVs, plus EVs, plus Steam A/C conversion – The network independent forecast modified for DER factors

5. Network Load Shapes

As previously noted, the Company believes the actual electric system and network load curves and DER forecasts are adequate for system planning and operations without an electric peak day hourly load shape forecast. The Company will revisit this potential concern as the DSIP evolves.

a) Historic Network Load Shapes

Con Edison develops historic load shapes for all networks and load areas in its service territory. The curves are based on actual historic load data and then normalized. The actual peak values are based on the forecasted peak for each network. Most network load shapes fall into three categories: (1) day peaking network; (2) afternoon peaking network; and (3) evening peaking network. Examples of all three based on representative networks are included below. While there is variety and diversity within each borough or county, the day peaking network shape is typical for commercial Manhattan networks. The afternoon peaking network shape is typical for most Westchester County and Staten Island load areas. The evening peaking network is typical for most Brooklyn, Queens, and the Bronx networks, as well as, some residential Manhattan networks and Westchester load areas.

An example early day peaking network is shown in **Figure 9** below:

Manhattan Network
Peak Hour: Hour Ending 1200 (12pm)

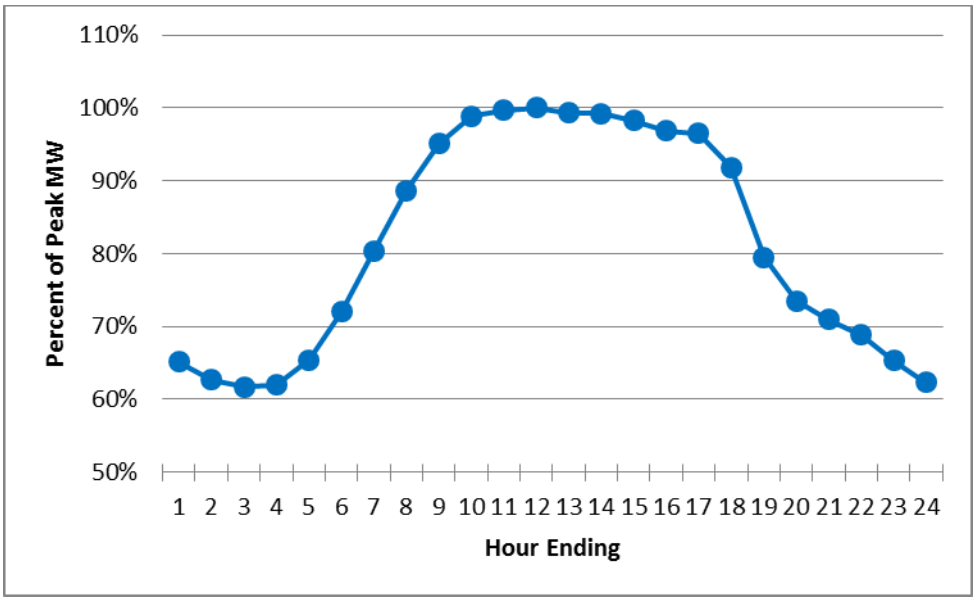


Figure 9 - Early Day Peaking Network Load Shape

An example afternoon peaking network is shown in **Figure 10** below:

Westchester Network
Peak Hour: Hour Ending 1700 (5pm)

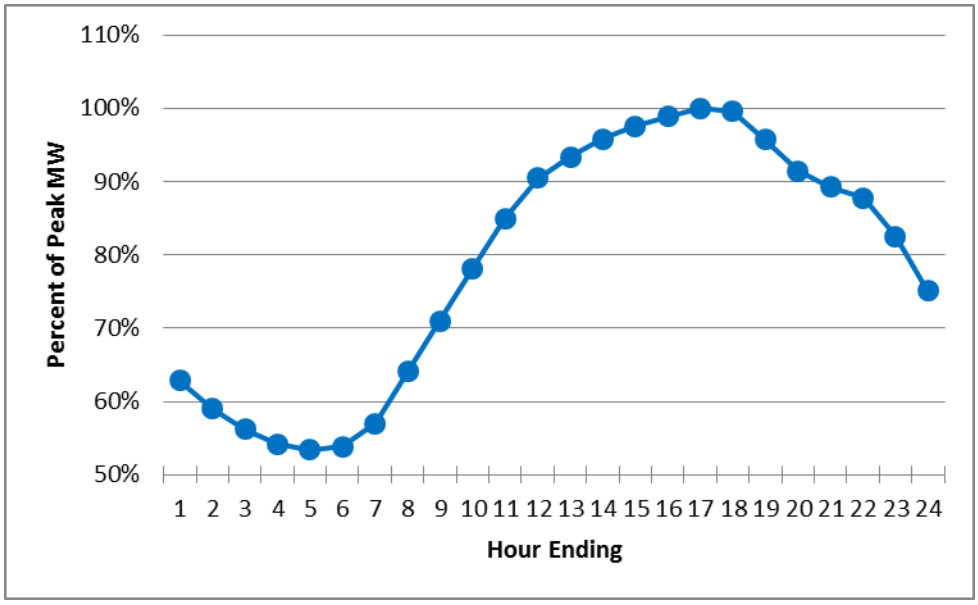


Figure 10 - Afternoon Peaking Network Load Shape

An example evening peaking network is shown in **Figure 11** below:

Queens Network
Peak Hour: Hour Ending 2200 (10pm)

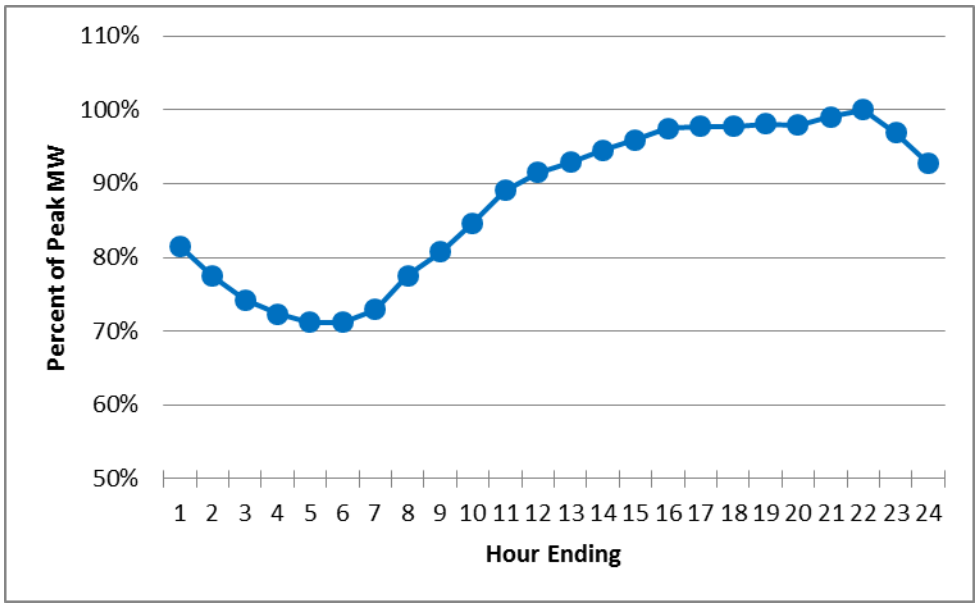


Figure 11 - Evening Peaking Network Load Shape

6. Network Forecast Data Sharing

a) Available Information

The Company has prepared forecasted 2016 network level 24-hour peak load duration curves and network level 24-hour minimum load duration curves based on 2015 historical loads. These curves have been plotted on a single graph along with a capacity curve that indicates the remaining capacity at the substation level, in the case where a substation feeds multiple networks; the capacity has been proportionally rated based on network peak values. Additionally each network load curve lists the five-year compound annual growth rate (CAGR).

The overall electric system load growth is forecasted to average 0.2 percent annually; load growth in many individual load areas is projected to be higher. The load growth in these areas is driven by the resurgence of certain residential neighborhoods, such as those in various parts of Brooklyn, and mixed-use neighborhoods, such as the Midtown West neighborhood in Manhattan. Contributing to the development of these mixed-use areas is the growth in the hospitality, tourism, health care, and technology sectors.

The system design varies by location and in some areas multiple networks or load areas may be fed by a single substation. A typical traditional solution to address load growth would be to transfer load to an adjoining network or substation, to be discussed further in the delivery infrastructure section, in order to maintain continuous reliable power to the customer. This solution may cause a noticeable change when reviewing historical load data, and should be considered when reviewing historical system data.

Given that the networks are geographically-specific, the data is naturally categorized geographically by borough. System data at a network and load area level is a more granular view and one level below the substation level. See **Figure 12** below for an example of this curve, which will be

posted on the Company's existing interconnection portal at www.coned.com/dg. The network peak is depicted by a solid orange line, the network minimum curve is depicted by a solid blue line, and the substation capacity is depicted by a dashed red line.

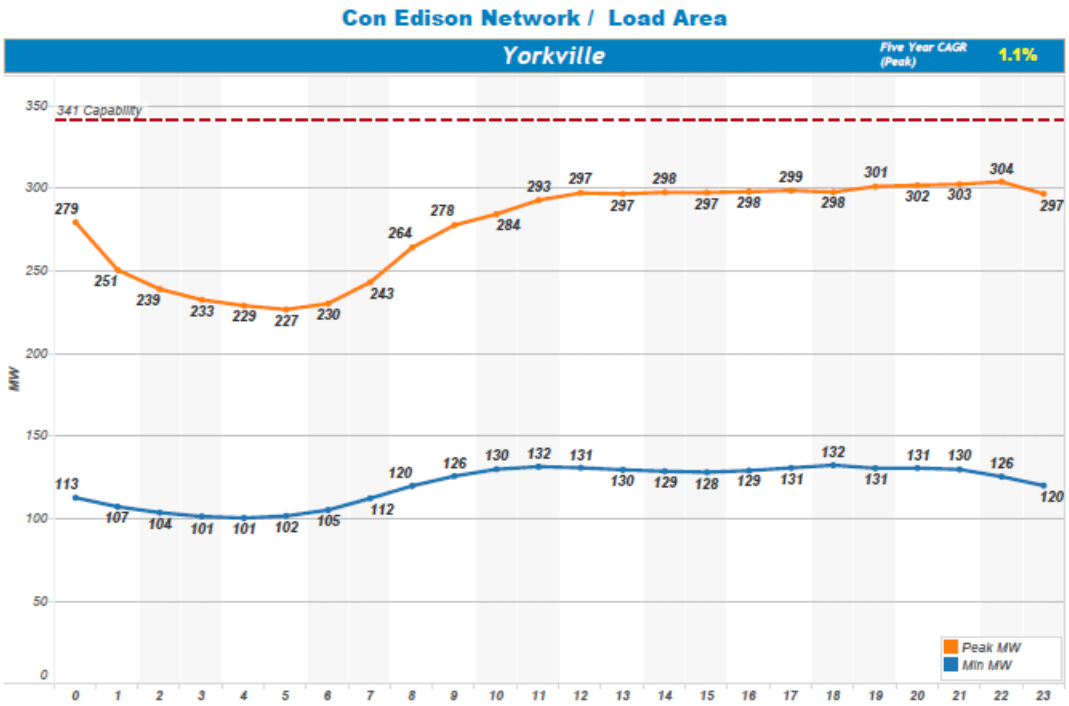


Figure 12- Example load curves provided through www.coned.com/dg

b) Data Access Plan

In describing how the Company is presenting granular system data, it is useful to begin the discussion with the different sources of system data.

(1) System Data

The Company utilizes an advanced SCADA[31] Energy Management System (EMS) to monitor and control both the electric transmission and distribution area substations. The current platform employed by the Company is based on industry-standards and distributed architecture. This system provides reliable system operability and situational awareness using the latest technology, user interfaces, and visualization tools to monitor load data, voltage, and power quality at the system, substation, and feeder level in real-time.

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[31] SCADA systems generally control dispersed assets using centralized data acquisition and supervisory control. K Stouffer, J. Falco, and K. Kent, *Guide to Supervisory Control and Data Acquisition (SCADA) and Industrial Control Systems Security*, Recommendations of the National Institute of Standards and Technology, NIST Special Publication 800-82, September, 2006, p. 1.

System data collected from the SCADA systems is archived and informs business processes for forecasting, load flow analysis models, and distribution planning. See **Figure 13** below showing the flow of data and control signals to and from EMS to various levels across the system.

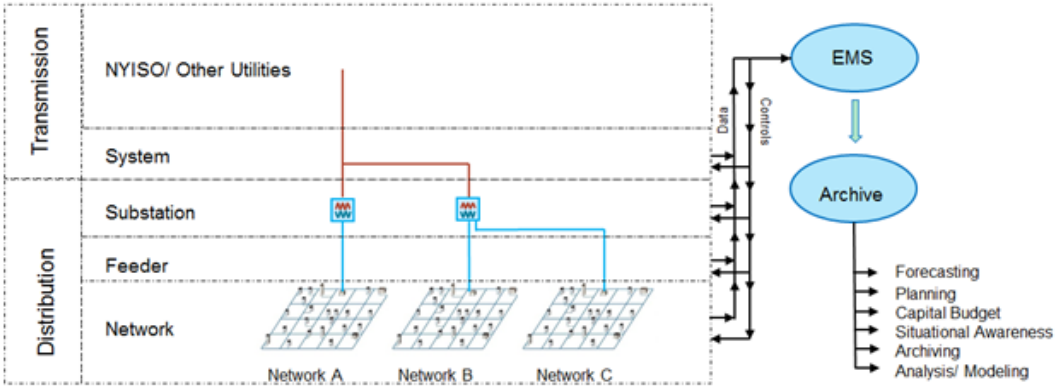

Figure 13 - Representative Data and Control Flows Through T&D System

(2) 8760 Load Curves

The Company is also making available the underlying historical 8760 hour load data for each network as part of this compliance filing and in response to the DSIP Order. The 8760 hour load data coincides with the all-time system peak upon which the forecast is based. The 8760 hour load curve data is a raw data export from a historical archiving system 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 networks as part of ongoing resiliency and reliability work, or due to system expansion. 8760 hour load data will also be organized by borough and be posted on the Company's existing interconnection portal at www.coned.com/dg.

As previously mentioned, the Company does not produce or use an 8760 hour load forecast, and the effort involved in producing such a forecast would require substantial utility resources. Additionally, there is no existing accepted or widely recognized methodology to develop an 8760 hour forecast. The Company is committed to further collaboration with stakeholders to determine what system data is basic versus value added, and to the extent that such an effort incurs costs that would not have otherwise been required, the appropriate fee structure for that data should be established. This topic will be further discussed as part of the Track Two proceeding and through the stakeholder engagement process initiated through the Supplemental DSIP.

As discussed in the Hosting Capacity section, the Company has made progress with an initial hosting capacity map which adds another layer of useful information to that already shared through existing DR programs. DER providers can geographically "see" where and when DER will add the most value and the system can handle any excess power transmitted back onto the grid with minimal or no additional cost to the customer to reinforce the grid. This is an example of the type of insightful information that is currently shared with the public through existing compliance filings and is currently available on the DPS website free of charge. Other ongoing proceedings will discuss Uniform Business

Practices,[32] fees for additional value added data and insightful information,[33] and additional locational benefit information[34] along with a robust stakeholder engagement and associated technical conferences to inform expansion of system data and insightful information. The supplemental DSIP filing[35] will introduce and expand on the establishment of standards and protocols for sharing information with customers and DER providers, while at the same time taking into account physical security, cyber security, and customer privacy issues.

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[32] Case 15-M-0180, *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products*, Notice of Technical Conference (issued April 21, 2015).
[33] REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (Issued May 19, 2016) (Track Two Order), p. 151.
[34] 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).
[35] The DSIP Order requires a Joint Utilities Supplemental DSIP. REV Proceeding, DSIP Order, p. 63.

7. DER Penetration Forecast Impacts

In the near term, the Company expects to maintain and refine the existing processes for determining the Weather Adjusted Peak (WAP), 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 forecasting process will credit DERs and will also forecast based on potential growth of DER. **Figure 14** below shows an analysis regarding when penetration levels in a utility's service territory would place it on the adoption curve for DER platform maturation.

The assessment identified that a DER penetration rate of five percent of the system peak demand is a key milestone on the adoption curve where utilities would transition from a low DER adoption/grid modernization stage to a moderate to high level of DER adoption/DER integration stage. The Company believes that higher penetration levels of DER are required to transition from a grid modernization stage to a DER integration stage. This is primarily due to the design of the underground distribution network system which can readily accept DER in highly loaded areas. The assessment shown in **Figure 14** was performed in areas that have predominantly radial, non-network electric distribution systems, and therefore DER has a greater impact to the system. The discussion on load relief in the Delivery Infrastructure and Capital Investment Plans section further defines the differences between DER impacts on a radial vs. network system.

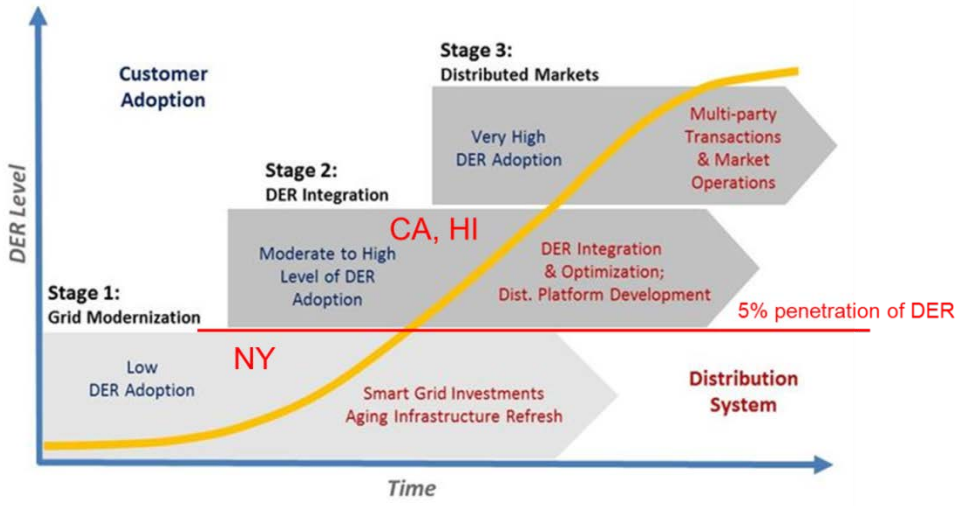

Figure 14 - DER Adoption and Distribution System Maturation[36]

[36] De Martini, Paul and Kristov, Lorenzo, *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight*, Lawrence Berkeley National Laboratory, August 13, 2015. The state designation and five percent penetration limit are Con Edison annotations.

As DER penetration increases and as the DERs contribute more cumulative load reduction, verifying DER performance will become more important to accurately forecasting demand. Monitoring existing DER is discussed in more depth in the System Operations Section. The Company will re-evaluate the forecasting process periodically to address any required changes driven by increased DER penetration or greater data availability.

DERs 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 Resources section, below. Briefly, EE and DR programs are the most mature, and no changes are expected in the forecasting process at this time. The assumptions for determining the load reducing credit applied to Non-solar Distributed Generation, such as CHP, have recently been modified. Additionally, PV and batteries were included for the first time for the electric system and network peak demand forecasts, issued in the fall of 2015 for the summer of 2016 and beyond. Electric Vehicles, historically calculated at the network level, are now forecasted at a system level as well. Targeted programs will be determined, as needed based on the results of BCA evaluations, and forecasted accordingly.

Forecasting DERs, owned and operated by third parties, inherently increases the complexity of the forecasting process and thus makes accurately forecasting demand more challenging. By design, there will be a time-lag in the forecasting process (to be discussed in greater detail in the Available Resources section), to verify DERs 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 processes 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 through a secure communications platform is required. Additional resources will be required as the volume of inbound DER data increases.

8. Electric Peak Demand Forecast Approach

As described previously, the electric system peak forecast generally utilizes a top-down methodology, with the exception of the Governmental sector for the first few years which is queue-based bottom-up. The top-down methodology prepares a holistic view of macro-economic conditions that influence electric demand and the bottom-up methodology focuses on known new business jobs and how they are phased into the load areas. The Company uses these two methodologies based on the availability of data.

The residential top-down econometric model considers the number of households, saturation of air conditioning, coincident use of air-conditioners, household occupancy, and hourly use per unit of an air-conditioner to determine sector growth. The commercial top-down econometric model considers the number of customers by service classification, the price of electricity, and other macroeconomic measures to determine sector demand growth. Meanwhile, the bottom-up load growth model is used for the governmental sector for years where data is available. This means that the Company aggregates announced projects for the initial years of the system forecast before it reverts to the top-down

approach. The combination of top-down and bottom-up works well for forecasting demand growth as it allows cross-referencing of the meter data and queued projects with the overall macro-economic trends. DERs are forecasted using primarily bottom-up methodologies by counting projects or program totals for both system and network forecasts. Energy Efficiency and Demand Response forecasts are based on program-level projections based on historic and expected future performance. On the system, Distributed Generation, including all solar, CHP, and energy storage are forecasted using cumulative historical penetration, known queued projects, and extrapolated future growth rates. The details and underlying assumptions regarding the forecasting of DER will be described in greater detail in the Available Resource section.

In addition to DER, load modifiers for Electric Vehicles and Steam to Electric Air Conditioning are forecasted using a bottom-up methodology. Electric Vehicle forecasting is based on current registrations and expected growth rates for both system and network forecasts. Similarly, incremental load growth from steam to electric air-conditioning is based on the aggregation of all customer conversions and is provided by the Steam Operations team. Other top-down predictions may be reviewed as an additional data point to gauge DER penetration, but cannot be relied on as verifiable load reduction by distribution planning and, as such, are not used in the forecasting process.

For the network load areas, the combination of bottom-up and top-down methodology for demand growth does provide a more accurate peak forecast, distributed across the networks. Networks are forecasted both for their independent peaks (Independent forecast) and for their coincidence with the system peak (Coincident network forecast). For the Independent forecast, the first five years are developed using a bottom-up approach where the Company has insight on upcoming jobs. Each individual job within the electric service territory is evaluated to determine the total load (and appropriate phasing-in), the network location, and when it will come online. In addition, the Company maintains a separate list for non-Energy Service jobs that are initiated outside the typical process. The forecast is produced by adding incremental demand growth of key sectors such as Residential, Commercial, and Governmental (NYPA). The compilation of the load growth is referred to as the bottom-Up Process because it is based on the aggregation of projects by network. For the outer years (beyond the fifth year), the top-down approach is applied. That is, the aggregated amount of the new job growth is compared to the system level growth to derive the total amount of miscellaneous growth that will be reconciled. The miscellaneous load is reconciled to the System load (which was developed using the top-down approach) by adding or subtracting the load at the individual network level. At this point the base load for the network forecast will be developed and will be added to the Weather Adjusted Peak (WAP) and load modifiers (DER, Steam to AC, EV, DMP) to develop the final network independent forecast.

The coincident network forecast, which uses the independent forecast as a starting point, evaluates the networks performance during the system peak hour. Therefore, the coincident network forecast must add up to the system forecast, minus any transmission losses. The annual coincident growth (or base load) is developed using the annual growth of each network (derived from the independent forecast), the total system growth minus transmission losses, and the ratio of the independent growth of each network to the sum of all independent growth. Once the base load for the

network coincident forecast is developed, it must be verified that the independent forecast is higher than the coincident forecast. Once verified, the base load will be added to the WAP and load modifiers to develop the final network coincident forecast.

9. Incorporating DER Provider Forecasts to Utility 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 both the coincident system forecast and the network load area independent forecasts. To close the feedback loop, the Company evaluates its prior year's forecast to evaluate the forecasting models and adjust accordingly. The Company is agreeable to reviewing 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 network 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. However, the Company reserves its right on whether to apply DER provider forecasts into its electric peak demand forecasts as the Company is ultimately responsible for the safe and reliable delivery of energy and is the provider of last resort, whereas DER providers are not.

C. Available DER

The proposed DPS Staff guidance requested, for each type of DER, how information is gathered to enhance forecasts of DER, how the DER contributes to peak demand, energy reduction and load shaping, and how the utility incorporates these DER modifications in its planning processes. These assumptions have been kept in the Company's Initial DSIP because they are important to understanding how DERs are included in the system and network forecasts described in the previous section. In this section, the Company will address the role demand and energy forecasts play in Company processes. The Company will then respond to the information gathered and contributions to peak and energy forecasts for each type of DER. That will be followed by a general discussion about how DER forecasts are used in utility planning processes. The final requirement of describing other procedures and programs that will increase the quantity and value of DER will conclude the section.

The peak demand and energy forecasts previously described in the Forecast of Demand and Energy Growth Section are used as inputs for other utility business processes. The peak demand forecasts produced both for the summer and winter peaks at a network and system level guide the Company's 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 can defer traditional utility system expansion investments or reduce wholesale energy and capacity costs. The factors and algorithms applied to the DER contributions, as described in more detail below, are designed to provide the necessary levels of performance and reliability.

Within internal planning processes, DERs are organized into one of two sub groups; Demand Side Management (DSM) or Distributed Generation (DG). DSM includes both Energy Efficiency (EE) programs and Demand Management (DM). The DG group includes subset types of DG, namely PV, CHP or other spinning generators, and energy storage (largely batteries). **Figure 15** below shows the breakout of the DSM elements:

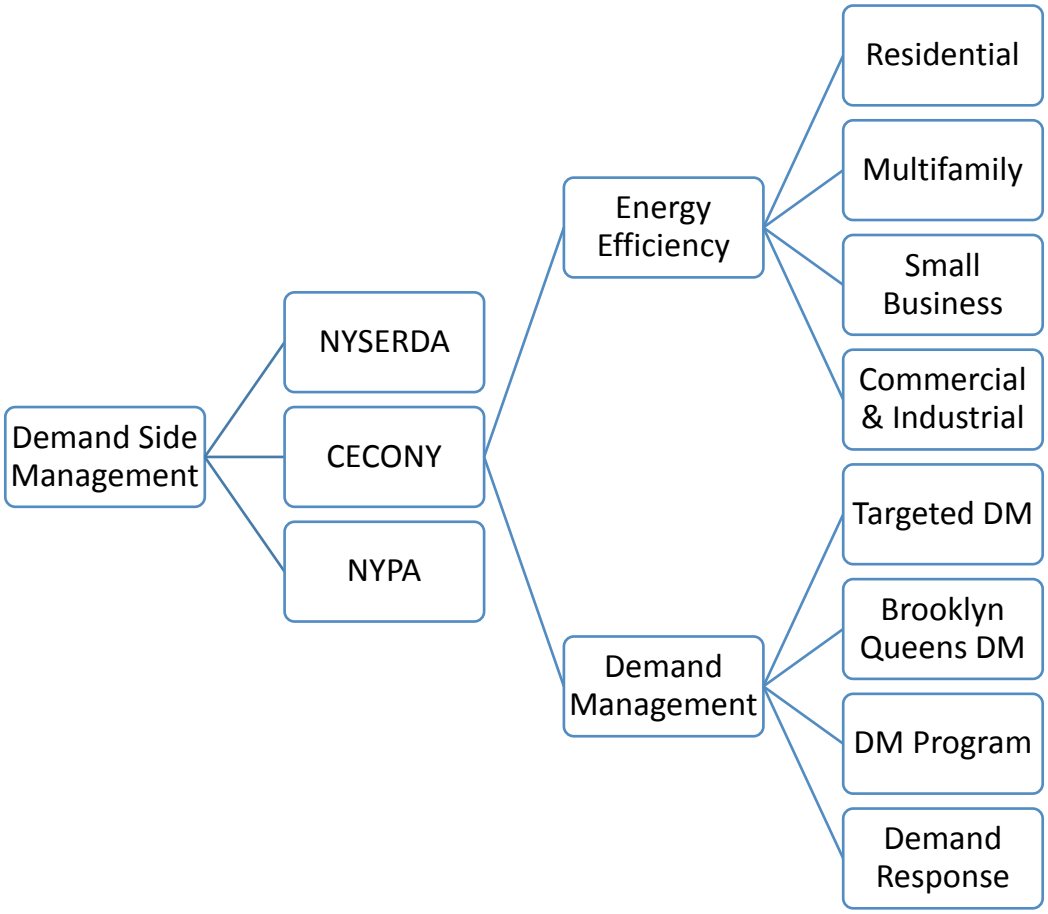

Figure 15 - Programs included in Demand Side Management

The NYSERDA and NYPA programs included above refer to their programs operating in the Company's service territory, to be detailed in the section below. Similar to the Company's own programs, there are multiple energy efficiency programs administered by NYSERDA; however, they are not included in the diagram above for simplicity because they are outside the Company's control. Both NYSERDA and NYPA programs will be discussed in depth in the appropriate sections below.

1. Demand Side Management

For the purposes of responding to the DSIP requirements, the elements of Demand Side Management will be grouped into three categories: EE (including both Con Edison and outside programs), DM, and DR, a subset of DM. The DSIP requirements will be answered in turn within each category:

- Information gathered
- Peak demand contributions
- Energy reduction contributions

Total system peak demand and volume (energy) reductions from DSM Programs are included in **Tables 4 and 5** below. Additional details provided in the sections following.

2016 - Electric System Peak Demand Forecast (in Megawatts)

		2015	2016	2017	2018	2019	2020
11	Coincident DSM (Incremental)						
12	Con Edison EEPS		-22	-15	-19	-25	-25
13	NYSERDA EEPS		-5	-7	-8	-7	-7
14	NYPA		-7	-5	-5	-1	-1
15	BQDM		-6	-24	-6	13	0
16	DMP		-36	-68	0	0	0
17	Demand Response		-32	-9	-8	-3	-3
18	TOTAL DSM:		-109	-126	-46	-24	-36
19	Cumulative DSM:		-109	-235	-281	-305	-341

Table 4- Electric System Peak Demand Forecast: DSM Programs

Delivery Volume Adjustments (GWh) – DSM Programs		**2016**	**2017**	**2018**	**2019**	**2020**
Con Ed DSM Impact	SC 1 – Residential	-43	-81	-116	-141	-173
	SC 2 – Small Commercial	-18	-39	-51	-62	-71
	SC 5 – Rail Road Platform and Stations Lighting	0	0	0	0	0
	SC 8 – Master Metered Apartments	-15	-27	-31	-36	-39
	SC 9 – Large Commercial	-606	-986	-1,151	-1,276	-1,423
	SC 12 – Multiple Dwelling Space Heating	0	0	0	0	0
Con Ed	**Total**	-682	-1,133	-1,349	-1,515	-1,706
NYPA	**Total**	-40	-71	-95	-111	-124
System	**Total**	-722	-1,204	-1,444	-1,626	-1,830

Table 5- Delivery Volume Adjustments by Service Class: DSM Programs

a) Energy Efficiency

(1) Information Gathering

All Con Edison energy efficiency programs are included in the volume and demand forecasts, as are NYSERDA and NYPA energy efficiency programs operating in the Con Edison service territory. The foundation of Energy Efficiency programs, as defined initially in the Energy Efficiency Portfolio Standard (EEPS) and carried forward into the ETIP, is to reduce greenhouse gas emissions by reducing energy consumption.

Information regarding the expected future reductions, volume and peak, comes from a variety of sources and varies based on the entity delivering the program. For Con Edison energy efficiency programs, forecast data comes from internal program managers who gather information from their implementation contractors and market participants. Future volume and demand reductions are tied to 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 Con Edison service territory are gathered from NYSERDA's regulatory filings and associated PSC orders. NYPA-related reductions are taken from a project list provided to Con Edison directly by NYPA and include planned energy efficiency and demand management projects. The NYPA projects are not easily sorted and for simplicity's sake are included in the EE category.

(2) Peak Demand Contribution

Energy efficiency is a proven tool to reduce emissions and will be a key component to reaching the State's Clean Energy Standard.[37] As shown in lines 12 through 14 in the system forecast (and included below for reference), energy efficiency programs are expected to also contribute 34 MW of load reduction in 2016, ramping to 159 MW of reduction in 2020. As described in detail below, there is a robust process and methodology for information gathering and modeling to forecast energy efficiency programs for inclusion in the Con Edison demand forecasts.

2016 - Electric System Peak Demand Forecast (in Megawatts)

		2015	2016	2017	2018	2019	2020
11	Incremental MW						
12	Con Edison EEPS		-22	-15	-19	-25	-25
13	NYSERDA EEPS		-5	-7	-8	-7	-7
14	NYPA		-7	-5	-5	-1	-1

Table 6 – Electric System Peak Demand Forecast: EE

The peak demand forecasts for the above 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. See **Figure 16** below for a graphical process diagram.

[37] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Staff Whitepaper on the Clean Energy Standard (issued January 25, 2016).

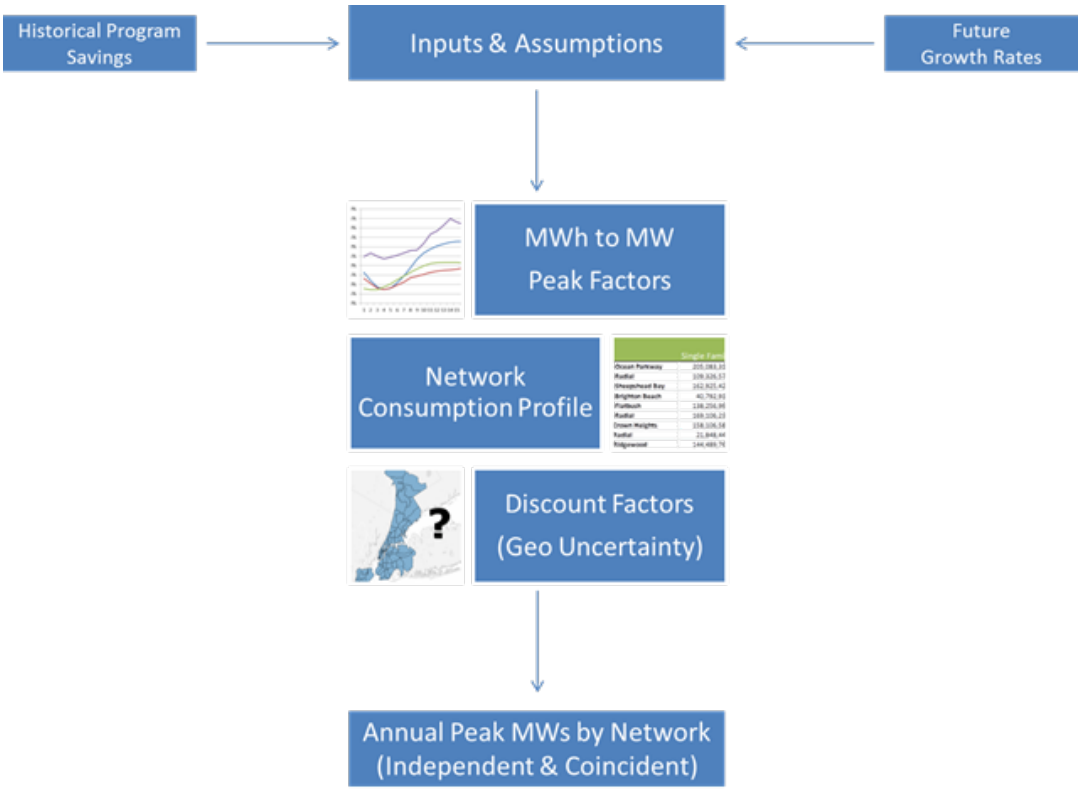

Figure 16 - DSM Forecasting Process Diagram

System-wide energy efficiency programs are designed to provide annual energy savings across the entire electric service territory. These programs may also result in peak demand reductions. In order to incorporate the associated demand reductions of these programs into the load forecast, the expected magnitude, delivery date, hours of operation, and geographic location of the energy efficiency savings must also be analyzed and projected. Expected energy savings are distributed across the electrical networks in the forecast using historical consumption data and customer demographic information because savings are expected to be achieved where the related load is located. These energy savings are then converted to peak demand savings using annual hourly load curves, 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. Incremental Energy Efficiency program savings are projected 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 codes and standards or customer-initiated energy efficiency occurring outside programs are not included in this forecast.

The specific Energy Efficiency Programs administered by Con Edison and NYSERDA included in the peak demand forecasts are:

Con Edison Electric Programs

- Small Business Direct Install
- Multifamily
- Commercial & Industrial Equipment Rebate
- Commercial & Industrial Custom Efficiency
- Residential Electric

NYSERDA Clean Energy Fund[38]

- Residential Sector
- Multifamily Sector
- Commercial Sector

Traditional NYSERDA EEPS programs are being supplanted by the NYSERDA Clean Energy Fund (CEF) to better align with the goals of REV. The 10-year market development benefit targets found in the CEF Information Supplement submitted on June 25, 2015 serve as a starting point for forecasting CEF energy savings. These targets are first discounted to estimate the impact in the Con Edison territory and then further reduced to reflect past NYSERDA EEPS 2 performance. Finally, a third factor is applied to represent the uncertainty surrounding the success of CEF implementation.[39]

New York Power Authority (NYPA) Projects

The NYPA forecast is developed from a list of projects received from NYPA's Economic Development and Energy Efficiency Department. The list contains expected project level demand reductions which are assigned by location to electric networks with timing per NYPA's expected completion dates. No additional NYPA demand reductions are forecasted beyond this list. The list is updated and provided to Con Edison by NYPA at least annually and sometimes more often as needed.

(3) Energy Reduction Contribution

Energy Efficiency Programs are expected to contribute 321 GWh of energy reduction in 2016, ramping up to 1,207 GWh of reduction in 2020. All Con Edison energy efficiency programs are included in the volume forecasts, as are NYSERDA programs operating in the Con Edison service territory, and NYPA energy efficiency. The breakdown of energy savings by program is shown below in **Table 7**:

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[38] Case 14-M-0094, *Proceeding on Motion of the Commission to Consider a Clean Energy Fund* (CEF Proceeding), Order Commencing Proceeding (issued May 8, 2014).
[39] CEF Proceeding, Clean Energy Fund Information Supplement (issued June 25, 2015).

Program	2016	2017	2018	2019	2020
NYPA	-40	-31	-24	-16	-13
NYSERDA EEPS & CEF	-45	-30	-26	-31	-28
Con Edison EEPS	-236	-176	-170	-170	-171
Total	**-321**	**-237**	**-220**	**-217**	**-212**

Table 7 – Incremental Delivery Volume (GWh) Adjustments by EE Program

The Volume Forecast takes historical DSM program performance and estimated future growth rates as inputs and uses MWh to MW and MW to MWh conversion factors based on customer and measure types. The Volume DSM forecast has an output of GWh savings and MW demand reductions from DSM measures. See **Figure 17** below for a graphical process diagrams.

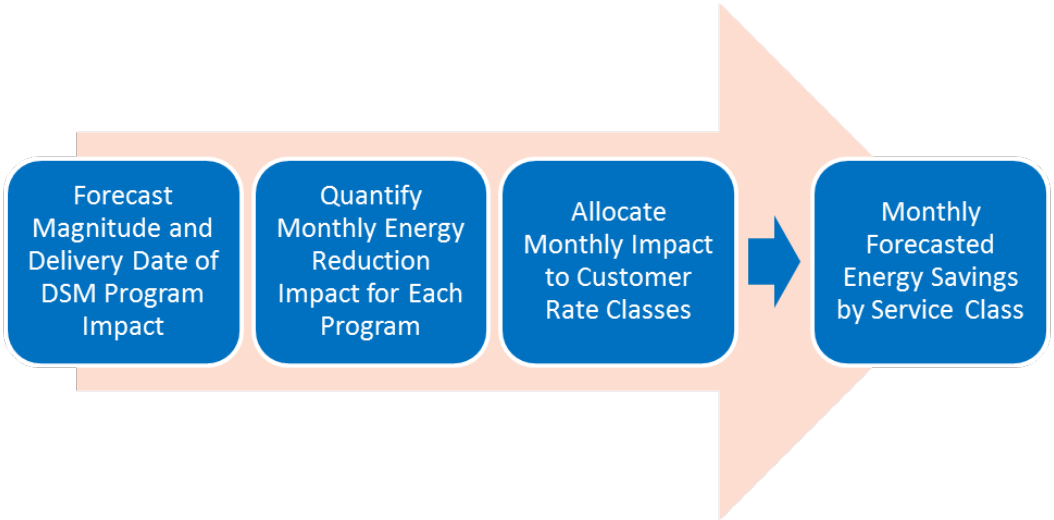

Figure 17 - Energy Forecast Process for DSM

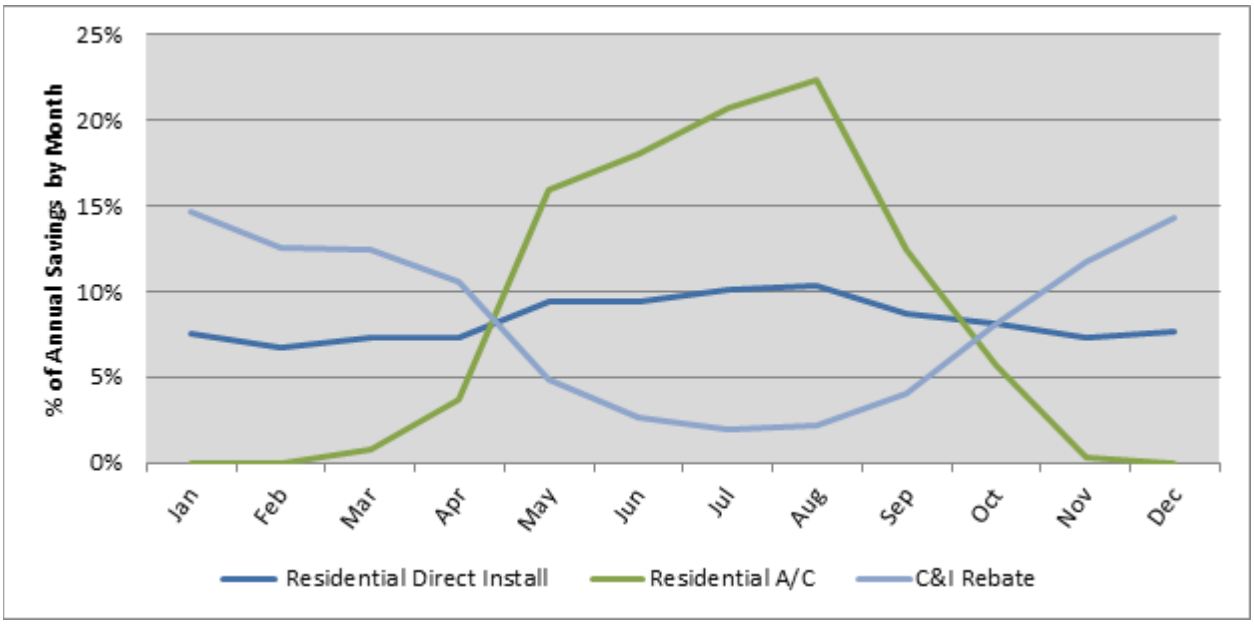

Figure 18 - Example Program Level Monthly Energy Savings Allocations

Energy Efficiency program savings are projected monthly and annually into the future as far as the programs are funded or highly likely to be funded. Incremental energy reductions in years beyond funding certainty are not included in the forecasts.

Specific Energy Efficiency Programs Included in the volume forecasts include:

Con Edison Electric Programs

- Small Business Direct Install
- Multifamily
- C&I Equipment Rebate
- C&I Custom Efficiency
- Residential Electric

NYSERDA Clean Energy Fund[40]

- Residential Sector
- Multifamily Sector
- Commercial Sector

[40] Case 14-M-0094, *Proceeding on Motion of the Commission to Consider a Clean Energy Fund, Clean Energy Fund*, Information Supplement (issued June 25, 2015).

Traditional NYSERDA EEPS programs are being supplanted by the NYSERDA Clean Energy Fund (CEF) to better align with the goals of REV. The ten year market development benefit targets found in the CEF Information Supplement submitted on June 25, 2015 serve as a starting point for forecasting CEF energy savings. These targets are first discounted to estimate the impact in the Con Edison territory, and then further reduced to reflect past NYSERDA EEPS 2 performance. Finally, a third factor is applied to represent the uncertainty surrounding the success of CEF implementation.

New York Power Authority (NYPA) DSM Projects

As with the demand forecasts, the NYPA contribution to energy reductions in the volume forecast is developed from a list of projects that are received from NYPA's Economic Development & Energy Efficiency department. The project list contains expected project level energy reductions which are assigned by location to electric networks with timing per NYPA's expected completion dates. No additional NYPA energy reductions are forecasted beyond the NYPA provided list of planned projects. The list is updated and provided to Con Edison by NYPA at least annually and sometimes more often as needed.

b) Demand Management Programs

(1) Information Gathering

Funded and operational demand management programs in the Con Edison service territory are included in both the volume and demand forecasts. For demand management programs, forecast data come from internal program managers who gather information from their implementation contractors and market participants. Future volume and demand reductions are tied to filed and approved program goals and budgets adjusted by historic performance and future performance expectations.

(2) Peak Demand Contribution

Table 8 below highlights the DM contributions to peak demand reduction without DR, which will be addressed separately in the following section:

2016 - Electric System Peak Demand Forecast (in Megawatts)

	Incremental MW	2015	2016	2017	2018	2019	2020
15	BQDM		-6	-24	-6	13[41]	0
16	DMP		-36	-68	0	0	0

Table 8 - Electric System Peak Demand Forecast: DM

[41] The positive load modifier for BQDM in 2019 is the result of no longer contracting and calling upon certain non-permanent DER, as was done in earlier years (2016-2018) of the BQDM program. The requisite load relief in 2019 is met through a traditional load transfer.

Demand management programs are designed to provide targeted peak demand load reductions to specific hours of the peak day in order to address potential constraints in the electric system. The method for including the impact of these programs in the Con Edison demand forecasts is straightforward because these programs are designed to provide a predetermined level of demand reduction by a specified date. Demand management program savings are projected annually into the future as far as the programs are funded and planned to deliver incremental reductions. Incremental demand reductions in years beyond funding certainty and program plans are not included in the forecasts.

Specific Demand Management Programs Included in DSM Forecasts

- Demand Management Program (DMP) - The Demand Management program offers enhanced incentives for energy efficient technology that will help improve operational performance of buildings and reduce electric demand during system peak. Con Edison customers and third-party developers acting on behalf of the building owners and building managers are eligible for the enhanced incentives based on their demand reduction for energy efficiency and demand management projects. Projects that achieve a peak reduction of 500kW or more can also earn additional bonus incentives. Some of the projects in the pipeline include advanced technologies such as battery storage.
- Brooklyn Queens Demand Management (BQDM) Program –The combination of customer-side solutions, non-traditional utility solutions, and traditional utility solutions being implemented to relieve projected overloads in Brooklyn/Queens, as discussed in the Executive Summary.
- Targeted Demand Management (TDM) Projects - TDM projects help reduce customer demand for electricity through customer-side solutions. Branded as the Neighborhood Program, it is offered in neighborhoods where a capacity constraint exists or is forecasted to exist in the near future, in order to help reduce the demand on the electric system, thereby allowing Con Edison to defer or avoid the need for infrastructure upgrades in targeted neighborhoods.[42]

(3) Energy Reduction Contribution

As shown in **Table 9** below, demand management programs are expected to contribute 400 GWh of energy reduction in 2016, ramping up to 628 GWh of reduction in 2020.

The volume (energy) reductions are determined for Demand Management programs and included in the Con Edison volume forecast by converting the forecasted MW to MWh based on expected future measures and customer types. Demand management program savings are projected annually into the future as far as the programs are funded and planned to deliver incremental reductions. Incremental energy reductions in years beyond funding certainty and program plans are not included in the forecasts.

[42] No TDM projects are currently identified so no impacts are included in the current peak demand or volume forecasts. As projects are identified and implemented, the demand and energy impacts will be included in the forecasts.

Incremental Volume Adjustments (GWh)					
Program	**2016**	**2017**	**2018**	**2019**	**2020**
BQDM	-52	-84	-20	30[43]	4
DMP	-348	-158	-	-	-
Total	**-400**	**-242**	**-20**	**30**	**4**
Total (Cumulative)	**-400**	**-642**	**-662**	**-632**	**-628**

Table 9 - Delivery Volume Adjustments by DM Program

c) Demand Response

(1) Information Gathering

Con Edison demand response programs are included in the peak demand forecast. Future volume and demand reductions are tied to filed and approved program goals and budgets adjusted by historic performance and future performance expectations.

(2) Peak Demand Contribution

Table 10 below highlights the demand response contribution to peak demand reductions:

2016 - Electric System Peak Demand Forecast (in Megawatts)

	Incremental MW	2015	2016	2017	2018	2019	2020
17	Demand Response		-32	-9	-8	-3	-3

Table 10- Electric System Peak Demand Forecast: DR

The expected peak demand impacts of Con Edison'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 by establishing nominal baseline reductions based on program enrollments in total and by network. Historic performance factors are then applied per program to account for the expected participant performance during peak demand events. Additionally, historic enrollment trends are analyzed to determine likely customer re-enrollments and dropouts based on year-over-year trends given the annual program enrollment designs. Discount factors are applied to enrolled MWs for network forecasts based on the size and diversity of enrollments in each individual network. Growth projections for future enrollments beyond current year baselines for each demand response program are generated based on a historic program trends and future program expectations as provided by direct program managers. As noted below, NYISO DR programs are not included in the demand forecast because they are considered a supply side resource.

[43] The positive energy adjustments for BQDM in 2019 and 2020 are the result of no longer contracting and calling upon certain non-permanent DER, as was done for years (2016-2018) of the BQDM program.

Specific Demand Response Programs Included in DSM Forecasts

- Con Edison's Commercial System Relief Program (CSRP) – Reservation Payment Option
- Con Edison's Direct Load Control (DLC) Program
- Distribution Load Relief Program (DLRP) and CSRP Voluntary Participation Options are not included in the forecast
- DLRP Reservation Payment Option is not included in the system forecast
- NYISO DR Programs (SCR) are not included in the Con Edison DSM forecast

(3) Energy Reduction Contribution

Demand Response programs are not included in the volume forecast because the energy savings are both uncertain (programs may or may not be called) and *de minimis* (even if events are called).

2. Distributed Generation

The other grouping of DER that contributes to demand and energy forecasts is DG. This group is defined as DERs capable of exporting power back to the grid, including PV, CHP, and other rotating generation, and energy storage (primarily consisting of batteries). The DSIP requirements will be answered in turn within each category:

- Information gathered
- Peak Demand contributions
- Energy Reduction contributions

a) Solar PV

(1) Information Gathering

The forecasting of solar PV uses a number of inputs. The details of the time to go-live and size of the solar installation are collected from DER providers through the interconnection process. Growth rates are determined in the short term (typically two years out) through queued projects (initiated through the interconnection process) and informed by long-term solar penetration studies (*e.g.*, NY SUN/NYSERDA).[44]. Solar peak coincidence is determined by extrapolating metered PV data. Each year the Company reconciles forecasted geographic dispersion of PV with actual installations so that solar generation is applied to the appropriate local areas, with consideration for the lead times of projects.

[44] NY-Sun is the New York State program to improve the efficiency, affordability, and reliability of state energy systems. http://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/About.

(2) Peak Demand Contribution

As shown in line 8 of the System Peak Demand Forecast (and included below for reference), PV is expected to contribute 8 MW of load reduction in 2016, ramping to 60 MW of reduction by 2020. This is based on the nameplate capacity of the PV, converting to AC, de-rating it to account for coincidence with system peak, and NY SUN/NYSERDA growth rates, as described below. The PV forecast is represented as rolling incremental where 2016 is the incremental decrease to system load, and each year thereafter is the reduction of that year and all years dating back to 2016.

2016 - Electric System Peak Demand Forecast (in Megawatts)

		2015	2016	2017	2018	2019	2020
8	Photovoltaics/Solar (PVs) (rolling incremental)		-8	-29	-40	-51	-60
	Coincident PV MW in AC (Cumulative)	25.7	33.7	55.2	65.9	76.4	86.0
	% MW Growth		31%	64%	19%	16%	12%

Table 11 - Electric System Peak Demand Forecast: PV

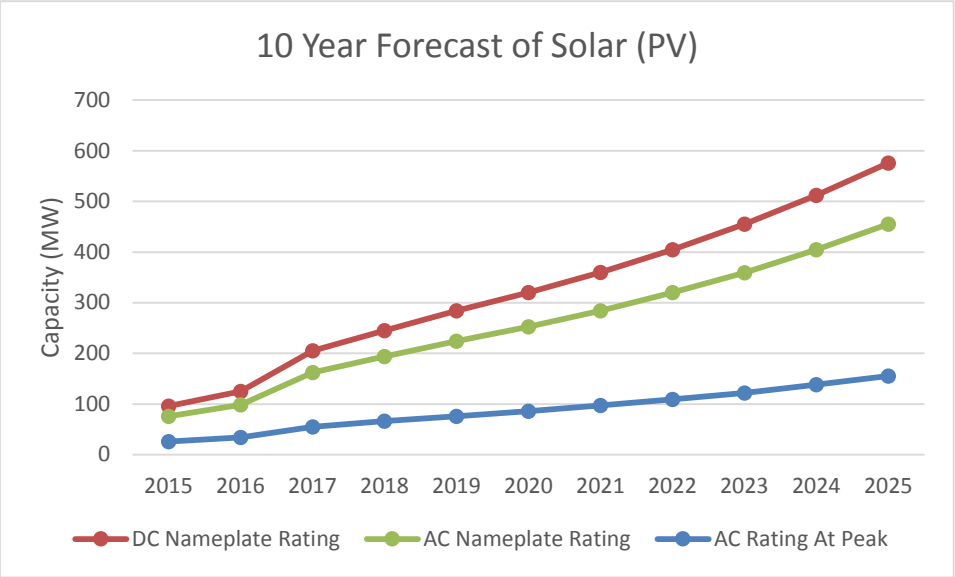

Figure 19 - Ten Year Forecast for Solar (PV)

The forecasting of solar PV, as with other DERs, 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 Company's Distribution Engineering group provides two more key components for assessing the impact of PV, the solar output per hour and the location of the PV project. The Company's Distribution Engineering group 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 determined by reviewing interval data and is representative of three summer (June-August) months of data across 20 PVs. The output curve is below in **Figure 20**.

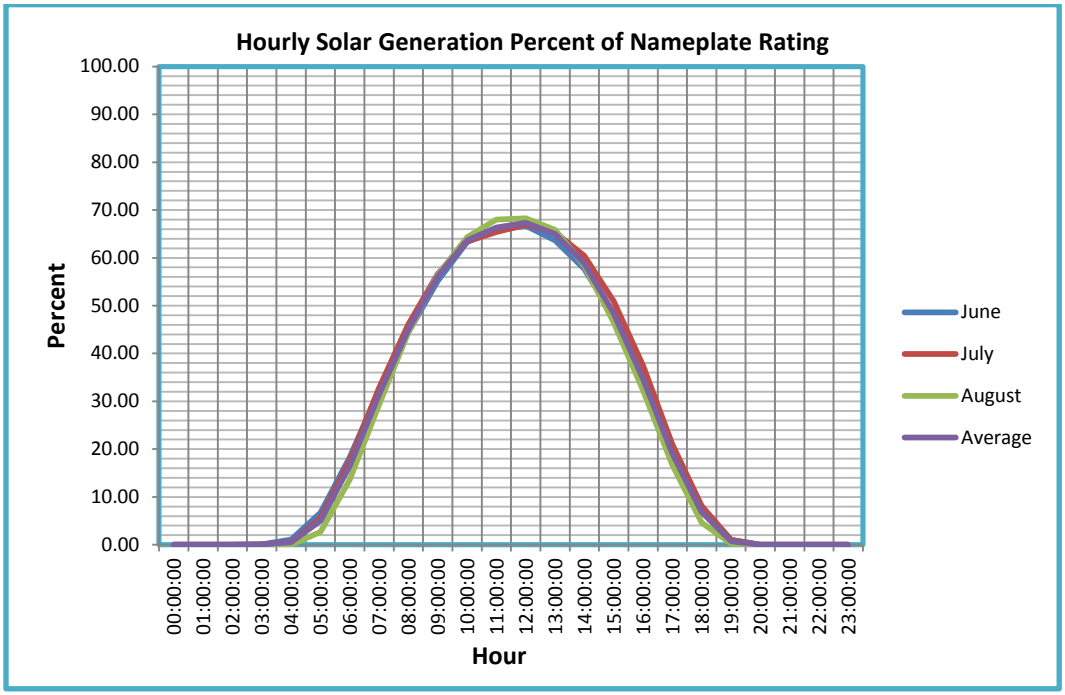

Figure 20 - Measured Solar Output Curve Using Sampled Interval Meter Data

Hourly Solar Generation as a Percent of Nameplate			
Hour	**Average**	**Hour**	**Average**
0:00:00	0.0%	12:00:00	67.3%
1:00:00	0.0%	13:00:00	65.0%
2:00:00	0.0%	14:00:00	58.8%
3:00:00	0.0%	15:00:00	48.4%
4:00:00	0.0%	16:00:00	34.7%
5:00:00	5.0%	17:00:00	19.1%
6:00:00	16.5%	18:00:00	6.8%
7:00:00	31.5%	19:00:00	0.8%
8:00:00	45.0%	20:00:00	0.0%
9:00:00	56.1%	21:00:00	0.0%
10:00:00	63.7%	22:00:00	0.0%
11:00:00	66.4%	23:00:00	0.0%

Table 12 – Average Summer Solar Output as a Percentage of Nameplate Capacity

Each hour's output percentage is the average of the output percentage for the two hours bounding the system peak. The system peaks between 4PM - 5PM; therefore, the average of the bounding hourly values is used instead of one discrete number. The resultant solar output percentage is multiplied by a Direct Current -to-Alternating Current 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 network information for each PV, it is 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 two years of growth is determined by using the interconnection queue. For the years beyond the queue, the DG Ombudsman works with Demand Forecasting using the best available data, including NY SUN/NYSERDA forecasts for the years beyond the interconnection queue. As noted earlier, for the initial PV forecast, the Company's Resource Planning team defined assumptions to build the forecast model:

- Residential customers include any account under 10 kW and commercial customers include any account over 10 kW
- Residential jobs go-live in 12 months after application date
- Commercials jobs go-live in 18 months after application date
- The peak occurs after July 1 of each summer

Ten kW was selected as an approximate 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 analysis. The O&R analysis indicates residential PV goes live approximately 12 months after the application date and commercial PV goes lives 18 months after the application date. This means that some PV jobs go-live the summer after the application and others go-live two summers after the application. As DER penetration increases, it is assumed that the entire interconnection process will continue to become more streamlined based on experience (see the Interconnection Section). As additional data is tracked and made available, the assumptions regarding go-live time will be updated and enhanced accordingly.

July 1 was assumed as a representative peak day for purposes of creating the model. By selecting a mid-summer day, PV jobs that are in the queue can be parsed into groups that will go-live in that 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. The queue does not contain enough information for when the current year forecast is created to determine how many PV jobs will go-live 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.

(3) Energy Reduction Contribution

As shown below, solar generation is expected to contribute 42 GWh of energy reduction in 2016, ramping up to 147 GWh of reduction in 2020.

Delivery Volume Adjustments (GWh) – Solar Generation		2016	2017	2018	2019	2020
Con Ed Solar Impact	SC 1 - Residential	-26	-48	-64	-75	-92
	SC 2 – Small Commercial					
	SC 5 – Rail Road Platform & Station Lighting					
	SC 8 – Master Metered Apartments					
	SC 9 – Large Commercial	-14	-25	-34	-40	-50
	SC 12 – Multiple Dwelling Space Heating					
Con Edison	**Total**	-40	-73	-98	-115	-142
NYPA	**Total**	-2	-3	-3	-5	-5
System	**Total**	-42	-76	-101	-120	-147

Table 13 – Delivery Volume Adjustments by Service Class – Solar PV

The solar forecast is determined by first evaluating the penetration of solar generation, measured as nameplate DC generation. In addition to future nameplate penetration, the Company'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 DC nameplate to an energy reduction modifier using NYSERDA's matrix conversion calculator.

b) Combined Heat and Power and Other Generation

CHP and other forms of rotating generation preceded the wide scale adoption of solar and energy storage. As such they are referred to within Company processes and forecasts as DG, even though they are one subset of DG. All references to DG in this section refer only to CHP and other rotating generation. This includes traditional DG like gas turbines and reciprocating engines, as well as newer technologies such as fuel cells and micro turbines.

(1) Information Gathering

Distributed Generation inputs are collected from DER providers prior to and throughout the interconnection process. DER Providers for large DG units will typically initiate exploratory conversations with the Company's DG group (part of the larger Distributed Resources Integration Department). The nameplate capacity and details of the go-live timing (looking three years out) are provided through the interconnection process and verified by the Company. Furthermore, for large (greater than 1 MW) DGs, operational performance data may be collected through interval meters or other mechanisms. Long-term growth of DG is extrapolated based on the historical penetration and currently queued projects.

(2) Peak Demand Contribution

As shown in line 9 of the system forecast (and included below for reference), non-PV DG is expected to contribute 22 MW of load reduction in 2016, ramping to 91 MW of reduction in 2020. The

DG forecast is represented as rolling incremental, where 2016 is incremental decrease to the system load and each year thereafter is the reduction of that year and all years prior through 2016.

2016 - Electric System Peak Demand Forecast (in Megawatts)

		2015	2016	2017	2018	2019	2020
9	Distributed Generation (DG) (incremental rolling)		-22	-48	-85	-90	-91
	Coincident DG MW (Cumulative)	-133	-155	-181	-218	-223	-224
	% MW Growth		16.5%	16.7%	20.4%	2.3%	0%

Table 14 - Electric System Peak Demand Forecast: DG

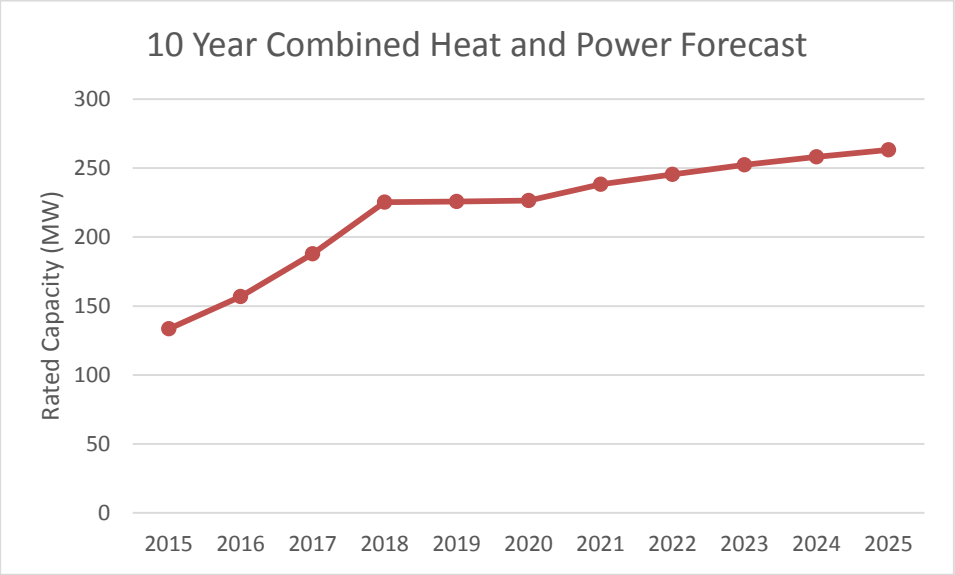

Figure 21 – Ten-Year Distributed Generation Forecast

The distributed generation load modifier is becoming a more important piece of the forecasting process; this is due to the increased penetration of DG and REV policy changes. To continue to provide safe and reliable service at reasonable rates, the Company will continue to work with customers with multiple DGs of demonstrated reliability to minimize the installed Con Edison infrastructure required to serve their needs. Over time as the Distributed System Platform is built out, the Company will be able to monitor more DG devices and can further refine tariff offerings to help customers save money while increasing their energy source flexibility and resiliency.

Because non-solar DGs are generally larger than PVs and can be dispatched at times of peak load, their impacts on the local grid are 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 apply coincident peak load reduction to the network forecast. The following are the assumptions used to determine if DGs provide relieving load on a network forecast:

Non-Solar Distributed Generation Assumptions

- All DGs that are less than 1 MW are assumed to be on at all times. Therefore, credit (-) will be taken to reduce load.
- For DGs that are greater than 1 MW, full load credit will be taken at the N-2 stations (as described in the Reliability Planning Criteria subsection of the Delivery Infrastructure and Capital Investment Plans section) (and their associated networks) to reduce load irrespective of whether the DG unit is the only one in that network.
- If there are multiple DGs greater than 1 MW, residing in the same network (with N-1 station criteria), then credit will be taken for the largest DG unit to reduce load.
- For DGs that are greater than 1 MW, full load credit will be assigned with 1 year lag of the DG completed/install year (*e.g.*, if the completed year is 2016, credit will be taken in 2017).
- Load in outer years will be divided equally into the commercial peaking networks which are comprised of previously listed/known DGs unit.

The non-solar DG assumptions that determined load reduction credit are characterized in **Table 15** below. DG for each network is rolled up for the system DG forecast.

			Station Redundancy	
			N-2	N-1
Size and Quantity of DG	Small (<1 MW)	All Small DG	Full credit for small DGs, beginning in the year of the service date	Full credit for small DGs, beginning in the year of the service date
	Large (>=1 MW)	One Large DG	Full credit for all large DGs, beginning 1 year after service date	No credit
		Greater than One Large DG	Full credit for all large DGs, beginning 1 year after service date	Full credit for the largest DG, beginning 1 year after service date

Table 15 - Determination of DG Demand Reduction Credit

Once the 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 separately.

(3) Energy Reduction Contribution

As shown below, DG is expected to contribute 74 GWh of energy reduction in 2016, ramping up to 179 GWh of reduction in 2020.

Delivery Volume Adjustments (GWh) - Standby Service (DG)		2016	2017	2018	2019	2020
Con Ed DG Impact	SC 1 – Residential					
	SC 2 – Small Commercial					
	SC 5 – Rail Road Platform & Station Lighting					
	SC 8 – Master Metered Apartments					
	SC 9 – Large Commercial	-39	-53	-53	-77	-89
	SC 12 – Multiple Dwelling Space Heating					
Con Ed	**Impact**	-39	-53	-53	-77	-89
NYPA	**Impact**	-35	-35	-35	-35	-90
System	**Impact**	-74	-88	-88	-112	-179

Table 16 - Delivery Volume Adjustments by Service Class - DG

In determining the energy forecast load modifier for DG, the Company evaluates only the large (greater than 2 MW) DG units owned by customers taking standby service. The scope prioritizes the standby service rates because of the laborious manual methods to determine the revenues associated with these customers, and as the largest DGs, they have the greatest impact on the energy forecast. The energy forecasting process requires an investigation of the past performance of each unit. For each of the Company's existing standby service accounts, the prior year's usage is reviewed to identify monthly consumption anomalies. For new customers, if available, their past consumption is analyzed to determine the difference between usage and planned on-site generation. In each case, the potential kW generation of the new DG is provided, and applied to historical energy/kW ratio to determine the account-specific monthly energy reduction to be applied to the forecast. These account-specific energy reductions are summed by existing service class to determine the energy forecast modifier.

c) Energy Storage

(1) Information Gathering

Energy Storage (typically batteries) is considered a separate line item in the DG forecast, often deployed in combination with other types of DG, due to specific interest in this technology. While batteries are still a small component of the forecast, it is understood that advancements in technology will result in many more batteries installed throughout Con Edison territory. Battery penetration and growth information are currently provided by the Distribution Generation Ombudsman.

The Company gathers information about potential distributed energy storage in its service territory from a variety of sources. The Company's interconnection queue provides a near-term view of proposed and under-construction projects, including distributed energy storage. The Company is

engaged with developers interested in deploying energy storage, both informally and through utility and NYSERDA programs such as NY Prize[45] and the Company's DMP. Additionally, the Company will participate in development of state policy regarding energy storage.

The Company recognizes that distributed energy storage is a relatively new technology with limited but growing data on technical and market potential in the Company's unique service territory. The Company has identified factors for adoption which 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 New York City Fire Department and Department of Buildings (FDNY/DOB) permitting and will be used to inform the forecasting process going forward.

(2) Peak Demand Contribution

As shown in line 10 the system forecast (and included below for reference), batteries are expected to contribute 2 MW of load reduction in 2016, ramping to 4 MW of reduction in 2020.

2016 - Electric System Peak Demand Forecast (in Megawatts)

		2015	2016	2017	2018	2019	2020
10	Batteries (incremental rolling)		-2	-3	-3	-4	-4

Table 17 – Electric System Peak Demand Forecast: Batteries

For 2016, the DG group (part of the larger DRI organization) of Con Edison reviewed existing and queued battery projects. Given the early development of battery technology in the service territory, the Company assumed 500 kW of battery growth per year. Trends and the interconnection queue will be monitored and analyzed to refine the forecasts going forward as batteries become cheaper and in turn become a larger load modifier. It is important to note that battery storage systems are a flexible resource in terms of the value that they can provide. For example a 10 MW, four-hour battery system can be discharged in several ways – 10 MW discharged for four hours, 5 MW discharged for eight hours, or different levels of discharge at different hours. Battery systems could also be used to provide more consistent output of intermittent renewable sources or clip the peaks of load curves of customers with highly variable loads. These systems are most predictable when they are discharged in a manner set by program rules – *i.e.*, battery must be discharged from 2 PM - 6 PM as in the Company's DMP. For planning purposes, the Company will view the load reduction from the battery as per the amount of discharge it can provide over four hours, in line with the peak load. Thus a 500 kW reduction from peak would be a 2 MWh battery discharged over four hours. It is understood that a battery system could be discharged in a variety of manners and if an incentive mechanism (demand response or program rules)

[45] NY Prize is a New York State-sponsored $40 million competition to help communities create microgrids that can operate independently in a power outage. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize.

caused the battery to discharge pattern to vary from this standard, then the amount of reduction used in forecasting could be adjusted as necessary.

The Company recognizes that due to the low numbers, and limited visibility, of installed energy storage as of 2016, the Company lacks adequate data to model the effect on peak load. The Company recognizes that several factors require further study, including storage use and charging method. In general an energy storage resource serves as a load to the utility when it charges from the grid, and serves as a resource to the utility (a DER) when it discharges. Charging at off-peak times and discharging at peak times generally leads to less carbon-intensive supply sources being utilized and serves to flatten the peak and fill in the troughs for the utility, leading to a better overall load factor and better system efficiency. Energy storage would not serve as a load to the utility if it charges using behind-the-meter generation (*i.e.,* solar and battery both behind a one-way inverter). The charging of the battery would not increase the load seen by the utility.

Storage use, and its impact on 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.

Other storage uses are measurable and able to be influenced or controlled by the utility (through contracts and/or in real-time). Programs which support a higher level of utility visibility include the DMP and REV Demonstration projects (Virtual Power Plant and recently issued RFP for energy storage), discussed elsewhere. These programs are administered by the Company and provide greater visibility and impact to peak demand. BQDM also provides an opportunity for the Company to control a battery storage unit as part of a larger suite of demand management projects. Similar RFPs, should they occur, would guarantee coincidence with the Company's greatest need. Depending on battery capacity, technology, and project economics, utility-owned battery projects may also be capable of bidding into NYISO demand response and/or ancillary services markets. The Company expects data from these programs to contribute to peak load and energy use impact studies in the coming years.

(3) Energy Reduction Contribution

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 is merited regarding the effects on energy consumption.

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 on 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.

3. Incorporation of DER in Planning Processes

a) Peak Demand Planning

Con Edison forecasts the anticipated peak demand impacts of DER in its service territory in order to better assess future capital planning needs. The Company started incorporating program reductions into the forecast in 2006 with the Targeted DSM Program and over the last ten years has added additional programs as they have been developed and implemented. 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. Forecasts of all types of DG are also allocated geographically and over time as they come online or otherwise contribute to reducing load. The projected impact of DER is 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, Con Edison will continue to include DSM and DG as load modifiers to its demand forecasts used for Transmission and Distribution (T&D) planning. As required by the DSIP Order, the Company will share peak load forecast information (including historical peak load duration curve, growth rates, and forecasted peaks) with authorized third parties, further discussed in the System Data and Acquisition section.

b) Energy Planning Process

Con Edison currently forecasts the anticipated volume impacts of DER programs and projects in its service territory in order to better assess future revenue requirements and operational needs. The Company started incorporating program reductions into the forecast in 2006 with the Targeted DSM Program and over the last ten years has added additional programs as they have been developed and implemented. The energy efficiency and demand management volume forecast also report MW reductions from selected service classes for Time of Day (TOD) meters. The revenue forecast is used by the Company for rate cases and to assess capital requirement needs. The EE, DM, and DG forecast include the GWh volume and MW demand of included reductions by month by service class. Going forward, Con Edison will continue to include energy efficiency and demand management programs in its volume forecasts. The delivery volume forecast is used to determine the revenue forecast. The sendout forecast is used by the Company's Energy Supply Panel to develop an energy supply cost forecast.

4. DER Programs

a) Programs

Beyond the energy efficiency programs to be included in the ETIP to be filed September 1, 2016 for 2017 – 2019 and the Company's residential and commercial DR programs for which modifications were recently approved by the PSC in orders issued January 25 and 27, 2016, respectively), there are two existing programs that could increase DER – the DMP and TDM Program.

In partnership with NYSERDA, the DMP will deliver over 100 MW of peak demand reduction. The Company is exploring how and to what extent the DMP can be expanded, following directives from the Track Two Order.

Beyond the existing 51 MW, $200M BQDM project, the TDM Program is authorized to commit up to $60M during calendar years 2016-2017 on distribution load relief projects. As of this writing, the TDM Program does not have any firm plans to roll out additional TDM projects to avoid or defer T&D infrastructure upgrades; however the Company is currently evaluating several potential projects.

The Company is also exploring the feasibility of expanding its energy efficiency offerings in light of the Track Two Order, including how additional energy savings can be achieved through market-based approaches.

b) Procedures

Additionally, the quantity and value of DER in the forecasting and planning process could be improved with information on the resources. Lack of reliability data or certainty can lead to discounts in forecasts. 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, the ability of DERs to come and go from a program year-to-year or ability to not provide reductions when needed by the utility can hurt 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 very near that of the T&D it is replacing or deferring. The reliability impacts of DER on the grid will be measured by the Network Reliability Index (NRI) and the performance of DERs will be governed by contractual terms and the UBP for DER.

(1) Energy Storage

The Company supports programs to address system needs, primarily programs with utility monitoring and control to maintain reliability and maximize grid value. For scenarios where direct-utility control is not possible, the Company advocates 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 Virtual Power Plant REV Demonstration project to best integrate storage with utility operations and planning.

The Company is actively engaged on multiple fronts in promoting DERs that benefit customers as well as partnering with DER providers and vendors to enable ready access to the DER products and services customers are seeking a cost-effective manner. This includes a long history of implementing multiple dynamic programs, testing and introducing new technologies to market, and seeking out and working with both large and small DER companies. Taken together, the Company has demonstrated an eagerness to test, learn, and develop procedures and programs to increase the quantity of DER resources to customers that demonstrate value.

(2) Energy Efficiency

The Company has been implementing energy efficiency programs in their modern context since the beginning of the New York Energy EEPS in 2008. Through its energy efficiency programs, the Company addresses market barriers to help customers optimize and manage their energy use. Current EE programs are designed for and delivered to all customer segments – residential (1-4 family), multifamily (5+ units), small business (<300 kW peak demand), and large commercial and industrial (>300 kW peak demand). Program offers, incentives, and delivery channels are specific to each of these segments and based on each segment's specific characteristics and needs. A detailed description of current energy efficiency programs is available in the 2016-2018 Energy Efficiency Transition Implementation Plan (ETIP).[46]

The Company's upcoming 2017-2019 ETIP, which will be filed on September 1, 2016, will introduce improvements to existing programs and new innovative programs and delivery channels, including leveraging the Company's REV demonstration projects. The Company, as part of the next and future ETIP filings, will advance opportunities to streamline its efficiency initiatives, improve cost efficiency, and introduce new technologies and delivery channels to meet customers' diverse and changing needs.

(3) Demand Management

The Demand Management program offers enhanced incentives for energy efficient technology that will help improve operational performance of buildings and reduce electric demand. Con Edison customers and third-party developers acting on behalf of the building owners and building managers are eligible for the enhanced incentives based on their demand reduction for energy efficiency and demand management projects. Projects that achieve a peak reduction of 500 kW or more can also earn additional bonus incentives.

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[46] Case 15-M-0252, *In the Matter of Utility Energy Efficiency Programs*, Final Energy Efficiency Transition Implementation Plan (ETIP) 2016-2018 (filed April, 1 2016).

(4) Targeted Demand Management

TDM programs help reduce customer demand for electricity through direct customer participation. Branded as the Neighborhood program, it is offered in neighborhoods where a capacity constraint exists or is forecasted to exist in the near future, in order to help reduce the demand on the electric system, thereby allowing Con Edison to defer or entirely avoid the need for expensive equipment upgrades in targeted neighborhoods.

Con Edison provides energy-saving and management solutions to local communities where the electricity demand is expected to grow significantly because of expanding businesses and housing markets. Each Neighborhood Program has its own specific incentives and opportunities based on Con Edison's operational needs in those specific neighborhoods. In August 2014, Con Edison issued virtual building audits to customers in the Brooklyn Queens target area who used more than 100kW of electricity. The results were used to show those customers how to better manage their electricity use.[47] The BQDM Program is currently underway will spend $200 million dollars to procure 41 MW of customer sided demand solutions, and 11 MW of non-traditional utility sided solutions.

(5) Demand Response

Commercial, industrial, and residential customers may participate in Con Edison's demand response programs. By managing load, demand response programs can provide a number of system and public policy benefits including reliability and economic benefits. Distribution-level demand response programs and other dynamic load management programs improve system reliability and resiliency, capture the benefits of increased system efficiency, and provide customers with another set of options to help them manage their utility bills and generate revenue. Distribution-level demand response programs, by reducing peak network loads, have the potential to provide substantial benefits to customers, the electric system, electric distribution utilities, and the state as a whole. These benefits include reduced distribution infrastructure costs and improved distribution system reliability.

Enrollment levels in the commercial demand response programs have increased over the last several years, primarily due to the Company's efforts to increase incentive levels, simplify program rules, as well as enhance marketing and outreach efforts. The programs today rely on tariff-based incentives that are administratively set. The Company is looking at potential opportunities to transition the incentive setting mechanism for one or both of its commercial demand response programs to a market-based mechanism.

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[47] Smart, Colin, *Preparing for, and Building, a Smarter* Grid, https://www.linkedin.com/pulse/preparing-building-smarter-grid-col-smart?trk=prof-post

On December 15, 2014, the PSC ordered the utilities without distribution-level demand response programs to implement such programs for the summer of 2015.[48] The PSC directed that Con Edison's demand response programs should be considered as models. On June 18, 2015, the PSC approved utility filings with modifications for demand response programs and directed utilities to file updated tariffs with an effective date of July 1, 2015. Today, each of the JU offer the Commercial System Relief Program, Distribution Load Relief Program, and the Direct Load Control program, all with similar rules to Con Edison's DR programs.

Con Edison residential customers with central air conditioning can receive a free smart thermostat. The thermostat and its app allow customers to control their thermostats from anywhere, cutting heating and cooling costs while allowing Con Edison to make brief adjustments to the customers' energy use during summer peaking hours. Customers can also participate in Bring Your Own Thermostat (BYOT), wherein the customer purchases a thermostat and receives a rebate from the Company in return for allowing brief adjustments to energy use during summer peaking hours.

(6) Demonstration Projects

Con Edison's initial demonstration projects are intended to show the potential of various aspects of REV. These projects demonstrate new business models, and inform decisions related to the development of DSP functions. DPS Staff has found that Con Edison's Connected Homes Platform project helps improve customer awareness through the use of home energy reports combined with targeted DER offers.[49]

In addition to the three demonstration projects for which Con Edison has filed and reported progress (discussed elsewhere), the Company is developing additional projects. As with prior demonstration projects, new projects will demonstrate new business models, inform the development of the DSP, measure customer response to programs and prices, and determine the most effective implementation of DER. In alignment with the Commission's goal of increasing access to DER for Low- to Middle-Income (LMI) customers, the Company is currently engaging external stakeholders to solicit input on potential areas of focus and intends to initiate a demonstration project addressing LMI customers in the upcoming months. Given this timing, it is too early to report results of an LMI-related demonstration project in the DSIP. Proposals, implementation plans, and quarterly results will be filed in the REV docket.

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[48] Case 14-E-0423, *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs,* Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings (issued December 15, 2014), p. 9.

[49] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Staff Assessment Report of Con Edison's Connected Homes Platform REV Demonstration Project (filed January 8, 2016), pp. 3-4.

(7) Electric Vehicles

Con Edison has long been exploring the potential benefits and unique characteristics of electric vehicles. The Company initiated EV pilot program in 2012 with up to 50 single-family residential customers to test the ability of a branch circuit energy management device (BCEMD) to disaggregate EV load from the whole house load and to evaluate participants' responsiveness to peak demand information. This pilot program recently concluded, with the results documented in an initial[50] and supplemental report.[51] The results, though drawn from a limited number of participants, address customer charging patterns, impact to the Company's system, access to energy information, ability to enable DR events, and potential for other incentives or rate structures using a BCEMD. The pilot identified several hurdles to using sub-metering technology for tariff-based incentive programs. Among the barriers identified were (1) accuracy and other revenue grade metering requirements, (2) billing and other administrative limitations, and (3) logistics and expense of installing equipment inside customer's homes.

The Company is incorporating the lessons learned on customer-charging behavior and sub-metering from the initial pilot and will build on that project in a new pilot to be launched in 2016. This R&D pilot will utilize connected vehicle technology for EV Load Management, Multifamily EV Charging, and EV Fleet Management. The pilot utilizes a device that plugs into the onboard diagnostics (OBD) port of the vehicle. The device collects and communicates both real-time and historic charging and driving data from the vehicle and displays it on an internet portal accessible to both the utility and the driver. The driver also has access to a free EV charging app.

For EV load management, the pilot will incent customers to charge off-peak based on network peak and to participate in utility-controlled demand response program. A screenshot of the EV charging and driving data available to the customer is shown below:

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[50] Case 13-E-0030, *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 2013 Electric Rate Case), Electric Vehicle Pilot Report (filed on March 31, 2015).

[51] Con Edison 2013 Electric Rate Case, Electric Vehicle Pilot Report (filed on November 15, 2015).

Figure 22 - FleetCarma Dashboard

In the Multi-Family Charging Pilot, the technology will be used by owners and operators of a multi-family dwelling to sub-meter EV charging of tenants and condominium/cooperative owners.

The Company also plans to pilot the Connected Vehicle Technology with an electric taxi fleet, allowing Con Edison to collect valuable data for understanding charging requirements of electric taxis and for optimal dispatching of the electric taxis utilizing real-time state of charge and GPS information.

The Company is working with New York City and the MTA/NYC Transit on examining the potential of siting a fast-charging hub in Manhattan incorporating energy storage, PV, and load management software for charging electric buses as well as private and fleet EVs. The Company is also working with NYC Transit, NYPA, and EPRI on an electric bus pilot. This 2.5-year project will gather data from a fleet of 10 electric buses in New York City to document vehicle performance and the electricity needs of the bus fleet in order to understand the most efficient way to help the electric bus program scale appropriately.

D. Delivery Infrastructure Capital Investment Plans

1. Reliability Planning Criteria

The planning 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. The criteria are consistent with 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. Area substations are either designed to supply anticipated peak loads on a first contingency (N-1) or second contingency (N-2) basis. First contingency (N-1) design stations are able to supply peak loads during an outage of any one transformer or its supply feeder without exceeding equipment thermal limits, while second contingency (N-2) design stations are able to supply peak loads during outages of any two transformers or supply feeders without exceeding equipment thermal limits.

The origin of the Company's current design criteria is the 1961 outage that affected roughly 100,000 midtown Manhattan customers for up to four hours. After this outage, the PSC formally required area substations in densely populated areas (*i.e.*, Manhattan) to meet an N-2 deterministic reliability requirement that was consistent "with the policy already in place for primary feeders." Today, area substations serving load areas outside of Manhattan are designed to meet N-1 criteria, while all Manhattan substations, as well as the Plymouth Street substation which feeds downtown Brooklyn (an area with a population density similar to Manhattan), meet the N-2 criteria. This criterion has been extended as follows:

- Each substation is designed to withstand the loss of two bus sections during peak load
- All N-2 combinations of network transformers are evaluated and transformers over 115 percent loading are considered for load relief. Unlike feeders, most network transformers can be air- or water-cooled during contingency conditions so only transformers over 115 percent loading were prioritized for load relief
- All N-2 combinations of open mains are evaluated but are addressed on a case-by-case basis for reinforcement.

The Company's unique and densely loaded distribution network design offers a great degree of flexibility in adapting the system at relatively low costs to system needs. The current planning criteria consider equipment thermal capability as well as duration of loading to rate equipment capacity. The criteria recognize changes to load shape and determine limits for failure of major equipment. The NRI model is the primary tool used to predict the reliability of the networks. The reliability model comprises

a Monte Carlo[52] simulation of the failure and repair of network feeder cable sections and joints, network transformers, and other components. The reliability model is used to predict the frequency of occurrence, in a heat wave, of a state in which four feeders in a feeder band and its two adjacent bands within the network system are out-of-service. Network component failure processes are characterized using failure data. The NRI modeling and characterization of failures will improve as new data are gathered, new insights into the failure process are gained, and inconsistencies between model predictions and reality are resolved.

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.

In response to changes to the utility business model, increased penetration of DER across the Con Edison service territory, and other REV-driven initiatives, the criteria are currently being further revised, to include DG and distribution automation. The application of the revised criteria will provide long range improvements in system performance.

a) Transmission Criteria

At the transmission level, there is a hierarchy of regulatory levels that include FERC, NERC, the NPCC, and NYSRC, as well as Con Edison's own reliability criteria. A brief summary of each level follows:

Federal level

Presently there are over 100 enforceable electric reliability standards approved by the Federal Energy Regulatory Commission (FERC).[53] Of those standards, about half are applicable to the Company based on its registration as Transmission Owner (TO), Load Serving Entity (LSE), Generator Owner (GO), Generator Operator (GOP) and Distribution Provider (DP). Con Edison will soon be designated as a Transmission Planner as well, which also carries additional compliance responsibilities. Compliance responsibility for a subset of these standards has been assigned to the System and Transmission Operations Organization (S&TO). Transmission Planning is responsible for ensuring compliance with all or part of 19 of the S&TO Standards. A list of these applicable standards can be found in Con Edison Transmission Planning internal specification EP-7550, which can be obtained on request.

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[52] Monte Carlo refers to the general designation for stochastic simulation using random numbers. Billington, W. Li, *Reliability Assessment of Electrical Power Systems Using Monte Carlo Methods*, Springer Science & Business Media, November 30, 1994.

[53] The FERC website is www.ferc.gov

In the United States, the Electrical Reliability Organization (ERO) is the North American Electric Reliability Corporation (NERC). FERC authorizes NERC to develop and enforce reliability standards to maintain the reliability of the Bulk Power System in North America. NERC has formally delegated enforcement authority to eight regional entities throughout North America. NERC is responsible for the definition of the Bulk Electric System (BES), associated regulatory requirements, and the bright-line criteria that defines the qualifications for this category as well as the specific inclusions and exceptions. The NERC BES definition document,[54] the NERC Summary of Standards,[55] and other NERC standards[56] are the sources for the most up-to-date planning criteria.

Regional Entity Level

The Northeast Power Coordinating Council (NPCC),[57] one of the eight regional entities with reliability enforcement authority, helps to promote and enhance the reliable and efficient operation of the internationally interconnected Bulk Electric System in Northeastern America. NPCC enforces compliance with the NERC reliability standards in the Con Edison service area.

State Level

The New York State Reliability Council (NYSRC) publishes a biennial report[58] that summarizes the Council's formation, mission, organizational structure, functional responsibility, initiatives, and continuing activities. Con Edison also must maintain compliance with the Reliability Rules and Compliance Manual[59] that the Council publishes. The specification that provides Con Edison's Transmission Planning Criteria[60] for assessing the adequacy of its Bulk Electric Transmission System to withstand design contingency conditions in order to provide reliable supply to all customers throughout the planning horizon. This specification also establishes Fundamental Design Principles and Performance Criteria. These two components complement each other and adherence to both is required by all new projects proposed by the Company and by independent developers. In addition to this specification, all facilities, generator and transmission, must be designed to conform with and adhere to all the

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[54] Project 2010-17 Definition of Bulk Electric System (Phase 2), http://www.nerc.com/pa/RAPA/BES%20DL/BES%20Definition%20Approved%20by%20FERC%203-20-14.pdf

[55] http://www.nerc.net/standardsreports/standardssummary.aspx

[56] http://www.nerc.com/ResourceCenter/Pages/default.aspx

[57] NPCC Directories and Standards are found on their website: https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

[58] New York State Reliability Council, *2013-2014 Biennial Report*, (June 2015).

[59] New York State Reliability Council, *Reliability Rules and Compliance Manual – Version 36* (adopted March 11, 2016).

[60] Consolidated Edison Company of New York, Inc., *Transmission Planning Criteria*, Company EP-7100-13 (March 29, 2016).

previously mentioned, applicable NERC, NPCC, NYSRC Reliability Rules, including NYSRC Local Reliability Rules, as well as applicable Con Edison specifications, procedures, and guidelines.

Excerpts from the Planning Criteria Document are highlighted below:

(1) Contingencies

Con Edison's Transmission Load Areas are designed as follows:

- Those supplied by the 345 kV Bulk Electric Transmission System are designed for second contingency
- Specific 138 kV Transmission Load Areas are also designed for second contingency; and
- The remaining 138 kV Transmission Load Areas are designed for single contingency.

Second contingency design means that the Con Edison Bulk Electric Transmission System is planned to withstand, at peak design customer demand, the more severe of independent Scenarios A and B, as described below:

A. The most severe of design criteria contingencies of Category I Single Event, Contingency events 1 through 9, in accordance with Table B-1 of the NYSRC Reliability Rules.

B. The most severe combination of two non-simultaneous design criteria contingencies of Category 1 Single Event, Contingency events 1 and 2, in accordance with Table B-1 of the NYSRC Reliability Rules.

For single contingency testing (Scenario A), applicable post-contingency thermal, voltage, and stability limits shall not be exceeded. In addition, the system must be able to be returned to within its normal state limits using all available operating reserves and system controls.

For second contingency testing (Scenario B), applicable post-contingency thermal, voltage, and stability limits shall not be exceeded. Prior to testing for the second contingency, the system should be able to be returned to its normal state limits utilizing ten-minute operating reserves and system controls. Although transfer levels are not explicitly identified in this Criteria, to the extent that the ten-minute operating reserves within the Con Edison service area are not sufficient, then ten-minute operating reserves from outside the Con Edison service area will be utilized, thereby resulting in an increase of transfer levels. In addition, after the second contingency has occurred, the system must be returned to within its normal state limits using all available operating reserves and system controls.

(2) Voltage

Voltages must satisfy both steady-state and post-contingency limits, as follows:

- Minimum: 328 kV < Actual 345 kV system < Maximum: 362 kV
- Minimum: 131 kV < Actual 138 kV system < Maximum: 145 kV

(3) Thermal Assessment

The Con Edison thermal planning criteria, expressed in ampere carrying capacity, consider three thermal categories. These are:

- Normal (operating) rating
- Long-Term Emergency (LTE) rating
- Short-Term Emergency (STE) rating

The post-contingency loading of any overhead facility or inter-utility tie must not exceed its LTE rating. In observance of NYSRC Reliability Rules, the post-contingency loading of any underground cable can exceed its LTE rating, but not its STE rating, following:

Loss of generation – provided that ten (10)-minute operating reserve and/or phase angle regulation are available to reduce the loading to its LTE rating and not cause any other facility to be loaded beyond its LTE rating; and

Loss of transmission – provided that phase angle regulation is available to reduce the loading to its LTE rating and not cause any other facility to be loaded beyond its LTE rating.

b) Stability Assessment

Unit and system stability shall be maintained during and following the more severe of independent scenarios A and B as identified in the previous Contingencies Section, with due regard to reclosing (in accordance with NPCC Criteria).

c) Transient Assessment

As changes occur in the topography of the Con Edison transmission infrastructure, appropriate analysis shall be conducted so that electrical equipment (*e.g.,* circuit breakers, transformers) are protected against transient overvoltage and harmful resonance conditions caused by switching operations and/or potential contingency events.

d) Short Circuit Assessment

The Con Edison Bulk Electric Transmission System shall be planned such that, when all generation and all transmission lines are in service, fault duty levels do not exceed the rated interrupting capability of breakers at 69 kV, 138 kV, and 345 kV substations. Determination of fault duty levels shall be made with due regard to fault current limiting series reactor operating protocols.

e) Extreme Contingency Assessment

Extreme contingency assessment recognizes that the Bulk Electric Transmission System can be subjected to events that exceed, in severity, the normal planning criteria. This assessment is conducted to determine the nature and potential extent of widespread system disturbances from such events and to identify measures that will be utilized, where appropriate, to reduce the frequency of occurrence of such events, or to mitigate the consequences that are indicated as a result of testing for such

contingencies. Analytical studies shall be performed to determine the effect of the Extreme Contingencies in accordance with the Table B-3 of the NYSRC Reliability Rules.

(1) Automatic under Frequency Load Shedding

The objective of an Under Frequency Load Shedding (UFLS) Program is to quickly attempt to restore the generation-load balance when generation is lost, by automatically shedding a corresponding amount of load. When the UFLS program operates successfully, the post-disturbance system frequency should settle between 59.5 Hz and 60.5 Hz, with the majority of the pre-event on-line generation and load remaining in service. Manual control can then restore the system to its nominal operating frequency of 60 Hz.

On June 26, 2009, NPCC issued Regional Reliability Reference Directory #12 with new UFLS requirements, along with a six-year implementation plan. The new requirements contain four "regular" stages of approximately seven percent load at each frequency of 59.5, 59.3, 59.1, and 58.9 Hz, with a 0.3- second time delay, and a fifth anti-stall stage of approximately two percent load at 59.5 Hz, with a 10-second time delay. Con Edison has three additional regular stages of approximately seven percent load, at each of 58.7, 58.5, and 58.3 Hz, with 0.3-second time delay. In total, approximately 51.5 percent load in eight different stages will be shed.

f) Distribution Criteria

(1) Distribution Contingency Criteria

Circuit - To meet the planning criteria for a single-circuit contingency, 100 percent of the circuit's peak load must be restored from all available adjacent circuit ties within one (1) hour using a maximum of four switching operations and resulting in less than 2,000 customer-hours of interruption.

To meet the planning criteria for a network feeder, 100 percent of the peak load must be met under the loss of any two feeders. This requires designing diversity on the minor bus sections where the feeders tie to the substation as well as traversing through the streets and avenues of New York City and Westchester.

Two-Bank Station - To meet the planning criteria for a single-transformer contingency in a two-transformer substation:

1. For an outage less than four (4) 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 LTE ratings.
2. For an outage greater than four (4) hours, the remaining bank must assume 100 percent of the in-service bank and 60 percent of the load of the lost bank with the assistance of adjacent circuit ties, keeping the bank near normal rating. The mobile transformer must then restore the remainder of the load within twenty four (24) hours, and the entire outage cannot exceed 60,000 customer-hours of interruption.

Area Substation – To meet the planning criteria for criteria on an area substation (with more than two banks), the areas substations are either designed to supply anticipated peak loads on a first contingency (N-1) or second contingency (N-2) basis. First contingency (N-1) design stations are able to supply peak loads during an outage of any one transformer or its supply feeder without exceeding equipment thermal limits, while second contingency (N-2) design stations are able to supply peak loads during outages of any two transformers or supply feeders without exceeding equipment thermal limits.

g) 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.

The table in **Appendix D** for service voltages is based upon ANSI Standard C84.1 1989 for Electric Power Systems and Equipment - Voltage Ratings (60 Hertz) and regulatory tolerances of plus or minus four percent (for voltages less than 150 volts to ground). Range A is the acceptable voltage limits on Con Edison's 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. 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 and corrective action will be taken if these conditions persist.

In conjunction with maintaining these service voltages, the distribution substation bus is maintained between 0.98 per unit (p.u.) and 1.03 p.u. of nominal voltage, depending on load. 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 will 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 derating. To limit motor derating to 90 percent, a maximum sustained imbalance of three percent is allowed at the meter under no-load conditions.

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 criteria. 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.

h) Voltage Regulation

Depending on load levels of the areas served by the substation and the time of day, distribution substation bus voltage schedules are typically maintained within 0.98 p.u. and 1.03 p.u. of nominal (4, 13, 27, or 33 kV), so as to maintain 122 volts (1.017 p.u.) at the customer's point of service, under normal conditions with all supply facilities available. The secondary distribution line voltages are then regulated between 126 (1.025 p.u.) and 118 (0.983 p.u.) volts. Secondary voltage limits are documented in the Company's EO 2065 procedure and based on the ANSI specifications.

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, up to 1,200 KVAR, and are located to provide up to plus or minus two percent regulation. Voltage regulators, providing plus or minus ten percent regulation in five or eight percent steps, are 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, secondaries, 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 levels, the efficiency of the system is maximized as well.

2. Capital Budgeting Process

On an annual basis, the distribution planning process commences to determine how best to serve forecasted load, net of load growth and DER-related load reductions. The distribution planning process is a complex and iterative process, the key steps of which are shown below in **Figure 23**. Ultimately the set of required projects needed to address system needs form the basis of the capital budget.

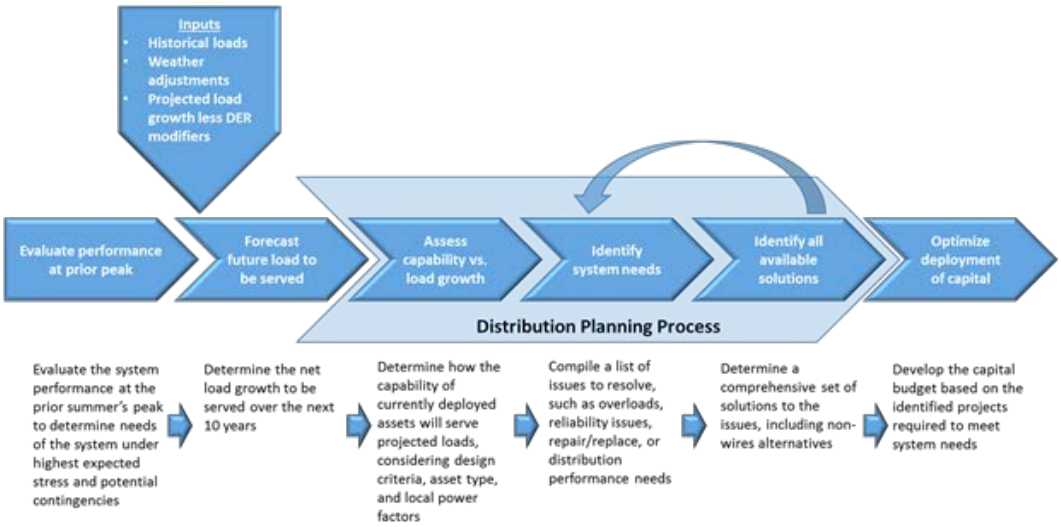


Figure 23 - Distribution Planning Process Leading to Capital Budgeting

The process for forecasting the peak load to be served is provided in the Forecasting and Available Resources sections. The next element of distribution planning is to assess the current capability of Company assets, based on the design criteria, type of asset, thermal ratings, and local power factors. For instance, if a substation has three transformers with 300hr ratings of 139 MVA and a fourth transformer with a rating of 142.2 MVA, and is in an N-1 station, the capability would be 3*139 MVA or 417 MVA. This capability is translated to MW by the planners as they consider the load power factor and capacitors in service MVAR rating. The capability of assets is then compared to the forecasted loads to determine when or if an asset would no longer be able to serve peak load. These types of projects would be considered system expansion, and reflect the organic load growth of existing customers. The distribution planning process includes analytical assessment of load flow modeling, network reliability modeling, and modeling of system performance.

Other areas of system need resulting from distribution modeling may include:

- Risk reduction programs to perform necessary inspections and replace components with known failure mechanisms known issues in order to enhance network reliability,
- New business projects to interconnect new customers, and
- Storm hardening or resiliency projects to bolster the electric grid.

In addition to the areas of need above, the Company also budgets for emergency response and replacement, IT solutions to meet strategic business needs, and public works projects to re-route Company equipment due to municipal right-of-way.

The Company's capital budget approach is to balance system needs to meet its customer expectations for safe and reliable service while managing costs to reduce customer bill impact. The Company achieves this through various planning and analytical processes and by leveraging its significant technical experience to create an optimized capital work plan.

An example of this philosophy in action is how the Company has actively managed its electric system to accommodate growth in individual underground networks in New York City without additional substation infrastructure build. The Company's planned build of new substations to meet new load has effectively been deferred by 10 to 20 years. Instead of new infrastructure, the Company continues to rely on marginal capacity in its existing substations and engineering solutions to maximize available capacity at its substations (referred to as "utilization factor," which is a factor of projected growth over substation capability) to accommodate new electricity needs. The traditional portion of the portfolio of BQDM solutions is an example of this, as customer demand from a network in Brooklyn is to be transferred to a network in Queens with spare capacity. In fact, since 2010, no new substations have been built, and none are planned through 2025.

Once a list of system needs is compiled, Con Edison planners will identify all potential solutions to address the issues. This process will often iterate as the plans develop, due to interdependence of projects or as cost estimates are refined. Load relief, as the most common driver of the need for system expansion capital projects, is worth discussing in greater detail.

a) Area Substation Load Relief

Acceptable area station or sub-transmission feeder loading is based on the ratio of forecasted load to station capability being less than or equal to 100 percent, when rounded, in any given year. Therefore, load in excess of station capability or an overload is defined as the above ratio being greater than or equal to 101 percent when rounded. To maintain system reliability and safety, projected overloads within design criteria on area station assets are not tolerated and the system must be reinforced or the load reduced by transferring load or DSM, to eliminate the overload condition. A projected overload may be resolved in different ways. Potential solutions are developed and evaluated for technical feasibility and cost-effectiveness by Distribution Planning in conjunction with Transmission Planning, Central Engineering, Distribution Engineering, and Regional Engineering. The most cost-effective solution is chosen and reflected in the Load Relief Program.

Potential overloads can be resolved by increasing capability through capital reinforcement, decreasing load, or a combination of the two. Capital infrastructure reinforcement projects that increase substation or sub-transmission feeder capability include:

- Installation of transformer, bus, or breaker cooling
- Installation of new or replacement of limiting transformer
- Addition of capacitor bank
- Upgrade of limiting bus or breakers
- Replacement of limiting cable sections
- Addition of cable cooling
- Establishment of a new area substation
- Establishment of a new switching station to supply area station

Otherwise, load supplied by the station may be reduced by:

- Transfer of load to another substation with sufficient excess capability
- Institution of demand side programs, such as EE, DR or targeted load relief programs.

During each annual load relief program cycle, improvements to operating conditions for load power factor or sub-transmission and distribution bus voltage schedule are evaluated to increase short term station capability and defer capital expenditure on permanent load relief projects. In N-2 design stations, five percent voltage reduction can also be employed as a planning tool (at the substation level only) to reduce sub-transmission feeder loading and defer load relief projects.

As described previously, existing and projected DER projects are integrated into a System and Network forecast as an input to the area station planning process. The increased penetration of DER could therefore result in decreasing capital expenditure that would be otherwise necessary to reinforce existing station assets to meet future demand.

b) Distribution Level Load Relief

Traditionally, load relief applied at the distribution level is determined using deterministic reliability planning criteria to address any forecasted overload (forecasted load > 100 percent of feeder rating). These projects are determined using the forecasted loads in the fall, after observing the prior summer's peak, and often must be implemented by the beginning of the next summer. This means that overloads must be determined, solutions compared, and projects implemented in an appropriate timeframe. Overloads can be driven by either new business needs or system expansion (greater usage by existing customers). The appropriate timeframes are approximately 18 months for new business (as driven by the in-service date of the new load) and approximately 9 months for system expansion. Components on the distribution system that require load relief are typically either feeders or transformers. The traditional solutions that are typically used to address load relief at the distribution level include:

- Feeders
    - Increase the size of the cable
    - Transfer load by rearranging feeders
    - Establish new feeders
    - Change feeder route to reduce the number of loaded duct banks
    - Update automatic (SCADA-enabled) switching plans
- Transformers
    - Upgrade transformer
    - Reinforce secondary mains
    - Install new transformer
    - A combination of transformer installation and secondary main reinforcement

Though the distribution projects listed above are determined with less forewarning and must be implemented on a tighter 9-18 month timeline, they are of a smaller scale and cost than area substation projects. The methodology and application of load relief on distribution feeders also differ from the

prior section on area substations. At the substation level, load relief applied anywhere within the supplied network(s) footprint directly translates to load relief received at the substation. For instance, 1 MW of a distributed generation load relief solution would directly translate to 1 MW less load to be served by the substation. However, on a distribution feeder, 1MW of load relief does not always translate to 1 MW of load reduction on the targeted feeder as the relief flows through the surrounding network. In some cases the 1 MW provides exactly 1 MW of relief on the targeted feeder section, however, in other cases it can be as low as 0.25 MW. For instance, an ideal scenario for a DER providing load relief would be an overload of one MW on three feeders that was supplied by a three bank fully isolated network. In this case, the 1 MW of relief provided by the DER, which is typically spread across the three feeders, is wholly directed to the area of need in an N-2 contingency. This is graphically represented in **Figure 24**, below:

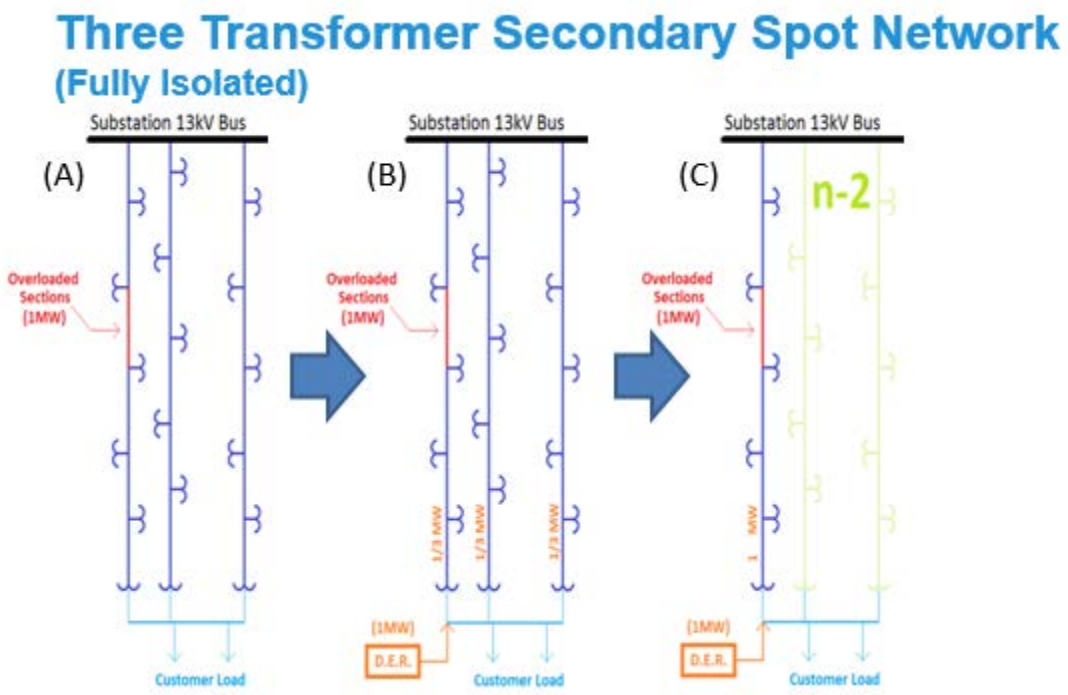


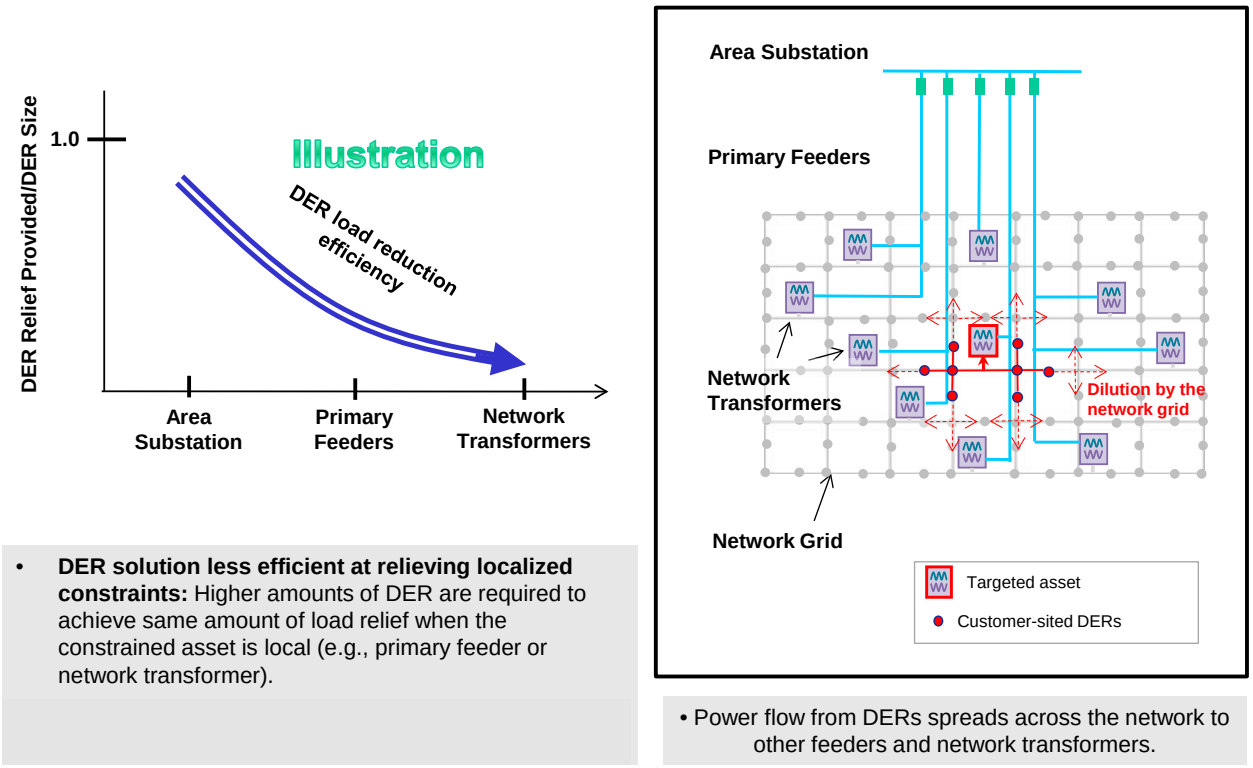
Figure 24 - The progression of load relief provided in an isolated secondary spot network: (A) The overload without DER to (B) A DER introduced, but spreading load relief across feeders, to (C) DER providing the necessary load relief in an N-2 contingency

In most other cases where the network is not isolated, load reductions quickly spread to a greater number of nearby feeders rather than the targeted feeder or transformer where they are most needed. As with any determination of the value of DER to the local distribution system, the topology of the network and attributes of the DER must be considered. As with radial feeders, a DER solution provides value to both the targeted section(s) and all the sections "upstream" of the DER back to the substation breaker.

One analogy that may be useful in thinking about load relief in a network is relieving traffic congestion. Assume a road (*e.g.,* Long Island Expressway) that had a rush-hour period traffic that exceeded the road's capacity, slowing down traffic not only on that road, but on nearby side roads. The

typical response would be to build another lane of highway to statically increase capacity. More targeted measures that would remove vehicles from the main road, by diverting travelers to an alternate form of transportation (trains or busses) or encouraging drivers to stay off the road at peak times (higher tolls during rush hour), would provide dynamic load reduction while utilizing existing capacity. This would be a more dynamic capacity solution, but would require that the alternative solutions are operational concurrent with the rush hour. Any load relief provide (whether static increases or dynamic responses) alleviates both the targeted road and nearby roads to a lesser degree.

Figure 25 below shows the load relief provided at different levels:



- **DER solution less efficient at relieving localized constraints:** Higher amounts of DER are required to achieve same amount of load relief when the constrained asset is local (e.g., primary feeder or network transformer).

• Power flow from DERs spreads across the network to other feeders and network transformers.

Figure 25- DER Locational Efficiency in a mesh network system, internal analysis and graphics based on Time and Locational Value of DER: Methods and Applications, EPRI, Palo Alto, CA, 3002008687

The Company has taken steps recently to probabilistically evaluate the need for feeder load relief in order to lengthen the present nine-month feeder load relief window. The procedures that dictate the criteria for planning and implementing load relief projects are being reevaluated to defer projects beyond the typical nine-month implementation time, which would both reduce capital expenditure costs and increase the likelihood that DER could meet the load relief needs.

As highlighted in the section discussing reliability planning criteria, the reliability of the solution for meeting load relief needs is paramount to maintaining the overall reliability of the distribution system. With traditional solutions, these reliability ratings are well known and analyzed. For DER solutions, the Company will need more visibility and insight into DER performance to verify the reliability of the non-traditional solution delivers approximately the same level of reliable service as the traditional

solution. In addition to the reliability of the solution, the revisions to processes related to feeder load relief that are being considered require consideration of the following factors:

- Projected overloads (as a percent of capacity)
- Availability of manual switching remediation plans
- Availability of SCADA enabled switching plans
- Reliability of the network, as described by the Network Reliability Index (NRI) rating
- DER Diversity/Reliability (*e.g.,* Location/Fuel Type/Generator Type)

The Company is evaluating increasing the bounds of tolerable emergency overloads in both N-2 and N-1 areas from 10 percent to 15 percent if the overloads can be remedied by remote SCADA-enabled Primary Cable Remediation switching plans. The general effect of this will be to defer action taken on projected overloads if a readily available solution is in place to mitigate any damaging effects of the overload.

Feeder level load relief projects are also subject to deferral based on the projected overload and the NRI rating of the network, which itself is based on component ratings and physical characteristics, local loading conditions, and available redundancy. The deferral periods allow sufficient time for non-traditional DER solutions to be evaluated and potentially implemented against traditional reinforcement plans. The risk of deferral is mitigated through available manual Primary Cable Remediation Plans that reduce the overload to 100 percent or below by transferring high tension or network transformer multi-bank load to other feeders load to the grid through operational methods. The table below summarizes the proposed deferrals based on the overloads and NRI ratings. The network reliability index[61] is used to determine the relative strength of each network by calculating the probability of failure of multiple associated feeders within a network over time as caused by individual component failures. The network reliability index is used to help the Company prioritize its conventional infrastructure investments.

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[61] Case 07-E-0392, *Ordinary Tariff Filing of Consolidated Edison Company of New York, Inc. to Modify Rider U - Distribution Load Relief Program to Enhance Participation in the Program, Consolidated Edison Company of New York, Inc.*, Order Regarding Tariff Filings (issued April 24, 2008) and Case 08-E-0176, *Ordinary Tariff Filing of Consolidated Edison Company of New York, Inc. to Make Revisions to Rider U - Distribution Load Relief Program, Consolidated Edison Company of New York, Inc.*, Order Regarding Tariff Filing to Make Revisions to Rider U - Distribution Load Relief Program (issued April 8, 2009).

NRI Rating	Overload	Deferral
< 0.2	10% or less	Up to 3 Summer load periods
>= 0.2 and <= 0.8	10% or less	Up to 1 Summer load period
>= 0.2 and <= 0.8	5% or less	Up to 3 Summer load periods
> 0.8	5% or less	Up to 1 Summer load period

Table 18 – Feeder Load Relief Deferral

The proposed changes to internal processes would also modify the effect of local distributed resources in reduced load, based on the network NRI rating, and the past performance of the DER, as follows:

Several different analyses will be conducted when evaluating acceptable feeder overload limits with DER integrated solutions. The first will be to consider whether or not using the loading data from the last planning peak, with DG operational data embedded in the load flow data, if there are any projected overloads for the coming peak. If not, then the first criterion has been met. However, analysis is also performed to determine the impact of the DER should it not be available for future peaks. Load flow analysis will also be conducted with a worst case scenario, if all DG were assumed operational for the prior period peak, but not operational for the upcoming network peak. If that impact is not seen as sustainable (based on the reliability of the network as judged by the NRI rating – described below), then work is required (load relief or more DER). The table below summarizes the proposed allowable overload limits, based on NRI rating of the local network and the different planning cases:

NRI Rating	DER Integrated "Planning Case"	All DER Removed "Worst Case Scenario"	Remove ONLY the largest single DER
< 0.2 (50% of Networks)	100%	115%	115%
>= 0.2 and <= 0.8 (25% of Networks)	100%	110%	110%
> 0.8 (25% of Networks)	100%	105%	105%

Table 19- Summary of Overload Limits Based on Planning Cases and NRI Rating

The general effect of the crediting of load reduction by DER will be to more accurately account for the relief that DER provide on a local feeder basis and avoid infrastructure investment in areas that are already well protected. In addition, the Company is incorporating DER into the NRI to recognize the reliability impact on the various network's reliability rating.

The Company is similarly revising procedures for deferring transformer projects, also based on the rating of the equipment and the reliability of the local network. Again analysis must be performed to analyze for overloads both with and without DG included. The proposed limits for allowable transformer overloads are currently under development and, as with the feeder limits, will be based on the planning case and reliability of the network (as measured by NRI).

c) *DER Solutions as Alternatives to Traditional Infrastructure*

Portfolios of DER solutions will be evaluated to determine their cost-effectiveness using the BCA Handbook and factors related to the cost of the project, the ability of each solution to meet the load relief timeline, the dependability/reliability of the DER solution, and any additional benefits, such as operational reliability benefits, providing excess capacity, and effects on surrounding areas. In all cases, the DER solution, or portfolio of solutions, must provide the dependability and reliability of a traditional grid solution when needed to meet the projected overload. Once the necessities of the project are addressed (timeline, reliability, full duration of the overload), the costs and benefits of the proposed solutions, both DER and traditional, are compared by the Distributed Resource Integration (DRI), Distribution Engineering (DE), or Regional Engineering teams as appropriate. In all cases, the utility maintains its role as the provider of last resort, and must plan traditional solutions as the backstop plan if DERs cannot be procured as needed to meet project timelines or capacity needs. Over time, the Company expects this will improve as the DER penetration increases and DER providers become more proficient at responding to capital needs. As Dr. Susan Tierney described in her recent analysis, *The Value of "DER" to "D"*:

> Competitive solicitations can reveal the portfolio of DERs with the attributes to satisfy the utility's local reliability requirements at lowest cost. The utility can then enter into contracts to assure that those DERs enter the market and help to resolve local reliability problems cost-effectively and reliably. Periodic procurements would also be able to take into account the changes that inevitably occur on the distribution system over time, with some changes pushing out the date of need and others leading to earlier reliability challenges than previously anticipated.[62]

As the BQDM program has demonstrated, sometimes a portfolio of DER solutions can be used to defer traditional infrastructure projects. The process by which these solutions are identified and implemented is discussed in greater detail in the Identify Beneficial Locations for DER Deployment Section.

3. Electric Distribution Capital Investment Plan

Con Edison invests capital on its system to provide safe, reliable, and cost-effective energy to all of its customers. This section describes the electric distribution system plan for asset management, regulatory compliance, and system growth and identifies the necessary design, operation, and infrastructure required to meet the required reliability standards (discussed earlier in this section). In

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[62] Tierney, Susan F., *The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability* (March 31, 2016) (Tierney White Paper). Dr. Tierney's White Paper may be found in Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Comments of the Joint Utilities on an Interim Successor to Net Energy Metering (filed April 18, 2016), Appendix B.

this and the following section, the Company will discuss how DERs are integrated into the planning process.

Budget Categories

The Company's distribution capital expenditure investments to maintain system reliability are categorized as New Business, System Expansion, Risk Reduction/Reliability, Replacement, Equipment Purchases, Environmental, Municipal Infrastructure Support, Storm Hardening, and Information Technology. These categories have evolved and provide an efficient means of managing the capital spend and focusing efforts on serving customers and maintaining and improving the safety and reliability of the system.

1. New Business – Investments required to connect customers to the Company's electric system.

2. System Expansion - Projects or programs that increase system capacity or provide new facilities or upgrades of existing facilities caused by customer demand growth or supply retirements.

3. Risk Reduction – Investments to support the reliability and/or availability of a facility or an operational function. This category also includes projects or programs that reduce or mitigate a risk associated with a facility or operation through proactive replacement strategies.

4. Replacement – Investments to replace failed, degraded, or difficult-to-maintain equipment.

5. Equipment Purchases – Investments required for the purchase of equipment such as transformers, network protectors, switches, and meters. As a rule of thumb, 100 percent of the meter purchases are allocated to New Business. For transformers, network protectors and switches, 45 percent are allocated to New Business and 55 percent are allocated to Replacement.

6. Environmental – Investments required to enhance environmental performance, reduce environmental impact, or comply with environmental regulatory requirements.

7. Municipal Infrastructure Support – Investments to relocate or otherwise support Company facilities impacted by Public Improvement/Interference.

8. Information Technology – Information Technology assigned to electric distribution.

9. Storm Hardening- Investments required to harden the overhead and underground electric systems. This capital allocation is specific to lessons learned from Hurricane Sandy and will be completed in 2016.

See **Figure 26** below for the breakdown of 2016 Electric Distribution Investment of $1,100,105,000.

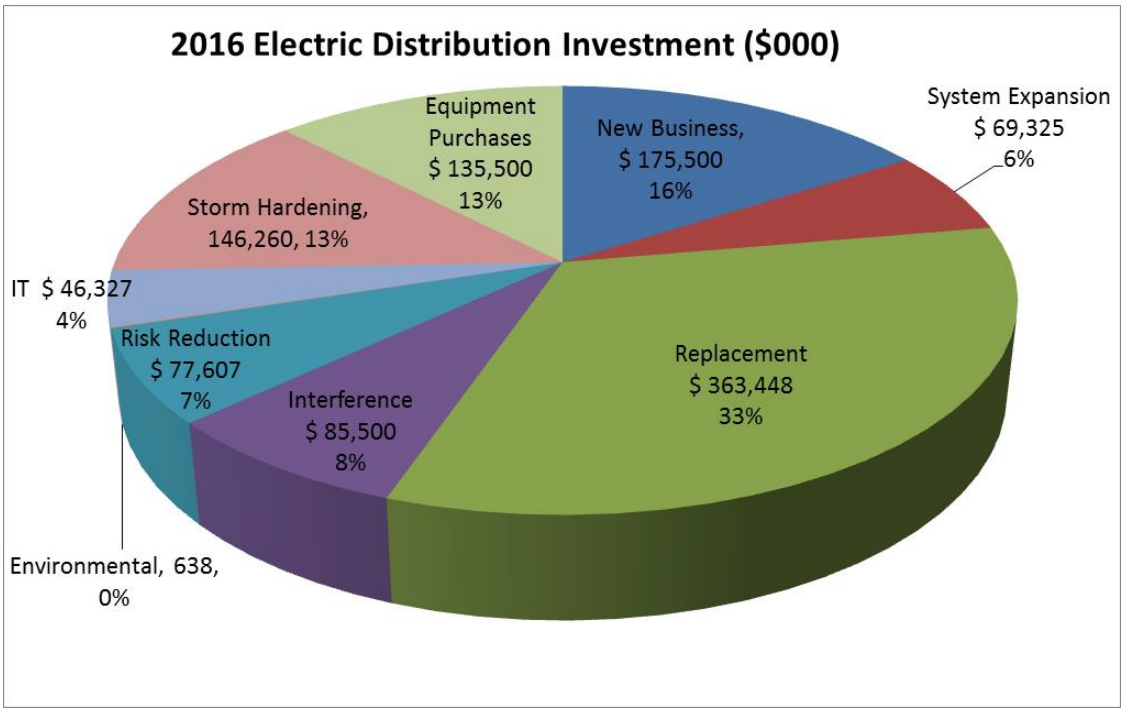

Figure 26 – 2016 Categorical Investments for the Distribution System

Electric Forecast and DER Market Implications for Capital Investments

As discussed in the Forecasting Section, developing an accurate electric forecast that takes into account population growth, usage patterns, and new technologies like DER and Electric Vehicles is critical to planning for electric system investments. This forecast drives the capital investments in the New Business and System Expansion categories and correspondingly the equipment purchases that support these categories (this accounts for roughly 37 percent of the capital budget in 2016). Replacement capital investment forecasts are based largely on historical experience. Interference investment forecasts are made taking into consideration large municipal projects that either New York City or Westchester County municipalities plan to undertake. Risk reduction investments are made based on compliance needs as well as targeted programs designed to improve reliability. Finally, storm hardening was created as a category to address issues raised by Hurricane Sandy, with associated spending to be completed in 2016. Overall, the electric system load growth is forecasted to be 0.2 percent annually (see **Figure 6** in the Forecasting section) representing slow but steady growth on the overall system; however, load growth in individual load areas is projected to be higher. At a system level, this load growth is predominately a reflection of the population growth and economic vitality of the Con Edison service territory. On the network load area level, load growth reflects specific neighborhood growth in that network. To date, given the low penetration of DER as compared with system peak loads, the impact of DER on capital investment has been limited. The area where DER can likely provide the greatest benefit is in utilizing NWA portfolios as substitutes for or to defer traditional

system expansion projects, as in the BQDM program. There are also opportunities to work with developers to encourage new business customers consider including DER in their energy portfolio.

In the areas with the highest load growth that are driving the system expansion, the Company is seeing a resurgence of certain residential neighborhoods, such as those in various parts of Brooklyn, and mixed-use neighborhoods, such as the Midtown West neighborhood in Manhattan. Contributing to the development of these mixed-use areas is the growth in the hospitality, tourism, healthcare, and technology sectors. The growth in these areas drives the need for utility and transportation infrastructure construction. The growth in Brooklyn is driving the BQDM project.

In total, as shown in **Table 20** below, there are 33 electric network areas that have compounded annual load growth rates of 1.0 percent or higher per year for the next five years, and in some of these networks, growth is much higher.

2016-2025 Network Area Forecasted Growth Rates		
Independent Summer Peak Demand Forecast (MW)		
Network Area (Excludes Radial Allocated Feeder Loads)		
Network		
	5-Yr CAGR	**10-Yr CAGR**
Freedom	28.0%	14.9%
Pennsylvania	7.1%	3.5%
Cortlandt	5.8%	3.3%
Roosevelt	6.4%	3.1%
Borden	4.5%	2.2%
Hudson	4.4%	2.0%
Boro Hall	3.8%	1.9%
Kips Bay	3.6%	1.7%
Long Island City	3.7%	1.7%
Turtle Bay	1.7%	1.4%
Grand Central	2.3%	1.3%
Sutton	1.9%	1.3%
Grasslands	2.6%	1.2%
Flushing	1.7%	1.1%
City Hall	2.2%	1.1%
Fashion	1.7%	1.0%
Prospect Park	1.7%	1.0%
Ridgewood	1.3%	0.9%
Sheridan Square	1.8%	0.9%
Chelsea	1.8%	0.9%
Lenox Hill	1.6%	0.9%
Plaza	1.4%	0.8%
Fulton	1.3%	0.8%
Triboro	1.4%	0.7%
Southeast Bronx	1.1%	0.7%
Williamsburg	1.2%	0.7%
Cooper Square	1.3%	0.7%
Herald Square	1.2%	0.6%
Yorkville	1.1%	0.6%
Beekman	1.1%	0.6%
Lincoln Square	1.3%	0.6%
Fox Hills	1.1%	0.6%
Ossining	1.3%	0.6%
Harlem	0.8%	0.5%
Brighton Beach	0.8%	0.5%
Granite Hill	0.6%	0.5%
Elmsford	0.8%	0.5%
Columbus Circle	0.8%	0.4%
Times Square	0.7%	0.4%
Bay Ridge	0.9%	0.4%
Madison Square	0.8%	0.4%
Randalls Island	0.1%	0.4%
Empire	0.6%	0.4%
Jamaica	0.4%	0.3%
White Plains	0.1%	0.3%

Table 20 - 2016-2025 Network Area Forecasted Growth Rates

The Company's forecast for 7.1 percent annual growth for five years for the Pennsylvania Network is due to the redevelopment of the west side of midtown Manhattan. This localized load

growth includes one of the largest private real estate developments in the history of the United States. The development will include more than 17 million square feet of commercial and residential space, including office towers, shops, restaurants, and residences. The second phase of the project will include more than seven million square feet of office and mixed-use space. This increased load growth has led to the creation of a new network, yet to be energized, named Midtown West, to alleviate overloads at a substation in the area.

The current ten-year forecasted compound annual growth rate for new housing in the area is approximately 0.7 percent, which corresponds to an increase of approximately 260,000 households by 2025. New construction projects in the Company's service territory include large commercial and large residential developments, renovations, and expansions as well as large transportation and municipal projects.

Capital Investment Detail:

Based on the forecast, the five-year electric distribution capital investment budget is shown below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget Total
Summary Electric Distribution						
New Business	175,500	168,765	166,569	168,857	173,764	853,455
System Expansion Less BQDM and REV	69,325	103,412	84,188	71,500	54,075	382,500
Risk Reduction	77,607	107,790	124,955	129,474	115,115	554,941
Replacement	363,448	389,156	387,505	389,722	390,093	1,919,924
Equipment Purchases	135,500	125,194	128,565	132,014	131,645	652,918
Environmental	638	667	695	715	718	3,433
Interference	85,500	77,501	77,168	70,394	78,800	389,363
Information Technology	46,327	36,445	21,116	15,068	14,412	133,368
Storm Hardening	146,260	0	0	0	0	146,260
Total Electric Distribution Capital	**$1,100,105**	**$1,008,930**	**$990,761**	**$977,744**	**$958,622**	**$5,036,162**

Table 21 - 2016-2020 Electric Distribution Capital Investment Budget

The following sections and **Appendix E** will discuss these expenditures in more detail. The BQDM costs are included in the Transmission discussion in the next section and the proposed REV budget will also be discussed in detail in the next section.

New Business

It is anticipated that New Business projects will require the Company to invest $853.5 million over the next five years as follows:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget Total
New Business						
New Business Capital	153,000	144,734	142,479	144,694	149,458	734,365
Meter Installation	22,500	24,031	24,090	24,163	24,306	119,090
Total	**$175,500**	**$168,765**	**$166,569**	**$168,857**	**$173,764**	**$853,455**

Table 22 - 2016-2020 Electric Distribution New Business Capital Investment Budget

Program Objectives

The New Business Capital program consists of projects that connect new customer load to the distribution system. The location of the new customer connection and local reliability criteria (N-1 or N-2 contingency) determines the infrastructure required to maintain reliability standards.

An analysis of the distribution system is performed each time load is added to the system. This analysis determines whether the existing system requires infrastructure upgrades in order to accommodate the new load. In addition to the facilities needed to interconnect an individual customer, upgrades to portions of the distribution system can be extensive, and include secondary main reinforcement, primary feeder extensions, and transformer vault installations to support these new loads.

The Meter Installation program is used for the installation of electric revenue meters and associated equipment for revenue collection as required by the PSC. Electric Operations personnel install metering equipment and revenue-grade instrument transformers. Meters are installed in new customer locations, in existing customer locations that were upgraded, and as replacements for mechanical meters. The AMI project does not account for the replacement of failed meters and new business work that will be performed by Electric Operations personnel.

These two New Business programs comprise the New Business projects. New Business Capital is tiered into three categories: New Business Major, New Business Retail, and New Business Conjunctional Reinforcement. New Business Major is comprised of customers with 1,000 kW or greater of estimated demand and represents 40 percent of the current annual budget. New Business Retail is comprised of customers with estimated demand less than 1,000 kW and represents approximately 45 percent of the annual budget. The remaining 15 percent of the annual budget is associated with conjunctional reinforcement required on the system to accept the additional new business load growth.

New Business Forecast

Over the next five years, the Company expects the trend for larger projects to remain flat, similar to the trend observed for smaller-scale and individual residential developments. Smaller projects are also foreseen to be flat. This forecast does include the City's plan to preserve 200,000 affordable housing units. The increase in funding in 2025 is accounted for as AMI is currently purchasing all meters. It is expected that this program will complete and the additional costs associated with buying and installing meters will return causing the increase.

New Business Forecasted Spending - does not include an allocation for equipment ($,000)

Cost Category	2016	2020	2025
New Business	$175,500	-1%	14%

Table 23 - New Business Forecasted Expenditures

System Expansion

The Company forecasts $382.5 million in capital investments for system expansions over the next five years and is actively soliciting NWA via the BQDM program for more than half of this capital investment.

The forecasted increase in customer demand in certain networks is causing projected overloads that exceed the local capacity. Enhancements to distribution system are needed to relieve those capacity constraints and serve the additional customer load.

The Company will use one or more of the following approaches to mitigate capacity constraints on the system at the lowest possible cost: (1) engage customers to reduce demand; (2) replace existing assets with ones that have higher capacity ratings; (3) install additional assets to increase system capacity, and (4) transfer load to other areas with spare capacity, and (5) DER, NWA, CSS, and USS.

There are fifteen programs/projects that comprise all of System Expansion projects at the distribution level as seen in the Table below: See **Appendix E** for description of each project and program.

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget Total
System Expansion						
Woodrow Load Area Autoloop		14,524				14,524
Part of Pennsylvania (74 MW) to create Midtown West network	3,000	0	0	0	0	3,000
Yards	6,000	8,265	3,585	1,837		19,687
Part of Richmond Hill/Brownsville (12MW) BQDM Traditional Solution	3,000	0	0	0	0	3,000
Sheridan to Canal	1,700	1,533	0	0	0	3,233
Part of Cooper Square (30 MW)	1,500	2,003	0	0	0	3,503
Cable Crossing (XW Riverdale & BQ Flushing)	7,733	7,631	8,587	1,008	1,014	25,973
59th Street Bridge Crossing	16,000	0	0	0	0	16,000
Yorkville Crossings and Feeder Relief	0	2,804	1,980	7,512	7,724	20,020
Part of Ridgewood/Brownsville to Glendale(85MW) BQDM Traditional Solution	16,500	30,225	32,088	19,242	0	98,055
Primary Feeder Relief	1,000	8,909	9,272	15,101	15,844	50,126
Network Transformer Relief	5,400	14,546	15,846	14,972	17,382	68,146
NonNetwork Fdr Relief (Open Wire)	1,484	6,955	6,874	6,970	7,283	29,566
Overhead Transformer Relief	2,307	2,394	2,097	2,062	2,299	11,159
Secondary Main Relief	3,701	3,623	3,859	2,796	2,529	16,508
Total	**$69,325**	**$103,412**	**$84,188**	**$71,500**	**$54,075**	**$382,500**

Table 24 - 2016-2020 Electric Distribution System Expansion Capital Investment Budget

System Expansion Forecast

Traditional Expansion Projects and programs are forecasted to decline slightly over the ten-year outlook, due to a reduction in need for capacity expansion due to the screening of capacity projects for possibility DER alternatives. Ease of access to third-party capital, such as the Green Bank and Clean

Energy Fund, may support the reduction in traditional expenditure. There are three load transfers that will be required by 2025: part of Pennsylvania network, part of City Hall network, and part of Chelsea network. These are the main drivers for the increase in spending in 2025.

System Expansion Forecasted Spending ($,000)

Cost Category	2016	2020	2025
System Expansion	69,325	-22%	-52%

Table 25 - Distribution System Expansion Forecasted Expenditures

Risk Reduction

It is anticipated that Risk Reduction needs will require the Company to invest more than $555 million over the next five years.

Risk Reduction programs and projects are designed to maintain the operational capability, reliability, and safety of the distribution system.

The Company's programs in this category address near-term reliability issues. The Company analyzes, assesses, and adjusts its capital programs to target expenditures to systems and components most in need of attention. Where deemed necessary and appropriate, Con Edison programmatically and continuously upgrades and proactively replaces system components before they become degraded or obsolete. This category also includes proactive programs, like the underground secondary reliability program, which systematically inspects all of the Company's underground structures.

There are fourteen programs/projects that comprise all of Risk Reduction programs at the distribution level. The five-year budget is shown below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget Total
Risk Reduction						
179th St Area Substation Reconstruction	500	480	469	477	488	2,414
Osmose (C Truss)	1,685	1,936	2,359	2,355	2,333	10,668
Aerial Cable Replacement	490	0	0	0	0	490
Vented Service Box Covers	8,250	7,625	7,376	7,613	0	30,864
Underground Secondary Reliability Program	25,880	46,212	63,055	68,095	68,084	271,326
Overhead Reliability	500	1,953	1,958	1,964	1,976	8,351
Transformer Vault Modernization	15,156	16,314	16,336	15,205	15,350	78,361
Remote Monitoring System 3rd Generation	4,446	4,708	4,005	4,044	3,222	20,425
Pressure, Temperature and Oil Sensors	5,055	5,550	6,405	6,433	0	23,443
Shunt reactors	2,500	1,272	1,286	1,269	1,290	7,617
URD Cable Rejuvenation/Fault Indicator	300	0	0	0	0	300
ATS Installation USS Reliability XW	669	0	0	0	0	669
Primary Feeder Reliability	9,000	12,999	13,049	13,226	13,261	61,535
Modernization and Other	3,176	8,741	8,657	8,793	9,111	38,478
Total	**$77,607**	**$107,790**	**$124,955**	**$129,474**	**$115,115**	**$554,941**

Table 26 - 2016-2025 Electric Distribution Risk Reduction Capital Investment Budget

See **Appendix E** for program objectives.

Risk Reduction Forecast

The Company will continue to utilize an asset management strategy in the establishment of a goal and the evaluation of the assets in the following programs: Underground Secondary Reliability, Non-Network Reliability, Primary Feeder Reliability, and Modernization and Other (USS 4kV Switchgear House Replacement and USS Transformer Replacement). The Primary Feeder Reliability program's goal was achieved in 2015 with all networks scoring above the targeted network reliability design standard. As reliability goals have been met (and will be maintained through the continued use of the NRI model), spending has decreased. As funds requirements for this program have decreased, funding has been reallocated to the Underground Secondary Reliability program in order to reduce manhole events by 2020 (as measured through Secondary Network Reliability Index). Modernization and Other has specific goals based upon USS transformer and switchgear models and replacements of equipment targeted by the models will continue. The balance of reliability programs described has program goals with defined end of program dates (when available). The Transformer Vault and Structure Modernization program is an annual program, projected to continue beyond the ten-year horizon of this assessment.

Risk Reduction Forecasted Spending ($,000)

Cost Category	2016	2020	2025
Risk Reduction	77,607	48%	104%

Table 27 - Distribution Risk Reduction Forecasted Expenditures

Replacement

It is anticipated that Replacement needs will require the Company to invest $1,920 million over the next five years.

Funding for each program under the Replacement category is based upon the historical rates of failure or degradation for each component covered by the program. The historical rates are normalized to account for major deviations. These programs are primarily emergency replacement, but in some cases (as with Direct Buried Cable (DBC)) include proactive replacement of components prior to the occurrence of degraded performance or failure. Distribution equipment replaced under this category includes burned-out underground and overhead primary and secondary cable or wire, conduit, transformers, and meters and services. Examples of this work are cable and splice abnormalities (known as C or D faults) or transformers that need to be taken off the system on an emergency basis due to leaks or other serious defects. Other types of replacement work covered by this program include repair and replacement of overhead poles, wire, and other equipment that fails during storms or other emergencies. The table below displays these capital expenditures:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget Total
Emergency Response - Replacement						
Primary Cable Replacement (OA's)	70,196	81,799	79,969	81,607	83,561	397,132
Overhead	35,588	38,242	38,379	38,508	38,825	189,542
Service Replacements	50,546	58,000	56,000	56,001	40,919	261,466
Street Lights (incl. conduit)	22,073	19,106	18,781	19,947	20,235	100,142
Transformer Installation	31,587	33,173	33,228	33,294	32,890	164,172
Secondary Open Mains	148,534	154,086	156,479	155,634	168,786	783,519
Targeted Primary DBC Replacement	4,924	4,750	4,669	4,731	4,877	23,951
Total	**$363,448**	**$389,156**	**$387,505**	**$389,722**	**$390,093**	**$1,919,924**

Table 28 - 2016-2020 Electric Distribution Replacement Capital Investment Budget

Appendix E describes these categories in more detail.

Numerous snow storms occurred in the winter of 2014-2015, that affected the underground system. There were 15.3 inches of snow in January, 11.9 inches in February and 18.6 inches in March. The total snow was 45.8 inches, which is 49 percent above the historical yearly average for New York City of 30.7 inches. The salting from these events leads to insulation breakdown of underground equipment. As such, the number of failures funded by the Service Replacement program, Street Lights Including Conduit) program, and Secondary Open Mains program during this period was higher than the historical average and increased the number of on-hand repairs that need to be made in these programs.

As discussed in the next section, at this time the Company does not plan to utilize DER for emergency and replacement work due to the urgency of the need (which can include restoring customers to service) and the need to restore the system to design conditions. The Company, however, has identified two specific areas of Replacement investment in which it is already considering DER. Before deciding to replace any of its open mains or transformer banks-off (*i.e.*, failed-in-service

equipment), the Company reviews its load models to verify whether the equipment is still required to meet its peak demand system design criteria. Because the Company's load models already incorporate DER forecasts, the Company is able to account for the future deployment of DER in its decision-making process to replace or retire failed-in-service mains and transformer banks.

Replacement Forecast

Overhead Emergency Response will continue to make repairs to in-service non-network distribution system failures and run at a zero backlog. Service replacements will continue to add additional units as backlog reduction until a three-month working backlog is achieved. At the current level of funding this is anticipated by year end 2019. Street lights will continue to make repairs with a goal to be under the current RPM's. Transformer installation will address network banks-off and will continue with additional units until a three-month working backlog is achieved. Secondary open mains will continue to prioritize each open main and will work with additional units until the backlog is reduced. Targeted Direct Buried Cable (DBC) replacement is currently targeting developments with failure prone DBC cables and is on a twenty-year replacement goal. The forecast reflects historical experience and backlogs.

Replacement Forecasted Spending ($,000)

Cost Category	2016	2020	2025
Replacement	363,448	7%	11%

Table 29 - Distribution Replacement Forecasted Expenditures

Equipment Purchases

It is anticipated that Equipment Purchases needs will require the Company to invest $653 million over the next five years in support of New Business, Replacement, and to a lesser extent System Expansion. To the extent DER influences New Business and Replacement investments, it would impact this category.

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget Total
Equipment Purchases						
Meter Purchase	11,500	0	0	0	0	11,500
Transformer Purchase	124,000	125,194	128,565	132,014	131,645	641,418
Total Equipment Purchases	**135,500**	**125,194**	**128,565**	**132,014**	**131,645**	**$652,918**

Table 30 - 2016-2020 Electric Distribution Equipment Purchases Capital Investment Budget

The Transformer Purchase program purchases new and/or reconditioned electrical distribution equipment, primarily underground network transformers, overhead transformers, pad mount transformers (including mini-pads), emergency generators, and network protectors to support the distribution system for relief, reliability/risk reduction, emergency, and growth programs.

The Meter Purchase program purchases PSC-approved electric revenue meters and associated metering equipment, such as revenue-grade instrument transformers, used for usage monitoring and

revenue collection. Approximately 167,000 electric meters and associated electric metering devices are required per year. These meters are installed in new customer locations, in existing customer locations that were upgraded and thus require a new meter, and as replacements for mechanical meters which require more frequent testing.

The Company's proposal for the use of AMI meters as a replacement for all existing metering and new meter applications were approved by the PSC on March 17, 2016.[63] Accordingly, no funding is currently being requested to fund the purchase of the existing type of meters.

Program Objectives

The Transformer Purchase program funding is needed to provide Electric Operations Construction and Energy Services with electrical distribution equipment in order to complete active and anticipated burnout, new business, system relief, and reinforcement projects. The Company continues to institute and expand the various failure mitigation programs to identify the electrical distribution equipment on its system for which removal is most urgent. These programs are designed to proactively inspect field equipment, replace equipment that exhibits warning signs of potential failure, safeguard the public, and maintain system reliability.

The equipment funded under this program is categorized as follows:

- Underground Network Transformers 45%
- Network Protectors 35%
- Non-Network (Overhead / Padmount) Transformers 10%
- Other (Shunt Reactors, Capacitors, *etc.*) 10%

In 2016, transformer and network protector purchases support storm-hardening initiatives, such as upgrading of 480V network protectors to submersible designs and replacement of non-submersible 125/216V network transformers and protectors with submersible equipment. Storm hardening is projected to end by year end 2016.

Equipment Purchase Forecast

Transformer equipment purchases are forecasted to decline slightly over the ten-year outlook. This decline will be driven by a reduction in units replaced due to corrosion and manufacturing defects

[63] 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*, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions (issued March 17, 2016) (AMI Order).

as well as a reduction system needs for system reinforcement and new business as DER penetration increases and serves system needs.

Equipment Purchase Forecasted Spending ($,000)

Cost Category	2016	2020	2025
Equipment Purchases	135,500	-3%	11%

Table 31 - Distribution Risk Equipment Purchases Forecasted Expenditures

Environmental

It is anticipated that Environmental program needs at the distribution level will require the Company to invest $3.4 million over the next five years.

Program Objectives

The Oil Minder program provides funding for the installation of oil minders in underground network transformer vaults. The Oil Minder program was developed to prevent the pumped discharge of dielectric fluid from network transformers into the sewer system. An oil minder senses oil in water and disables the associated sump pump to prevent the discharge of oil. The oil minder control system registers an alarm in the local control room through the Remote Monitoring System (RMS) whenever the oil minder operates. This remote warning signal facilitates early detection and cleanup of leaking dielectric fluid. The Company plans to continue this program at a rate of 75-100 new oil minder installations per year.

Environmental Forecast

There are approximately 5,700 oil minders installed in the system in underground vaults. Oil minder installations are prioritized by first addressing older transformers which are more likely to leak and then addressing newer transformer installations which are added to the Company's system every year.

Oil minder installation is expected to be completed at the end of this ten-year outlook. This timing corresponds with the completion of the current cycle of Secondary Inspection Programs/Computerized Inspection of Network Distribution Engineering (SIP/CINDE) inspections such that all transformer locations visited with a sump pump will have an oil minder also equipped.

Additional new environmental programs are anticipated upon completion of the Oil Minder Program, and thus the need for Environmental program investment will continue in the ten-year horizon.

Environmental Forecasted Spending ($,000)

Cost Category	2016	2020	2025
Environmental	$638	13%	57%

Table 32 - Distribution Environmental Forecasted Expenditures

Municipal Infrastructure Support (Interference)

It is anticipated that municipal infrastructure support will require the Company to invest $389.4 million over the next five years.

Program Objectives

When New York City or another municipality performs work, such as installing or repairing a sewer or water main in the vicinity of the Company's facilities, the Company bears all the costs to locate, move, support, protect, and/or relocate the facilities affected by the municipality's construction activity.

Interference can be direct or indirect. A direct interference is when an existing Con Edison facility occupies the space of a proposed municipal facility and must be located, identified, and relocated to a new location in order to accommodate and provide space for a new municipal facility. An indirect interference is when Con Edison facilities do not occupy the space of the proposed municipal facilities, but requires the Company to identify the location of its facilities, monitor construction work by the municipality's contractor, and take steps necessary to support and protect its facilities.

The typical municipal activities that affect Company facilities are the installation of water, sewer and drainage facilities, reconstruction of roads, highway bridges, curbs, and sidewalks, and the repaving of roadways.

Municipal Infrastructure Forecast

Municipal infrastructure forecasts are related to municipal project planning and are subject to material changes, both up and down, based on evolving changes in public policy, community needs and public safety concerns.

Municipal Infrastructure Spending ($,000)

Cost Category	2016	2020	2025
Interference	85,500	-8%	-6%

Table 33 - Distribution Municipal Infrastructure Forecasted Expenditures

Information Technology

The Information Technology category specifically identifies information technology expenditures assigned to the electric distribution capital budget.

Information Technology Spending ($,000)

Cost Category	2016	2020	2025
Information Technology	46,327	-69%	-62%

Table 34 - Distribution IT Forecasted Expenditure

Storm Hardening

The Company's Storm Hardening project will introduce a number of measures to make the underground and overhead systems more resilient to storm events. The goal of these measures is to minimize the extent of damage to and de-energization of networks, maintain public safety, and recover from storm events in an expeditious manner. The storm hardening investment will conclude in 2016. This is the only distribution level storm hardening program during the five-year period of the DSIP.

Program Objectives

Underground Storm Hardening: In the underground systems, 903 non-submersible 120/208 V transformer/network protector units in the Federal Emergency Management Administration (FEMA) 100-year-plus-three-feet zone throughout the electric system will be replaced with submersible equipment. 110 network protectors are planned for 2016. There are 417 non-submersible 460 V network protectors in the FEMA 100-year-plus-three-feet zone throughout the electric system will be replaced with submersible equipment. There are 111 network protectors planned for 2016. 22 underground primary switches will be installed in order to isolate High Tension Customers. This work is expected to be completed in 2016.

Overhead Storm Hardening: In order to reduce storm impact to customers, non-network feeder segments will be reduced to sizes of fewer than 500 customers where feasible. This will be accomplished through installation of additional automatic devices (reclosers or gang switches). 200 Kyle switches are planned for in 2016. Fuses, fuse bypass switches, and automatic sectionalizing switches will continue to be added to spurs and sub-spurs with open wire that are more than two spans in length (about 200 feet). 185 fuse locations are planned. Through use of the NNRI (Non Network Reliability Index) application, measures to include the reliability of auto-loops have been undertaken including:

- Introducing additional supply feeders to allow for continued service during feeder outages
- Dividing large auto loops into several smaller loops
- Upgrading wire and pole sizes to improve storm resiliency
- Using of Hendrix Aerial Cable which has been proven to be more resilient than traditional open wire design
- Adding sacrificial components, such as breakaway hardware and detachable service cable and equipment to prevent pole and customer equipment damage during storms

- Undergrounding of selective components.

The following loops currently have storm hardening projects working in 2016:

Auto-Loops with 2016 Storm Hardening Work
Banksville Loop in BQ
Dyker Loop in BQ
Gravesend Loop in BQ
Marine Park Loop in BQ
Croton Loop In BW
West Laconia Loop in BW
Sing-Sing Loop in BW
Ossining Loops 1 & 2 in BW
East Laconia Loop in BW
Elmsford Loop in BW
Harbor Island Loop in BW
Bowman Loop in BW
Southside Loop in BW
Port Chester Loop in BW
Ludlow Loop in BW
Warburton Loop in BW
Tuckahoe Loop in BW
Gun Hill Loop in the BW
Lake St Loop in BW
Hamilton Loop in BW
Furnace Dock Loop in BW
Eastchester Loop in BW
Shrub Oak Loop in BW
Ridge Street Loop in BW
Clason Pt Loop in BW
Woodlawn Loop in BW
Sommers Loop in BW
Ferncliff Loop

Table 34 - Auto-Loops with 2016 Storm Hardening Work

Additionally, three Staten Island feeders (33R06, 33R13, and 33R15), 39 projects to underground overhead facilities, and 685 breakaway service connections will be installed in Westchester County and all have storm hardening projects.

Storm Hardening Forecast

All distribution storm hardening projects are anticipated to be completed by year-end 2016.

Storm Hardening Spending ($,000)

Cost Category	2016	2020	2025
Storm Hardening	146,260	-100%	-100%

Table 36 -Distribution Storm Hardening Forecasted Expenditure

Optimization of Distribution Capital Programs

All distribution capital programs or projects are scored and optimized. Capital Optimization is the first step of the capital budgeting process and aligns and ranks all capital project and program requests with the Corporate Strategic Drivers, Risks, and Benefits. Proposed capital projects or programs are grouped under one of three categories—Regulatory Mandated, Operationally Required, or Strategic. The Company has adopted a strategic alignment methodology to evaluate projects and programs so that funds are allocated to reduce operating risks and meet strategic objectives efficiently. This methodology takes into account the portfolio's cost, benefits, and weighted strategic value allowing for analysis of all projects and programs as an integrated portfolio. Business Improvement Services and Business Finance perform the optimization analysis by applying the constraints outlined in the Budget Guideline Memos. In addition, they provide the strategic value and ranking of the projects and programs within the portfolio to the respective portfolio Optimization teams. Several iterations may occur until an optimized the portfolio is submitted and approved by the Electric Governance Committee. The final recommended portfolio is then input into the next step of the budget process.

The Company has identified and prioritized nine Strategic Drivers (Enhance External Relationships, Improve Customer Experience, Improve Public and Employee Safety, Provide Reliable Service, Reduce and Manage Risk, Reduce Cost to Customers, Strengthen and Develop Employees, Strengthen Company Processes and Sustain Environmental Excellence). Each driver has a corresponding weighting, with a combined total of 100 percent.

The Company has further identified measurement criteria that are used to assess the level of a project's impact on each of the strategic drivers. Each project is rated as extreme, strong, moderate, low, or none based on individual criteria for each driver. The final strategic value is determined by the weight of the driver and the mathematical sum of the weightings across all nine drivers, yielding a relative ranking/score per project.

See **Table 37** below for the 2016 optimization of distribution programs/projects.

No.	Project Name	Priority
1	120_208 V Non-Submersible Unit Replacement	1.33%
2	460V Network Protector Replacement	1.29%

No.	Project Name	Priority
3	Overhead Equipment Upgrades	1.29%
4	Selective Undergrounding	1.29%
5	Switches for Network Redesign	1.18%
6	Primary Feeder Reliability	1.10%
7	BQDM	1.03%
8	Part of Cooper Square (30 MW)	1.03%
9	Part of Pennsylvania (74 MW) to create Midtown West network	1.03%
10	Part of Richmond Hill-Brownsville (12 MW)	1.03%
11	Part of Ridgewood /_Brownsville to Glendale (85MW)	1.03%
12	Penn Network New feeders for Hudson Yards	1.03%
13	Sheridan to Canal	1.03%
14	New Business Capital	1.01%
15	Pressure, Temperature and Oil Sensors	0.97%
16	Overhead (Emergency Response)	0.96%
17	Temporary Services (including conduit)	0.92%
18	Primary Cable Replacement (OA_s)	0.91%
19	Vented Service Box Covers	0.89%
20	Remote Monitoring System 3rd Generation	0.80%
21	Street Lights (including conduit)	0.75%
22	Secondary Open Mains	0.73%
23	Transformer Vault Modernization	0.71%
24	ATS Installation USS Reliability XW	0.69%
25	179th St Area Substation Reconstruction	0.64%
26	59th Street Bridge Crossing	0.64%
27	Underground Secondary Reliability Program	0.64%
28	Primary Feeder Relief	0.62%
29	Yorkville Crossings and Feeder Relief	0.60%
30	Network Transformer Relief	0.58%
31	Targeted Primary DBC Replacement	0.57%
32	Aerial Cable Replacement	0.53%
33	Meter Installation	0.53%
34	Meter Purchase	0.53%
35	Overhead Transformer Relief	0.53%
36	4 kV USS Switchgear House Replacement	0.50%
37	Interference	0.44%
38	Secondary Main Relief	0.44%
39	Non-Network Feeder Relief (Open Wire)	0.43%
40	Transformer Purchase - Storm Hardening	0.43%
41	4 kV UG Reliability	0.40%
42	Cable Crossing (XW Riverdale/BQ Flushing)	0.38%

No.	Project Name	Priority
43	USS Transformer Replacement Program	0.36%
44	Transformer Installation	0.34%
45	USS Life Extension	0.31%
46	Shunt Reactors	0.29%
47	Tap Changer Position Indicator System Frame Relay	0.28%
48	Osmose (C Truss)	0.27%
49	Transformer Purchase	0.24%
50	_4 _ _6 Self Supporting Wire	0.17%
51	Oil Minders	0.17%
52	USS Transformer Temperature Gauges	0.14%
53	URD Cable Rejuvenation Fault Indicator	0.13%

Table 35 - 2016 Optimization of Distribution Programs/Projects

Capital Expenditures

Once projects have been approved and budgets are finalized, each operational area has controls in place to review expenditures. Business units review capital expenditures against the monthly and year-to-date annual budget. Business Finance prepares, issues, and distributes to appropriate Con Edison personnel a monthly capital budget status report. This report provides information as to approved budget amount, actual expenditures, and explanations of significant variances. Based on the analyses of the year-to-date variance to the budget, the annual Capital Budget can be adjusted by the governance committees or senior officers. Business Finance monitors variances between the authorization, appropriation, and expenditure levels on all individual capital projects, as well as the overall capital budget funding level. This continuous review of capital expenditures for projects, variance from budget analyses and related reports, and additional levels of approvals allows for the close monitoring and controls of capital expenditures.

4. Electric Substation System Operations (SSO) Capital Investment Plan

The Substation System Operations (SSO) Capital investments are made to support the safe, reliable and cost-effective energy to all customers and to provide funding at the area substation level which sits between the transmission system and the electric distribution system. The substation investments follow similar categories to the distribution capital investments with the exception of New Business (which takes place specifically at the distribution level) equipment purchases which is not broken out at the substation level and interference.

Budget Categories

The Company's capital investments in substations are presented under the following categories: System Expansion, Risk Reduction/Reliability, Replacement, Environmental, Information Technology, and Storm Hardening. These categories have evolved and provide an efficient means of serving customers while maintaining and improving the safety and reliability of the system.

1. System Expansion - Projects or programs that increase system capacity or provide new facilities or upgrades of existing facilities caused by customer demand growth or supply retirements.
2. Risk Reduction – Investments to support the reliability and/or availability of a facility or an operational function. This category also includes projects or programs that reduce or mitigate a risk associated with a facility or operation through proactive replacement strategies.
3. Replacement – Investments to replace failed, degraded, or difficult-to-maintain equipment.
4. Environmental – Investments to enhance environmental performance, reduce environmental impact, or comply with environmental regulatory requirements.
5. Information Technology – Information Technology assigned to electric distribution.
6. Storm Hardening- Investments required to harden substation and associated equipment. This category was the result of lessons learned from Hurricane Sandy.

See chart below for the breakdown of 2016 Substation Capital Investment of $382,380,000.

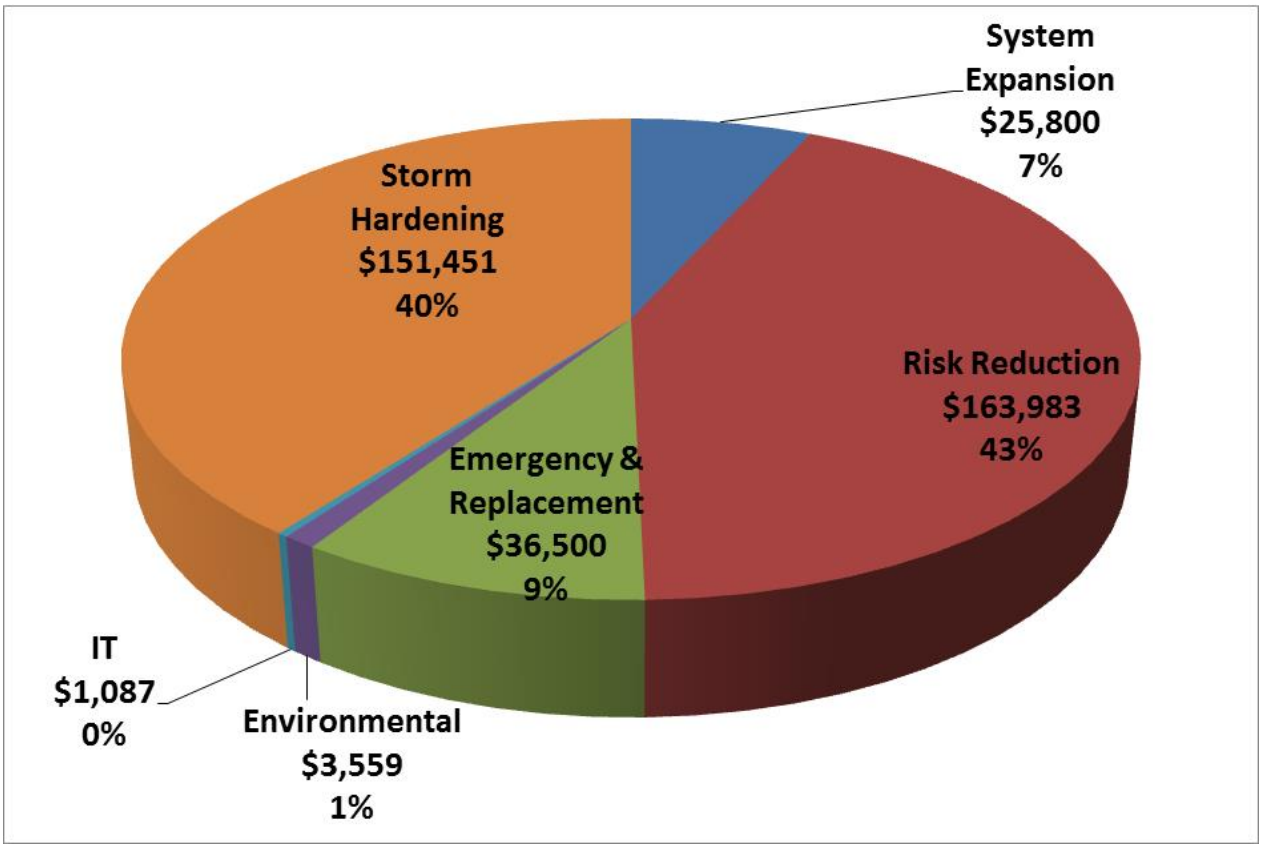

Figure 27 - 2016 Categorical Investments for SSO

Electric Forecast:

The electric forecast that is discussed in the Electric Distribution section is the same forecast used to inform these investments.

SSO - Capital Investment Detail:

Based on the forecast, the five-year electric substation operations capital investment budget is shown below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Summary Substations						
System Expansion	$ 25,800	$ 86,937	$ 69,851	$ 17,769	$ 13,600	$ 213,957
Risk Reduction	$ 163,983	$ 224,296	$ 211,306	$ 170,575	$ 155,020	$ 925,180
Emergency and Replacement	$ 36,500	$ 36,500	$ 36,500	$ 36,500	$ 36,500	$ 182,500
Environmental	$ 3,559	$ 15,775	$ 16,375	$ 19,625	$ 17,775	$ 73,109
Information Technology	$ 1,087	$ 1,081	$ 1,077	$ 1,077	$ 1,077	$ 5,399
Storm Hardening	$ 151,451	$ 34,700	$ 17,700	$ 10,000	$ 7,119	$ 220,970
Total Electric Substation (SSO) Capital	**$382,380**	**$399,289**	**$352,809**	**$255,546**	**$231,092**	**$1,621,115**

Table 36 - Five Year Substation Operations (SSO) Capital Investment Budget

SSO - System Expansion

The Company forecasts $214.0 million in capital investments for system expansions over the next five years and is actively soliciting NWA via BQDM for more than half of this capital investment which includes both SSO and Electric Distribution Investments. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
System Expansion - SSO						
Cricket Valley Contractor Oversight	$ 250	$ 1,200	$ 1,000	$ -	$ -	$ 2,450
E179th St - Switchgear and Bus Replacement	$ 10,000	$ 3,800	$ 3,400	$ 9,700	$ 12,200	$ 39,100
East 179 St. Transformer #4 - Fans for Bus, Bkr & Reactor	$ 750	$ -	$ -	$ -	$ -	$ 750
East 179 Street - Install water spray on Transformer #5	$ 500	$ 475	$ -	$ -	$ -	$ 975
Emergent Load Relief Program	$ 1,100	$ 1,100	$ 1,100	$ 1,100	$ 1,100	$ 5,500
Greenwood - Install Surge Arrestor, Bkr 3N, and Reconfigure Station	$ -	$ 9,197	$ 4,563	$ -	$ -	$ 13,760
New 138kV Fdr Vernon-Glendale & Newtown & Inst 5th Tsf @ Glendale	$ 2,000	$ 65,178	$ 59,788	$ 6,969	$ -	$ 133,935
Parkchester 2 - Replace Limiting 13KV Bus Sections No. 2	$ 3,300	$ 1,616	$ -	$ -	$ -	$ 4,916
Plymouth Street - Install Transformer Cooling on all Transformers	$ 2,500	$ 2,375	$ -	$ -	$ -	$ 4,875
Queensbridge: Replace Overdutied Disconnect Switches (3ES0800)	$ 1,000	$ 950	$ -	$ -	$ -	$ 1,950
Replace Limiting Bus at Plymouth Street	$ 4,400	$ 1,045	$ -	$ -	$ -	$ 5,445
Uprate Syn Bus Sections At West 65th Street	$ -	$ -	$ -	$ -	$ 300	$ 300
System Expansion Total	**$25,800**	**$86,937**	**$69,851**	**$17,769**	**$13,600**	**$213,957**

Table 37 - Five Year SSO System Expansion Budget

SSO - Risk Reduction

It is anticipated that Risk Reduction, which also includes safety and security investments such as substation security enhancement programs, will require the Company to invest $925 million over the next five years. Risk Reduction programs and projects are designed to maintain the operational capability, reliability, and safety at the area substation level. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Risk Reduction						
138 kV Feeders 34051 & 34052 Reactors Foundation	$ -	$ 7,120	$ 3,038	$ -	$ -	$ 10,158
138kV Disturbance Monitoring Program	$ 5,503	$ 8,518	$ 8,430	$ 6,318	$ 6,318	$ 35,087
Area Substation Reliability	$ 10,000	$ 9,952	$ 9,508	$ 10,776	$ 10,776	$ 51,012
Buchanan - Addition of New Breakers for Nuclear Switchyard	$ -	$ 6,000	$ 6,000	$ -	$ -	$ 12,000
Buchanan - Y94 Upgrade to Solid Dielectric	$ 9,900	$ -	$ -	$ -	$ -	$ 9,900
Category Alarm Program	$ 2,680	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 14,681
Circuit Switcher Replacement Program	$ 1,500	$ 1,500	$ -	$ -	$ -	$ 3,000
Condition Based Monitoring	$ 275	$ 279	$ 281	$ 281	$ 281	$ 1,397
DC System Upgrade Program	$ 2,994	$ 5,678	$ 4,637	$ 5,900	$ 5,900	$ 25,109
Disconnect Switch Capital Upgrade Program	$ 3,500	$ 3,499	$ 3,000	$ 3,500	$ 3,500	$ 16,999
East River Automation - Upgrade The 69KV Yard	$ 4,000	$ 4,000	$ 4,000	$ -	$ -	$ 12,000
Farragut - Feeder 32077 Breaker and V Disconnect Switch Addition	$ -	$ -	$ 500	$ 3,280	$ -	$ 3,780
Fire Suppression System Upgrades	$ 6,000	$ 9,000	$ 8,000	$ 7,000	$ 7,000	$ 37,000
Gateway Park Substation	$ -	$ -	$ 1,425	$ 12,825	$ -	$ 14,250
GE Area Substation HMI Upgrade	$ 1,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 9,000
High Voltage Circuit Breaker Capital Upgrade Program	$ 8,715	$ 9,500	$ 9,500	$ 9,500	$ 9,500	$ 46,715
High Voltage Test Set Program	$ 4,585	$ 3,644	$ 4,182	$ 3,682	$ 3,682	$ 19,775
Jamaica - Install Additional 138kV Breakers in B/S 2E & 3W	$ 5,000	$ 5,000	$ -	$ -	$ -	$ 10,000
Other Capital Equipment Upgrades	$ 3,673	$ 3,200	$ 4,000	$ 4,000	$ 4,000	$ 18,873
Pumping Plant Improvement Program	$ 6,650	$ 5,700	$ 5,700	$ 5,700	$ 5,700	$ 29,450
Ramapo - Install New Surge Arrestors	$ 764	$ 2,000	$ 2,000	$ -	$ -	$ 4,764
Reinforced Ground Grid Program	$ 1,605	$ 1,625	$ 1,639	$ 1,639	$ 1,639	$ 8,147
Relay House Enclosure Program	$ 500	$ 2,000	$ 1,030	$ 1,030	$ 1,030	$ 5,590
Relay Modifications Program	$ 9,750	$ 9,750	$ 9,750	$ 9,750	$ 10,000	$ 49,000
Relay Protection Communication Upgrades	$ 1,000	$ 5,500	$ 5,500	$ 5,500	$ 5,500	$ 23,000
Retrofit Overdutied 13kV and 27kV Circuit Breaker	$ 10,500	$ 10,500	$ 10,500	$ 10,500	$ 10,500	$ 52,500
Roof Replacement Program	$ 3,026	$ 3,065	$ 2,590	$ 3,090	$ 3,090	$ 14,861
SSO Loss Contingency Area Stat Rapid Recov/Transm Resiliency Tsfs	$ 6,800	$ 29,085	$ 37,500	$ -	$ -	$ 73,385
Stabilization of Pothead Stand	$ 1,010	$ 2,000	$ 2,862	$ 2,862	$ 2,862	$ 11,596
Structural and Infrastructure Upgrades	$ 6,852	$ 9,001	$ 9,001	$ 10,588	$ 10,888	$ 46,329
Substation Transformer Replacement Program	$ 25,000	$ 36,000	$ 24,354	$ 24,354	$ 24,354	$ 134,062
SwitchGear Enclosure Upgrade Program	$ 500	$ 500	$ 500	$ 500	$ 500	$ 2,500
Tejas RTU Replacements	$ 1,000	$ 1,001	$ 750	$ 1,000	$ 1,000	$ 4,750
Transmission Station Metering & SCADA	$ 700	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 12,700
U Type Bushing Replacement Program	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 15,000
Add Natural Gas To E13th Street Storm Hardening Generator	$ -	$ 2,400	$ 3,700	$ -	$ -	$ 6,100
Add Natural Gas To Fresh Kills Storm Hardening Generator	$ -	$ 280	$ 430	$ -	$ -	$ 710
+ Safety/Security:						
Critical Infrastructure Protection (NERC) Security Upgrades	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 5,000
Substations Security Enhancements Program	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 75,000
Risk Reduction Total	**$ 163,983**	**$ 224,296**	**$ 211,306**	**$ 170,575**	**$ 155,020**	**$ 925,180**

Table 38 - Five Year SSO Risk Reduction Capital Budget

SSO - Emergency & Replacement

It is anticipated that Replacement will require the Company to invest $182.5 million over the next five years. Funding for each program under the Replacement category is based upon the historical failure or degraded performance rates of each component covered by the program. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Emergency and Replacement						
Failed Substation Transformer Program	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 150,000
Failed Substation Equipment Other Than	$ 6,500	$ 6,500	$ 6,500	$ 6,500	$ 6,500	$ 32,500
Charges To Completed Projects - Failures	$ -	$ -	$ -	$ -	$ -	$ -
Emergency and Replacement Total	**$ 36,500**	**$ 36,500**	**$ 36,500**	**$ 36,500**	**$ 36,500**	**$ 182,500**

Table 39 - Five Year SSO Emergency and Replacement Capital Budget

SSO - Environmental

It is anticipated that SSO environmental program will require the Company to invest $73.1 million over the next five years. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Environmental						
Substation EH&S Risk Mitigation Program	$ 3,559	$ 15,775	$ 16,375	$ 19,625	$ 17,775	$ 73,109
Charges To Completed Projects - Environmental	$ -	$ -	$ -	$ -	$ -	$ -
Environmental Total	**$ 3,559**	**$ 15,775**	**$ 16,375**	**$ 19,625**	**$ 17,775**	**$ 73,109**

Table 40 - Five Year SSO Environmental Capital Budget

SSO - Information Technology

The Information Technology category specifically identifies IT expenditures assigned to the SSO capital budget. The investment details are outlined below.

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Information Technology						
Non-Routable Commumications Phasor Measurement Unit	$ -	$ -	$ -	$ -	$ -	$ -
Substation Technology Improvements Program	$ 1,087	$ 1,081	$ 1,077	$ 1,077	$ 1,077	$ 5,399
Charges To Completed Projects - Other	$ -	$ -	$ -	$ -	$ -	$ -
Information Technology Total	**$ 1,087**	**$ 1,081**	**$ 1,077**	**$ 1,077**	**$ 1,077**	**$ 5,399**

Table 41 - Five Year SSO Information Technology Capital Budget

SSO - Storm Hardening

With the goal of minimizing the extent of damage to networks, maintaining public safety, minimizing de-energization of networks, and allowing for an expeditious recovery from Superstorm events, the Company's Storm Hardening project introduces a number of measures to make the underground and overhead systems more resilient to such events. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Storm Hardening						
Substation Storm Hardening	$ 151,451	$ 34,700	$ 17,700	$ 10,000	$ 7,119	$ 220,970
Storm Hardening Total	**$ 151,451**	**$ 34,700**	**$ 17,700**	**$ 10,000**	**$ 7,119**	**$ 220,970**

Table 42 - Five Year SSO Storm Hardening Capital Budget

5. Electric Transmission (System & Transmission Ops) Capital Investment Plan

The System and Transmission Operations (S&TO) Capital investments are made to support the safe, reliable, and cost-effective energy to all customers and to provide funding at the transmission level which delivers power to the area substations and ultimately to the electric distribution system. The S&TO investments follow similar categories to the Electric Distribution capital investments with the exception of New Business (which takes place specifically at the distribution level) and equipment purchases which is not broken out at the substation level.

Budget Categories

The Company's capital investments in S&TO are presented under the following categories: System Expansion, Risk Reduction/Reliability, Replacement, Environmental, Interference, Information Technology, and Storm Hardening. These categories have evolved and provide an efficient means of serving customers while maintaining and improving the safety and reliability of the system.

1. System Expansion - Projects or programs that increase system capacity or provide new facilities or upgrades of existing facilities caused by customer demand growth or supply retirements.
2. Risk Reduction – Investments to support the reliability and/or availability of a facility or an operational function. This category also includes projects or programs that reduce or mitigate a risk associated with a facility or operation through proactive replacement strategies.
3. Replacement – Investments to replace failed, degraded, or difficult-to-maintain equipment.
4. Environmental – Investments to enhance environmental performance, reduce environmental impact, or comply with environmental regulatory requirements.
5. Interference (Municipal Infrastructure Support) - Investments required to relocate or otherwise support Company facilitates impacted by Public Improvement/Interference work.
6. Information Technology – Information Technology assigned to S&TO.
7. Storm Hardening- Investments required to harden transmission and associated equipment. This category was the result of lessons learned from Hurricane Sandy.

See chart below for the breakdown of 2016 S&TO Capital Investment of $91,091,000.

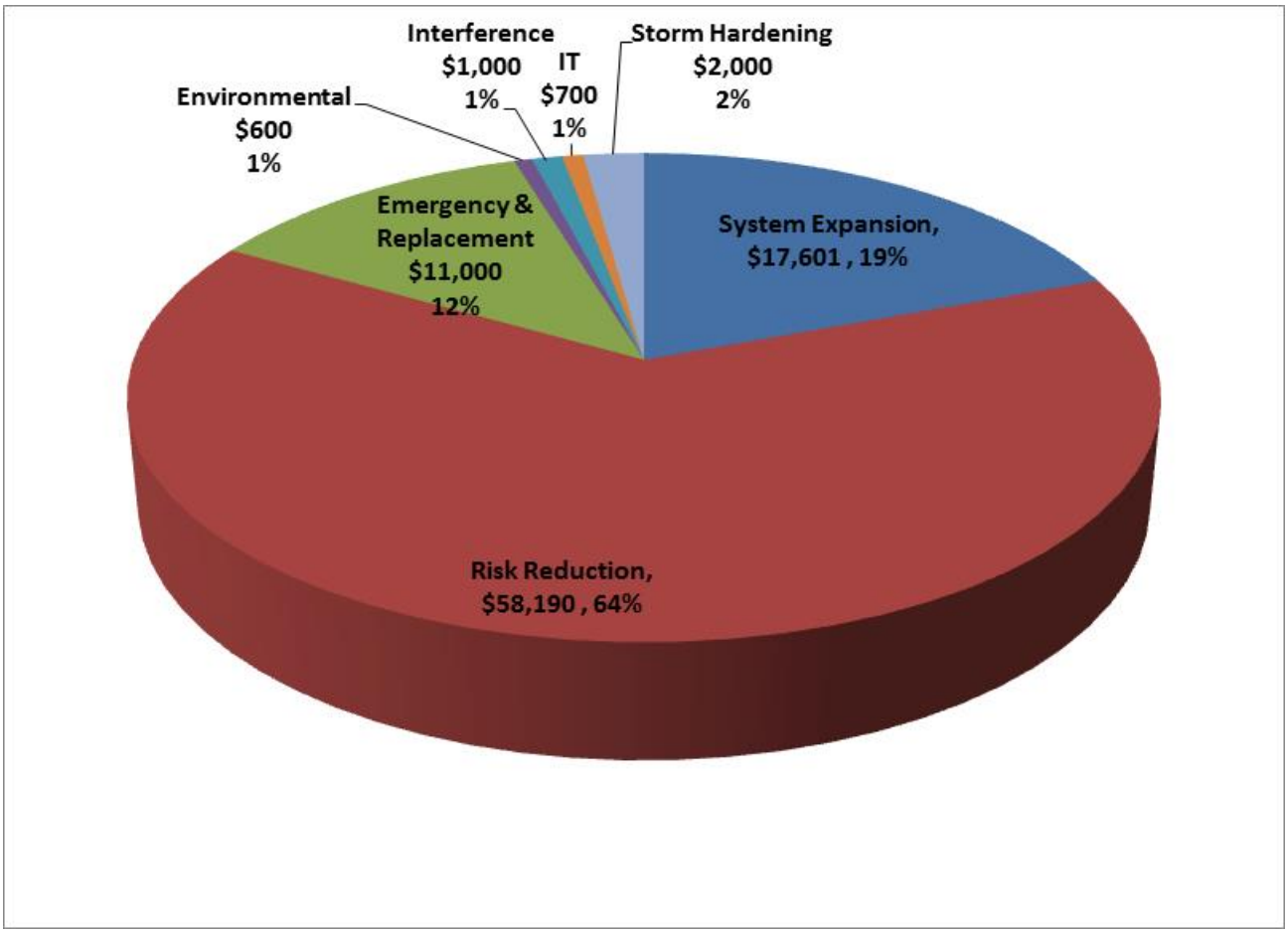

Figure 28 - 2016 Categorical Investments for S&TO

Electric Forecast:

The electric forecast that is discussed in the Electric Distribution section is the same forecast used to inform these investments.

S&TO - Capital Investment Detail:

Based on the forecast, the five-year electric distribution capital investment budget is shown below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Summary Electric Transmission (S&TO)						
System Expansion	$ 17,601	$ 78,927	$ 67,795	$ 49,514	$ -	$ 213,837
Risk Reduction	$ 58,190	$ 53,225	$ 50,650	$ 36,500	$ 35,800	$ 234,365
Emergency and Replacement	$ 11,000	$ 11,000	$ 11,350	$ 15,900	$ 14,500	$ 63,750
Environmental	$ 600	$ 600	$ 600	$ 600	$ 600	$ 3,000
Interference (Municipal Infrastructure Support)	$ 1,000	$ 13,577	$ 25,837	$ 26,604	$ -	$ 66,018
Information Technology	$ 700	$ 750	$ 750	$ 850	$ 800	$ 3,850
Storm Hardening	$ 2,000	$ -	$ -	$ -	$ -	$ 2,000
Total Electric Transmission (S&TO) Capital	**$91,091**	**$158,079**	**$156,982**	**$129,968**	**$51,700**	**$586,820**

Table 43 - Five Year S&TO Capital Budget

S&TO - System Expansion

The Company forecasts $213.8 million in capital investments for system expansions over the next five years. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
System Expansion - S&TO						
Rainey to Corona 138kV Feeder	$ 14,001	$ 65,281	$ 67,795	$ 49,514	$ -	$ 196,591
Replace Limiting Sections Feeder 38Q04	$ -	$ 7,015	$ -	$ -	$ -	$ 7,015
Vernon to Glendale - Repl Limiting Section(s) Ca	$ -	$ 6,631	$ -	$ -	$ -	$ 6,631
Farragut - Plymouth St - Uprate Feeders 32071	$ 3,600	$ -	$ -	$ -	$ -	$ 3,600
System Expansion Total	**$ 17,601**	**$ 78,927**	**$ 67,795**	**$ 49,514**	**$ -**	**$ 213,837**

Table 44 - Five Year S&TO System Expansion Capital Budget

S&TO - Risk Reduction

It is anticipated that Risk Reduction, which also includes safety and security investments such as substation security enhancement programs, will require the Company to invest $234 million over the next five years. Risk Reduction programs and projects are designed to maintain the operational capability, reliability, and safety at the transmission substation level. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Risk Reduction - S&TO						
Pipe Enhancement Program	$ 34,000	$ 34,000	$ 34,000	$ 20,000	$ 20,000	$ 142,000
Transmission Fdr. Pipe Support at Queensboro	$ 7,500	$ 2,250	$ -	$ -	$ -	$ 9,750
Joint Replacement Prgram	$ 5,700	$ 5,700	$ 5,700	$ 5,700	$ 5,700	$ 28,500
LP Reservoir Replacements	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 12,500
Emergent Transmission Reliability Program	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 1,000	$ 9,000
Dynamic Feeder Rating System Program	$ 1,500	$ 750	$ 750	$ 1,500	$ 1,500	$ 6,000
RTU Replacement ECC and AECC	$ 500	$ -	$ -	$ -	$ -	$ 500
ECC Replacement of EMS Video Wall	$ 840	$ 1,025	$ -	$ -	$ -	$ 1,865
Operations Network for EMS	$ 600	$ 200	$ 200	$ 300	$ 300	$ 1,600
EMS Reliability AECC and ECC	$ 500	$ 700	$ 300	$ 300	$ 300	$ 2,100
System Operation Enhancements	$ 300	$ 300	$ 350	$ 300	$ 300	$ 1,550
Distribution Orders Enhancements	$ 300	$ 300	$ 300	$ 400	$ 300	$ 1,600
Overhead Transmission Structures Program	$ -	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 8,000
ECC UPS Battery Replacement Room 1	$ 250	$ -	$ -	$ -	$ -	$ 250
AECC Replacement of EMS Video Wall	$ -	$ -	$ 850	$ -	$ -	$ 850
+ Safety/Security:						
Overhead Tower Rapid Rail Program	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 5,000
Cyber Security	$ 500	$ 500	$ 500	$ 500	$ 500	$ 2,500
ECC and AECC Facility Security Enhancements	$ 200	$ -	$ 200	$ -	$ 400	$ 800
Risk Reduction Total	**$ 58,190**	**$ 53,225**	**$ 50,650**	**$ 36,500**	**$ 35,800**	**$ 234,365**

Table 45 - Five Year S&TO Risk Reduction Capital Budget

S&TO - Emergency & Replacement

It is anticipated that Replacement will require the Company to invest $63.8 million over the next five years. Funding for each program under the Replacement category is based upon the historical

failure or degraded performance rates of each component covered by the program. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Emergency and Replacement - S&TO						
Transmission Feeder Failures	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 50,000
Transmission Failures - Other	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 5,000
ECC UPS Replacement	$ -	$ -	$ 350	$ 400	$ -	$ 750
EMS Replacement ECC and AECC	$ -	$ -	$ -	$ 4,500	$ 3,500	$ 8,000
Emergency and Replacement Total	**$ 11,000**	**$ 11,000**	**$ 11,350**	**$ 15,900**	**$ 14,500**	**$ 63,750**

Table 46 - Five Year S&TO Emergency Replacement Capital Budget

S&TO - Environmental

It is anticipated that S&TO environmental program will require the Company to invest $3.0 million over the next five years. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Environmental - S&TO						
Environmental Enhancements Program	$ 600	$ 600	$ 600	$ 600	$ 600	$ 3,000
Dec Program Line	$ -	$ -	$ -	$ -	$ -	$ -
Environmental Total	**$ 600**	**$ 600**	**$ 600**	**$ 600**	**$ 600**	**$ 3,000**

Table 47 - Five Year S&TO Environmental Capital Budget

Municipal Infrastructure Support (Interference)

It is anticipated that S&TO municipal infrastructure support will require the Company to invest $66.0 million over the next five years.

When New York City or another municipality performs work, such as installing or repairing a sewer or water main in the vicinity of the Company's facilities, then the Company bears all the costs to locate, move, support, protect, and/or relocate the facilities affected by the municipality's construction activity.

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Interference - S&TO						
Interference STO	$ 1,000	$ 13,577	$ 25,837	$ 26,604	$ -	$ 66,018
Interference Total	**$ 1,000**	**$ 13,577**	**$ 25,837**	**$ 26,604**	**$ -**	**$ 66,018**

Table 48 - Five Year S&TO Interference Capital Budget

Information Technology

The Information Technology category specifically identifies information technology expenditures assigned to the S&TO capital budget.

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Information Technology - S&TO						
Operation Management System At Energy Contr	$ 400	$ 450	$ 450	$ 300	$ 400	$ 2,000
District Operator Task Managing	$ 300	$ 300	$ 300	$ 300	$ 400	$ 1,600
Plant Information System	$ -	$ -	$ -	$ 250	$ -	$ 250
Information Technology Total	**$ 700**	**$ 750**	**$ 750**	**$ 850**	**$ 800**	**$ 3,850**

Table 49 - Five Year S&TO Information Technology Capital Budget

S&TO - Storm Hardening

With the goal of minimizing the extent of damage to networks, maintaining public safety, minimizing de-energization of networks, and allowing for an expeditious recovery from Superstorm Sandy, the Company's Storm Hardening project introduces a number of measures to make the underground and overhead systems more resilient to such events. The investment details are outlined below:

($000) Description	2016 Budget	2017 Budget	2018 Budget	2019 Budget	2020 Budget	2016-2020 Budget
Storm Hardening - S&TO						
Transmission Feeder Failures	$ 2,000	$ -	$ -	$ -	$ -	$ 2,000
Storm Hardening Total	**$ 2,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,000**

Table 50 – Five Year S&TO Storm Hardening Capital Budget Planning and Budgeting Process

6. Integration of DER

The Company's capital budget for delivering electrical service includes distribution, substation, transmission, and a share of common capital is depicted below in **Figure 29**:

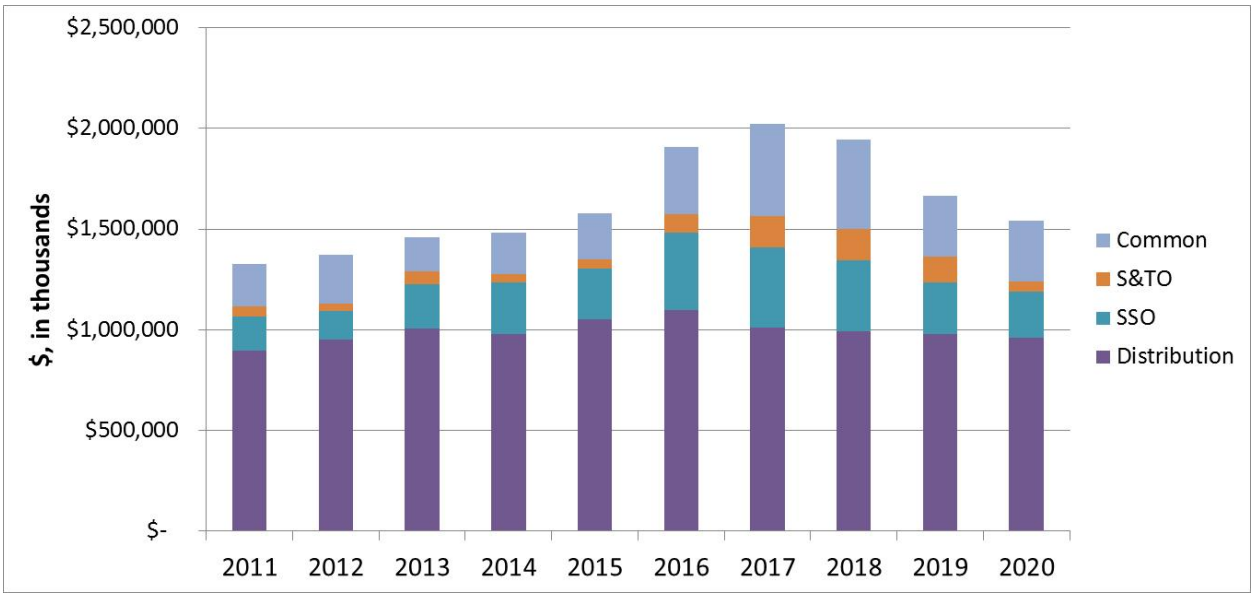

Figure 29 - Historical Spend and Budget by Common, Transmission, and Distribution

The Distribution category represents spending on the electric distribution system. The SSO category represents spending on the electric substations and S&TO which represents spending on the electric transmission system. The Common category includes cross commodity investments, such as information technology systems including specific projects like AMI or DCX. Generally speaking, electric is assigned 83 percent of Common investments. The AMI and DCX investments will be discussed at length later in this section and support REV and DSP objectives. The focus of this section will be T&D infrastructure investments (*i.e.,* distribution, SSO, and S&TO) which are combined into the seven categories shown in **Figure 30** below:

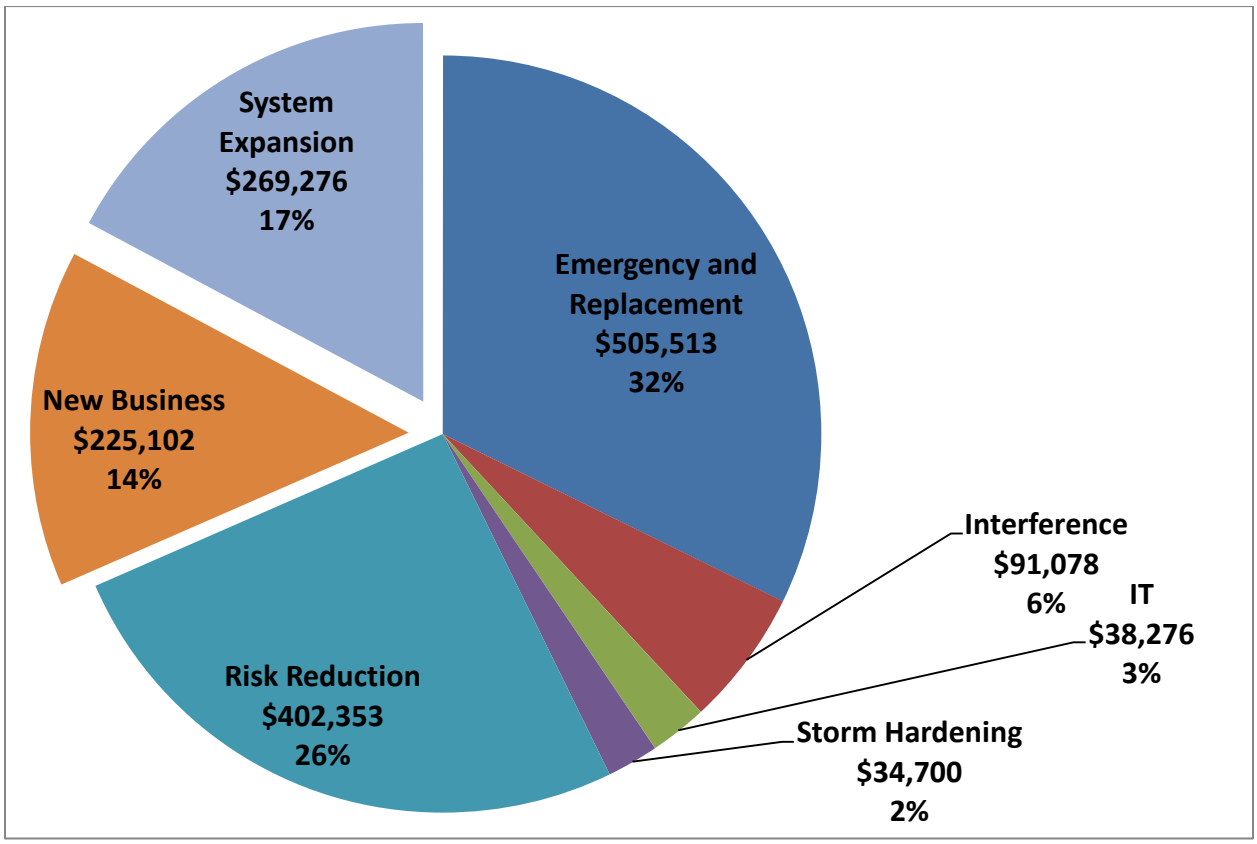

Figure 30 - 2017 T&D Budget by Category with Equipment Purchases Incorporated into New Business and Emergency

For simplicity, the category of equipment purchases was incorporated into new business (*i.e.,* 100 percent of meter costs and 45 percent of transformer costs) and emergency replacement (*i.e.,* 55 percent of transformer costs). In addition, environmental costs were rolled into risk reduction as were safety and security. The categories were re-ordered to facilitate the discussion of which job categories are most suitable for NWA consideration.

Considerations for NWA

The Company is considering DER in several areas of utility investments and will look to expand these areas over time based on experience. Based on Distribution Planning analysis, the Company considers NWAs to address system expansion investments at both the area substation and distribution

level as the best place to utilize DER, and is pursuing this in the BQDM program. The planning horizon for these projects is typically longer (allowing for a solicitation process) and the potential savings are larger. The Company's TDM programs provide resources to find projects that defer investment and help facilitate early NWA. The Company also sees opportunities to promote DER inclusion in the new business category by streamlining the interconnection process and reducing barriers to interconnection. The Company also evaluated Risk Reduction investments for DER substitution, and is working to expand NWA opportunities into this category as the effects of DER on reliability of the electric system are better understood. Storm Hardening needs may be addressed equivalently through DER alternatives, such as microgrids, but in the five-year timing of the DSIP, there are no funding opportunities. The details of this discussion are below. Finally, areas like Emergency Response and Public Works are non-discretionary items that are not suited to DER solutions. With emergency work in particular, the timing of the system need is immediate and does not lend itself to a solicitation process.

System Expansion

As previously discussed, the Company plans infrastructure investments, based on forecasted demand, on an annual basis over a 10- year time horizon. As described in the Forecasting and Available Resources Sections, the Company recognizes DERs as load-modifying resources in its load forecast. Additionally, the Company has enhanced its evaluation of DERs as a potential load relief solution. DERs address load relief through programs deployed broadly across the service territory (through the load forecast as discussed above) and through targeted programs at a substation level.

For more targeted reductions, the Company seeks to develop a portfolio of CSS and non-traditional utility solutions, NWAs. These portfolios may also include traditional utility projects that support the development of the non-traditional solutions. The Company's ongoing implementation of the BQDM program is the most prominent example of meeting system expansion needs through a combination of DER and utility solutions. As described in the Capital Budget Section above, when forecasted demand shows a need for system expansion investment, such as area substation load relief, the Company determines which traditional projects will cost-effectively address those needs. The Company will then evaluate projects to determine if they are suitable for NWA solutions. These suitability criteria will be discussed in greater detail in the Identify Beneficial Locations for DER Deployment Section. In short, the Company used an interim set of criteria for this Initial DSIP and is working with the JU to determine uniform suitability criteria to apply prior to the BCA evaluation. If a project meets the suitability criteria, Company planners will solicit proposals and construct NWA portfolios according to the unique set of attributes of each type of DER that can contribute to load relief. For instance, DR can be limited in the duration and number of times it may be deployed, whereas EE is a more permanent reduction in load, but is generally not dispatch-able. The Company uses applicable DER shapes and parameters to compare an NWA portfolio to the traditional utility project. The Company will then perform a preliminary feasibility test, using the Integrated Demand Side Management (IDSM) model to determine the ability of local resources to meet load relief needs. The NWA is then to be evaluated using the Societal Cost Test (SCT), an economic test of costs and benefits. The Company then implements the optimal portfolio of solutions. The Company will use internal processes for

implementing utility-sided solutions (traditional or non-traditional) or procure CSS through a competitive process. The competitive processes used to procure NWA/CSS include Requests for Purchase (RFP), Requests for Information (RFI), Auctions, and more, as documented in a recent Targeted Demand Management Filing.[64]

Load-relief solutions in the system expansion category are projected in the ten-year load relief plan and addressed over a long time horizon. At a substation level, the most recent ten-year load relief plan indicates a projected overload and load relief need at ten of the Company's 62 substations. The details and locations of these will be discussed further in the Identify Beneficial Locations for DER Deployment Section. In addition there are load relief needs based on two sub-transmission constraints.

While the Company has recently taken steps to redefine internal processes regarding how distribution level load relief can potentially be deferred to open more possibilities for load relief, NWAs are most effectively applied at the area substation level[65]. Due to the network design of most of the Company's distribution system, load relief applied gets dispersed across local area, requiring more nameplate load relief than what is required. Dr. Tierney's *The Value of "DER" to "D"* captures this complication of applying load relief in a network.[66] The Company also notes that incorporating DER into the forecast directly affects the distribution level relief needed because DER can postpone the need for these projects.

New Business

Customers may be more likely to consider DER during the planning phase of a new business project. To the extent Con Edison can help customers explore all their options in the early stages of planning, it may help promote mixed solutions that include traditional and DER. In addition, the Company is proactively engaging with DER providers to facilitate interconnection by developing hosting capacity algorithms and maps and also improving the interconnection process through the NYS SIR proceeding, discussed above. These improvements are expected to lower the costs and time to interconnect DERs, thus making them more appealing in the consideration of new businesses.

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[64] Case 15-E-0229, *Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects That Support Reforming the Energy Vision*, TDM Incentive Mechanism - Final (filed on March 4, 2016).
[65] Electric Power Research Institute, *Time and Locational Value of DER: Methods and Applications,* Palo Alto, CA, 3002008687, April 15, 2016.
66 Tierney White Paper, pp. 33-41, available in Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Comments of the Joint Utilities on an Interim Successor to Net Energy Metering (filed April 18, 2016), Appendix B .

Risk Reduction

Risk reduction programs are typically targeted to maintain or improve reliability of the system. These programs include compliance initiatives (like inspections of the secondary network) or targeted replacement of high failure rate components (*i.e.,* the proactive replacement of a component with known reliability issues). Current programs do not look to reduce loading on equipment and this is because, historically, equipment loading is typically not the cause of equipment failure (weather and product life cycle are the cause). While DERs may not be able to replace these programs directly, the Company will investigate whether DERs could offer operational benefits by focusing DER in areas with reliability needs (as indicated by the NRI rating) but without an impending load relief need. Any initiative like this would be accompanied by a review of the network operations after DER is added to determine whether equipment failures are reduced. The Company envisions further collaboration with stakeholders in regard to implementing programs and measuring results.

The Company also performed an analysis of the Risk Reduction projects for both the SSO level and the Distribution level (**Figures 31 and 32**). The Company's budget for Risk Reduction projects were categorized as:

- Compliance Items – Mandated projects or programs (*e.g.,* inspections or venting of service box covers)
- Environmental – Programs to mitigate the risk of future environmental hazards
- Enhanced Monitoring – Programs to gain enhanced insight into asset conditions
- Targeted Upgrades or Replacements – Replacing equipment with known failure risks proactively to avoid outages
- Contingency Planning – Funds set aside for projects or programs that may be required to address immediate changes in capital plans

The majority of the budget is allocated to targeted upgrades and replacements to replace faulty equipment before an outage. The Company does not believe that DERs would help in this scenario because the failure mode is driven not by an overload, but rather discrete equipment failure modes. This is supported by the causes of failures reported in the annual New York State Reliability Report (**Figure 33** below). As such, applying DER to generally reduce load in a targeted area is unlikely to produce an in-kind response in reduction of emergency replacement budgets. The Company will continue to explore ways to apply Targeted Demand Management funds to support the reliability of the grid.

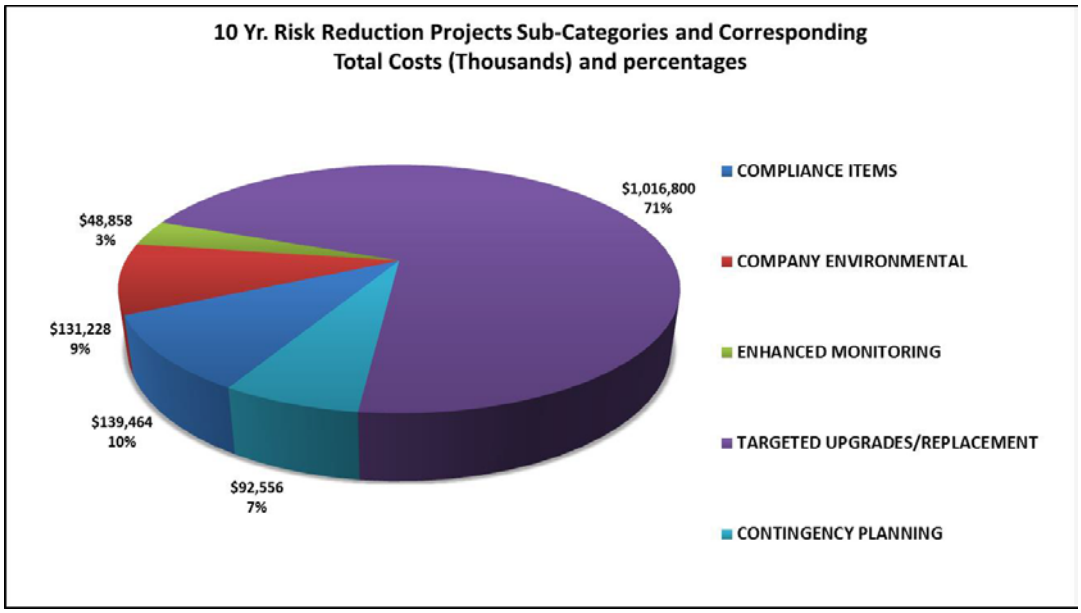

Figure 31 - SSO Risk Reduction Categorical Project Spending

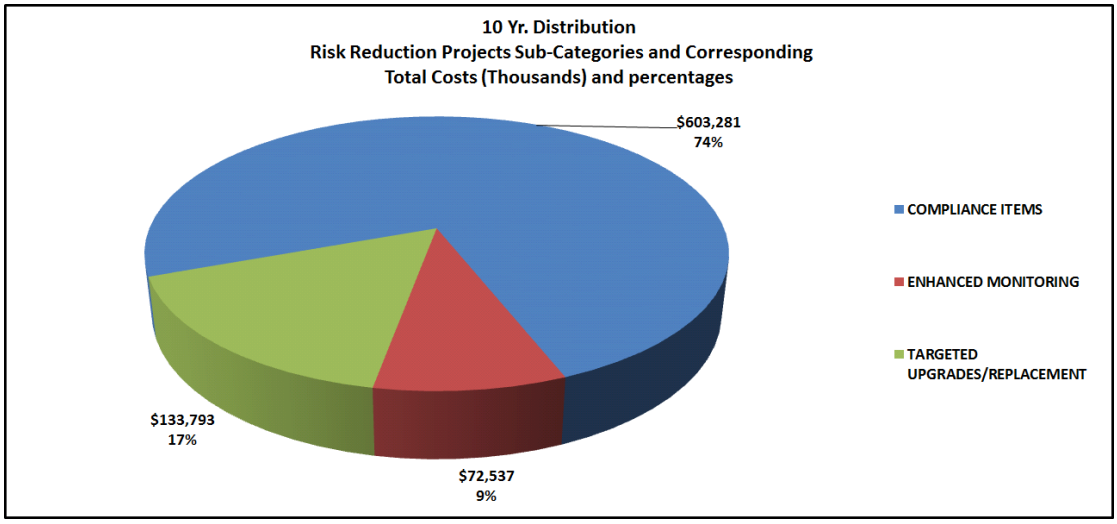

Figure 32 - Distribution Level Risk Reduction Categorical Project Spending

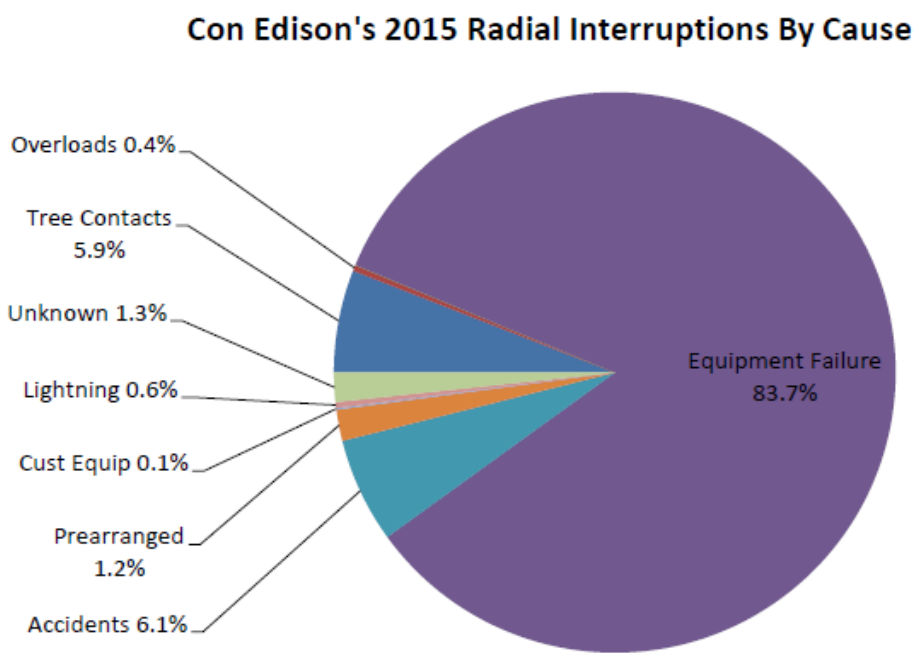

Figure 33 - Categorical Causes of Interruption

Resiliency/Storm Hardening

Resiliency or storm hardening programs are implemented periodically and usually address a system need provoked by an exceptional event. The most recent example is the storm hardening program instituted after Hurricane Sandy. While this program is scheduled to conclude in 2016, for the next iteration of storm hardening, DERs with favorable resiliency characteristics would be considered alongside traditional utility solutions. Examples of DER characteristics that are appealing for storm resiliency purposes include microgrids with the ability to operate independently as islands. The Company perceives that most of the benefits of microgrids accrue to the owner of the DER, but not the wider distribution network unless the microgrid can improve the reliability of the network, as measured through NRI. The Company is currently improving upon the NRI modeling tool to incorporate DER effects, and the contribution of DER to NRI will be studied further as these capabilities progress.

Emergency Response/Replacement

The Company is now considering DER for emergency response and replacement projects. These projects are typically undertaken after a loss of service has occurred, and the Company is obligated to return the customer(s) to service as quickly as possible and replace damaged equipment. Customer-side solutions are focused on load relief rather than replacement because DERs consist of a portfolio of assets with unique operating characteristics, whereas traditional assets provide specified capacity on a continuous basis. Should traditional equipment require replacement, the solution proposed must provide capacity continuously to maintain grid reliability and safety. For this reason, an NWA portfolio of DERs is well suited to address load relief needs, but not for replacing existing equipment.

Public Works/Interference

Public works projects are undertaken whenever New York City, through the terms of the franchise agreement with the Company, determines that Company assets must be removed or relocated to accommodate a new public works project. An example is the re-routing of Company cable to clear right of way for a new water main. At this time, the Company does not foresee application of DERs to address this sizeable, but unavoidable, category of investments.

IT/Other

This category of investments includes the systems required to plan and operate the transmission and distribution systems. These systems will be discussed at length in a later portion of this section, particularly for systems needed to operate a DSP.

7. Historical Spending and Forecasted Budgets – Transmission, Substations, and Distribution

The historical spending and forecasted budgets, by category, for five years forward and back are shown graphically below in **Figure 34** and in **Appendix F** in tabular form.

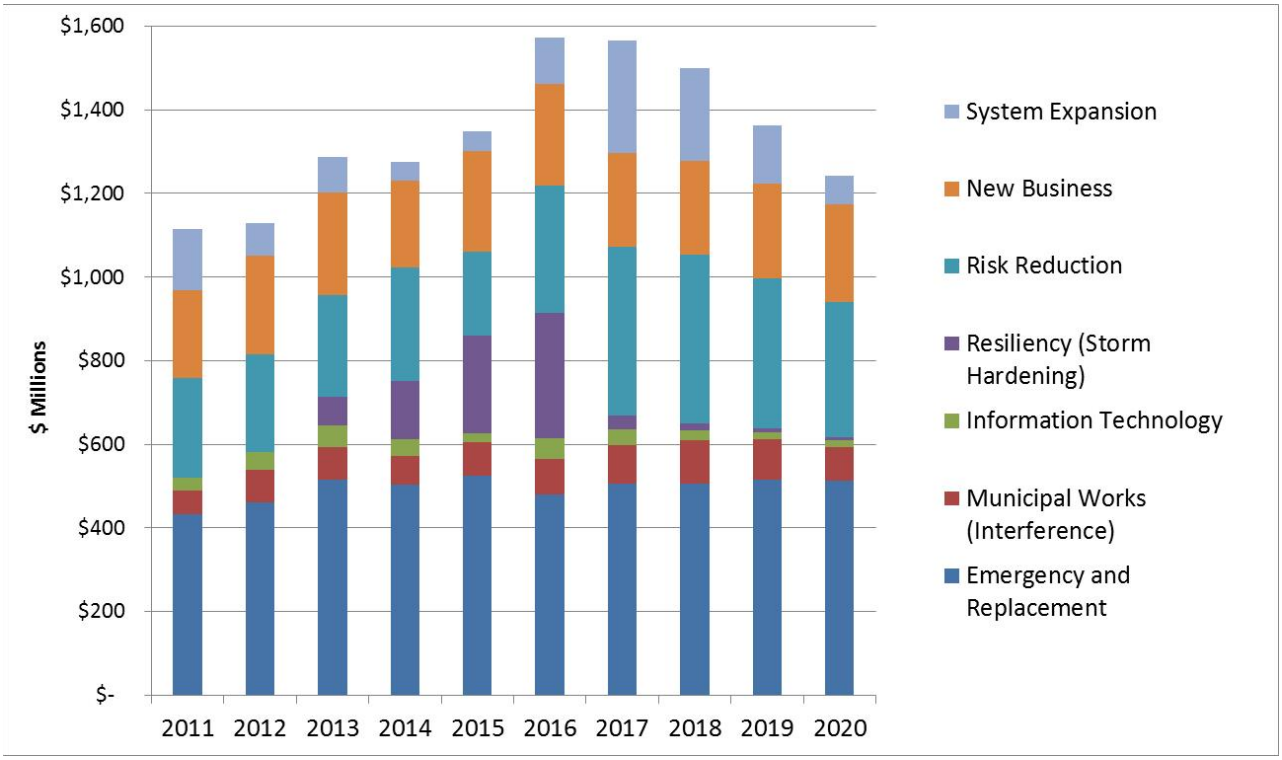

Figure 34 - Categorical T&D Historical Spend and Budgets 2011-2020

8. Historical Spending and Forecasted Budgets– IT, Communications, and Shared Services

The Company's current state, as it relates to the systems required to serve as the DSP, is explored in the standalone DSP Systems Roadmap chapter. That chapter assesses the needs of a DSP, based on the required functionalities, how current systems and processes address that functionality, the gaps between current functionality and future required functionality, and what systems would be required going forward. These needs are addressed over both a near-term and long-term horizon. What follows is the discussion of the historical spending and near-term budgets, including those systems that were requested as a part of the Company's current rate case. The historical spending and forecasted budget for IT and communications systems can be considered as the sum of the discrete IT needs for Distribution, Substation Operations, and System and Transmission Operations plus the electric portion of the business's share of the Common IT budget. **Appendix F** shows the breakdown of IT historical spending and budgets.

The details of the systems that will be required to support DSP capabilities are categorized and included in the forward budget. The Company proactively sought funding for the elements to create a DSP in its current rate case filing.[67] The core functions of the newly-established DSPs are to be "highly integrated with utility planning and system operations."[68] These functions will be pursued in a phased and iterative approach, addressing largely the near-term requirements of a DSP over the five year scope of this filing.

Initially the staff Straw Proposal and Track One Order provided high level guidance of items that should be included in the DSIP/DSP. These categories (presented in the submitted budget breakout and repeated in **Table 51** below) were identified through a combination of this guidance, proceedings in California and other stakeholder engagement discussions and available industry papers. Con Edison developed this DSIP based on its best understanding of the Staff DSIP Proposal. The Company does not anticipate any significant budget changes in response to the DSIP Order but continues to believe that there is significant uncertainty associated with these proposed expenditures. It should also be noted that overhead charges had to be added to the line items after they were budgeted which is why the numbers are not rounded. For example, $500,000 allocated to data analytics in 2016 became $633,000 after overheads were added.

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[67] Case 16-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, EIOP Exhibits (EIOP-01)-(EIOP-14)(filed January 29, 2016).

[68] REV Proceeding, Track One Order, p. 45.

	2016	2017	2018	2019	2020	2016-2020
Data Analytics	$ 633	$ 1,194	$ 1,230	$ 1,260	$ 1,279	**$ 5,595**
Load Flow	$ -	$ -	$ 1,230	$ 1,260	$ 1,279	**$ 3,769**
NRI	$ 127	$ 1,194	$ -	$ -	$ -	**$ 1,320**
Interconnection Portal	$ 4,407	$ 4,509	$ -	$ -	$ -	**$ 8,917**
DERMS (extend smart grid)	$ 1,265	$ 2,388	$ 4,919	$ 5,040	$ 6,394	**$ 20,006**
DRMS	$ 1,518	$ 2,388	$ 2,460	$ 1,260	$ 1,279	**$ 8,904**
DMTS	$ -	$ 3,581	$ 2,460	$ 2,520	$ 2,557	**$ 11,119**
DMAP (analytics platform)	$ 1,265	$ 3,581	$ 2,460	$ 1,260	$ 1,279	**$ 9,845**
Customer Portal	$ -	$ -	$ -	$ 6,198	$ 6,496	**$ 12,694**
Data Exchange	$ 3,306	$ 11,273	$ 1,127	$ -	$ -	**$ 15,705**
Modernize Protective Relays	$ 633	$ 2,865	$ 5,534	$ 6,931	$ 9,590	**$ 25,553**
Voltage VAR Control (VVC)	$ -	$ -	$ 2,460	$ 2,520	$ 5,115	**$ 10,095**
	$ 13,154	$ 32,972	$ 23,879	$ 28,250	$ 35,267	$ 133,522

Table 51 - Con Edison's proposed budget for the DSP

Data Analytics: This category is one of the less developed categories in terms of guidance and market experience. Nonetheless, the Company envisions a possible need for data analytics early in the process; the Company allocated some funding starting in year 2016 and reserved a relatively small amount of funding throughout the five-year period.

Load Flow: This category is similarly less developed in terms of guidance and market experience. Nevertheless, Con Edison believes its load flow models are relatively advanced and likely not in need of immediate modifications so the Company allocated expenditures for this item later in the five-year period.

NRI (Network Reliability Index): Con Edison knows that upgrades to the NRI model to reflect the effect of DER on reliability are necessary. The Company has already begun this work so there is relative comfort around the 2016 expenditure. It is less clear whether funds will be required in 2017, but $1 million (plus overhead) has been reserved in case the 2016 work and evolving market conditions require a larger work scope.

Interconnection Portal: Con Edison has worked over the past several years to streamline its interconnection process and become more responsive to DER customers via the DG Ombudsman group. A smoother interconnection process is also a PSC priority, as evidenced by the recent New York Standardized Interconnection Requirement (NYS SIR) Order.[69] As a result, $4 million is reserved in funding in 2016 and 2017 to meet these goals and this direction. As described in the Interconnection Process section, the Company is in the process of upgrading its customer project management system (CPMS) and Project Center.

[69] 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).

Distributed Energy Resource Management System (DERMS): Tracking, mapping, and monitoring of DER is an important function of the DSIP and a DERMs system is expected to be required. Con Edison is also developing a DERMs system as part of the Company's Smart Grid work. The timing and cost are highly uncertain. Con Edison is in the process of evaluating all the IT needs for the DSP (including a DERMs system), perceives a sizeable gap between current state and future needs for DER management, and has reserved substantial cost expenditure over the five-year period for this system.

Demand Response Management System (DRMS): DRMS is a robust operational control system that Con Edison uses to provide command and control over its portfolio of demand response resources. Currently, the DRMS is configured to support the Con Edison Commercial DR programs (CSRP and DLRP). The system was designed and configured to enable customer enrollment, calculate baselines, and handle notification of demand response events as well as monitoring, settlement, and reporting functions. The commercial implementation began in early 2014 and was ready for use during the summer 2015 DR season. After successful implementation of Commercial DRMS, EE, and DM are incorporating the Residential DR programs into the system (to be ready for the summer 2017 season with some testing occurring in 2016), starting with the Bring Your Own Thermostat (BYOT) program and preparing the system for any other residential DR programs including Direct Load Control.[70] All of the residential DR programs allow the Company to make brief, limited adjustments to a customer's central air-conditioner setting during the summer peak to reduce demand and high-energy use.

Demand Management Analytics Platform (DMAP): This robust customer-centric analytical tool will be used to support management and operational decisions, vendor activity, targeted marketing campaigns, and future EE program design. DMAP is a repository for a wide variety of information pertinent to the overall operations, marketing, and evaluation of the Energy Efficiency and Demand Management programs. The primary purpose of DMAP is to transform raw data into meaningful/useful information. The DMAP will combine data from internal sources, such as CIS and MDM, and external sources such as NYC Department of Building's database. In addition, data from demographic sources, marketing vendors, social media channels, and other external sources will provide a much richer capability to manage the customer relationship. DMAP will also provide the critical infrastructure to link and analyze customer behaviors and the impact on distribution network assets and performance.

Demand Management Tracking System (DMTS): The DMTS is an essential customer relationship management (CRM) and operational management tool for the Energy Efficiency and Demand Management programs. CRM is essential to allow the Company to track and adjust marketing campaigns, forecast participation rates, and move customers from potential participants to fully engaged customers. Operationally, DMTS will serve as a the system of record where individual customer projects and performance are managed and tracked through work flows specific to each

[70] Bring Your Own Thermostat, Direct Load Control, and other DSM programs are discussed in detail in the Available Resources Section.

program. DMTS will additionally be the financial center of program management where incentives are generated, program vendors are managed, and customer projects are delivered. DMTS will fully track a customer or program from enrollment to eligibility checking to workflow, M&V, incentive processing, and reporting. DMTS will continue to serve as the central repository of the Company's interactions with customers and third parties such as other DER providers, outside agencies, aggregators, and contractors. The CRM base was implemented for the Demand Management program and the BQDM program, and is currently being expanded for the full portfolio of ETIP Energy Efficiency programs as well as for future targeted DSM programs. The cost and timing of DMTS expenditures is uncertain as implementations are underway and will be underway for all EE programs prior to the end of 2016.

Customer Portal: Con Edison plans to demonstrate a customer portal to test the concept of an energy marketplace. This will be funded as a REV Demonstration Project and not through the DSP. Based on lessons learned, the Company would then integrate a customer portal into the DSP, and thereafter fund it through the DSP.

Data Exchange (Green Button Connect): Information regarding the purpose and implementation of Green Button Connect is included in the Customer Data section of this DSIP. The $15 million cost estimate is based on benchmarking with other utilities, a review of the Company's unique systems and the high-level implementation estimate.

Modernize Protective Relays: Con Edison's network system requires making relay changes in situations when DER like solar facilities create back feed conditions at network protectors. Similarly, on the overhead system, there are modifications that may be necessary for relay protection with a sufficiently high level of DER penetration. Con Edison has reserved sufficient funding in this category to proactively respond to a sudden proliferation of DER.

Voltage VAR Control (VVC): Con Edison believes additional investment is required to enable VVC on overhead systems with high penetrations of solar facilities. As such, the Company has reserved some monies for later in the five-year period because VVC could be an issue on the overhead system in the next three to five years.

Each of the foregoing systems requested either leverages or improves upon existing assets or is allocated for new systems that support required DSP functionality. The initial investments are focused on building the necessary interfaces to engage customers, increase the volume and granularity of data, and enable greater DER penetration. These proposed building blocks of a DSP will also leverage the phased rollout of AMI as it becomes available across the service territory.

9. T&D System Expansion Projects with Potential for DER

The complete listing of area substations for System Expansion projects have potential to impact project needs is included in **Appendix H**. In assessing the suitability of DER to impact project needs, utility planners considered the progress and capital allocation to date on the project, whether that project was a direct or supporting component of the BQDM Program, and the lead time required to procure traditional and DER solutions.

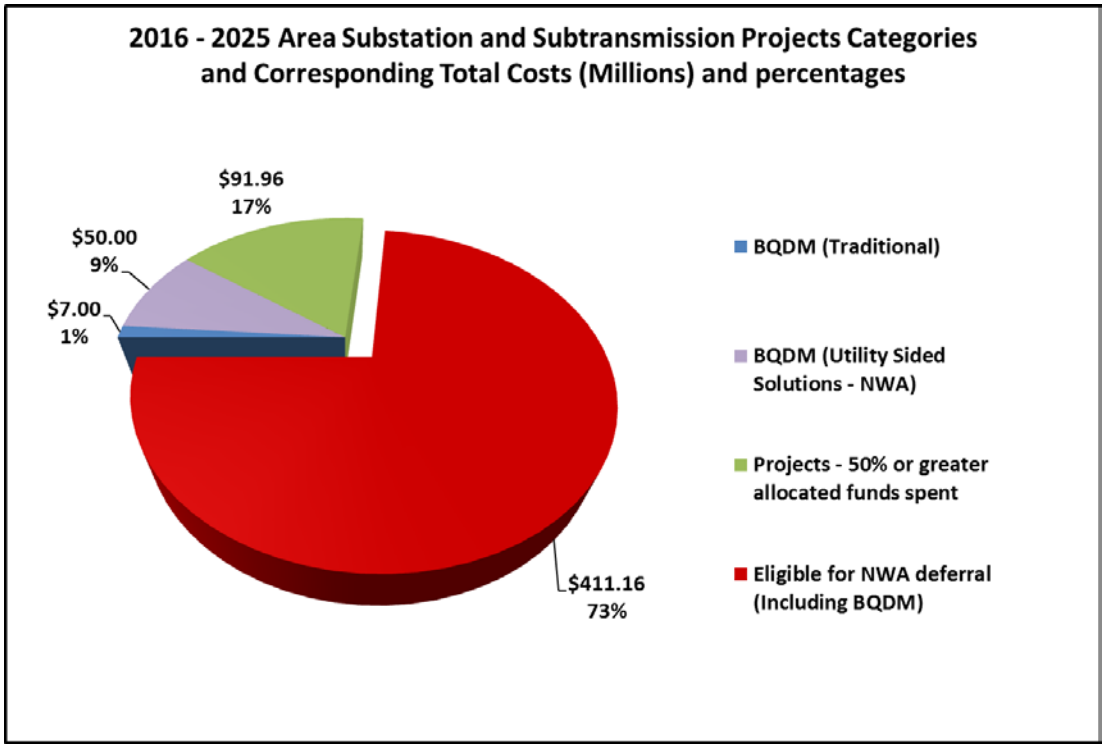

Figure 35 - Categorical Spend of Area Station Load Relief Projects

This first DSIP represents the Company's evaluation of all substation and sub-transmission projects for the ten years between 2016 and 2025. This is a point-in-time assessment, and many projects have been planned and initiated prior to publishing the DSIP. As such, 16 percent of the projects in the ten-year load relief plan have already spent 50 percent of their allocated budget and have limited deferral opportunity. BQDM remains the area of greatest need for the Company at the area substation level and represents most of the capital budget spending. The non-traditional utility projects that support BQDM include a utility-owned and operated battery installation and Brownsville area PV pilots which make up nine percent of the capital budget. The traditional solutions for BQDM that have already been implemented include a 12 MW load transfer and capacitor installation total $7M and make up one percent of the capital budget.

The remaining category is those projects for which the Company will consider NWAs to traditional solutions. This includes the ongoing BQDM solicitation which is already funded, the Glendale projects (substation transformer and load transfer) that make up the traditional side of the BQDM portfolio as currently constructed, and three smaller area station projects. The key distinction is that

the ongoing solicitation for BQDM CSS has already passed a benefit cost analysis and has an established funding mechanism, whereas the Glendale projects and smaller area substation projects must still go through that process.

The ten-year view is presented to show projects on a longer horizon than the requested five-year scope of the DSIP. The Company anticipates that this longer view will help queue projects for system needs and allow sufficient time to procure DER solutions. Biannually updated DSIPs, and projects posted for RFP on an ongoing basis (likely annually to align with the planning cycle), will show the evolution of load relief needs.

The Company also performed an analysis of distribution level system expansion expenditures using similar categories. In this case, the categories again include areas eligible for NWA, projects that are over 50 percent spent, and traditional projects supporting BQDM. Several distinctions are worth noting. Given the difficulties of forecasting at a granular level, and the short turnaround time traditionally associated with distribution level load relief projects, budgets for system expansion programs are estimated and allocated as load relief needs are determined. As such, one category of the budget reflects these programmatic line items. When targeted needs are identified (generally with more lead time), there are discrete projects at the distribution level. These projects were then separated by those that have spent 50 percent of the budget to date and those that have not. The projects that have not yet spent half the budget are open for consideration for DER alternatives. Within the projects already 50 percent spent, there are several larger projects that are not available for NWA substitution today, but if the need would have been identified now (rather than more than nine months ago), those projects would have been suitable for NWA comparison. The projects and programs for distribution level system expansion are summarized in **Appendix I**. In future DSIPs and evaluations, these projects would be included in the Portion for NWA category. Though the BQDM project has its own program budget and funding mechanism, it is expected the TDM program will be leveraged to move quickly on funding for distribution level projects that defer capital investments.

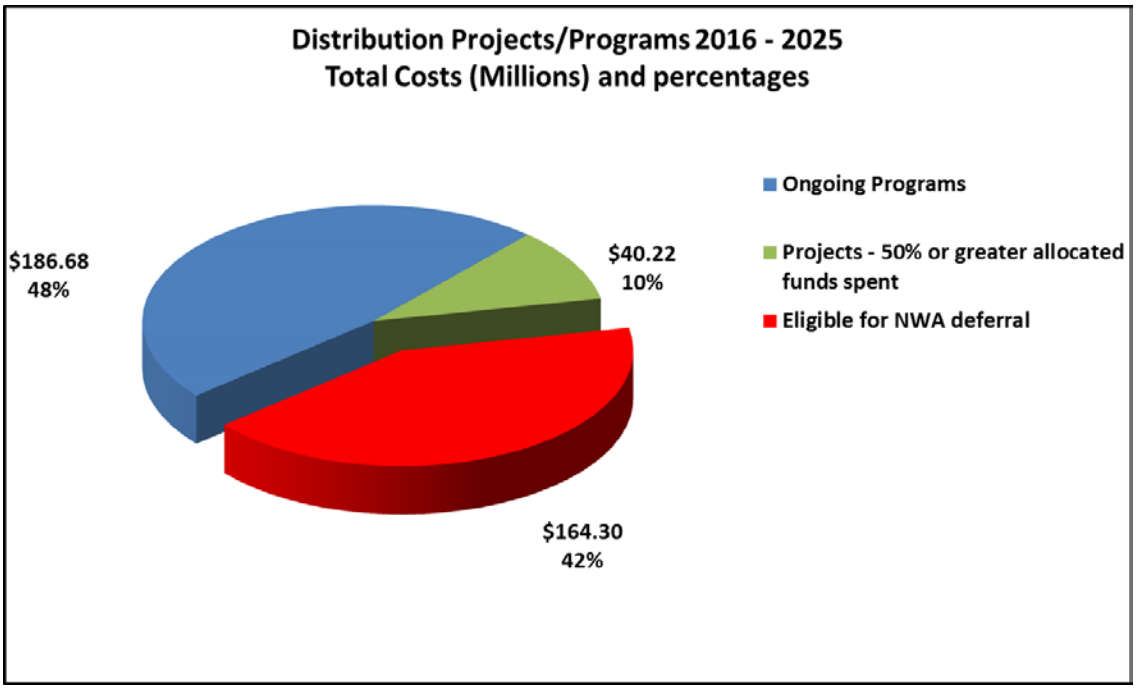

Figure 36 - Categorical Spend of Distribution Level Load Relief Projects

10. Large Budgetary Changes

The Company recently filed an electric rate case, and has not made any large budgetary changes from that filing to date.

E. Beneficial Locations for DER Deployment

1. Information Necessary for Developers

The Company supports providing DER providers with insightful information resulting from and in context with utility planning processes performed by utility distribution planners. As previously described in the Forecasting Section, the Company is introducing network historical 8760 load data, peak and minimum 24-hour load duration curves relative to station capacity, and network forecasted growth rates, all shared publicly through a Company website. Additionally, the Company is preparing Phase 1 hosting capacity maps for the underground network electric system that will show a visual representation of where the Company anticipates it can accept solar DG output with little to no additional cost to the project. These early hosting capacity maps will be described in greater detail in the Hosting Capacity Section. As part of the ongoing DSIP stakeholder engagement process, Con Edison is actively working to identify what other system information and insights will have the greatest value, including the timing of the updates, in order to assess the relevance and value to DER providers, also being explored in the Value of D proceedings.[71]

As the DSP evolves and the physical security, compliance with cyber security and privacy concerns are addressed, the Company will be better able to provide additional information and the results of system analysis at the grid edge.

Existing System Data

In addition to the new forms of system data provided through this DSIP, the Company makes many other forms of system data and useful information publicly available. These have been developed from in-depth analysis of historical load and actual operating conditions. The elements of data that are made available to the public will be discussed in greater detail in the sections below.

The Company also provides more granular system data to DER providers through other channels. Utility partners, such as EPRI and IEEE, as well as educational institutions work closely with Con Edison, under a non-disclosure agreement (NDA), in order to protect the sensitive nature of system data. Con Edison is committed to streamlining its system data and is continually looking to leverage existing systems to integrate growing programs that support the development of the DSP. The Commission noted that "integrating the DLC program into the DRMS may result in operational savings, and is an early step toward Con Edison's transition to its future role as the Distributed System Platform

[71] 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).

(DSP.)"[72] As areas where DER are expected to have more value are identified, the Company will continue to provide the local circuit design and nearby feeder peak values to registered DERs as has been done in support of other initiatives, such as NY Prize applicants.

Additionally, the latest SIR requires that the Company provide additional system data as part of the pre-application report that can be requested through the interconnection application. See **Appendix K** that identifies the specific system data that will be provided by the Company in response to the pre-application report request submitted by a customer or authorized provider.

See **Table 52** below for a summary of the system data that is provided by the Company today

Data Field	Professional Org. (NDA)	SIR/ fee based	Public
System Load Forecast	Public	Public	coned.com/DR
System Reliability	Public	Public	Annual report
Substation Voltage	As Applicable	Pre-Application Report	Internal Use Only
Network Load	Public	Public	DR Annual Evaluation
Network Voltage	As Applicable	Pre-Application Report	Internal Use Only
Network Reliability	Public	Public	Tier 2 Networks
Feeder Load	As Applicable	Pre- Application Report	Internal Use Only
Feeder Voltage	As Applicable	Pre-Application Report	Internal Use Only
Phase 1 Hosting Capacity	Public	Public	Coned.com/DG

Table 52- System Data Provided by the Company in Various Formats

RFI/RFP for Non Wires Alternatives

The Company has embarked on an RFI process to engage providers and customers in identifying NWA solutions, as done for the BQDM program. The Company will use the BQDM process as the starting point for a similar process whereby additional RFIs will be issued to support the planning process, to incorporate CSS as appropriate to meet future system expansion and growth. RFIs for NWAs

[72] Case 15-E-0593, *Petition of Consolidated Edison Company of New York, Inc. for Approval to Continue its Residential and Small Commercial Demand Response Programs*, Order Adopting Modifications to the Direct Load Control Program and Instituting the Connected Devices Pilot Program (filed January 25, 2016), p. 9.

will contain greater system data detail regarding the specific nature of the need (*e.g.*, quantity and hours of need, local system design). The format and information provided in the BQDM RFI[73] will serve as the template for future NWA RFIs.

System and Daily Forecast

The System forecasted annual peak is updated each year and posted online at www.coned.com/DR, along with a daily forecast, see **Figure 37** below.

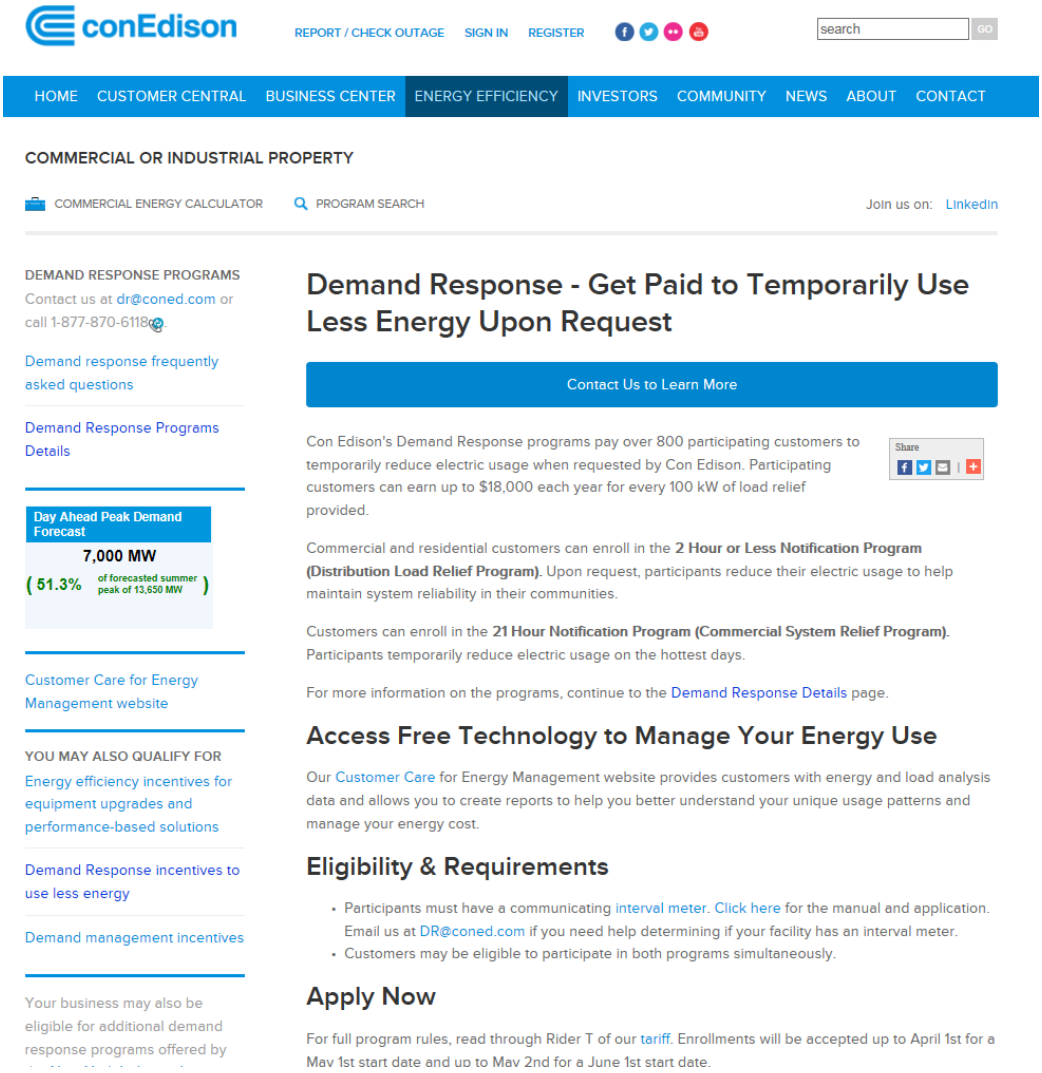

Figure 37 - Screenshot of Day Ahead Peak Forecast on coned.com/dr

[73] http://www.coned.com/energyefficiency/Documents/Demand_Management_Project_Solicitation-RFI.pdf

Network Locations and Peak Times

Network load areas peak at various times throughout the day and do not always coincide with each other or with the system peak itself. As part of the network peak shaving demand response program, Commercial System Relief Program (CSRP), DR event call windows are posted for every network and load area in the service territory. These call windows are generally based on the projected time that each network peaks. The four call windows are listed in tabular format by network and also by borough, see **Figure 38** below. Maps are provided that are color coded to show geographically when each network peaks, see **Figure 39** below. The list and maps are updated every year and may be found at www.coned.com/dr. Additionally the previous year's network peak value is included in the DR Annual Evaluation filed by December 1 each year.[74]

Con Edison Demand Response Programs
Commercial System Relief Program (21 Hour Notification Program):
Event Call Windows for 2016

Customers participating in CSRP will be asked to reduce their load for four hours. Notice will be provided 21 hours in advance. Customers will be called to participate during their network's peaking time.[1] Table 1 lists the networks by network event call window. Table 2 lists the same information by borough.

Network boundaries are typically different from neighborhood borders. For example, the Richmond Hill network includes parts of Brooklyn and parts of Queens. To determine the network in which your building is located, email Con Edison's Demand Response Group at DR@ConEd.com.

Table 1

11:00 AM - 3:00 PM	2:00 PM - 6:00 PM	4:00 PM - 8:00 PM	7:00 PM - 11:00 PM
BATTERY PARK CITY	BAY RIDGE	BUCHANAN	BRIGHTON BEACH
BEEKMAN	CANAL	CEDAR ST.	CENTRAL BRONX
BORDEN	CHELSEA	COOPER SQUARE	CENTRAL PARK
BOROUGH HALL	EMPIRE	ELMSFORD #2	CROWN HEIGHTS
BOWLING GREEN	FASHION	FOX HILLS	FLATBUSH
CITY HALL	GRASSLANDS	FRESH KILLS	FLUSHING
COLUMBUS CIRCLE	HERALD SQUARE	HARRISON	FORDHAM

Figure 38- Screenshot of the Demand Response Program Call Windows Which Describe the Time of Network Peak

[74] Case 09-E-0115, *Proceeding on Motion of the Commission to Consider Demand Response Initiatives, Consolidated Edison Company of New York, Inc.*, Report on Program Performance and Cost Effectiveness of Demand Response Programs (filed December 1, 2015).

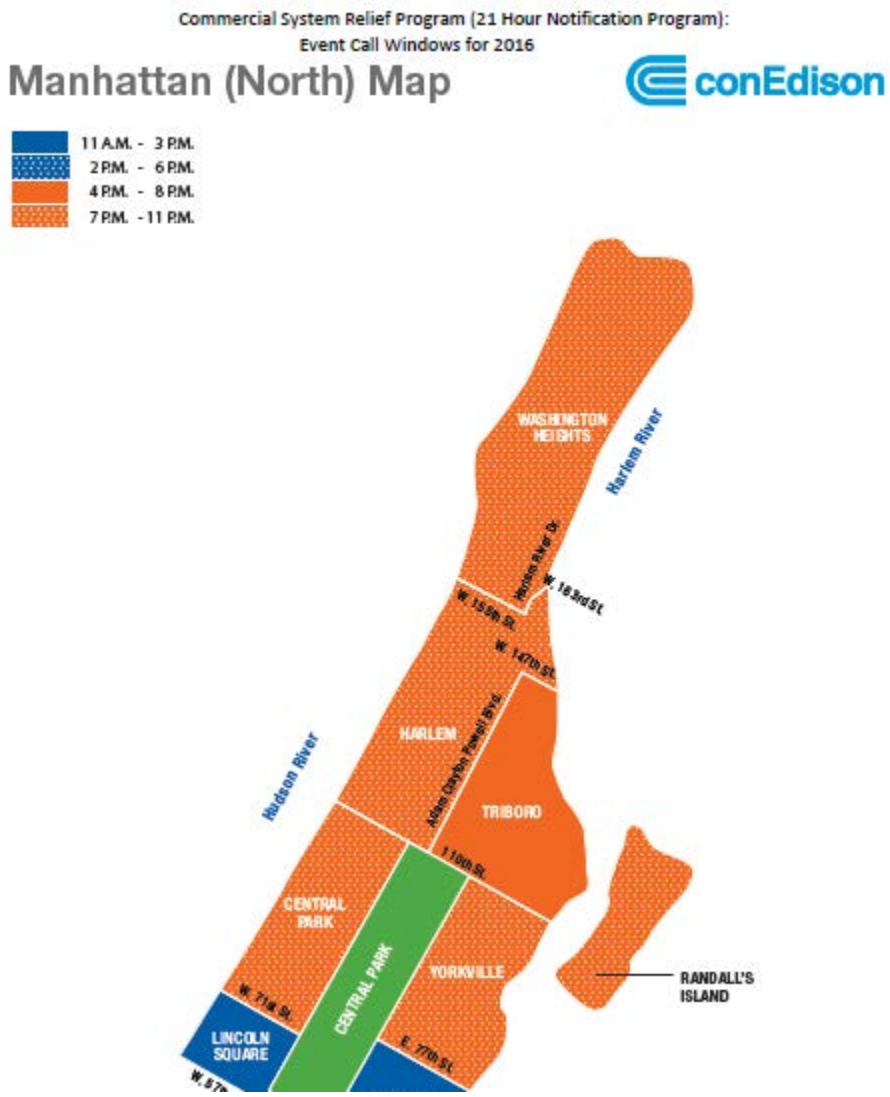

Figure 39 - Screenshot of the Demand Response maps which show the Geographic Boundaries of Networks

<u>System and Network Reliability</u>

The two key components in achieving a highly reliable system are pursuing a high Mean Time to Failure and a short Mean Time to Repair. This is typically measured by two metrics commonly used in the industry to measure reliability performance: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration).[75] SAIFI

[75] SAIFI is the average number of times that a customer is interrupted for five minutes or more during a year.

and CAIDI are used to measure the reliability performance of the radial, non-network portion of the system. In addition, the Company measures two additional network performance metrics: the number of outages per 1,000 customers served (# Outages / 1000 Customers served) and the Average Outage Duration.[76] The metrics are designed to reflect and take action on the different underlying system configurations. These metrics are reported to the PSC in the Annual Reliability and Power Quality Report, which is integrated into a statewide assessment report annually.[77] See **Table 53** for five-year historic performance excluding major storms.

Performance Metric	2011	2012	2013	2014	2015	Current RPM Target	5-Year Average
Network Systems							
Frequency Customer Interruptions per 1,000 Customers	2.49	1.94	2.17	2.36	2.30	2.50	2.25
Duration Avg. Interruption Hours	4.58	4.75	4.20	4.92	4.58	4.70	4.60
Radial System							
Frequency (SAIFI)	0.48	0.36	0.40	0.33	0.35	0.495	0.38
Duration (CAIDI)	2.12	2.02	2.02	1.83	1.95	2.04	2.00

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Table 53 - Company Reliability Metrics from 2015 Staff Reliability Report

The Company uses its demand response (DR) resources, which are available across the entire service territory, to enhance reliability. To encourage these resources in networks that need them most, the Company offers a higher DR incentive in those networks as part of its Distribution Load Relief Program (DLRP). The full program rules are documented in Rider T of the Company's tariff.[78] There are ten networks (*i.e.*, Tier 2 networks),[79] that are identified in the Annual Reliability and Power Quality Report and also listed and published every year on the Company's website at www.coned.com/dr. The

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CAIDI is the average interruption duration time in hours for those customers that experience an interruption during the year.

[76] "# Outages / 1000 Customers served" measures the number of outages or "jobs" or events per 1000 customers served. Average Outage Duration measures the average duration of the "jobs" or events as opposed to the average duration of the customers interrupted. It is calculated by summing up the duration for all the events and dividing by the number of events.

[77] Case 16-E-0147, *In the Matter of 2015 Electric Reliability Performance in New York State*, 2015 Electric Reliability Performance Report (filed June 15, 2016).

[78] Con Edison's current rates and tariffs are found at this website http://www.coned.com/rates/elec.asp

[79] See Note 11 above.

Tier 2 networks identify where geographically in the service territory DR (and other DER) would provide the most benefit to the distribution system. When this information is used with existing CSRP maps, that identify geographic and municipal boundaries at the distribution network load area level and provide a window of time when each network is expected to peak, DER providers can start to identify when and where various DER can add value and at what point in the day they will provide additional value.

The Company has well established DR programs and has continued to develop engaging programs for both C&I customers as well as mass market customers. Recent program changes have been made to increase customer engagement as well as the number and type of cost-effective DER across the service territory, as the Commission recently noted: "The Commission's acceptance of the proposed modifications reflects the Commission's increased expectation that Con Edison will manage the needs of its distribution system, obtain cost-beneficial DER to assist it in achieving that end, and make further progress toward the goals of the REV proceeding and the New York's energy policies."[80]

2. Specific Areas of Need

a) Area Station and Sub-Transmission

As mentioned in the Delivery Infrastructure Capital Investment Plans section, load relief needs at an area substation, sub transmission, and feeder level are analyzed on a yearly basis. The load relief needs over a ten-year window at each level are found in **Figure 40** below:

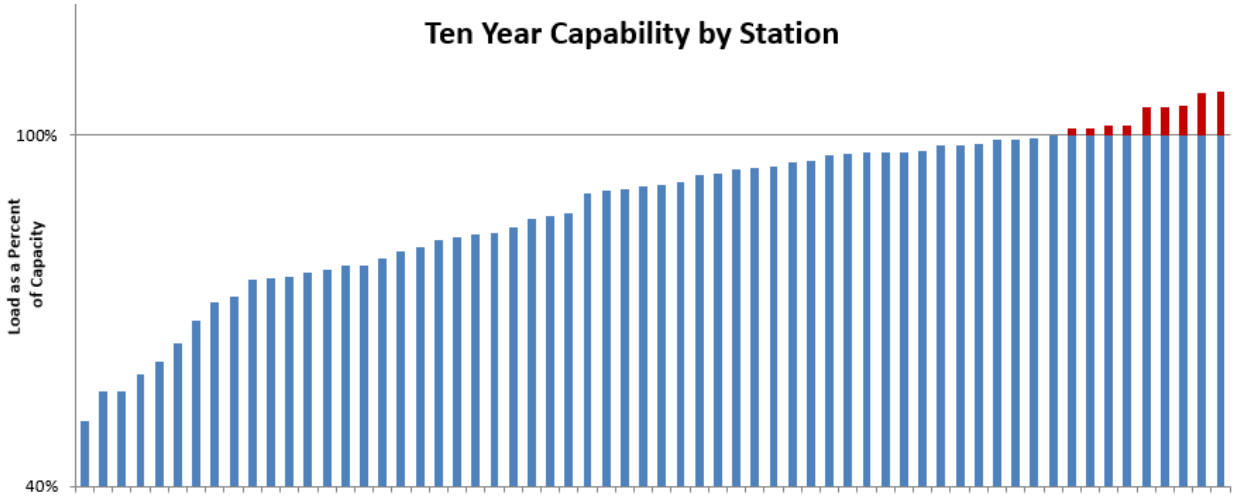

Figure 40 - 2016 Ten-Year Area Substation Load Relief Plan

[80] Case 15-E-0593, *Petition of Consolidated Edison Company of New York, Inc. for Approval to Continue its Residential and Small Commercial Demand Response Programs*, Order Adopting Modifications to the Direct Load Control Program and Instituting the Connected Devices Pilot Program (filed January 25, 2016), pp. 6-7.

The most recent ten-year load relief plan indicates nine substations of the 62 that would be overloaded by 2026.

The area stations with projects suitable for DER comparison are shown in **Table 54** below:

Substation	2025 Load as a Percentage of Capacity
East 179th Street	101%
West 65th Street No. 1	101%
Harrison	102%
Parkchester No. 1	102%
Wainwright	105%
Parkchester No. 2	105%
Avenue A	105%
Millwood West	107%
Plymouth Street	108%

Table 54 – Ten Year Substation Load Relief Needs

There are also areas with capacity constraints at the subtransmission level, but with no constraints at the substation level. Furthermore, there are some areas where the load relief constraints at the subtransmission level, once relieved, would then become constrained by capacity at the substation level. This is presented in **Table 55** below:

Sub Transmission Load Pocket	2025 Load as a Percentage of Capacity	Constrained by Sub Transmission (ST), Substation (SS), or both
East 179th Street	101%	Both
ST - Glendale, Newtown, Amtrak	102%	ST
Parkchester No. 1	102%	Both
ST - Eastview Elmsford Loads	104%	ST first, then SS
Wainwright	105%	Both
Parkchester No. 2	105%	Both
ST - Avenue A	107%	ST first, then SS
Millwood West	107%	Both
ST - Brownsville LP	109%	ST

Table 55 - Ten Year Sub Transmission Load Pocket Load Relief Needs

Area Substation Projects

There are three traditional area substation projects eligible for comparison to NWA, with details listed below:

(1) Glendale

The Farragut-Brownsville 138 kV sub-transmission feeders supplying the Brownsville No. 1 and Brownsville No. 2 area stations will be overloaded during normal operating conditions in 2019. To provide load relief for these feeders, it is recommended that 60 MW (part of the Ridgewood network, supplied from Brownsville No. 1) be transferred to the Glendale area station in Queens.

To accommodate this load transfer, it is necessary to increase the capability of the Vernon-Glendale/Newtown 138 kV feeders as well as Glendale substation's capacity. To achieve this, a fifth Vernon-Glendale/Newtown 138 kV feeder, 38Q05, will be established and supplied from the Vernon 138 kV East Ring. The new 138 kV feeder will supply a new fifth transformer at Glendale and 14 additional new distribution feeder positions. While new duct banks will be installed the entirety of the route from Vernon substation to both Glendale and Newtown substations, cable will be installed only in the portion of the route between Vernon and Glendale for a service date of pre-summer 2019. When the Newtown transformer bank is required for service, the balance of the bifurcated cable run will be installed to serve Newtown at that time. Please note this is related to the Glendale project listed in the Distribution Level Section below.

(2) West 65th Street No. 1

Load flow analyses conducted by Area Substation Planning have forecasted that in certain contingency circumstances, the electrical loads experienced on the north and south synchronous bus and transformer bus at West 65th Street Substation No. 1 can be as much as 4,916A, which is 1,916A in excess of the 3000A bus capacity of the existing bus. This project proposes to install forced cooling on the affected synchronous bus tie connecting sections 1 and 2 to sections 3 and 4 and the associated transformer bus. It is estimated that forced cooling will achieve the required ampere rating increase ahead of the summer of 2020.

b) Distribution Level

The distribution system expansion budget is best understood as a division of programs and projects. Load relief projects address discrete system needs where the local needs and solution are understood in advance. Load relief programs are budget line items that address a particular type of need (*e.g.,* primary feeder relief) that become apparent on a shorter time frame and are addressed as they emerge. As such, the distribution load relief projects will be more suitable for DER alternatives than the load relief programs, though the Company is taking steps to utilize DER for each category at the feeder level. The Distribution projects that are suitable for comparison to DER alternatives are all those for which 50 percent of the budget has not been spent. These include:

Distribution Load Relief Projects

(1) Glendale

In addition to installing the fifth transformer at the Glendale substation (as described above in the area substation level projects) the Company plans a transfer of approximately 60MW from Brownsville No. 1 Substation to Glendale Substation to de-load the Brownsville sub-transmission feeders, shown in **Figure 41** below. The northern portion of the Ridgewood (5B) network was selected as the most viable option to transfer the 60 MW because of its geographical location. The design involves extending 12 network feeders from Maspeth to the Ridgewood network. Fifteen feeders in the Ridgewood network will be split to accommodate the transfer.

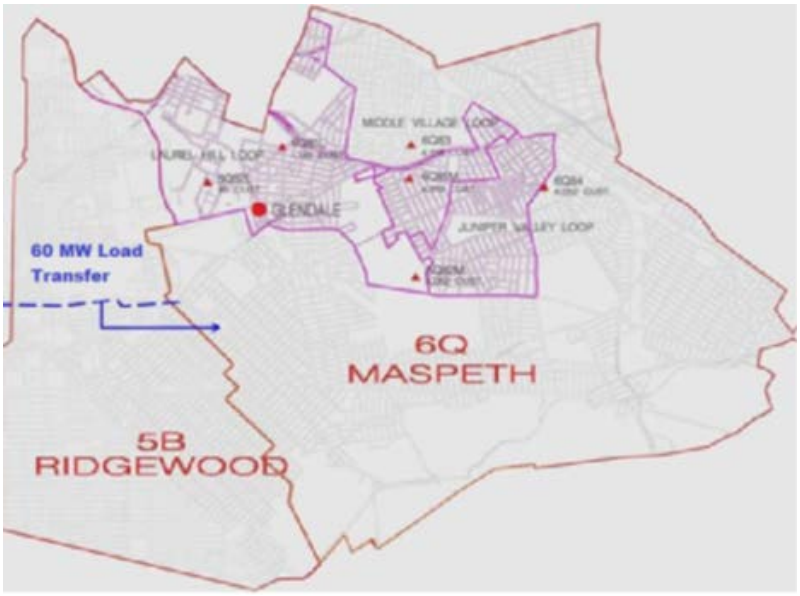

Figure 41 - Map showing the load transfer from the Ridgewood to Maspeth network

(2) Flushing Crossing

The Flushing load pocket is located two miles from the Corona No. 1 substation and the feeders cross various geographical obstructions. Four of the crossings run under the Grand Central Parkway, and four other crossing are routed under the Flushing River. With load forecasted to increase in the Flushing Network, the feeders are at or nearing their capacity at six of those crossings. Additional conduit systems will need to be built to accommodate this load growth.

Based on loading and availability of spare ducts, the Company plans on reinforcing the Flushing crossing over the next five years are listed in order below:

1) Horace Harding Expressway (Long Island Expressway) and the College Point Boulevard ($3.8M)

2) North of Northern Boulevard and Flushing River ($1.8M)

3) Roosevelt Avenue and the Flushing River ($7.6M)

4) Roosevelt Avenue and Grand Central Parkway ($4.0M)

5) Northern Boulevard and Grand Central Parkway ($6.3M)

6) 44th Avenue and Grand Central Parkway ($3.1M)

It is anticipated that the latter stage projects would be better candidates for NWA consideration.

(3) Yorkville

To sustain the expected load growth in the Yorkville Network, while maintaining the required design criteria (EO-2073: Network Feeder Contingency Design), a comprehensive load-relief plan must be developed and implemented.

The traditional solution is to utilize the full breaker capability of the station by bifurcating the feeder from the station to the load via a new duct system in order to decrease duct occupancy and increase the ratings of the feeders.

As part of this plan, two new crossings must be created from the Bronx to Manhattan. The anticipated capital expenditure for the proposed work is $35 million over six years. The breakdown is included in **Figure 42**.

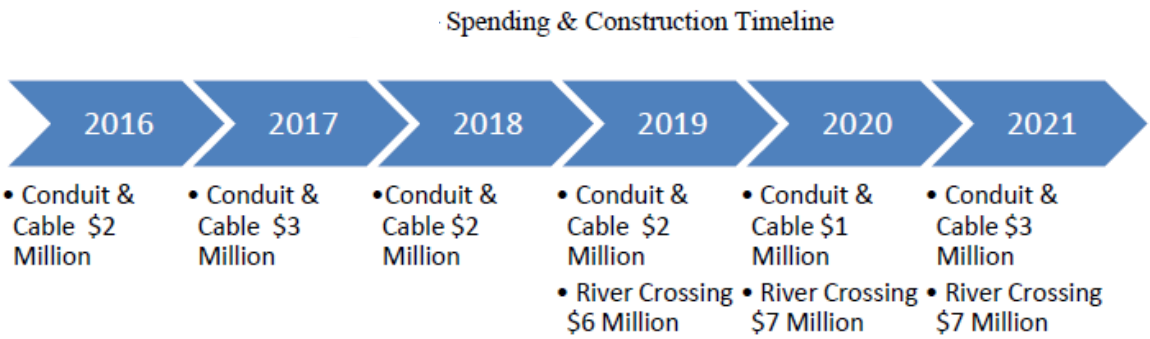

Figure 42 - Spending and Construction Timeline for Yorkville Crossing project

It is anticipated that the latter stage projects would be better candidates for NWA consideration.

(4) Penn Network New Feeders for Hudson Yards

The redevelopment of the West Side of Manhattan has led to historic levels of new business load growth in the Pennsylvania Network. The largest customer in this load pocket is the Hudson Rail Yards. The project footprint is bounded by W. 30th Street and W. 33rd Street, between 10th Avenue and 12th Avenue. The projected load for the East Rail Yards portion of the project is estimated at 65 MVA.

As a result of the proposed load growth, distribution feeders will require additional reinforcement to maintain reliability for customers. This project will result in all Pennsylvania Network feeders operating within their capability and maintaining capacity for future load growth. This proposed transfer utilizes two vacant station cubicles at W. 42nd Street No. 1. The remaining four feeders will need new spare cubicles.

Based on an analysis of the projected new business loads in the Pennsylvania Network, which is supplied by W. 42nd Street No. 1 substation, it is projected that the following six feeders will exceed their emergency breaker limitations of 1,200 amps between 2017 and 2019, shown in **Table 56** below:

Feeder	Emergency Breaker Loading	Year of Anticipated Overload
16M72	1,438 amps	2017
16M76	1,272 amps	2017
16M80	1,393 amps	2017
16M79	1,576 amps	2018
16M77	1,223 amps	2019
16M82	1,340 amps	2019

Table 56 - Estimated overloads on Penn Network Feeders

These six existing feeders will initially supply the Hudson Rail Yards, East Platform loads. The load for the Hudson Yards towers will begin to come online by mid-2015 and will continue through the early 2020's. To avoid overloading these feeders, six new feeders from W.42nd Street No. 1 will need to be established. These new feeders will be extended from the substation to the Hudson Yards footprint, and this load pocket will be transferred to the new feeders. It is anticipated that the latter stage projects would be better candidates for NWA consideration.

c) Distribution Load Relief Programs

Traditionally, distribution load relief programs only identify overloaded feeders and transformers one year in advance to obtain the most accurate forecast and optimize capital spend. As described in the Delivery Infrastructure and Capital Budget Section, the Company is taking steps to lengthen the planning cycle. The Company is interested in testing the deferral concept in areas where feeder loading outlooks indicate potential candidates. The networks of interest for proving this concept are Columbus Circle, Williamsburg, and Hudson. Though these projects require small investments, they will offer insight into how DER can be applied to defer distribution load relief program capital. The results of this analysis are included in **Table 57** below:

Network	Feeder	Overload Percentage	MW Reduction (Network)	Estimated Cost	Estimated Cost/MW
Columbus Circle	**21M34**	103%	**3.99**	**$ 216,000**	**$ 54,135**
Williamsburg	6B43	106%	20	$ 883,500	$44,175
Williamsburg	6B44	106%	23	$ 1,050,000	$45,652
Williamsburg	**All**		**43**	**$ 1,933,500**	**$ 44,965**
Hudson	39M52	104%		$ 26,000	
Hudson	39M53	103%		$ 35,000	
Hudson	39M54	103%		$ 196,000	
Hudson	39M55	112%		$ 75,000	
Hudson	**All**		**7.1**	**$ 332,000**	**$ 46,760**

Table 57 - Distribution Load Relief Programs for NWA Consideration

3. Infrastructure Project Listing and DER Evaluation Process

a) Potential for DER to Resolve or Mitigate System Needs and Required Output

The list of projects, described above in the Capital Budget Section that resolve or mitigate system needs, is listed in **Appendices H and I**.

b) Process for Identifying projects for DER Comparison

(1) BCA Suitability Criteria

The design and implementation of non-wires alternative (NWA) sourcing processes will continue to evolve as experience is gained from REV demonstration projects and as the JU begin to incorporate NWAs as a routine aspect of distribution system planning. A major component of this evolution is the development of suitability criteria to 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 forthcoming Supplemental DSIP filing.

The application of suitability criteria for NWAs can help the JU 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 NWAs have the greatest chance of providing comparable value and being chosen in a competitive solicitation, they can help make the NWA procurement process more efficient and cost-effective for utilities and market participants. Additionally, the criteria would provide DER developers with greater clarity, certainty, and long-term visibility to the market and also 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 NWA procurement can become a routine aspect of system planning.

In designing the NWA suitability criteria, it is important that they not be overly restrictive to avoid the criteria eliminating potentially valuable projects. Also, the criteria should be sufficiently

adaptive to allow utilities to incorporate experienced gained with NWA procurement and respond to changing cost structures and market conditions. Finally, the criteria should reflect stakeholder input and experience. To that end, the JU have launched a stakeholder engagement process in conjunction with the preparation of their Supplemental DSIP filing that will solicit input from stakeholders on the NWA suitability criteria concepts described below.

(2) Interim BCA Suitability Criteria

While uniform suitability criteria are being developed jointly across the New York utilities, the Company used interim criteria to evaluate projects for this Initial DSIP. Given the discussion on the categories of capital investment, covered in the Delivery Infrastructure and Capital Budget Section, system expansion projects were deemed most suitable for DER substitution. Thus, the Company performed a thorough evaluation of system expansion projects to determine the suitability for DER substitutes to traditional infrastructure. As previously discussed, the area of greatest system expansion need where DER can offset the build of a substation continues to be the Brooklyn Queens load area. Con Edison is considering whether the Glendale project, which is a traditional load transfer that supports the BQDM program, may also be a candidate for further NWA substitution. The remaining projects that make up both the traditional and non-traditional utility-sided aspects of the BQDM solution portfolio were thus removed as they already enable significant ongoing DER procurement.

The second interim criterion of capital projects was an evaluation of the capital spent to date on ongoing traditional infrastructure projects. Work began on several projects prior to the filing of the Initial DSIP, and thus those projects have a smaller opportunity for capital deferral based on DER substitution. The threshold for screening for this criterion was whether a project's budget had been more than half spent by 2016. This screening criterion is unique to this Initial DSIP, as new projects will be assessed prior to spending a considerable portion of their budgets. Going forward, the Company will evaluate projects on a continuous basis, so this criterion will be unnecessary.

For distribution level projects, a distinction has to be made between specific projects (like the Yorkville crossing) that have specified network needs and programs (like primary feeder relief) that reserve money in anticipation of emergent system expansion needs. For the project-specific work, it is likely that the same criteria apply as for the projects at the area substation level. For the program-specific work, the Company is evaluating how to more accurately forecast further in advance of this work and utilize the new feeder reinforcement procedure, that allows for deferral of potential overloads (so long as reliability criteria is met). The Company's efforts to lengthen the deferral time for overloads (described in the Distribution Load Relief Section) in areas where probabilistically they are more tolerable is designed to expand the window for DER comparison and substitution beyond the typical nine-month cycle. This may facilitate expanding NWA opportunities to feeder and ultimately transformer relief programs, but requires testing of the concepts (*e.g.*, see the discussion of the Columbus Circle program above) and integration into the planning process.

All remaining projects at the substation level, and those distribution projects that have been defined from the overall system expansion budget are listed in **Appendices H and I**, and details will be

made available for BCA evaluation in an RFP, and posted in a manner consistent with the RFI posting for BQDM.

The Commission's order authorizing the TDM program authorizes the Company to implement NWA solutions that defer capital outside of rate case filings and budgeted programs in an amount up to $60 million for the period beginning on January 1, 2016 and ending December 31, 2017.[81] The process by which these programs are evaluated, procured, and implemented is documented in the Company's TDM Implementation Plan[82] and its TDM General Accounting Procedure 952-A.[83] Because the TDM program is only available for the years 2016-2017, it is best suited to address distribution load relief projects, rather than the non-BQDM area substation level projects that would be undertaken in 2020 and beyond.

(3) Future BCA Suitability Criteria

In the future, projects will be subjected to a uniform set of suitability criteria across the JU. The effort to determine those criteria is underway. NWA suitability criteria capture 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 NWA solicitation, projects in this category would have 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 NWAs. New business might be a great opportunity for DERs to work with customers directly prior to issuance of their load letter. Once the customer files a request for electric service, the Company is obligated to provide service at a standard that meets reliability planning criteria, based on the tariff.[84]

In some cases, the type of work does not lend itself to procurement of NWAs. In the case of planned repairs or replacements of existing infrastructure, the ability of NWAs to displace the utility

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[81] Case 15-E-0229, *Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs That Support Reforming the Energy Vision* (Con Edison REV Petition), Order Implementing with Modification the Targeted Demand Management Program, Cost Recovery, and Incentives (issueed December 17, 2015).

[82] Con Edison REV Petition, Targeted Demand Management Program Implementation and Outreach Plan (filed February 16, 2016).

[83] Con Edison REV Petition, General Accounting Procedure (filed February 16, 2016).

[84] Schedule for Electric Service Tariff, P.S.C. No. 10 – Electricity. The Company's current electric rates and tariffs information can be found at: http://www.coned.com/rates/elec.asp

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 the NWA to be suitable from a timing perspective, the NWA 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 RFP, collect proposals, review bids, undertake purchasing processes, secure board approval, and contract with the winning bidder(s). The NWA 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. Experience conducting competitive solicitations for NWAs and implementing DER 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 also have an impact on its suitability for a NWA 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 NWAs 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 and could perhaps be implemented as a guidance criterion in parallel with 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 development of these concepts.

(4) Application of BCA Handbook

The application of the Benefit Cost Analysis (BCA) Handbook (attached hereto) will occur as part of the utility's process for planning capital investments. Elements of this process (*e.g.,* forecasting, determining load relief) have been discussed in depth already in this DSIP and will be referred to accordingly. This process was described in a recent implementation filing by the Company in a separate

REV proceeding.[85] The process steps occur primarily on an annual basis (unless otherwise noted) and include:

- Forecast system and network loads based on historical loads, sector-driven growth, technology-based load growth, and load modifiers for DERs.
- Determining the capability of substations, sub-transmission, and feeders and compare to forecasted load growth. Identify where load growth exceeds capacity.
- Apply NWA suitability criteria to determine the listing of projects which are eligible for BCA consideration.
- Where a project meets the NWA suitability criteria, a preliminary portfolio of DERs is assembled based on the Integrated Demand Side Management (IDSM) model, which identifies what DERs could feasibly be constructed in the area of need.
- The Societal Cost Test (SCT) of the BCA is then applied to the portfolio of DER using estimated costs. For details of the BCA or SCT, please refer to **Appendix N**.
- If the BCA indicates the portfolio of DER is cost-effective, the procurement process for DER begins including, but not limited to, the following to determine actual costs:
    - Requests for Information (RFI), sometimes leading to directly to actual cost determination and sometimes leading to:
        - Requests for Purchase (RFPs)
        - Requests for Comments (RFCs)
        - Auctions
        - Block Bids
        - Direct Solicitations
        - Pre-negotiated menu approach
        - Sole source contracts

  Note: Even when the BCA indicates the DER solution is the most cost-effective, traditional solution plans must be developed as the backstop if implementation issues arise or if subsequent BCAs indicate the DER portfolio is not the most cost-effective.

- The BCA is re-run based on actual costs as determined through the procurement process above.
- If the BCA indicates the DER portfolio is the most cost-effective, contracts are signed with DER providers.

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[85] Con Edison REV Petition, Order Implementing with Modification the Targeted Demand Management Program, Cost Recovery, and Incentives (issued December 17, 2015).

- Contract fulfillment is evaluated triennially for large projects (large projects are defined as those that seek to defer infrastructure at the area station level or further upstream) and annually for small projects
    - If more CSS are needed, the Company will determine how much time is available (based on pending load relief needs) and re-solicit DER solutions or implement an appropriate traditional solution

If fewer customer-side solutions are needed (*e.g.,* another year of load data indicates load relief needs are not as severe), the Company will reduce future CSS to meet reliability needs without over-procuring.

F. Hosting Capacity

1. Definition

Con Edison concurs with the definition of hosting capacity recently outlined in *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State* (EPRI Hosting Capacity White Paper).[86] The EPRI Hosting Capacity White Paper accurately defines hosting capacity and addresses the inherent variability of hosting capacity on a dynamic grid:

> 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.[87]

Hosting capacity can be used to inform utility interconnection and planning processes and to support DER providers' 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 EPRI also defined, the key factors that influence hosting capacity methods are DER location, DER technology, and feeder design and operation:

> **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

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[86] Electric Power Research Institute, Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, 2016. 3002008848.
[87] *Id*., p. 3.

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.

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 because 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 as shown in **Figure 43.**

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 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 NY.

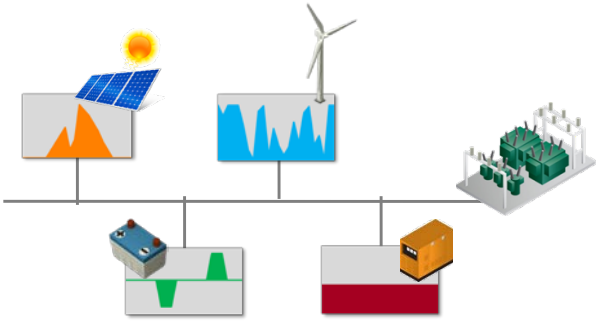

Figure 43 – The Technology - the various DER technologies integrated with the grid

Feeder Design & 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 44** summarizes hosting capacity results on 28 different feeders. Each has a unique hosting capacity based on the factors described above when looking at PV.[88]

[88] *Id*., pp. 8-9.

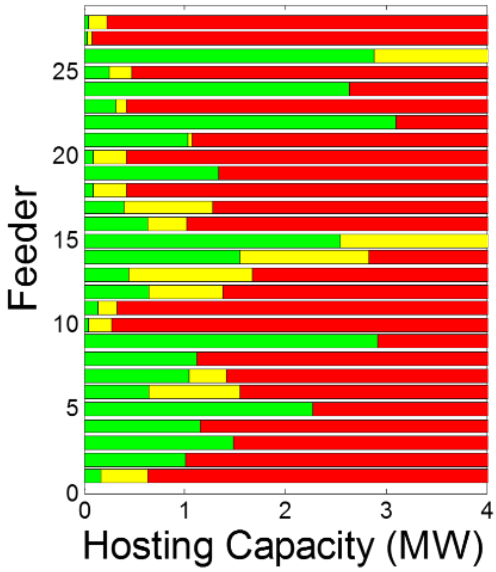

Figure 44 - The Feeder – The Spectrum of Hosting Capacity Values Across 28 Feeders

2. Hosting Capacity in the Company's Service Territory

Con Edison's service territory consists of both network and radial systems. Network distribution systems comprise 86 percent of the distribution system and non-network (including radial) systems make up the remaining 14 percent of the distribution system. As one of the JU, the Company is actively participating in developing a common methodology to determine and share hosting capacity information with market participants. This effort has begun and will be developed further in DSIP technical conferences and stakeholder engagement, and will be reported out in full in the Supplemental DSIP to be filed November 1, 2016. The Company has made notable progress in developing hosting capacity maps for the distribution network systems. The Company started with network systems, as they represent the largest and most dense form of distribution system in its service territory. For both network and radial systems, the Company's approach is to present hosting capacity information as a geographic heat map overlaid on a map of the service territory. Considering the unique nature of the network distribution systems, the Company has made significant progress here. The methodology and mapping representation for non-network/radial distribution systems is still being determined.

Given the unique network design of Con Edison's network territory, the determination of hosting capacity will require a different methodology. As no other utility in New York State has a network design at a similar size or level of complexity as Con Edison's, the Company has begun implementing a methodology to determine hosting capacity independently for its underground network system with the algorithm and an example of the results shown below in **Figure 45**.

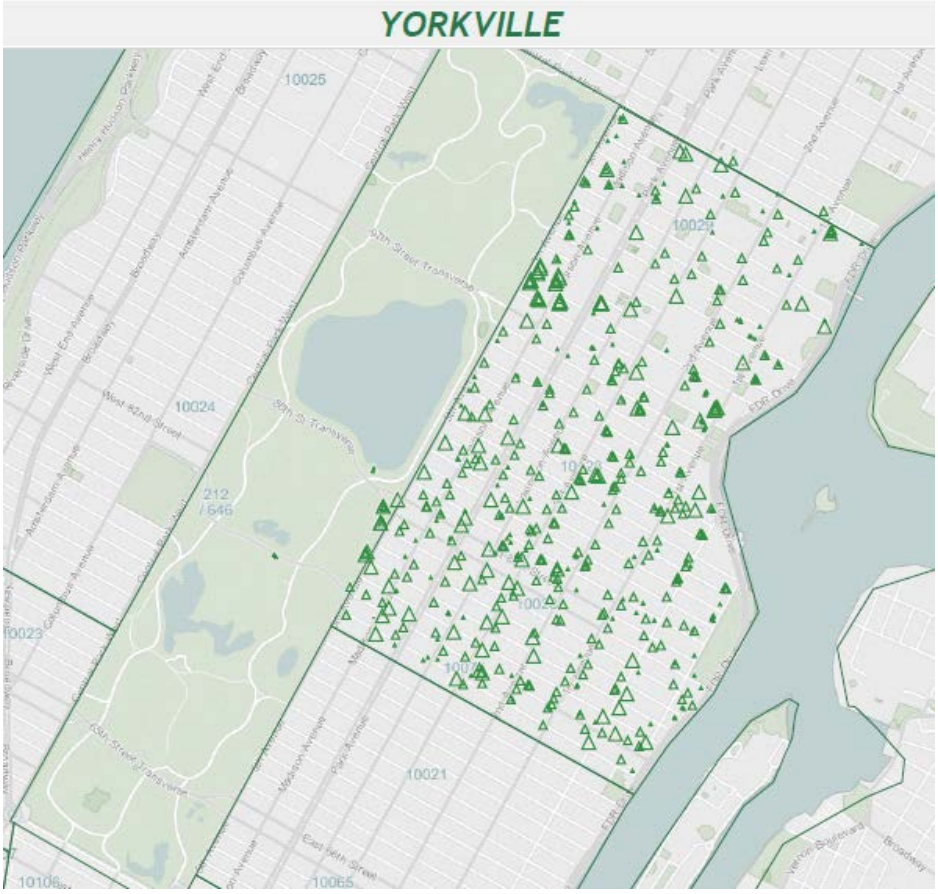

Figure 45 - Example Network Hosting Capacity

The hosting capacity data the Company will provide, concurrent with the initial DSIP filing, will be in the form of a static map for the underground network system. The data is provided regardless of whether the circuits present a high- or low-value proposition in terms of hosting capacity on the circuits. The map will be presented through the Company's DG website (www.coned.com/dg) and updated on an annual basis initially, with more frequent updates expected as the methodology and supporting tools mature. By presenting the hosting capacity information in a map, developers can visually assess where projects can easily interconnect, or conversely where interconnection may require more detailed studies. The hosting capacity methodology, described more fully below is a phase 1 approach that identifies areas where solar PV will be connected with no additional cost or impact to power quality and reliability. As such, determining the remaining hosting capacity is not possible at this time, though it is expected that will be developed through technical conferences and further collaboration with the JU and stakeholders.

3. Calculating Hosting Capacity

The initial approach for determining the phase 1 hosting capacity static maps is the results of a load flow analysis performed for each underground network load area. The maps provide a visual representation of where in these areas solar PV is expected to be able to interconnect and not have an adverse impact on power quality and reliability. Projects that are sited in close proximity to the large

triangles should not have any additional costs to interconnect than beyond the standard interconnection fees in order to deliver proper power quality and reliability to nearby customers. It is expected that initially these hosting capacity results would be updated annually and presented in the interconnection portal to display the areas that should offer the greatest ease of interconnection. Given the dynamic network system and the steady influx of interconnection requests, a large green triangle on the hosting capacity map is meant to indicate only where there is the highest probability of low-cost interconnection, a medium-sized green triangle on the hosting capacity map indicates areas of moderate-cost interconnection, and a small green triangle indicates some potential additional cost for interconnection. The indicated areas do not obviate the need for detailed interconnection studies, but should help guide DER providers identify areas of lower interconnection cost.

The Company's initial efforts to provide hosting capacity maps will be focused on locations where DERs can easily connect to the distribution system. As such, the Company and the other JU are proposing a phased approach to the implementation of distribution system hosting capacity maps. The hosting capacity implementation roadmap, as defined in the EPRI Hosting Capacity White Paper, 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
- Phase 4 will provide fully integrated DER value assessments

The Company's current proposal is an Indicator Assessment (Phase 1). The development of the subsequent phases of hosting capacity maps will be largely informed by parallel proceedings related to the value of DERs to the distribution system. The Company continues to work with DPS Staff and various stakeholders to provide input into the development of hosting capacity data. This development will also be further informed by technical conferences facilitated by DPS Staff, and will develop along with the supporting technologies (*e.g.,* a GIS (currently not available)) provides the ability to map customer accounts to their corresponding transformer). Through these efforts, the Company is working towards a hosting capacity methodology that includes the power system criteria cited in the EPRI Hosting Capacity White Paper, shown visually in **Figure 46** below:

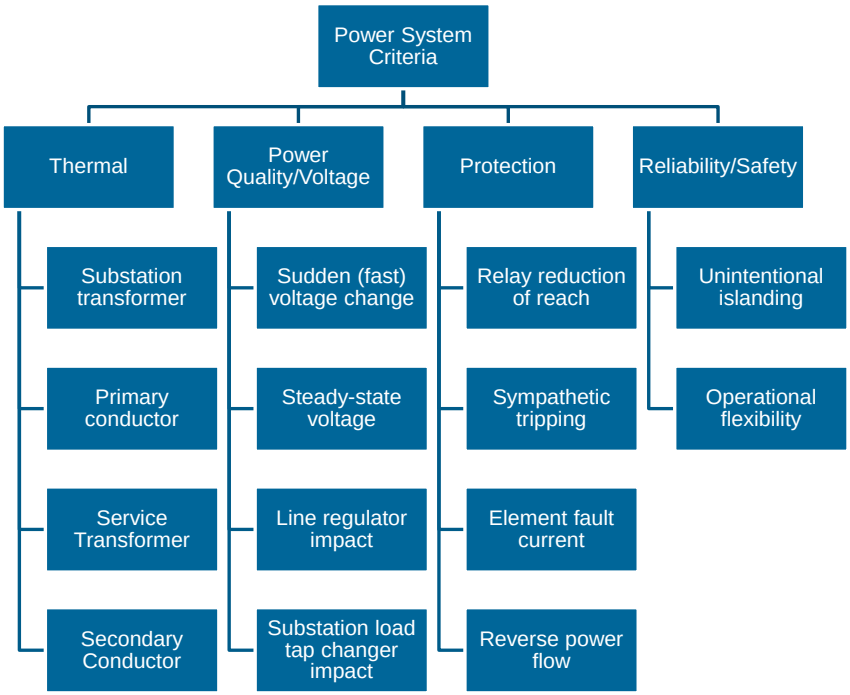

Figure 46 – Power System Criteria for Determining Hosting Capacity

IV. Distribution Grid Operations

A. Introduction

Con Edison has safely operated the electrical grid in New York City since 1882 and is consistently recognized as one of the nation's most reliable utilities. Con Edison delivers power to one of this country's largest and most densely populated urban areas, where reliability of service is critical. As a result, 86 percent of the system is an interconnected network grid, which is best suited for this type of area. One challenge is the complexity in the day-to-day operation of the grid. This chapter outlines how DERs 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 (VVO) capabilities, and how DERs can be more smoothly interconnected.

The electric distribution system was originally designed for power to flow from the energy source to the various points of energy consumption by the end user. From this fundamental system design feature came the most efficient solutions for distribution system needs under various circumstances. The Company has continued to evolve solutions for distribution system needs to keep pace with evolving technologies and is already experienced with rolling out EE/DR programs as well as interconnecting customer DG. The impact of significant expansion of DERs to the distribution system under REV will require the Company to perform extensive engineering studies and evaluations to understand how best to integrate DERs. This integration will result in changes in modes of operation contrary to the original distribution design, by way of bi-directional energy flow. Careful consideration must be taken throughout this process so that the introduction of DERs to the distribution system does not compromise the safety and reliability of the distribution system.

To date, penetration levels of different types of DERs have been 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 effects of these resources on the unique network grid will become evident. In this chapter the Company references different existing processes and procedures and evaluates how those would be modified with increased DER penetration.

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 maintaining a safe and reliable grid and realizing the most value to customers and the system from DER. To that end, the Company envisions the establishment of certain requirements for DER providers including and beyond those that may be established by the Commission in a Uniform Business Practices for DERs in a separate proceeding.[89] This

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[89] Case 15-M-0180, *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products*, Notice of Technical Conference (issued April 21, 2015).

would be consistent with existing DER contracts 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 for safety and reliability, and contractual obligations/penalties for programs such as NWAs and demonstration projects. This set of requirements will be developed jointly by the JU, informed by the stakeholder process, and introduced in a parallel proceeding.[90] Monitoring of DER will be necessary for 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. Cybersecurity 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 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 and standards.

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. These capabilities are enhanced by the rollout of AMI, as operators will rely on visibility across the service territory, and as such are within reach in the near term.

Finally, the Company addresses its continuing improvements to the interconnection process. The Company has been addressing gaps identified in the September 2015 report prepared by the EPRI[91] for NYSERDA in conjunction with the recent amendment of the New York State SIR finalized on March 18, 2016.[92] In addition, the Company has established an interconnection application portal through www.coned.com/dg, which will be refined to meet requirements of the Track One order.

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[90] *Id.*

[91] Electric Power Research Institute, Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment, Final Report Number 15-28, (September 2015) (EPRI Gap Analysis).

[92] 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).

Hosting capacity maps, discussed in the Distribution System Planning chapter, will be presented within this portal to deliver the information valuable to DER providers when it is needed.

B. System Operations

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

As shown in the Introduction, the penetration of DER is expected to follow an "S" curve of adoption (**Figure 1**), now in the early stages. The Company's systems operation plan follows accordingly. The current levels of DER penetration are not significant enough to cause dramatic near-term effects on serving customers. The Company intends to maintain the same award-winning level of reliability regardless of DER penetration. The table below demonstrates, as an example, the levels of PV capacity installed and currently in the queue (this includes all current applications, not just those approved) as of May 31, 2016.

DG (PV* + CHP) Installations MW Capacity	Nameplate Capacity	Derated for Peak Coincidence
Total Nameplate MW Installed**	**279 MW** 168 (CHP) + 111 (PV)	**198 MW** 168 (CHP) + 30 (PV)
Total Nameplate MW Proposed*	**129 MW** 78 (CHP) + 51 (PV)	**92 MW** 78 (CHP) + 14 (PV)
Grand Total MW	**408 MW**	**290 MW**
Record Peak System Load**	**13,322 MW**	

Table 58 - PV Capacity Installed and Queued as Compared to All-Time Peak Load

** PV is rated at system peak coincidence of 27 percent of nameplate.*
*** Data provided is nameplate DC capacity, but is derated for forecasting and planning purposes as described in the Available Resources section.*
**** The queue reflects all currently proposed projects as of April 12, 2016 and reflects jobs planned in the next 12-24 months.*
***** Record Peak System Load is net of DER load modifiers implemented that day.*

Con Edison has a lower degree of DG penetration relative to the other JU, underscoring the inherent challenges in siting resources in a dense urban population. As shown in **Figure 47** below, net-energy-metered penetration is approximately two percent relative to the 2005 peak load. The 2005

peak load was the legislative reference point to set net metering caps. The PSC ended any ceiling for net metering,[93] pending a determination of the value of net metering.[94]

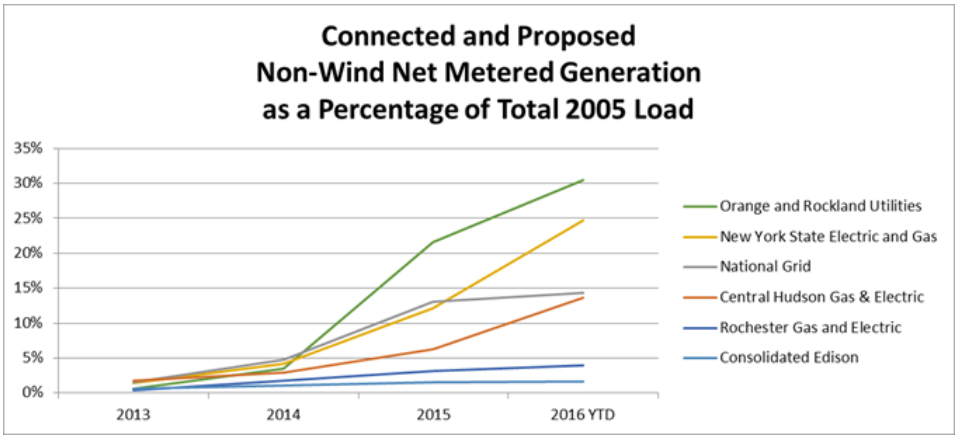

Figure 47 - Net Metered Generation as a Percentage of 2005 Peak Load by Utility[95]

DERs provide the greatest value by relieving capacity constraints on the distribution system or avoiding distribution upgrades, provided it is done so with the same reliability and/or functionality afforded by traditional distribution investments. Different DER technologies have different load and/or output profiles across the hours of any year, across years, and in different locations. For example, a CHP unit is capable of providing load-following resources over the course of the day, up to the maximum capability of the CHP unit's size. CHP units are often optimized to serve the customers thermal load and the electrical output would supplement the customers electrical load. By contrast, solar PV output will vary across days and the hours of any day, in relation to the cloud cover, existence of daylight, and the season. While DERs could potentially provide a variety of benefits to the grid, there are also challenges that will need to be taken into consideration as the DER penetration grows.

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[93] Case 15-E-0407, *Orange and Rockland Utility Petition for Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j*, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation (issued October 16, 2015), JU Petition for Rehearing (filed November 16, 2015)(pending).
[94] 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).
[95] Case 13-00205, *Standardized Interconnection Inventory*, JU Reports (filed 2013 through February 2016).

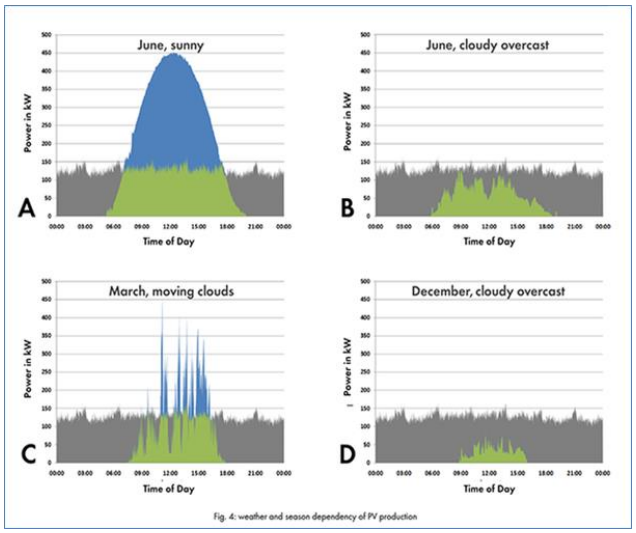

Figure 48 – Sample solar output variability (seasonal and cloud cover)[96]

Current PV inverters are either set, or can only produce at a unity power factor to optimize the kW output to benefit the customer under current net metering regulation. In addition, the absence of reactive power tariffs at the residential level creates no incentive for DER providers to meet their customers' reactive power needs. This, in addition to voltage fluctuations that are inherent to intermittent DERs, can put increased stress on distribution equipment as well as affect the reliable delivery of power to customers. Some of these issues can be addressed by coupling intermittent generation with storage or proven smart inverter technology and providing the appropriate amount of reactive support throughout the load cycle. Because the distribution circuits' loading patterns change due to the intermittent generation of DER, the existing voltage control devices, which are typically upstream of the DER providers, may no longer provide proper voltage regulation. If allowed to persist, especially with increased DER penetration, this condition could cause failure of utility and customer equipment. The existing voltage support devices such as capacitors, voltage regulators, and transformers could be supplemented by DERs that can demonstrate similar, if not identical, levels of performance and reliability commensurate to traditional voltage support devices. As DER integration into distribution circuits grows, the Company may need to deploy Volt/VAR control schemes to manage voltage and power factor across distribution circuits. It will also be important to understand how the utility reactive control devices and multiple distributed inverters interact together. These system upgrades are essential to maintaining grid reliability and mandated voltage levels on the distribution system.

[96] Tierney White Paper, p. 18, available in Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, JU Comments, Appendix B.

Another operating challenge Con Edson is mindful of with increased DER penetration is fault clearing and locating as multiple sources of power are interconnected to the system. Faults on circuits with DG have the potential of creating miscoordination between reclosers and fuses in the overhead portion of the Company's service territory. Faults can also create fuse-fuse miscoordination and potential station relay 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 Order Modifying Standardized Interconnection Requirements.[97] However, as DG penetration increases, these challenges may require more in-depth study.

Con Edison's distribution system was originally designed for power to flow from central energy sources to the respective load areas. As such, protective relays are specified and set to operate uni-directionally (from substations to loads) at the current fault duties, and coordinated with downstream protective devices for minimal impact to customers during individual component failure. Con Edison already has several years of experience integrating distributed generators into the network. This experience has shown that the densely loaded electric grid can typically absorb most solar installations' output before it creates backfeed for network protectors. In any event, the reality of real estate and rooftop availability typically limits the size of PV export onto the Company's system. In the handful of cases where Con Edison has dealt with large installations (*i.e.*, over 1 MW), the Company has developed techniques and relay modifications to resolve backfeed challenges. Con Edison is taking advantage of both its engineering capabilities and the densely loaded system characteristics to promote DER opportunities for customers by offering an initial hosting capacity map to DER providers that will evolve with the DSP.

In addition, multiple DERs on the circuits translate to many possible energy sources on the circuit. As such, the complexity of coordination studies increases and protection becomes paramount. In many cases, the existing uni-directional protective relays may need to be replaced with bi-directional or other advanced relays for proper protection. **Table 59** lists the most common DER categories along with the opportunities and challenges that contribute to the Company's ability to serve customers.

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[97] 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 17, 2016).

Type of DER	Effect on Operations
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 reactive support and voltage support Challenge: • Intermittent source of power • Currently operate at unity power factor with 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 • Provides emergency backup • Potential alternate to spinning reserve to provide frequency support 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 operational complexities, and must be permitted by local building and fire codes

Type of DER	Effect on Operations
Combined Heat and Power (CHP)	Opportunity: • Provides continuous power, exhaust heat, and potential energy savings • Could be used during a contingency if islanding capability is installed • Potentially greater efficiency than many traditional generating sources Challenges: • Dispatchable only at owners' discretion and may not be available at a time of system need • Maintenance procedures vary by owners • If not operating, the utility system may have to serve a significant amount of additional load • May create lung-level emissions • Operational challenges may be specific on a case-by-case basis depending on the size of the unit, the customer's load profile, and interconnection location
Microgrids[98]	Opportunity: • May provide continuous power • Could be used during a contingency for demand response 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 • Maintenance procedures vary by owners

[98] The U.S. Department of Energy defines microgrids as a "group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single, controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode." http://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Microgrids-101.

Type of DER	Effect on Operations
Peaking/Emergency Generator	Opportunity: • Provides power on demand • Could be used during a contingency for demand response Challenges: • Can contribute substantial amounts of fault current into the system • Can potentially operate in an islanded state • Dispatch-able only at owners 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 as an operational response to contingencies • Dispatchable Challenge: • Limited in duration • Dispatch ability may be influenced by the owner of the resource - may not be available at a time of system need • Customer fatigue
Energy Efficiency	Opportunity: Reduces stress on infrastructure components by lowering overall system load Challenge: • Not dispatchable • Sustainability and penetration limitations

Table 59 – DER Operational Opportunities and Challenges.

2. Policy and Process Changes

The Company is responsible for maintenance of the safety and reliability of the electric distribution system. In most cases DERs do not adversely affect the safety and reliability of the electric distribution system. As such, the Company is an active participant in the ongoing SIR discussions and the New York State Interconnections Technical Working Group (TWG). Part of the DSIP is to leverage progress made in parallel proceedings.

Energy efficiency programs do not require the customer to generate or export electric power. These programs only reduce the demand and energy consumption of the customers participating in

these programs. Encouraging or expanding these programs will not have any adverse effects on the safety and reliability of the electric distribution system.

Distributed Generation technologies generate, and at times export, electric power; therefore, the safety and reliability aspects of the electric distribution system must be considered. Interconnection procedures are the best way to verify that DG is interconnected (installed) and operated in a manner that safeguards against adverse effects on reliability and safety. Current interconnection requirements set the standards for DG technologies in how they must disconnect from the system when grid power is not present. This is necessary to prevent DG systems from energizing parts of the electric distribution system that Company field forces may be repairing. As DG penetration increases, these requirements will continue to be refined and administered to protect the reliability and safety of the electric distribution system, employees and the public. For DG smaller than 5 MW, the SIR sets clear requirements for safety and reliability. For those units greater than 5 MW, the Company maintains policies in alignment with IEEE standards.

The Company's service territory does not yet have the levels of DG penetration seen in other parts of the country or New York State. As penetration of net meter eligible technology (such as PV) expands, policy and procedures that can control and adjust the aggregate output of these technologies may need to be developed in order to maintain safe and reliable service. Current PV penetration is less than one percent of the system peak; therefore the Company is not yet to a point where these aggregation and control policies and procedures need to be developed.

An important safety concern associated with increased penetration of DG is unintentional islanding. Unintentional islanding occurs when the DG system continues to energize a circuit after the circuit is disconnected from the rest of the grid following a system fault or utility-switching action. While current interconnection standards are established such that the inverters disconnect the DG from the system, these standards must be updated as these systems age and maintenance procedures associated with the DG are unknown. It is important that these issues continue to be addressed in subsequent amendments of the New York State Standardized Interconnection Requirements which cover interconnections up to 5 MW, and it other utility interconnection procedures for larger interconnections. The PSC has established other forums to address technical solutions to other interconnection issues such as the NYS Interconnections Technical Working Group (TWG) and NYS Interconnection Policy Working Group (PWG).

Another consideration is the power quality of the distribution system. Certain power quality (PQ) issues, such as voltage fluctuations, can potentially harm both the Company's and the customer's equipment. The automatic devices placed at the interconnection point will address this issue as they isolate the DER when PQ parameters are not met. As DG penetration increases, these requirements will continue to be refined and administered to protect Company and customer equipment and maintain the reliability and safety of the electric distribution system.

Large DG installations increase the likelihood of reverse power flow through a substation, especially on the 4 kV overhead systems. This concern will require that revised protection standards be

developed. Substation and field equipment will need to be installed or upgraded to comply with these new requirements. Increased maintenance activity will be required on substation tap changers and distribution reactive devices, such as capacitor banks and voltage regulators.

Processes, procedures, and equipment will be needed to allow the operator the ability to curtail DGs in the event of overloads. Additional Con Edison Control Center staffing will be needed as the complexity of the system changes due to increased penetration of DGs on the system. The need to monitor, control, and potentially dispatch some DGs will fall outside of the normal functions of the Control Center Operator and will require round-the-clock attention in the Control Center.

3. Visibility and Communication Protocols

As stated above, the Company is responsible for maintenance of the safety and reliability of the electric distribution system. DERs have the ability to provide grid benefits, including, resiliency, voltage, frequency control and peak shaving if they exist in sufficient quantities where needed and if there are adequate communications protocols to guide and enable interaction. The penetration of DERs at high levels, however, at times causes the need for additional voltage control and frequency regulation. In order to gain system benefits from DERs there must be adequate communications infrastructure to gauge the impact and location of the DERs.

As mentioned above, there are no known safety or reliability implications associated with EE programs, which do not involve generators capable of exporting power onto the grid. Con Edison's interconnection requirements address any safety and reliability concerns to the extent that a DR resource could parallel to the system or export power. There are also no anticipated visibility and communication protocols for EE as the technology provides a constant demand and energy reduction which can be calculated. AMI will provide faster and more precise information about the effects of EE. The rollout of AMI will provide greater visibility into DR effects as well. Currently DR response is measured through metering which can provide performance data every 15 minutes. New demand response communication protocols such as OpenADR[99] have the potential to standardize, simplify, and automate communication with DR resources. The Company's Demand Response Management System (DRMS) is OpenADR compliant. Open standards are important to enabling wider participation in DR programs.

Distributed Generation covers a wide range of technologies, and thus would have a wide variety of communication protocols. Communication protocols associated with safe and reliable system operation are not specifically addressed in the New York SIR and IEEE 1547, therefore effective standards will need to be developed to provide adequate levels of communication and visibility while adhering to cyber and physical security protocols. These communication protocols often do not provide

[99] The OpenADR Alliance was begun to standardize, automate, and simplify DR to permit utilities to cost-effectively meet growing energy demand and customers to control their energy future. http://www.openadr.org/

visibility to observe and interact with DERs or DER providers in the normal operation of the electric system. Metering in some form remains the most important tool in gaining visibility to DG performance and as stated previously AMI will further enhance visibility with more frequent data and metering with more advanced features. In general, the Company will require visibility into DG units larger than 1 MW. At times, local reliability requirements will necessitate monitoring for units smaller than 1 MW, and this issue will be raised during the technical review portion of the interconnection process.

Combined Heat and Power customers will be required to have metering on their generating facility with communications to the Company's meter data management systems in order to take advantage of the Company's credit available for reliable performance of their generating units. Large PV systems also utilize methods of metering to provide visibility. For smaller systems the Company is exploring software applications to further enhance visibility. There are software providers with software tools to gather performance data on small-scale PV through direct connection to the systems inverter. The Company is working with innovative software providers on a pilot project to begin viewing performance data on small-scale PV in its service territory through direct connections to the system's inverter. For energy storage, the Company expects the Virtual Power Plant (VPP) demonstration project to provide insight into battery performance and protocols for communication.

In the event of an outage or other urgent need for capacity from DERs, the capacity is typically required in a relatively short period (less than 30 minutes for most systems/ratings). A short time frame puts pressure on the communication and subsequent operation of the DER for reliability. Communications that enable swift response to system needs are critical to safe and reliable operation of the distribution system. For DERs to be relied upon during times of system need, they need to be signaled or dispatched and must respond expeditiously when called upon. Operators of DER must also have the ability to alert the Company when the resource is not available, whether is a planned or unplanned unavailability (outage). When a DER is unavailable, the Company must plan to secure other resources (customer-side or traditional) to safely and reliably service the load; thus, the Company must have access to the schedule and availability of DERs on its system. A communications protocol with proper cyber security attributes is required for DERs to communicate safely with the Company's supporting systems. The AMI initiative is the first step in this direction.

The ability of AMI communications and smart meters to better monitor the Company's distribution system and performance of DER equipment will 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 planning.

4. Operational Needs – Normal, Outage, and System Stress

a) Normal Operations

During normal operations, network areas are supplied by a number of primary (13, 27, or 33kV feeders) feeders from area substations. These feeders connect to a number of distribution transformers

and mains and secondary feeders which connect to a low-voltage network grid. The feeders and transformers are interconnected through a grid/mesh network, to form a uniform and well-diversified intermesh of feeders and transformers. Because of this intermesh through the low-voltage grid, a distributed network area will operate satisfactorily (*i.e.*, within specified voltage limits) with one feeder out-of-service for a first contingency (N-1) design, or with two associated feeders out-of-service for a second contingency design (N-2). Network areas in Manhattan, Brooklyn, Queens, and the Bronx have been designed for second contingency operation. Load Areas in Westchester County and Staten Island have been designed for first contingency operation.

Per the Company's design requirements, underground feeders are typically installed in a duct system. By design feeders that supply an area are physically separated into diverse ducts to increase reliability. In networks with a large number of feeders, more than two feeders of one network may be installed in the same duct bank provided that no more than two supply the same part of the network.

The design criteria for a network area include normal and contingency loads for feeders, transformers, and secondary mains. Con Edison is responsible for determining that transformer, secondary main and feeder loads are within the design criteria. When there are no feeders out-of-service, conditions in the network area are considered normal. Feeder loads under these conditions should not exceed the established normal ratings of the feeders. With one or two feeders out-of-service, the load dropped by these feeders is picked up by nearby functional transformers and feeders. The transformers that are nearest, "impedance-wise", to feeder(s) out-of-service will pick up most of the load dropped. Therefore, unless the secondary grid is very strong with a "low through impedance," the load picked up does not spread more than two to four blocks on either side of the transformers that dropped their loads.

The operational needs during normal operations are to maintain the secondary system voltages within prescribed limits. The table in **Appendix D** shows the secondary system voltage needs[100] during normal conditions and during outage events or other periods of system stress.

b) Contingency Operations:

Although during normal operation, nothing should happen to interrupt power other than regularly scheduled maintenance, contingencies do occur. Contingency operation is the ability of a system to operate when an unlikely fault or unplanned event occurs. A network is in contingency mode of operation any time one of its primary supply feeders is out-of-service due to scheduled work, off on emergency (OOE) or open auto (OA). Transformer or network protector outages for any reason can also subject a portion of the network to a contingency operation. The net effect is that the network is one event closer to possibly impacting customer service.

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[100] ANSI standard C84.1 sets acceptable secondary voltage ranges.

Impact of Scheduled Outages

For scheduled outages, the Company uses network analysis tools to determine when feeder(s) can be removed from service without adversely impacting the network. Networks with a second contingency design may not be adversely affected by a scheduled feeder outage; whereas, an outage in a first contingency network may put a network in a situation where the loss of another feeder will result in an outage to the customer. As the Company relies to a greater degree on DER, its operators must know when a scheduled feeder outage may impact local DER.

Impact of OOE or OA Outages

System equipment is removed from service OOE when it is in imminent danger of failure and poses a direct hazard to people and equipment in the area. An OA feeder is one that has opened automatically due to the occurrence of a fault on the feeder. Feeder outages as a result of OOEs could result in unavoidable network problems such as outages or feeder restrictions because the feeder is immediately removed from service regardless of existing network conditions.

The operational difference between scheduled outages and OOE or OA outages lies in preparation and timing. The consequences of a scheduled outage is studied prior to taking the feeder out-of-service, and a plan is made to operate without that feeder and to pay close attention to the network equipment that must absorb the excess load. A feeder outage due to an OOE or OA occurs without any planning and the control center must quickly identify problems and minimize impact on the network. As stated above, the operators must be aware that losing feeders may impact DER operation.

Multiple Feeder Contingencies and Service Restoration

As a result of OOEs, OAs, and scheduled feeder outages, networks may be subjected to multiple feeder contingencies. This can present a wide variety of network problems that must be addressed by control center personnel and engineering. Some of these problems may result in customer outages, low-voltage problems, or overloads.

Some or all of the following corrective actions may be used to alleviate identified problems and restore system integrity:

- Alleviate overload conditions quickly
    - Load reduction
        - Individual buildings (use emergency generators)
        - Initiate load reduction programs
        - Selective appeals for load reduction
        - Network-wide appeals for load reduction

    - Voltage Reduction
- Reconfigure the system
    - Restore one leg of a multi-legged feeder
    - Sectionalizing affected area (overhead system only)
- Expedite restoration of out-of-service feeders
    - Live end cap (LEC) one or more out-of-service feeders for partial restoration
    - Use of primary shunts to restore feeder

Thermal Limits and Voltage Threshold Exceedances

A main limitation of equipment is the amount of heat it can tolerate. Substation transformer thermal limit 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, and 15-minute Short-Term Emergency capabilities. The 24-hour rating (is the maximum load the transformer is capable of carrying without any loss of life every day of the year. The 4-hour rating is the maximum load that a transformer can carry under emergency conditions for a period no longer than 4 hours. The 15-minute rating is the maximum load that a transformer can carry under emergency conditions with a 1 percent loss of life. Operations above any of the above ratings requires field switching/load shedding to relieve the overload condition and to reduce the specific ratings within predetermined amounts of time.

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 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.

As can be seen in the listing above, DERs may be able to help alleviate overload conditions. Demand Response programs are already used to address contingency situations, and in the future a larger spectrum of DER solutions could be employed, such as batteries or DG.

A distribution system emergency occurs when the system is operating outside design limits or a large number of customers are out-of-service. In extreme emergencies, Con Edison may initiate voltage reduction in order to protect the overall integrity and stability of the Con Edison system. Such measures may also be required in situations of severe generation shortage on the system. Con Edison follows ANSI standards that allow utilities to reduce voltage in emergency situations. Con Edison will reduce voltage by either five or eight percent to help lower the electric usage on the network.

Voltage reduction in the distribution system has the effect of reducing resistive loads (heaters, incandescent lighting, *etc*.) to customers. Generally speaking, a five percent voltage reduction results in a three percent reduction in MW consumption and an eight percent voltage reduction results in a five percent reduction in MW consumption. Voltage reduction can be used to relieve voltage and thermal stresses on the primary distribution cable in order to prevent a cascading effect of feeder outages. Also, in the event of a shortage of generation during a high load period, voltage reduction can be used to reduce MW load on the system. Voltage reduction on the distribution system has the added benefit of raising transmission voltages and thereby improving transmission system stability.

Generators

Electric generators are emergency equipment used for the support of electric distribution systems restoration and of customers during system contingencies or disturbances. Generators may be utilized under any of the following conditions:

- System conditions that have resulted in outages to customers
- Electric contingencies or disturbances where sufficient feeders are out-of-service and the remaining in-service feeders will exceed their load carrying capacity. In this case mobile emergency generator(s) (MEG) may be used to de-load the in-service feeder(s) to avoid further damage to Company facilities and/or prevent outage to a critical customer
- In the event of a total outage to a critical customer due to loss of all supply feeders, and alternate means of restoration via remaining distribution system facilities is unavailable or impractical
- Planned or scheduled outages where a customer is unable to take a shutdown and Company work must be done during this time
- A known system condition (defect) has a high probability of failing and resulting in customer outages
- Implementation of system upgrades
- Support for substations, transmission, gas, steam, and/or other Company facilities
- Possible standby for critical customers

Critical customers are defined as hospitals, public service installations, prisons, nursing homes, water and sewage treatment plants, can include selected government agencies, research institutions, and transportation systems, and may include those locations deemed critical by New York City's Office of Emergency Management.

As DER penetration levels increase, specific DERs that are consistently available to reliably support distribution system needs may potentially be able to play a role similar to emergency generation.

DERs may be able to provide value to the distribution system during periods of system stress and contingencies. 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 distribution system. Alternatively, having the ability to dispatch DER may prove valuable to correcting low-voltage conditions on distribution circuits.

Load Reduction

During severe outage events, Con Edison seeks to reduce demand in the affected network(s) through a number of mechanisms. These mechanisms may include demand reduction requests to large and small commercial customers, requests to customers to move to alternate sources of supply where available, direct customer appeals made by employees in the field in impacted areas, appeals broadcast by the NYPD with mobile public address systems, and broadcast media appeals to reduce usage.

Con Edison offers demand-management and energy-efficiency related activities and programs. Edison's Marketing and Sales Among these are a Targeted Demand-Side Management program and a system-wide program that NYSERDA and Con Edison jointly promote to foster effective Demand Side Management (DSM) opportunities and new DSM initiatives through a coordinated marketing plan in the Company's service area. A critical and ongoing part of this DSM initiative is the promotion of strategic demand-management opportunities that shape customer demands, such as the NYISO's Emergency Demand Response (EDRP) and Special Case Resources (SCR) programs and Con Edison's DLRP and DLC programs. These programs help balance supply and demand for electricity, especially during times of peak customer demand, and increase the overall reliability of the electric system.

Con Edison annually solicits customers to participate in demand response programs. The Commercial Demand Response team strives to raise awareness of the programs by presenting at conferences, engaging third-party entities to become aggregators, advertising in major publications and on social media and holding webinars. Marketing and sales account executives promote these programs, which enable the NYISO and Con Edison to call upon these large customers to curtail their energy usage during times of need. Additionally, the account executives can, and often do, reach out to assigned customers who have decided not to actively participate in these programs. Due to the relationship developed by the account executive and the education of the customer on the potential problem, virtually all customers contacted reduced energy requirements in their facilities. Their willingness to assist Con Edison during these periods is a direct result of the relationship fostered and the proper and timely exchange of information.

Installed Capacity Program (ICAP) Zonal

Under the New York Independent System Operator (NYISO) Special Case Resources Program (SCR), incentives are available through the Installed Capacity Program (ICAP) for customers who reduce electric load by using their generators or other means of curtailment without having to meet daily bidding and scheduling requirements. The NYISO may declare an event when New York State's major transmission and distribution system could be compromised, or that power demand may exceed

available supply. Customers receive a day-ahead notice from the NYISO to curtail power, followed by a notice two hours before the event. Customers who do not supply the amount of load reduction they pledge to ICAP will be subject to financial penalties and/or reduced incentives.

Emergency Demand Response Program Zonal (EDRP)

The Emergency Demand Response Program (EDRP) is a NYISO program that is activated during periods of actual power shortages or other emergencies. EDRP provides a mechanism for load reduction during emergency conditions, thereby facilitating the reliability of the New York State bulk power system. When the NYISO anticipates that reliability of New York State's major transmission and distribution system could be compromised, or that power demand may exceed available supply, NYISO may invoke the program.

Distribution Load Relief Program (DLRP)

DLRP is designed to reduce the strain on local distribution lines in specific load areas/networks or on area substations during times of constraint due to network or area substation conditions. Con Edison may request load reductions from DLRP participants when demand could strain one or more local distribution areas. A DLRP load relief event may be declared if the next contingency would place the load area/network in Condition Yellow or if voltage reduction of five percent or greater has been implemented in the load area/network.

Targeted NYISO ICAP/EDRP Sub-Zonal Zone J Program (TDRP)

The Targeted NYISO ICAP/EDRP Sub-Zonal Zone J Program is a NYISO program that may be activated to relieve a specific load pocket within Zone J for the Con Edison transmission or distribution system. On average a sub-zone contains eight networks. This program may be implemented at Con Edison's request, if all Con Edison demand response resources have been utilized. The TDRP program is composed of SCR and EDRP participants, all acting on a voluntary basis. Participation in an activated TDRP event is voluntary- there are no financial penalties for not responding.

Con Edison Commercial System Relief Program (CSRP)

The Con Edison Commercial System Relief Program (CSRP) is designed to shave the Con Edison network and load area peaks. The Program is invoked when the day-ahead forecasted system load level is at least 92 percent of the Company's forecasted summer system peak. Participants receive a minimum of 21 hours advance notice before a planned event and are asked to respond at a pre-assigned time that corresponds to the historic time of the peak of the network in which the participant is located. SC11 generation export participants are called to export from 2 PM to 6 PM to relieve the system-wide peak, regardless of the time their network peaks. Con Edison may also request voluntary load reductions from CSRP participants in specific networks/load areas when the DLRP has been invoked.

CSRP events can be requested Monday through Friday from May 1 through September 30.

Direct Load Control Program (DLC)

The Con Edison Direct Load Control (DLC) Program is designed to reduce the strain on local distribution lines in specific load areas/networks during times of heavy demand or constraint due to network **c**onditions. The DLC program permits Con Edison to control the central air conditioners of participating customers, thus demand reducing potential of the DLC Program is heavily weather dependent. The program can be called if the next contingency would place the load area/network in Condition Yellow or if voltage reduction of five percent or greater has been implemented in the load area/network or when the day-ahead forecasted load level is at least 92 percent of the Company's forecasted summer system peak. The Program can only be called from May 1 through September 30.

(1) Reliability enhancing protocols

One of Con Edison's primary implementation plans for reliability enhancement is enhancing the Network Reliability Index (NRI). The NRI prioritizes the networks that require the most improvement and the feeders in each network require the most improvement. The NRI is a minimum standard of 0.001 for all networks thus improving the overall system wide probability to a 1 in 20 year's target. An NRI of 0.001 translates to a 1 in 1000 year probability (or higher) of a network being susceptible to shut down as defined below. The NRI is re-calculated annually and network improvements are developed as needed to meet the target.

The NRI is an amalgamation of factors, refreshed annually, following the previous summer's network performance, to produce a statistical rating that reflects the probability of a network's susceptibility to a shutdown.

Key factors that affect network's ranking are:

- Feeder and component loads
- Feeder length
- Feeder cable composition by type and age
- Joints by type and age
- Load shift factors
- Component failure rates based on temperature variable and refreshed annually
- Feeder subjected to successful hi-pot test
- Structure congestion
- Use of sectionalizing switches
- Occurrence of Open Automatic (OA)

Con Edison issues a Network Reliability Improvement Plan on a yearly basis to address those networks that are below the established minimum standards. The Company's Distribution Engineering Network sections in conjunction with the Regional Service Area Distribution Engineering groups annually review and identify each of the items discussed above for each network and publishes a conceptual plan. Upon agreement by interested parties, the annual plan is published and disseminated as the Company's Network Reliability Improvement Strategy.

Areas identified as requiring load relief as part of the Company plan may serve as locations where DER deployment can provide benefit to the distribution system.

(2) Fault Location, Isolation, and Service Restoration (FLISR)

Feeder processing under normal system conditions is the continuous effort by Con Edison to process an Open Automatic (OA) or scheduled feeder from the time it becomes unavailable until the time it is back in service. This feeder processing includes making the feeder safe for work, performing the work, and restoring the feeder to service.

Feeder restoration under extreme conditions is described as an expedited effort by key working groups to process all OA feeders from the time they become unavailable until the time they are restored to service during network contingencies and periods of extreme weather.[101] This expedited effort includes the pre-positioning of groups that participate in the feeder restoration process. The effort may also include sectionalizing the impacted portion of the feeder. All working locations are staffed with the appropriate personnel to minimize feeder restoration time. The precautions the Company takes during extreme conditions for fault location, isolation, and service restoration are listed below:

- Scheduled work is not permitted during extreme weather periods or during a Heat Alert State.
- Reasonable efforts are made to perform scheduled feeder work during weekends and off shifts.
- Before facilities can be scheduled out-of-service for work, the regional scheduling group reviews the request to determine that:
    - No other facilities (primary or secondary) are out-of-service that conflict with the proposed scheduled work.
    - There are no Company and/ or customer-imposed restrictions.
    - Staffing is adequate to process facilities and complete the required work.
    - Facilities remaining in service will meet the load and voltage criteria under first and second contingency.

[101] Extreme weather condition exists whenever the forecasted temperature variable (TV) is expected to be greater than or equal to 82°F for two consecutive weekdays (approximately 12,500 MW).

- A feeder outage shall not be scheduled unless all possible "dead work or moves" have been completed prior to the removal of the facilities from service. This includes cable installation, splicing, and transformer installations. However, the completion of unfinished dead work may be performed concurrently with the feeder outage as long as the completion of such dead work does not increase the feeder outage time and does not cause a shortage of resources necessary to complete other essential work.

- All manhole locations shall be pre-inspected to verify access and adequate working condition of the structure. In addition, all necessary flushes and environmental cleanups shall be completed prior to removal of any feeder from service.

The Company consistently works to develop measures to enhance fault location, identification, and service restoration, such as Alive on Backfeed (ABF) and Reactance to Fault (RTF). These are described further in the subsections below.

Alive on Back Feed (ABF)

When a primary feeder goes out-of-service, power can reverse flow from the secondary grid back to the feeder or high tension customer. Under these conditions, the network protector is designed to trip open to prevent this reversal of flow. In the event that a network protector fails to open, it is also equipped with fuses that will isolate the low-voltage secondary system from the transformer and the primary feeder. These fuses are coordinated with the cable limiters that are on the secondary mains in manholes and service structures, such that the fuse will operate before the limiter during back feed conditions. If the network protector switch and the fuses remain closed, the secondary mains continue to back feed into the primary fault. This condition is called "alive on back feed" (ABF). Whenever a feeder remains alive on back feed, it delays the fault-locating and repair process until the ABF condition is found and eliminated. One means of clearing the back feed is to apply grounds at the substation to blow the fuses at the network protector and isolate the feeder from the secondary system. If this is not successful, the back feed has to be located by field crews visiting each network switch on the feeder. Hence, an ABF condition could result in a considerable effort and delay in restoring a faulted feeder.

There are innovative processes to manage ABFs and reduce the number of occurrences and duration. Devices called the Portable ABF Device (PAD) or the Permanent ABF Device (PADx) can provide more data during an ABF which, in turn, can help identify the network protector that failed to open. This can reduce the amount of time to isolate the feeder from the secondary system. The Company is also developing an algorithm which proactively causes the network protector to go through a trip and close cycle remotely. If the network protector fails either of these operations, the Company would be notified and schedule a visit to repair the switch. This auto-exercise algorithm will catch malfunctioning switches preemptively and reduce the chances of having an ABF.

Advances are also being made in ABF detection via the Remote Monitoring System and Pressure, Temperature, and Oil Level Program (RMSPTO). The RMSPTO program is the installation of new Remote Monitoring System (RMS) third-generation transmitters and Pressure, Temperature, and Oil Level (PTO) sensors at various network transformer vault locations throughout Manhattan, Brooklyn,

and Queens. The advancement of this program will enhance and optimize system performance by providing accurate real-time information about network transformer conditions. Under the RMSPTO program, newly installed RMS transmitters will have ABF detection algorithms built in to the units that will help locate transformer locations that are back-feeding. This will help shorten feeder restoration times during ABF events. The new transmitters also have asset management software that can be used to correlate transmitter serial numbers to vault location. The asset management feature documents that the ABF software is deployed at the vault location and the transmitter has successfully processed the field parameters needed to operate and the ABF software is enabled.

DERs have the potential to lead to ABF conditions. Con Edison's interconnection standards, in alignment with the recent modifications to the SIR, require DGs to clear the system to avoid exacerbating an ABF condition, which could otherwise slow restoration.

Reactance to Fault application

Part of the Company's FLISR initiatives includes a RTF application that is used to help locate distribution feeder faults in all customer service areas. The system uses PQ data collected from area substations when an underground feeder automatically opens and calculates the probable location of the underground fault. PQView software (PQView®) together with Poly-Voltage-Load Flow (PVL) impedance data are used to assist the Control Centers with feeder fault locating. The project continues to help reduce fault-locating time in the service areas by an average of one hour. AMI will provide greater insight into PQ disturbances at and beyond the meter, as well as improve the PQ and reliability of the system.

A further FLISR initiative is arc-fault detection and reporting program. This project aims to develop a solution to detect and report faults on the underground distribution system before they develop into safety and/or operational concerns. The AMI communications system could provide the capability to remotely monitor abnormal conditions in the Company's network protector vault locations.

5. Cybersecurity[102]

Events on the world stage underscore the increasing need for cybersecurity of information technology (IT) and operational technology (OT). 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.[103] The Department of Energy's Quadrennial Report,

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[102] This section represents the Company's position on cybersecurity that is informed by the framework in Appendix M.

[103] 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."[104]

a) 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 our 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 (CIA)) that apply to the items being protected.
- Cybersecurity is designed into all computing and communications elements used by the Company and 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.

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[104] 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.

The Company continuously improves its defenses. To 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:

- **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 perspectives support the Company's goal to provide reliable electric, gas, and steam service to customers – commercial entities, government agencies, and residential customers.

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 protect the Company's 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 for data flows follow data pull techniques from High Trust to Low Trust networks. Data is never pushed into High Trust from Low Trust networks
- External data exchanges are encrypted to protect information transmitted between business applications and external organizations.
- Authentication techniques utilized by users and system components

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.

b) 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 its system so that data is not exposed and would limit 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.
- Logging of all approved changes/commands with alerting of unauthorized activities.

(1) Baseline Cybersecurity Controls

1. A governance program led by senior management should be established to reinforce the business need for an effective, holistic, and risk-based approach to managing cybersecurity and privacy.

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 CIA 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 designed 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.

(2) 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.

6. Volt/VAR Optimization

a) VVO Implementation Plans

Con Edison defines Volt/VAR Optimization (VVO) 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 Company has a near-term VVO implementation plan and a long-term implementation strategy. The near-term implementation plan is limited to voltage optimization only and has two aspects. One aspect is for system protection, which is used on very limited bases for short durations. The other is for peak shaving or demand management and this effort is referred to as Conservation Voltage Optimization (CVO). CVO has also been used to refer to as Continuous Voltage Optimization, but for the purpose of this filing CVO only refers to Conservation Voltage Optimization.

(1) Voltage Reduction for Peak Demand Management

The Company already has the ability to lower voltage five or eight percent during a system contingency, where one (first contingency) or two (second contingency) feeders are out-of-service in the same area. The voltage reduction is a method used to protect the system during contingency. It reduces the stress on the feeders that are supporting the additional load when nearby feeders are out-of-service. When feeders are overly stressed it can lead to a brown-out or cascading effect of feeder outages. Additionally, the Company also implements CVO during expected system peak times. Various utilities, Con Edison included, have demonstrated that reducing system supply voltage will also reduce system load. Various utilities, such as Duke Energy and PG&E, in the United States have been using CVO to manage peak demand. The goal of CVO is to reduce the system supply voltage by small percentages, while still remaining within the ANSI allowable voltage range, when the system is operating in normal conditions. The load reduction from CVO combined with the various demand management tools that the Company employs allows for deferred capital investment while maintaining system reliability.

The current usage of voltage reduction is at the discretion of the system operator with no opportunity (nor need) for third party involvement. In the future, the opportunities for third parties related to the voltage reduction aspect of voltage optimization could include demonstration or R&D projects to further optimize voltage reduction through automation and expanding existing Demand Response programs to include VAR reduction in addition to kW reduction.

(2) Dynamic Conservation Voltage Optimization

Dynamic CVO will enable the adjustment of the supply voltage based on real time load and voltage information at the customer meter. The goal of Dynamic CVO is to maintain voltage level closer to the lower end of the ANSI range, thus reducing the amount of energy consumed by our customers to power a given load. Reducing voltage for short periods during peak is not enough to provide any real impacts to the customer energy bill. These capabilities will progress from the current limited geographic usage of CVO to continuously and dynamically adjusting voltage to optimize system efficiency.

Current CVO capabilities are limited to an automatic voltage drop base on a load set point in the area station bus voltage schedule. This is in essence static CVO because the real-time voltage data at the customer site is not available. The current CVO project has been deployed as part of the BQDM to lower voltage during the 12-hour network peak. Additional voltage monitoring devices are necessary and have been installed strategically based on the model results such that the voltage reduction does not deliver voltage out of ANSI specifications. The installation of these devices is cost-effective for the BQDM network, but not across the service territory, thus limiting the geographic scope. Extensive modeling has been performed to understand the impacts of voltage optimization during these non-contingency/standard peak load condition.

The next progression in capabilities is expanding the capability both geographically across the entire service territory and temporally throughout the day. The networked nature of the Company's grid provides exceptional reliability and quality of service delivery capabilities, but also presents complex monitoring and control challenges. Most electrical distributions systems are radial in nature. A radial system is characterized by a single path for current and real power flow from the substation to the distribution transformers and ultimately to the customers. A networked system has primary feeders that are supplied by multiple substations. Voltage sensors can be deployed at the endpoints of a radial system, and system operators can lower the system voltage at these specified end points, thereby regulating the voltage level in the system. However, because 86 percent of the Company's distribution system is constructed as a network grid (*i.e.,* a mesh grid rather than radial feeders), determining the precise location of voltage low points is more complicated. In order to reliably optimize system voltage levels, AMI is required to sense the voltages at the end points of the system. A further complicating factor for CVO on the Company's system is the variety of customer loads behind the meter. Customer behavior may also impact the voltage with certain types of electrical equipment and DERs. Thus, deployment of CVO functionality across the service territory is enabled with AMI, and will geographically coincide with that rollout, starting initially in Staten Island and Westchester County.

The rollout of AMI will provide real-time data on customer voltage and load, which is a critical input for Dynamic CVO. AMI would provide visibility to statically lower the voltage to an optimal supply voltage level throughout the day. However, AMI alone will not be enough to enable a truly dynamic CVO without the addition of controls. Dynamic CVO requires continuous monitoring of supply voltage and system load to redefine the low point of the network and adjust the voltage accordingly. This dynamic process will yield additional efficiency gains, but requires additional management software to make use of the granular AMI data. The software development for enabling dynamic CVO will be occurring in parallel to the AMI installations.

Therefore, the Company plans to continue using voltage reduction on a *status quo* basis until the phased geographic rollout of AMI is complete. In the short term, this optimization will only be utilized as a tool for peak demand management. In the long term, AMI will enable the development of dynamic voltage optimization based on real-time data.

As CVO is only being used on a prescribed and limited basis for BQDM, there is at this time no opportunity for third-party involvement. As AMI enables the ability of system operators to lower

voltage continuously across the system, there may be opportunities for third parties to optimize what the "low point" of the system is to provide further efficiency gains. As with peak voltage reductions, this dynamic and continuous shifting of the lowest voltage point in the system should be demonstrated in pilot projects before widespread adoption.

(3) VAR Optimization

VAR Optimization will help improve the Company's overall load factor. Currently VAR control is primarily limited to large capacitors mounted in the area substations and they are sized for maximum load. The system can gain in efficiency if VAR control is more distributed and dynamic with the change of load during the day. In the short term the Company is piloting small pole mounted capacitors and underground capacitors in areas identified by load flow models. These capacitors can adjust the supply of VARs according to the local load requirement, therefore improving the load factor where it is needed. CVO is also known to reduce system VAR and improve the power factor. CVO generally provides a 1:1 ratio or better for the reduction of VAR in the system. The dynamic CVO pilots will also provide dynamic VAR control at the local level in the BQDM area in 2016 and 2017.

The opportunity for third-party involvement in reducing losses through VAR optimization lies primarily with using smart inverters to achieve the right balance of active and reactive power, beyond balancing their own load profile, thus improving grid efficiency by reducing line losses. Con Edison is working to better understand the interaction of multiple smart inverters on the distribution system and expects to work with researchers and third parties to advance this capability.

b) VVO Capabilities, Costs, and Benefits

The benefits and costs of upgrading VVO capabilities were first explored by the Company in the AMI business case. That assessment focused on the CVO subset of VVO, and used conservative assumptions based on a static CVO deployment. The benefits of CVO, as estimated in the AMI business plan and based on a one and a half percent average reduction, are a $346M NPV cost savings for the 20-year BCA analysis, of which $292M results from fuel savings and $54M is due to CO_2 reductions.

Dynamic CVO is also enabled through the AMI rollout with additional infrastructure upgrades to produce additional efficiency benefits. A more dynamic CVO would enable operators to further optimize the system voltage across the territory. It is estimated this would result in an, average voltage reduction of two and a quarter percent which translates to an NPV of $439M, of which $380M results from fuel savings and $59M is due to CO_2 reductions. The details of the NPV analysis, including a high and low case are found in **Appendix J**.

The Company recognized the need for these advanced CVO capabilities as REV Track One was developing and included investments to build the CVO/VVO capabilities of the Distribution System

Platform in the recent rate filing.[105] The investment would provide various engineering solutions such as new tap changing transformers, local capacitors and SCADA controls to remotely manage CVO functions. These investments are informed by engineering solutions of CVO in targeted areas as part of BQDM. The estimated cost of 4MW of peak demand reduction in the BQDM networks for 2017 is $4M.

Once all VVO measures are 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.

Costs and benefits for the peak-shaving element of voltage reduction are not estimated as they are used only on a contingency basis, as infrequently as possible. Costs and benefits of VAR optimization through smart inverters are also not estimated, as that is a nascent technology that should be demonstrated in a pilot or lab setting prior to wide-spread implementation. It is worth noting that the infrastructure upgrades mentioned above that would support dynamic CVO, also enables smart inverters to communicate with the grid interface to optimize the power factor.

C. Interconnection Process

1. Track One Order Compliance

The NYS SIR was established in 1999 to provide a framework for processing applications to interconnect DG systems to the to the State's investor-owned utilities' electric distribution systems. The NYS SIR currently serves as the process guidelines for interconnection of DG systems up to 5 MW, with any requests to interconnect to the transmission system handled by the NYISO utilizing the FERC interconnection process. The NYS SIR lays out a six-step procedure for DG systems 50 kW or less and an eleven-step procedure for DG systems from 50 kW to 2 MW of aggregate nameplate capacity which includes both a supplemental technical review and a more detailed impact study, known as the Coordinated Electric System Interconnection Review (CESIR). In 2009, the NYS SIR was revised to require that utilities provide a system for applicants with systems 25 kW and less to submit their application for interconnection via the web, and that their interconnection application status be available online at a customer-specific level. A series of minor revisions followed as the State expanded the definition of net metering and allowed more technologies to participate in these programs. The basic framework, however, is largely unchanged since 2009. Additionally, the PSC 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.

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[105] Case 16-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Electric Infrastructure and Operations Panel Exhibits (EIOP-01) – (EIOP-14) (filed January 29, 2016).

In the PSC's *Order Adopting Regulatory Policy Framework and Implementation Plan* (Track One Order), the PSC stated, "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."[106] The PSC envisions the development of a customer-engagement web platform for DER integration and interconnection via the New York Interconnection Online Application Portal (IOAP) to facilitate easier access to DER providers. The Track One Order[107] calls for utilities to streamline their interconnection processes for smaller distributed generation projects like residential solar, increase the transparency of their interconnection approval process, and adequately prepare for greater amounts of DG deployment expected as a result of New York State's energy policy goals.

In addition, the Track One Order directed PSC Staff to work with utilities and interested parties to expand the NYS SIR to be applicable to DG systems up to 5 MW of aggregate nameplate capacity. This portion of the Order became part of a broader call to revise the NYS SIR, and on November 9, 2015 the PSC initiated a proceeding[108] to accept public comments on proposed NYS SIR revisions, which included the expansion from 2 MW to 5 MW. Many of the Track One Order requirements are addressed through the revisions to the NYS SIR approved by the PSC on March 18, 2016.[109]

Following the Track One Order, in connection with the SIR revision, the Electric Power Research Institute (EPRI) issued *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment* (EPRI Gap Analysis).[110] The EPRI Gap Analysis identified a number of issues in the Company's interconnection process:

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[106] REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (Track One Order)(issued February 26, 2015), p. 92.

[107] The Track One Order defines two phases of interconnection improvements. Phase 1 is the period between the Track One Order (February 2015) and the Initial DSIP filing (June 2016), and Phase 2 is the period after Initial DSIP filing. *Id*., pp. 92-93. The NYS SIR process also is divided into two phases with Phase 1 ending with the latest revision to the SIR followed by ongoing technical working group discussions in Phase 2. 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* (NYS SIR Proceeding), Order Modifying Standardized Interconnection Requirements (issued March 18, 2016)(NYS SIR Approval), pp. 2-3.

[108] NYS SIR Proceeding, Notice Soliciting Comments on Proposed Modifications to the Standardized Interconnection Requirements (issued November 8, 2015).

[109] NYS SIR Proceeding, NYS SIR Approval.

[110] Electric Power Research Institute, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment*, Final Report, Report Number 15-28 (EPRI Gap Analysis), September 2015, pp. 31-33.

- Removing the human element would be problematic; there are many considerations unique to the system and the local grid that cannot be picked up by a software program.
- All the tools required for feasibility and CESIR studies would have to communicate well with one another, which would require a significant investment of time and resources; Con Edison's tools in particular differ from other utilities due to their network structure.
- Much of the data that would be required for fully automated impact studies does not exist. Additionally, data resides in different databases and would need to be consolidated.
- Con Edison urges clarification of the State objective to share information via a publicly available queue. Con Edison currently provides application and job status via an online portal to aid in Contractor/customer knowledge of their job status. Access to specific job information is limited in part due to the personally identifiable information and sensitive market information of vendors working in the territory. Consideration could be made to summarize the active queues and make such summary data available upon real time inquiry. This level of transparency could be useful to confirm expected job processing time periods. Note also that this functionality would supplement existing job tracking information that is currently filed with the PSC.

In the following section, Con Edison will follow the framework presented in the DPS Staff's DSIP Order to present the current and proposed interconnection processes readiness to achieve the original Track One Order functionalities as well as close the gaps identified by EPRI.

Phase 1 of the Track One Order states that each utility must establish nine functionalities within their interconnection processes. The nine requirements and the mechanism by which Con Edison complies with the Order are listed below:

Track 1 Requirement	Con Edison Compliance
(1) The customer should be able to apply through an online portal	Con Edison's Project Center is an online portal and has been the primary source of new business and interconnection applications since 2009. The interplay between Project Center and internal case management systems has shown it to be a robust platform that can be configured to the business needs of the Company.
(2) The online portal should manage the interconnection approval process	Project Center provides grey/yellow/green icons upon login to help customers or contractors understand the status of interconnection requests. Just below the icons is the milestones tab which provides a step-by-step process flow of the case, the responsible party for completing that step, and a completion date if that step has been completed in the CPMS case management system. This automated update from the internal case management system to the customer facing external portal is key to managing next steps for the project.

Track 1 Requirement	Con Edison Compliance
(3) The online portal should clearly communicate interconnection status and which party is responsible for the next step in the process	In addition to the Project Center communications, Con Edison's case management system CPMS has many built in tools for communicating between customers and contractors (*e.g.,* standard letter templates that can automatically populate appropriate data fields).
(4) The interconnection process should provide for automated technical screening and impact studies	As cited in the EPRI Gap Analysis, there are several issues that make automated technical screen and impact studies a challenge. While automation is a challenge, the Company is moving towards automating individual elements of the technical screening and impact study process (*e.g.,* mining SCADA data or using PVL modeling software to use for CESIR represent some building blocks for process automation)
(5) Results of these studies to be issued in a consistent and timely manner	The definition of timely and consistent is addressed in the latest NYS SIR order. The Company will maintain compliance with the NYS SIR guidelines through EAMs that are to be developed within the Track Two portion of the REV Proceeding
(6) Enable increased transparency into the process of interconnection approvals and rejections	The Company's DG Ombudsman has been working to make the process of interconnection DG more transparent for over a decade. Company representatives have worked with industry and research groups like NYSERDA, NYSEIA, CUNY, SEPA, and Pace Energy and Policy Center to explain and understand the unique challenges of installing solar generation in the NYC area. Con Edison's *Understanding Solar* web video describing the process of net metered billing for Solar PV customers recently won a Platinum Award from the international AVA Digital awards completion.
(7) Share information via a publicly maintained queue	The content timeliness and personal security questions that arise from the discussion of a publicly available queue were well documented by EPRI. Much of this information will be displayed in the hosting capacity maps discussed in its respective DSIP section, but if a public queue is still required, Con Edison envisions using CPMS and Project Center to provide accurate queue information.
(8) Provide standardized interconnection forms and contract terms	The standard forms required for interconnection application and contract terms are provided by the NYS SIR Appendices. In addition to the NYS SIR application forms, Con Edison has several tariff-driven application forms that would have to be standardized in a common way with other members of the JU. These will be further addressed in the Technical Working Groups established by the SIR Order.
(9) Improve the overall timeliness for identification of study requirements	The NYS SIR establishes the definition of timeliness and the EAMs incentivize timely identification of study requirements

Table 60 - Con Edison Compliance with Track One Requirements for Interconnection

2. Interconnection Process and Portal

The Con Edison Interconnection Process was accurately described in the EPRI Gap Analysis, the content of which is quoted below:

> For DG interconnections, the customer (or developer, with customer's consent) applies in Project Center with account and address information. Once the request is submitted, Project Center packages all documents and information and creates a case in the Customer Project Management System (CPMS). If the application is 25 kW or smaller, Con Edison's assigned Energy Services Representative reviews the application for completeness and, if all paperwork is complete and accurate, approves the project for construction, usually within one-two business days. All other applications would go through an initial technical feasibility evaluation, after the application has been verified as complete, to determine feasibility of the project as-is or if a more detailed study is needed. This technical evaluation is needed for approximately ten percent, or 400 applications per year. Of these applications, approximately 50 to 75 require a full CESIR study.
>
> The Project Center portal is linked in with Con Edison's internal customer project management system (CPMS), which also links into other Con Edison's systems such as work management (WMS), billing (CIS), and metering. Once applications are submitted, the Customer Project Managers receive and review the applications. They are automatically placed in Con Edison's internal work management system for tracking. Customers can log into the Project Center to review the latest status of their application as well as the remaining steps to completion. All related documentation is also available to the manager and the customer.[111]

Following a successful technical review or CESIR study, the contractor would build the DG system in parallel with Con Edison setting the net meter, if required. This is a slight departure from the prescribed process of the NYS SIR framework which was necessitated by frequent issues with meter exchanges (*e.g.,* customer refusal, successful exchanges occurring on stalled and incomplete jobs). The timing of net meter installations is being discussed in the revision of the NYS SIR with the JU requesting more flexibility to set the meter later in the process.

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[111] EPRI Gap Analysis, pp. 31-32.

For PV systems 25 kW and below, contractors can submit results of the equipment verification testing on the completed DG system via a Con Edison Contractor Self-Certification Form uploaded to the Project Center. The uploading of this form triggers an automatic email to the Energy Services Representative to provide the Final Acceptance Letter and close out the case by sending emails to the mapping group to update the Company's internal electric distribution maps as well as the net-metering billing group to code the customer's account for net metering. The case is then completed in CPMS and the customer can see the completed case status on Project Center as well.

For all other DG interconnection applications, the contractor will request an onsite inspection and field verification test be performed by Con Edison's System Design Group accompanied by the Energy Services Representative for the case. Following a successful verification test, any discrepancies noted by the onsite inspection will be documented in a Field Report provided to the DG installer by the Energy Services Representative. Once the installer provides documentation of the corrective actions taken, Con Edison will process the Final Acceptance Letter and complete the final activities to close out the case as described above.

After the interconnection application is completed, all documents and correspondence for the case remain on both Project Center and CPMS for future reference. The status of the case, the completion date of all steps associated with the case, and internal case notes are automatically maintained on the CPMS database. For each NYS SIR Report to the PSC, which is currently scheduled monthly, all interconnection cases created in the previous review period are added to the internal Distributed Generation Master List Database which is maintained by the Distributed Resource Integration department's DG Group. Current statuses for all open interconnection applications are manually updated, along with all calculations of start and end dates for the individual process steps of the NYS SIR. Once updated, the database can export the Excel spreadsheets for PSC reporting and internal stakeholder uses, such as area station planning and electric and gas forecasting needs. In addition, the database is linked to internal Tableau software, which provides data visualization and analytics capabilities, to provide easy and consistent reports to internal and external stakeholders on current DG interconnection status.

3. Current Improvement Efforts and Future Plans

Prior to the REV Initiative, Con Edison has worked to improve its interconnection approval processes for both internal and external stakeholders. The improvements are made to the three systems critical to the interconnection process: Project Center, CPMS, and the DG website. The details are available in the Interconnection section of the DSP IT Roadmap chapter of this DSIP. In addition to the improvements to the systems described in the DSP IT Roadmap, the increased transparency and reporting capabilities resulting from these changes will fundamentally enhance communication capabilities both internally and externally to DG stakeholders. The following section summarizes how Con Edison plans to solicit stakeholder input to continue to make improvements to the interconnection process and make better system planning decisions.

4. Stakeholder Input for Interconnection

Con Edison has been actively engaged in stakeholder discussions on interconnection. As a baseline, interconnection will be one of the topics to be included in the JU Stakeholder process, as it is a topic that informs many aspects of the DSIP. In parallel, Con Edison has been an active participant in the revision process for the New York State Standardized Interconnection Requirements, and continues this role in the current Interconnection TWG. This Working Group looks to further investigate technical issues associated with interconnection and includes representatives of several solar development companies.

Con Edison has long recognized that communication with external DER stakeholders is important. For example, Con Edison established a DG Ombudsman position over a decade ago to facilitate improved communications between Con Edison's interconnection specialists and the developers of distributed generation projects. Today, this group has grown to five full-time employees and has expanded its role to include proactive communications to prospective and existing DG customers, leadership of the JU DG interconnection discussions, design and implementation of internal interconnection process improvements, and research and analysis on rate and policy treatments for DERs. This DG Ombudsman role has now been replicated by each New York electric and DPS Staff to create a DG Ombudsman's working group to review administrative issues associated with the interconnection process and Utility DG queues.

Con Edison also recently hosted approximately 100 installers at the sixth annual NYC Solar Installer Training at its Learning Center. In addition to presentations by NY-BEST, the FDNY, and the NYC Department of Buildings, Con Edison presented a primer on its network grid system, guidance on interconnection, and an overview of net metering.

V. Advanced Metering

A. Introduction

So that customers continue to benefit from reliable service and affordable electric service, it is important that expectations and codes of conduct are in place for all stakeholders. This will be particularly relevant for communicating sensitive information among the customer, the Company, and third parties. As stated in the JU stated in connection with the first Customer Data Technical Conference, "the success of REV depends on the ability and willingness of customers to engage in Distributed Energy Resource ("DER") programs directly with third-party providers." [112] To that end, the Company is committed to providing relevant, useful, and accurate information while also laying the groundwork for the secure two-way flow of data between stakeholders and customers. This chapter outlines Con Edison's intention to expand data collection through AMI.

The Company addresses the development of the proposal for AMI in its service territory, and where information related to those plans will be further developed. AMI will expand the collection and granularity of grid-edge data, supporting operations and DER interaction, as well as customer engagement.

B. Summary of AMI Rollout

Con Edison filed a proposal for AMI prior to the DSIP on November 16, 2015.[113] On March 17, 2016, the PSC issued *Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions* (AMI Order),[114] authorizing the Company's proposal with several contingent requirements. These requirements include a customer engagement plan, which includes overlapping requirements with many of the DSIP requirements, to be filed on July 29, 2016. Given this overlap, the Company will briefly address each topic required by the DSIP Order, with links to the appropriate sources and filings.

The Company's current AMI implementation plan is the November 16, 2015 business plan, which includes:

- Plans and schedules for deployment

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[112] REV Proceeding, Utility Comments in Response to November 3, 2015 Notice of Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues, p. 3.
[113] 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 AMI Business Plan (filed November 16, 2015).
[114] 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), Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions (issued March 17, 2016) (AMI Order).

- New or upgraded data management, communications, billing or other back-end systems to support AMI, along with associated budgets

An updated BCA and Rate Impact Measure (RIM) will be filed with the Customer Engagement Plan on July 29, 2016.

C. Customer Engagement Plan

The customer engagement plan required of Con Edison as a result of the AMI Order addresses the requirements of the DSIP Order as well. As part of the Customer Engagement Collaborative required by the AMI Order, a pricing pilot will be utilized to test new rate designs. The Company plans to comply with the requirements of the Customer Engagement Collaborative.

D. AMI Metrics

In response to the AMI Order, on April 21, 2016, the Company filed[115] a list of metrics by which the success and value of AMI can be measured.

E. Third-Party Meter Ownership

In response to the AMI Order, the Company is developing contract requirements regarding interoperability, cybersecurity, and maintenance and technology requirements. These will be filed on July 29, 2016 as well.

[115] 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*, Consolidated Edison Company of New York, Inc.'s Testimony Update Regarding Metrics for the Commission's Use to Monitor the Success of the Advanced Metering Infrastructure Project (filed April 21, 2016).

VI. Customer Data and Engagement

A. Introduction

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 therefore a central element of Con Edison's role as the DSP. As the DSP is implemented 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. Con Edison's near-term initiatives to improve access to customer data, described below, will enable provision of useful data to customers and authorized third parties via tools that are secure, easy-to-use, and based on industry standards and best practices.

Con Edison 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.

The Company takes protection of customer information, including personal information provided by the customer as well as usage data, very seriously. The Company's longstanding policy is that it does not share customer information without customer consent, except where required or permitted by PSC order (such as with Community Choice Aggregation where the PSC requires utilities to provide customer-specific information to a third party, or as permitted by the Commission to carry out utility energy efficiency programs pursuant to the OPower Order).[116] The Company does not sell or otherwise share customer lists, and will not disclose customer information to third parties that may want to market products or services to customers. These principles are reflected in the Company's approach to each of the following initiatives. Additional information on Con Edison's approach to data privacy and security is provided at the end of this section.

B. Digital Customer Experience

In tandem with the AMI roll-out, Con Edison will enhance the ability of customers and third parties to obtain and utilize customer data as part of its Digital Customer Experience (DCX) program.

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[116] Case 14-M-0224, *Proceeding on Motion of the Commission to Enable Community Choice Aggregation*, Order Authorizing Framework for Community Choice Aggregation Opt-Out Programs (issued April 20, 2016).

This program is designed to deliver an improved experience across all digital touch points. This redesign will cover www.coned.com, the Con Edison mobile website, the My Account portal, Customer Care, the Corporate Customer Group (CCG) Website, and the mobile app. All of the Company's customer-facing information channels will be consolidated and accessible through a single sign-on process. In addition, as part of the AMI Customer Engagement filing, the Company will work with third parties to define the data sets and access functionality beyond GBC that is needed to facilitate current and future energy markets. 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 DCX program will be rolled out in phases starting in 2016 through 2020, coinciding with the Company's AMI rollout with a total estimated project cost of $47M in capital and $11M in O&M expenses.[117]

1. Green Button Connect Implementation Plan

In its pending rate filing, Cases 16-E-0060 and 16-G-0061, Con Edison proposed to implement a data sharing tool that uses GBC 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, on 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 personally identifiable information (PII).

The Company is proposing to implement GBC for a number of 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, importantly, the GBC transfer process is secure and customer-driven.

Due to the administrative complexity and cost of GBC implementation, and because some of the JU may not consider GBC viable at this time or in the foreseeable future, Con Edison believes that any utility that decides to implement GBC should do so in a phased approach. At Con Edison this phased approach will begin with GBC implementation first with respect to customer usage data. Other aspects of customer profile information create added complexity and cost and it is unclear at this time what other data customers, third parties, or the Commission has determined to be necessary, relevant,

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[117] For additional information on the DCX program, including detailed budget and timeline descriptions, see Case 16-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Direct Testimony of Customer Operations Panel (filed January 29, 2016).

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.

In the Commission's AMI Order, Con Edison was directed 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."[118] 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."

Con Edison is in the process of developing its AMI Customer Engagement Plan, and has scheduled multiple engagement sessions with relevant stakeholders, including ESCOs and DER providers, to collaborate on the content of the plan, including a detailed implementation plan for GBC. In these sessions, the Company will consult with stakeholders regarding the "range of datasets and other parameters regarding data delivery" that GBC is designed to accommodate, as required by both the AMI Order[119] and the DSIP Guidance.[120] Further information regarding the Company's implementation of GBC will be available when the Company files its AMI Customer Engagement Plan on July 29, 2016.

C. 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 Con Edison this web interface is referred to as the Retail Access Information System or 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 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 for their data to be shared if an authorized ESCO provides the utility with a customer account number. This same arrangement has been proposed to apply to all DER providers in Case 15-M-0180, which would include Community DG Sponsors and other third parties.

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[118] Con Edison 2013 Electric Rate Case, AMI Order, p. 41
[119] Con Edison 2013 Electric Rate Case, AMI Order, pp. 41-42.
[120] REV Proceeding, DSIP Order, p. 61.

Table 61 details the information that can be obtained by authorized third parties in the RAIS portal, and EDI:

Data Field	Channel
15 minute interval data	RAIS
Actual vs estimated read	EDI, RAIS
Bill amount	EDI, RAIS
Customer name	EDI, RAIS
Demand history/Peak demand	EDI, RAIS
ESCO status	EDI, RAIS
Hourly interval data	RAIS
Hourly meter indicator	EDI, RAIS
ICAP tag	EDI, RAIS
Industrial code	EDI
ISO load zone	EDI, RAIS
KVAR	RAIS
Load profile ID	EDI, RAIS
Meter number	EDI, RAIS
Min demand	EDI, RAIS
Net meter status	EDI, RAIS
Next read date	EDI, RAIS
NYPA indicator	EDI, RAIS
Percent residential	RAIS
Previous account number	EDI, RAIS
Recharge NY status	RAIS
Seasonal customer	RAIS

Data Field	Channel
Y/N	
Service address	EDI, RAIS
Service class	EDI, RAIS
Summary kWh history	EDI, RAIS
Tax status	EDI, RAIS
Tension code	RAIS
TOD code	EDI, RAIS
Trip schedule	EDI, RAIS

Table 61 - Information That Can Be Obtained by Authorized Third Parties

EDI will continue to play an important transactional role in the New York Retail Access market, as indicated by the Commission in the AMI Order,[121] and therefore will continue to be supported by investor-owned utilities. Additionally, in the AMI Order Con Edison was directed to make interval usage data available via EDI on a monthly basis. Currently there is no established EDI transaction for interval data, so the Company is investigating options to make month-end AMI interval data available through EDI. Con Edison anticipates working with the JU on this effort, so that any new transactions or specifications that are developed are suitable for use statewide.

In the DSIP Order, the Commission directed utilities 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."[122] To fulfill this requirement, the Company plans to offer a new data exchange for interested 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 a file from RAIS for customers with interval data. Because the ESCO interval data exchange will rely on the same RESTful APIs developed for the GBC tool, the project will not have any incremental costs, and will proceed on the same timeline as the Company's GBC implementation.

[121] Con Edison 2013 Electric Rate Case, AMI Order.
[122] REV Proceeding, DSIP Order, p. 62.

D. 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. As noted above, the Company has maintained a longstanding policy that it does not share customer information with others without customer consent, except where required by PSC order. The Company does not sell or otherwise share customer lists, and will not disclose customer information to third parties that may want to market products or services to customers. The Company may, however, share specific information with its own agents and contractors. The Company maintains its current privacy policy online at www.coned.com/privacy, which addresses aspects of customer data collection and disclosure.

E. Consumer Engagement

In the area of Customer Engagement, the Company's core objectives in developing the DSP are two-fold: first, to engage customers by providing them with information, education and tools to make informed 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-pronged strategy that incorporates and builds on existing initiatives and strategically expands the Company's scope into new areas. The following section outlines the current state of our 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 the Company 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 our relationships with customers, and
- Focusing on understanding and anticipating customers' evolving needs and expectations.

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

Enhancing Customer Relationships

The Company has a number of ongoing initiatives that focus on enhancing customer relationships. Employees are trained in a one-day training class to help them improve their interactions with customers and better meet their 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 work may impact them. The Company uses email blasts to notify customers of projects going on in their neighborhoods that may affect their service, traffic, or parking. 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, an appointment scheduling application was recently implemented in Electric Operations.

A standing cross-functional team assists in developing new initiatives to maintain employee engagement and customer focus. This year the team will develop two information forums to share best practices for enhancing the customer experience.

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 coned.com:

- ESCO bill comparison tool for Retail Access customers to determine what their bills would have been if they were taking supply from the utility
- 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
- Voluntary Time-of-use (VTOU) calculator to compare the cost of using an appliance during different VTOU periods (*i.e.*, peak, off-peak, and super-peak), and to compare the VTOU rate to the standard residential electric rate, and
- Other calculators to estimate the energy costs for different appliances, estimate savings to be gained by installing and setting a programmable thermostat, and compare purchase prices and operating costs of CFL lighting.

In addition to these tools, the website presents information about various programs and services available to customers, including the Company's robust 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 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.

While the DSP marketplace is in its early stages, the Company is taking steps to make customers more aware of the resources available to them. As proposed in Customer Operations Panel testimony in the January 2016 rate filing,[123] the Company plans to expand the information provided about its tools and resources and diversify the methods used to communicate with, educate, and raise awareness among its customers. Specifically, the Company will initiate more sustained and substantial messaging campaigns to increase customers' understanding, familiarity, and engagement, and encourage the use of available tools, resources and programs. The Company's sustained outreach will focus in four key areas:

1) Expanding upon and sustaining Con Edison's robust gas safety awareness program
2) Engaging customers around ways to better manage their energy use and increasing awareness of energy management tools
3) Educating customers about time-sensitive rates, including voluntary time-of-use and mandatory hourly pricing (MHP), and any programs being developed as part of the REV proceeding and
4) Expanding the Company's educational program for schoolchildren.

Additionally, the Company plans to develop sustained energy management campaigns tailored for our low-income customer population, for whom energy costs account for a disproportionately high percentage of total household income.

At the same time the Company is diversifying its communication methods to reflect changing customer preferences. The Company will dedicate additional funding to digital advertising campaigns, including placing banner advertisements (ads) on third-party websites, developing ads to be incorporated into customers' social media feeds, and placing ads in third-party mobile apps. Use of e-mail marketing will also continue to grow, and the Company will continue to utilize more traditional channels such as direct mailings, bill inserts, subway ads, print ads, and radio spots.

Finally, the Company intends to provide additional outreach to customers in its MHP program to help them identify opportunities to reduce demand and react to pricing signals. This will involve using a variety of communication channels including web and in-person meetings. Customer research will also be utilized to identify ways to better educate customers on MHP. These efforts will leverage existing

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[123] Case 16-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Customer Operations Panel testimony (filed January 29, 2016), pp. 102-118.

online tools, webcasts, videos and newsletters designed to empower MHP customers and help them make the most of time-variant pricing.

Listening to Customers

Con Edison 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, Con Edison is redoubling its efforts to engage customers in an ongoing dialogue about the service that they receive, and ways to enhance their experience. Key initiatives include:

- Sustaining the twice-annual customer satisfaction surveys has long been required by the Company's electric and gas rate plans. These in-depth surveys measure customer satisfaction with four of the core customer service functions: electric emergency calls, gas emergency calls, non-emergency calls, and visitor center interactions. Survey results are used to identify pain points and areas for improvement.

- Leveraging the online Con Edison Advisory Community for easy access to customer feedback on a wide range of research-related topics. The Advisory Community was launched in 2015 and contains over 10,750 customers who have agreed to participate in a private online forum. Information collected has resulted in better decision-making and ideas for an enhanced customer experience. Details of a recent Advisory Community survey on data sharing are included in **Appendix L**. The main takeaways of the survey were that customers would trust the Company to be DER advisors, but information supporting DERs is not readily available on the Company's webpage.

- Sustaining the twice-annual Customer Awareness and Understanding Surveys that measure customer awareness of recent educational campaigns.

- Engaging regularly with customers and stakeholders participating in special rates or programs, both to understand their unique needs and concerns, and to offer education on ways to manage their energy consumption and costs. Examples include semi-annual webinars for MHP and Reactive Power customers, small business gatherings, and attending the annual CUNY Solar Summit conferences to speak with interested customers and stakeholders.

- Maintaining regular communication with stakeholders and agencies that represent certain customer segments including elderly, blind and disabled; low income; and life sustaining equipment customers.

Additionally, new survey and feedback-gathering capabilities into recent investments have been incorporated into the Company's customer care infrastructure. The new Customer Interaction Center – a state-of-the-art telephony platform providing automated call distribution, IVR, media recording, dialer, reporting, and speech analytics – allows 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 the Company's Scope to Improve Customer Engagement

As the Company builds on existing customer engagement activities, it is also beginning in earnest 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 DER 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, and Green Button Connect

As described earlier in the Customer Data section, Con Edison is poised to invest in AMI, DCX, and GBC 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, DCX 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. DCX will provide seamless interfaces for customers participating in the Company's REV Demonstration Projects and later iterations of REV market development. DCX will also enable clear communications with participants in complex rates and programs such as MHP and Community Net Metering.

REV Demonstration Projects

Con Edison will also begin implementation of multiple REV demonstration projects in 2016, including the Connected Homes, Building Efficiency Marketplace, and Virtual Power Plant programs. Each of these projects will present a prime opportunity to experiment with customer engagement strategies and refine potential service offerings as the DSP takes shape. Please see **Appendix B** for additional information on these programs.

Another demonstration project to be initiated in late 2016 or early 2017 is a customer portal. This proposal was included in the Track One Order. The customer portal will offer a marketplace platform, hosted through the utility, where customers can purchase energy products and services. The results of this demonstration project will inform a similar platform on the DSP.

VII. DSP IT Roadmap

A. Introduction

The DSP as envisioned in this five-year initial DSIP filing will consist largely of IT investments that will complement existing planning and operational needs by providing insightful tools to planners and control room operators, respectively, and help to best integrate the increase in DER portfolio of assets into the electric distribution system. The DSP should also build upon existing customer interfaces to facilitate enhanced customer engagement as the Company evolves to the fully transactive market place envisioned in REV. The role of the DSP IT roadmap is to identify the foundational tools required to provide the most value to integrating DER today while establishing the framework for future expansion of the DSP in unison (and complementary to) the expansion of DER on the electric distribution system. The DSP IT Roadmap examines the Company's current IT and communications capabilities, the near-term DSP functionalities required, the gaps in meeting those requirements, and outlines the approaches to developing the DSP functionalities proposed in the future.

These plans are an early conceptualization of the foundational and functional requirements that will be necessary to fully support the programmatic changes outlined in this DSIP. These plans are subject to change and modification as time and circumstances evolve in this new utility environment. The pace of technology development and required investment will be driven by the rate of DER penetration and the availability of resources required to implement each technology solution.

B. Functionality Needed to Support REV Implementation at Con Edison

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

- Providing customers with more choices in their energy supply.
- 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.
- Achieving increased visibility and automation across the system in order to better plan for and operate the high DER penetration grid.
- Integrating DER into forecasting and planning in order to encourage third-party investment and defer traditional capital investment (NWAs).
- Sharing system information in order to aid providers in developing DER in beneficial locations and configurations.
- 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 can present.

C. Approach to Developing the Technology Roadmap

In order to visualize, monitor, dispatch, and potentially control DER on the Con Edison system, a number of systems and applications will need to be developed and integrated. While there are a number of tools the Company has to collect information related to DER, they generally do not communicate and require significant manual intervention to develop a view of the resources on the system. In order to meet the goals of REV, the Company will need to develop enhanced capabilities to manage a diverse portfolio of DER and fully meet system needs for operations and planning. It is important to articulate the vision of the end-state Distribution System Operator (DSO) model in order to understand the technology required to facilitate a distribution-level marketplace. However, based on DER penetration at the time of this initial DSIP filing, the Company believes that the most cost-effective approach is to start with the initial building blocks of a DSP.

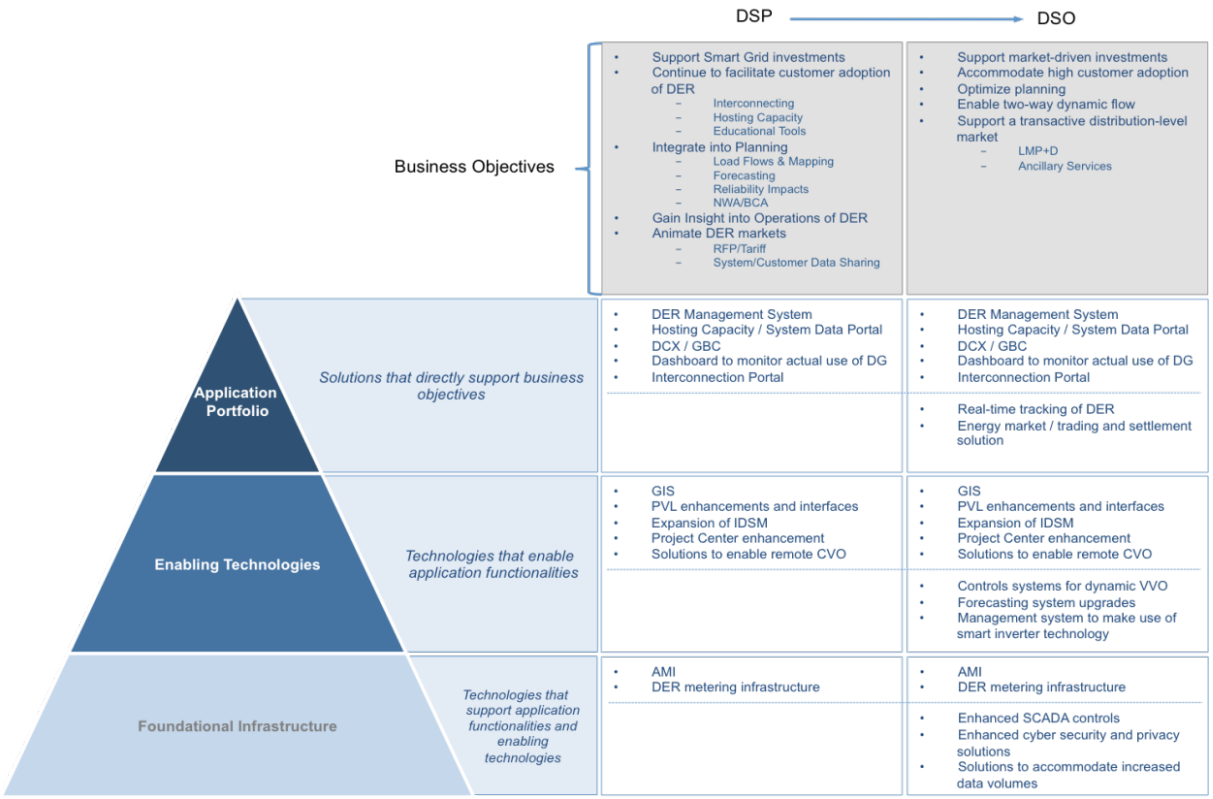

Figure 49 – Con Edison REV Enabling Technologies

Key technology platforms supporting DER integration will likely include:

- **Automated Metering Infrastructure (AMI),** which will be implemented in 2017-2022. The system will provide granular energy usage information to utilities and customers. The system will have three major components: (1) smart meters (and associated communication modules), (2) a communications network, and (3) AMI back office information technology (IT) systems to manage the two-way communications enabled by AMI. This system will increase the visibility into the distribution system by taking inputs from field sensors/meters, automated devices, and

fault indicators. AMI will enable both grid edge intelligence and – in the longer term – a transactive distribution-level energy market.

- **State Estimator** achieved via a load flow model (PVL). The model performs power flow analysis and voltage drop calculations with accurate and reliable results. The robustness of the model has streamlined certain aspects of the interconnection process (*e.g.*, auto approval of solar requests 25kW and under).

- **DER Management System,** which is an immediate need to address key purposes of the DSP by optimizing DER resource tracking and utilization. The purpose of a DER Management System is to manage diverse distributed energy resources, to understand the unique status and capabilities of each, and present these capabilities to other applications in a useful and manageable way. The Company's vision is for the DER Management System to be the system of record for all DER and to interface with other key systems, including the Demand Response Management System (DRMS) system, which supports the management of enrollment, event initiation, and settlement of the Company's Demand Response (DR) programs. In the near future, such a single system of record is needed to facilitate planning of the distribution system. ADER Management System that accurately captures specific locations and circuit connections, capacity, peak characteristics, operating patterns, and performance data, along with proper mapping of DER, will help inform the distribution planning process and provide useful information to DER providers. Ultimately, the system will help support a DSO function by enabling Con Edison operators to better respond to system operational events, environmental and equipment conditions, and changing market conditions by including DER in the portfolio of tools.

- **Data Analytics Solution:** An IT platform to store various aspects of DER data for analytical and operational purposes. Initially, it is expected that this platform would be populated with interval meter data from DER providers. Extensions would incorporate data streams from other devices (such as voltage from existing RMS data and other utility owned SCADA and/or third-party devices).

- **Enterprise-Level Mapping Solution (GIS):** An enterprise-wide GIS platform to replace current mapping systems that are siloed and function-specific. Appropriate localization and visualization of DERs system-wide will help realize maximum benefits of the evolving DSP and the Advanced Metering Infrastructure (AMI). GIS Is a significant enabler for multiple planning and operations processes.

- **Communication Infrastructure:** The transition to real-time, automated distribution management will require internet-like speeds throughout the communication network while handling increased volumes of data. In addition, as third-party inverters start interacting with the Con Edison distribution system, the current communication network may not be able to handle the additional data traffic and support all required file formats. Utilizing the new AMI communication infrastructure may help provide a secure interface between the Company and

the DER providers. In the long term, as the Company assumes the role of a DSO, performance and latency requirements may require a more robust, dedicated communication network.

- **Cyber Security Architecture:** Cyber security protocols, policies, hardware, and software architecture must be able to support the real-time system with communications in milliseconds. As access to and sharing of data become 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. Cyber security is designed into all computing and communications elements used by the AMI system. As the Company continues to develop its DSP capabilities, it will examine cyber security needs stemming from the potential use of cloud services by third parties and the need for alignment with control system requirements.

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.

D. Distribution System Planning

In order to effectively plan and operate the distribution grid, Con Edison needs better visibility into both traditional customer usage and the performance of DER on the system. This insight will help form the basis for the distribution planning the Company performs on an annual basis to identify required upgrades and changes to the distribution system. As the penetration of DG technologies increases, the Company will need to build upon the existing forecasting tools to produce and utilize forecasts more dynamically and at a more granular level.

1. Forecasting

Accurate forecasting of electric demand is a foundational element of system planning. Forecasting DERs, owned and operated by third parties, inherently increases the complexity of the forecasting process and thus makes accurately forecasting demand more challenging.

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Annual system peak demand	- Capability exists system-wide - DER are integrated at the system level - Current forecasting is inclusive of most types of DER for both demand and energy forecasts (including DG, PV, EE, targeted DSM (*i.e.*, DMP, BQDM), and DR) - Excel (Forecasting templates)	**Immediate (2017-2019):** Same as current state **Long-term (2020+):** - Added DER monitoring and forecasting - Full utilization of AMI data; increased data volume	**Immediate (2017-2019):** None **Long-term (2020+):** - Integration of AMI data - Systems to handle increased data volumes and analytical needs	**Immediate (2017-2019):** None **Long-term (2020+):** - AMI and ad-hoc solutions as needed
Annual network peak demand	- Available for all load areas - Forecasting at network level for DG, PV, EE, targeted DSM (*i.e.*, DMP, BQDM), and DR - Excel (Forecasting templates)	**Immediate (2017-2019):** Same as current state **Long-term (2020+):** - Increased data volume - Added DER monitoring and forecasting - Full utilization of AMI data	**Immediate (2017-2019):** None **Long-term (2020+):** - Systems to handle increased data volumes and analytical needs - Integration of AMI data	**Immediate (2017-2019):** None **Long-term (2020+):** - Transmission Owners Data Reconciliation System (TODRS) upgrade (potential additional source of network and large account data) - AMI and ad-hoc solutions as needed - Additional analytical tools such as advanced / customized forecasting model - Metrix IDR upgrade
Daily network peak demand	Not available	**Immediate (2017-2019):** Being developed **Long-term (2020+):** - Daily load forecast for the Con Edison distribution areas/networks - Daily DER forecasts by network, including DG, PV, EE, targeted DSM (DMP, BQDM), and DR - Coordination with Distribution Operations on forecasted DER requirements for reliability - Monitor and understand the impact of large energy customers on the network and how they may influence network peak demand forecast	**Immediate (2017-2019):** Being developed **Long-term (2020+):** - Weather forecasting to predict PV/Wind generation 10-days ahead - Support for additional analytical needs	**Immediate (2017-2019):** Being developed **Long-term (2020+):** - AMI - Metrix IDR upgrade - Additional solutions to accommodate increased data volume - Additional analytical tools such as advanced / customized SAS forecasting model - TODRS upgrade

Table 62 - Forecasting Technology Needs

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
1-10-Day Ahead system forecast	- Provide daily system forecast using Metrix IDR	**Immediate (2017-2019):** Same as current state **Long-term (2020+):** - Increased amount of data available / utilization of AMI data - Improved analysis and understanding of the impact of large customers and DERs on the system - Reconciliation of network and system forecasts	**Immediate (2017-2019):** None **Long-term (2020+):** - Tools to analyze outliers / increase accuracy - Support for additional analytical and reconciliation needs	**Immediate (2017-2019):** None **Long-term (2020+):** - Upgrade Metrix IDR (new release or install required systems) - AMI - Additional analytical tools such as advanced / customized forecasting model - TODRS upgrade
Energy Sendout	- Provided at the system level annually - Open-source R software solution is used for regression analysis	**Immediate (2017-2019):** Same as current state **Long-term (2020+):** - Potential need to break down sales forecast by network / customer class	**Immediate (2017-2019):** None **Long-term (2020+):** - Integration of monthly peak forecasting data with additional process / methodology changes - Full integration of DER data	**Immediate (2017-2019):** None **Long-term (2020+):** - Databases to host increased volumes of data - Interfaces with AMI and DER Management System - Additional analytical tools

Table 63- Forecasting Technology Needs (Cont'd)

a) Current State

The Company currently integrates REV-like DER data (including DG, PV, EE, targeted DSM (*i.e.*, DMP, BQDM), and DR) at the system level into its annual system peak demand forecast and short-term (1-10 Day Ahead) forecasts. An annual network peak demand forecast is also produced for all load areas. The impacts of DERs on the system are generally reflected in forecasts as load modifiers, based on data from several sources, including the Customer Project Management System (CPMS), Distributed Energy Resource System (DERS) database, information from EE and DG groups, and a variety of Excel-based data inputs through a manual processes. The Company uses a combination of Excel-based models and open-source R software for statistical analysis. For short-term (1-10 Day Ahead) forecasting, the Company uses the Metrix IDR, a solution that generates sub-hourly, hourly, or daily forecasts for lists of delivery points or portfolios of electric retail customers. The system utilizes multiple weather data inputs, including temperature, humidity, cloud cover, precipitation, *etc.*, to forecast weather impact on the system peak.

The Energy Sendout forecast is provided annually at the system level to support the budget process and at other times as needed to support rate cases. Separate forecasts are available for each customer service class, but are not separated on a geographical basis (*e.g.*, by borough). In developing Energy Sendout forecasts, the Company relies on source data from CPMS verified against the Work Management System (WMS) and uses open-source R software and the eViews solution for statistical analysis.

b) Future State

In the near future, the Company will provide daily load forecasts for the Con Edison distribution areas/networks, including DER forecasts by network. In the longer term, Con Edison will explore utilizing AMI data as it becomes available to increase precision in system- and network-level forecasts to fully account for DER factors in demand growth, enable decisions on NWA solutions, and support capital project planning. Energy Sendout forecasting will transition to forecasting by network as well, resulting in monthly sendout forecasts for each network by customer class.

c) Required System Upgrades

Con Edison has integrated DER into their forecasts and does not expect any additional one-to-two--year functionality needs in support of the bulk of its forecasting activities. However, as increased amounts of data become available and REV becomes more definitive, the need to analyze and forecast the impact of large customers and DERs on the system grows, the Company may need additional tools to analyze outliers, increase forecast accuracy, and support reconciliation of network and system forecasts. These tools will need to integrate with downstream systems and data standards to enable the usage of data by planning and operations processes. To accomplish this, key system upgrades will be required:

- **Transmission Owners Data Reconciliation System Next Generation (TODRS NG):** Current version of the system will need to be upgraded to handle AMI data, accommodate DSP requirements, and interface with Metrix IDR
- **Metrix IDR Upgrade:** Installation of the new release will be required to integrate DER information into short-term forecasts as well as handle AMI data, and accommodate DSP requirements
- **Advanced Analytics:** Current functionality gaps include solutions for advanced analytics, such as advanced/customized Statistical Analysis System (SAS) forecasting models. In addition, the Company lacks the necessary toolset and infrastructure to handle additional data volume as the number of data points increases both system-wide and at the network level
- **AMI Integration:** The implementation of enhanced forecasting tools is dependent on the availability of AMI, which will provide granular, real-time usage data. AMI data will feed into and increase the precision of network-level forecasts. However, additional solutions will be required to integrate and overcome possible limitations of the AMI data.

2. Planning

Con Edison uses sophisticated planning tools (poly voltage load flow models (PVL), network reliability indexes (NRI), etc.) to model the T&D system and identify required upgrades. The integration of DER will increase the data required to accurately model the system, including an additional DER performance and reliability component. The Company will leverage the increasing amounts of data that are produced by smart grid devices to improve the load basis and its overall planning process. Ultimately, system-wide planning processes will also incorporate hosting capacity-related parameters as well as identifying where DER provides the most value to the system (*i.e.,* LMP + D).

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Integration of DER into circuit planning analysis	- PVL model has the capability to integrate DER information - Siloed approach to storing and using DER information (DRMS, DERS, etc.) - DER information not included in NRI calculation	**Immediate (2017-2019):** - DER Management System, including an asset repository - DER information included into NRI in PVL **Long-term (2020+):** - Verification of actual DER performance data for inclusion in planning - Integration of forecasting and hosting capacity data	**Immediate (2017-2019):** - Back-end analytics on AMI data / integration into operational models **Long-term (2020+):** - DER performance tracking - Expanded functionality for the planning tool	**Immediate (2017-2019):** - DER Management System **Long-term (2020+):** - DER metering infrastructure - Ad-hoc solution to inclusion DER performance data into the DER database - Enhancements to the Load Flow Model (visualization, transient analysis)
Integration of BCA into planning process	- Estimates done by project managers at the area substation level - Excel spreadsheets (including IDSM) - Manual process	**Immediate (2017-2019):** - Manual updates annually based on the process outlined in the BCA Handbook **Long-term (2020+):** - Analysis of solutions at the feeder and transformer level using BCA methodology - Modeling integration to enable LMP+D	**Immediate (2017-2019):** None **Long-term (2020+):** - Same (utilize full functionality of IDSM)	**Immediate (2017-2019):** None **Long-term (2020+):** - Additional screens and improved processes – Potential IDSM enhancement
Determination of areas that can benefit from DER / NWA	- Spreadsheet by E3 (IDSM) (as screened for BCA evaluation) - PVL model	**Immediate (2017-2019):** - Modeling to assess solution portfolio in the planning tool **Long-term (2020+):** - Analysis of reliability of DER included into analysis	**Immediate (2017-2019):** None **Long-term (2020+):** - Portfolio feasibility and actual reliability data integrated with planning tools	**Immediate (2017-2019):** - AMI - Expansion of, or similar program to, IDSM with a more granular view **Long-term (2020+):** - Add-on solution to incorporate probability calculations into the DER database and PVL

Table 64 - Planning Technology Needs

a) Current State

Determining the capacity of assets for long-term planning is accomplished by using system architecture, equipment ratings, contingency design, and load flow analysis. Load Flow Models, which currently have the capability to integrate DER information, are used for planning purposes (including contingencies and upgrade scenarios) and show the flow of power throughout the system and highlight areas where system components may become overloaded during a contingency. For station capabilities, Con Edison uses an in-house Excel-based substation capability calculator, and for sub-transmission feeder capabilities – the PSSE (Siemens Load Flow Tool). Network modeling is done using the PVL tool. The Company uses the Network Reliability Index (NRI) simulation to model the reliability of a network based on contingency design and failure rate probabilities for distribution components. NRI does not directly account for the impact of DERs.

Tracking of DER resources is currently done in several systems, including an Access database, which serves as the system of record for interconnected DGs, the Distributed Energy Resource System (DERS) database, which focuses on statistics related to distributed generation capacity, and the Demand Response Management System (DRMS), which supports the enrollment, event initiation, and settlement of the Company's Demand Response (DR) programs. Energy efficiency (EE) projects are also tracked separately. As such, there is no single enterprise-wide system of record for DER resources, which affects the accuracy of inputs into the planning process and creates manual processes around data validation and transfer.

BCA process determinations are currently manual. There is no direct link between capital project planning tools and the financial data for project costs, which are necessary when performing benefit-cost analysis. Project cost estimates are developed by project managers and are typically collected via spreadsheets.

The identification of areas that could benefit from DER/NWA is performed using a spreadsheet solution by IDSM /E3. This is an Excel-based solution that allows the Company to sort potential projects and prioritize the load areas or stations that have the greatest opportunity for load relief.

b) Immediate System Needs

Integration of DER into the planning process at Con Edison is limited by the lack of a single DER database, potentially including an asset repository. Such a single system of record is needed to facilitate planning of the distribution system and should include DER type, location, capacity, peak characteristics, operating patterns, and performance data. Currently, the limited communication and process ties between the databases that register a customer's DER interconnection and the mapping and load flow systems create delays between DER commissioning, mapping, and modeling of the DER asset.

Modeling tools may also have to undergo some changes in the short term to accommodate DER data (including reliability data) while assessing solution portfolios. The Company will need additional tools to compare load forecasts against the capacity of area substations and distribution assets to determine where load relief is needed. DER information will also need to be included into NRI calculations as well as the PVL load flow models.

c) Long-Term System Needs

With greater DER penetration, load flow modeling becomes more complex and must be accounted for in modeling tools. The updates to the applications need to have the capability to depict the impact of significant DG output on intermittency of voltage, frequency, and protection in order to provide for safe and timely interconnect. The Company will also need add-on solutions to incorporate probability calculations based on actual DER reliability data into its planning tools, along with solutions to automate portfolio feasibility analyses. The Company will also work to better understand whether there is value in developing a model that consolidates load flows from the transmission level to the customer distribution level and helps inform better integration of DER.

3. Hosting Capacity

Con Edison's approach to sharing hosting capacity information is still being developed and will be further refined in the JU Supplemental DSIP to be filed by November 1, 2016. Con Edison is following the phased EPRI approach to developing and visualizing hosting capacity. With the JU and in collaboration with EPRI, the Company is working to establish a uniform methodology that can be scaled at the state level. As this effort is developed further in technical conferences and stakeholder engagement, related technology needs will continue to be defined.

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Initial determination	- Minimum load data used to determine hosting capacity for the underground network at the transformer level - DG currently tracked in a standalone repository (DERS) that is an outgrowth of the SmartGrid DERMS project - EE resources tracked through programmatic tools (*e.g.*, DMAP, DMTS) - Interconnection queue (from CPMS) not currently integrated - Static presentation (PDF) of hosting capacity available for the underground network	**Immediate (2017-2019):** - An interactive hosting capacity for the underground network and non-network system **Long-term (2020+):** - Refined hosting capacity evaluations that take into account additional criteria - Comprehensive hosting capacity and DER value assessments considering both distribution and transmission - Upcoming projects reflected in hosting capacity determinations	**Immediate (2017-2019):** - Visualization solution for an interactive map that can be 'drilled down', including radial system **Long-term (2020+):** - Integration of inputs from a DER registry, interconnection queue, and mapping system	**Immediate (2017-2019):** - Registration portal for interactive maps (depending on granularity and sensitivity of data) - Mapping solution **Long-term (2020+):** - GIS to replace many discrete mapping tools (may continue to rely on existing system models) - Real-time tracking of DER - Integration with PVL modeling software, CPMS, DER Management System, and the interconnection portal
Periodic updates	Annual updates currently planned	**Immediate (2017-2019):** - Quarterly refresh **Long-term (2020+):** - Dynamic updates - Outputs integrated in LMP+D	**Immediate (2017-2019):** None **Long-term (2020+):** - Integration of inputs from a DER registry, interconnection queue, and mapping system	**Immediate (2017-2019):** None **Long-term (2020+):** - Dynamic system tool that is integrated with the DER Management System, interconnection queue, and the mapping system

Table 65 - Hosting Capacity Technology Needs

a) Current State

Hosting capacity assessments should consider a wide range of factors, including voltage/flicker, protection, thermal impacts, as well as safety, reliability, and power quality. Initially, the Company will focus on minimum load data as a key component in determining hosting capacity. This data is currently available only for circuits in Con Edison's underground network.

DG resources are currently tracked in a standalone repository (DERS). Projects in the interconnection queue are currently managed through the Customer Project Management System (CPMS) and linked to multiple mapping solutions through Cuflink. None of these systems are currently integrated.

b) Mapping Portal Implementation

The Phase 1 implementation of the Planning Map Portal will provide DER Hosting Capacity information for the network system, which accounts for the vast majority of Con Edison electric distribution system. The network hosting capacity maps will convey hosting capacity determinations at the network transformer level. The map display will be accessible from the Con Edison distributed generation home page (www.coned.com/dg) and will utilize the existing PVL SQL Server database and will display transformer location as well as regional and distribution network boundary graphic layers using Microsoft's Bing™ map as the base. The Phase 1 version will only include the network system. Initially, the map will be available as a static PDF file. This approach will provide interim guidance to developers in identifying areas with little to no additional cost to interconnect DG resources. This version of the map will not require additional system interfaces.

Beginning in 2017, as part of the Phase 2 implementation, the Company envisions an interactive map that can be "drilled down" from a network level overview to transformer/street level overview. The ongoing stakeholder engagement, technical conferences, and working groups will define any additional information to be embedded in the future, along with the necessary physical and cyber security controls, to help DER providers make more informed investment decisions and provide maximum value to the system. The interactive map will clearly identify the Con Edison regional boundaries, municipal, county, and state boundaries, roads and road names, public transportation, building footprints, and satellite imagery.

Con Edison is currently working to determine the key characteristics of the map including:

- Area displays such as broad zone, circuit, towns, *etc*.
- Criteria for information being displayed
- Information to be included (min load, max load, average load, primary voltage, *etc*.)
- Determination of beneficial location data
- Determination of supporting data associated with beneficial locations

The Company has and will continue to take the appropriate measures to safeguard the sharing of hosting capacity data as to not compromise physical and cyber security.

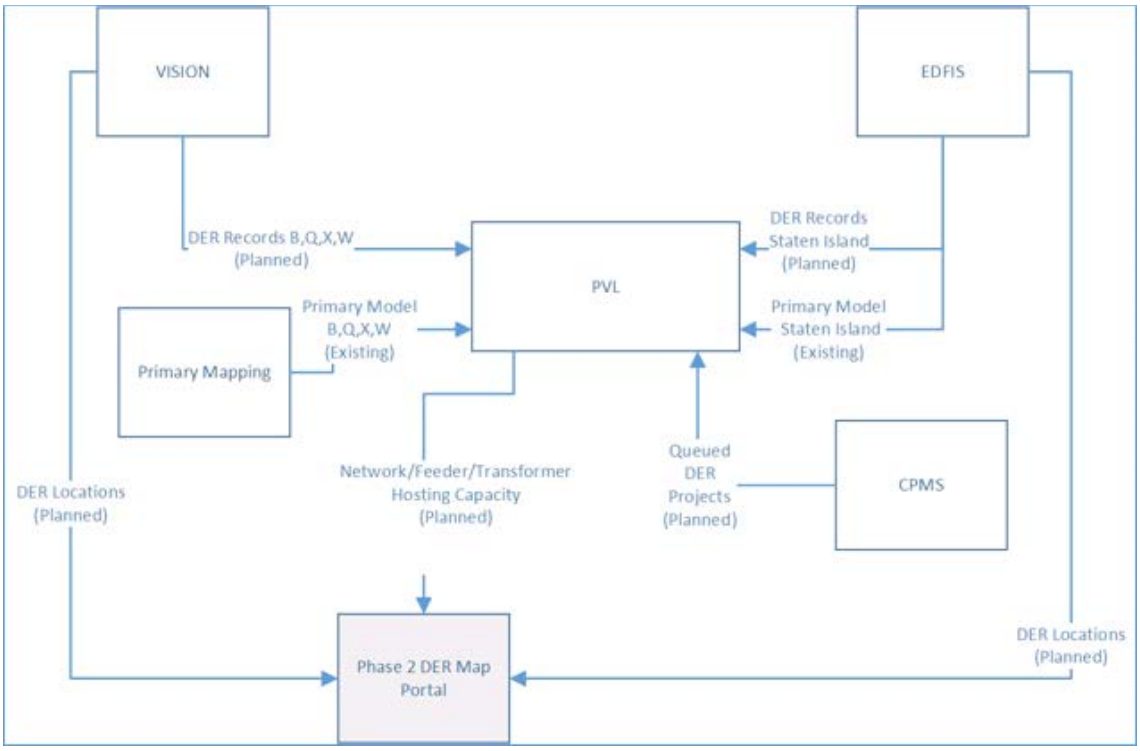

Figure 50- Interfaces Required to Support the Phase 2 Implementation

c) Long-Term System Needs

In the long term, the Company will need to develop a process for periodic updates. Depending on the desired update frequency, the Company will need to develop solutions to automate inputs from forecasting, planning, operations tools, including the DER system of record and interconnection queue. Con Edison will include non-network areas in future updates. Additionally, the hosting capacity will have to track queues and projects at a more and more granular level. To facilitate such integration, the Company will also need to implement an enterprise-level GIS tool that would replace many discrete mapping tools.

E. 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 of the ability to dispatch large scale DER on peak days, aggregation of behind the meter DER to provide load reduction and facilitate NWAs, or the ability to tap DER to provide Volt/VAR and other ancillary services when needed, will require significant investments in new technology platforms. In addition, coordination with the NYISO (which might also be dispatching DER) will be important. These systems will be deployed based on the rate of DER penetration and the need for operators to have visibility and control of these assets.

1. Monitoring and Control

Real-time monitoring of DER is essential to preparing the Company to effectively manage increasing penetration of customer DER, Utility Sited DER, and NWA solutions. Real-time monitoring of these resources enables timely operational decisions, near-term forecasts, and scenario analyses. As the amount of information collected from AMI meters and metered DER increases – and the Company prepares for a transactive energy market – the need for a system that will aggregate, analyze, validate, and display the information about the status of DERs 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.

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Monitoring and dispatch / control of large DER	- Control over some of the breakers for emergencies (DTT - disconnect only, not curtail), including large CHP - Limited monitoring of large DGs through PI telemetry - Some large DGs bid directly into the transmission market - Current focus on performance - voluntary meters on generators	**Immediate (2017-2019):** - On/off status available upfront; SCADA control - System location mapping for all DER - Standby performance credit - automated data flows to support performance management **Long-term (2020+):** - Real-time data flowing into control dashboard	**Immediate (2017-2019):** - Generation - specific meters - Dashboard and mapping for operational use **Long-term (2020+):** - A platform supporting aggregation and dispatch of DG in real time	**Immediate (2017-2019):** - DER Management System - AMI **Long-term (2020+):** - Expanded metering infrastructure - DER Management System integrated with operating tools
Monitoring and aggregation / dispatch of small DER	- Currently exploring forecasting solutions for small DGs - Manual billing process	**Immediate (2017-2019):** - Need to understand the impact on circuits as total volume of small DG increases **Long-term (2020+):** - Potential role as an aggregator	**Immediate (2017-2019):** Under evaluation **Long-term (2020+):** - A platform supporting aggregation and dispatch of small DG in real time - Generation - specific meters - Dashboard and mapping for operational use	**Immediate (2017-2019):** Under evaluation **Long-term (2020+):** - Expanded metering infrastructure - AMI - DER Management System
Switching plans and real-time contingency analysis	- There is some distribution automation within Con Edison's network - Operators can view present issues and the next worst case fault for contingency planning in the Contingency Analysis Program (CAP), Visual CAP (VCAP), NetRMS, PVL, WOLF (PVL-RT)	**Immediate (2017-2019):** - Real-time contingency analysis based on DER - DER modeled into load flow analysis **Long-term (2020+):** Same	**Immediate (2017-2019):** - Dashboard and mapping for operational use - Integration into real-time tools **Long-term (2020+):** Same	**Immediate (2017-2019):** - DER Management System - AMI **Long-term (2020+):** Same
FLISR (Fault location, isolation and service restoration)	- RealFlex monitors through the loop system monitor equipment and outages; support outage notification, feeder processing - Reactance To Fault (RTF) tool for the underground network	**Immediate (2017-2019):** - Feeder processing (open / closed) - Additional automation - Updated maps **Long-term (2020+):** Same	**Immediate (2017-2019):** - Outage notifications - Automate (parameters to be defined as new sources start affecting the system) - Converge with GIS **Long-term (2020+):** Same	**Immediate (2017-2019):** - Outage notifications - GIS **Long-term (2020+):** Same

Table 66 - Monitoring and Control Technology Needs

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Utility battery dispatch	- 1 MWh installed currently; 12 MWh planned for BQDM - No capability	**Immediate (2017-2019):** - On/off status available upfront; SCADA control - Location mapping - Real-time data flowing into control dashboard, including charging cycle **Long-term (2020+):** Same	**Immediate (2017-2019):** - Dashboard and mapping for operational use **Long-term (2020+):** Same	**Immediate (2017-2019):** - DER Management System **Long-term (2020+):** Same
Demand Response management	- Current DR have interval metering - DR notification by email / phone (SendWordNow) - DRMS to be used for enrolling DR customers and analyzing response - Large DG operators are called separately - NetRMS (real time monitoring)	**Immediate (2017-2019):** - None **Long-term (2020+):** - Economic - driven DRM with real-time pricing - Real-time DRM tied to control room	**Immediate (2017-2019):** - None **Long-term (2020+):** - Automated baseline calculations and additional analysis based on AMI data	**Immediate (2017-2019):** - Additional meters at the source - Dashboard for DR (actual use) **Long-term (2020+):** - Automated connection (or a process change) to integrate with control room
NWA solution management	- Currently being piloted as part of BQDM	**Immediate (2017-2019):** - The ability to monitor and dispatch DERs as part of a specific NWA **Long-term (2020+):** Same	**Immediate (2017-2019):** - Dashboard and mapping for operational use - Integration into real-time tools **Long-term (2020+):** Same	**Immediate (2017-2019):** - DER Management System - AMI **Long-term (2020+):** Same

Table 67 - Monitoring and Control Technology Needs (Cont'd)

a) Current State

To date, metering, monitoring, and control have been implemented with varying levels of customer participation and based on system needs. Monitoring of large DG sources is limited. However, PI telemetry exists to measure output of select DGs on the system. In the underground system, operators can view various alarms across the network by region. Loading and voltage information driven by Network Remote Monitoring System (NetRMS data) is also available. In the overhead system, operators can monitor equipment and outages through RealFlex, a solution that monitors and allows for remote operation of pole mounted Vacuum Reclosers, as well as the status of 4 kV breakers and secondary bank breakers through the Unit Substation Automation (USA) and the Energy Management System (XA-21).

There is no dispatch capability for any of the generation sources or storage solutions. Relay protection is used to operate breakers as a blunt instrument to curtail certain generation sources (including CHP over 2 MW) through Direct Transfer Trip (DTT) to meet operational requirements. The Reactance to Fault (RTF) tool is used for outage monitoring and isolation on the underground network. Finally, operators can view current system status and perform contingency analysis in a number of tools, including the Contingency Analysis Program (CAP), Visual CAP (VCAP), NetRMS, and PVL. The "real-time PVL" - World-Class Load Flow (WOLF) system currently used by engineers in the control room can perform analysis inclusive of DER if data is appropriately stored and pulled from a DER Management System.

Dispatching DR resources is a manual process, and currently is not a control room function. Notifications are generated by the SendWordNow application and delivered via email or phone.

Tracking of DER is currently done in several systems, including:

- An Access database, which contains information on all DG sources applying through the Interconnection process. This data becomes the basis for the Company's regulatory reporting.
- Distributed Energy Resource System database, which uses data from the DG database, among other sources, but includes no real-time tracking or dispatch capabilities and requires manual editing and manual reconciliation of data from multiple data sources. The current DERS dashboards focuses on statistics related to distributed generation capacity.
- The Demand Response Management System (DRMS) system supports the enrollment, event initiation and settlement of the Company's Demand Response (DR) programs. This system enables Con Edison to interact with customers enrolled in demand response programs during peak periods (either system or network level peaks) to manage customer demand downward.

- Emergency Operations System (EMOPSYS), maintained by the Energy Services group, tracks customer side emergency generators and critical customers. It is also used as a source of information on generators that can be used in an emergency to get load off the system.

b) Future State

Monitoring and control of DERs in the short term will focus on areas where large DER exists (*i.e.*, over 1 MW) and/or where the Company relies on them as part of NWA portfolios. NWA solution management is currently being piloted as part of the BQDM Program, which includes a storage solution. The Company's ability to monitor and dispatch DERs as part of a specific NWA is a critical functionality, which will require DER integration into real-time operational tools as NWAs are deployed.

As DER penetration increases, and particularly as the transactive energy market develops, the Company will need to be able to monitor all DER resources on its network, including nameplate information, reliability (based on past performance or generalized heuristics), availability/status, and, for storage solutions, charging cycle. To dispatch DER solutions, the Company's operators will need a user interface to enable real-time decisions (automated whenever possible). DER location should be available for each load area, incorporated into a real-time reflection of the electrical topology of the system. The dashboard would ideally interface with an enterprise-wide GIS, updated in real time.

c) System Needs

Current tools and systems are not sufficient to integrate DER into the Company's monitoring and control systems, processes, and procedures. A thorough assessment will need to take place Company-wide to determine future system needs as the impacts of DER penetration on the system become clear. The Company will also investigate whether AMI can be used to facilitate this monitoring and control by providing a cyber-secure back bone to the customer site, a port to connect DER output to (*i.e.,* MW, MVAR, *etc*.) and the back office to interpret the data.

The Company's ability to monitor and control DER is predicated on the availability of accurate, real-time data on the entire range of solutions and DER locations for each load area, incorporated into a real-time reflection of the electrical topology of the system. In the long term, the Company envisions a single, comprehensive DER data repository (DER Management System), fully integrated with operating and planning systems. The purpose of a DERMS is to manage diverse DER, to understand the unique status and capabilities of each, and present these capabilities to other supporting applications to facilitate enhanced monitoring and control of the system. The tool will be used in response to system operational events, environmental and equipment conditions, and eventually market conditions as well as to track and report on the growth of DER in our service territory. A DER Management System will provide visibility and control of a diverse portfolio of resources to address local constraints while flexibly addressing system-wide concerns. The system will visualize, predict, and optimize demand response and distributed generation at the circuit, feeder, or segment level, presented in a dashboard suitable for operational use.

An enterprise-level GIS is another key prerequisite for integration of DER into Con Edison's operations. The system will provide appropriate localization and visualization of DER system-wide, which will be particularly important as the Company moves towards real-time monitoring and dispatch of DER.

d) Implementation Approach

The Company has taken the initial steps towards defining the solutions it will need to enable real-time monitoring and dispatch of DER. **Figure 51** below depicts an illustration of a potential operator screen in the Yorkville Network. This view has been developed by the Company to emulate the types of controls that would be necessary for system operators to make real-time decisions around dispatching various DER. In addition to the feeder boxes across the top of the figure, which are traditional monitoring points in any network, the operator could also see what resources are available for dispatch, including DG, DR, and storage solutions.

The Company is in the process of evaluating the existing processes and tools that it currently uses to manage the integration of DER into the electric system. During this process the Company will evaluate all feasible solutions including commercially available platforms. Part of the evaluation process includes leveraging lessons learned from the recent Secure Interoperable Open Smart Grid Demonstration Project (SGDP) sponsored by the United States Department of Energy (DOE). The project included piloting a real-time tool to capture DR data in select areas across the Company's electric system. The project mapped and ran simulations for contingency, showed status of networks, and included reliability information on individual DER based on prior performance. In addition, the Company is actively engaged with the JU to work with stakeholders to determine requirements for monitoring and control of DER. Initially, system capabilities may be limited to providing visibility into the status and location of DERs on the system, and may eventually include direct dispatch.

As DER penetration continues to grow, the Company will need to incorporate DER data to support switching plans and real-time contingency analysis. While the current WOLF system may accommodate these needs to a limited degree, front-end analysis and integration of AMI data from DER will have to be well designed and include aggregated meter inputs where appropriate (*e.g.*, a multi-unit apartment building that, as in one electrical location, would be considered as one input, not hundreds of meters). The Company will continue evaluating the tools needed to perform load flow analysis at the distribution level to incorporate DERs into distribution system operations and planning processes. The eventual market/trading and settlement solution may be similar to the OATI (www.oati.com) platform commonly used for transmission-level energy trading, with expanded SCADA monitoring and control. Such a solution would need to be capable of processing multiple transactions and settlements in real time while interfacing with the Company's DER Management System and other operational tools.

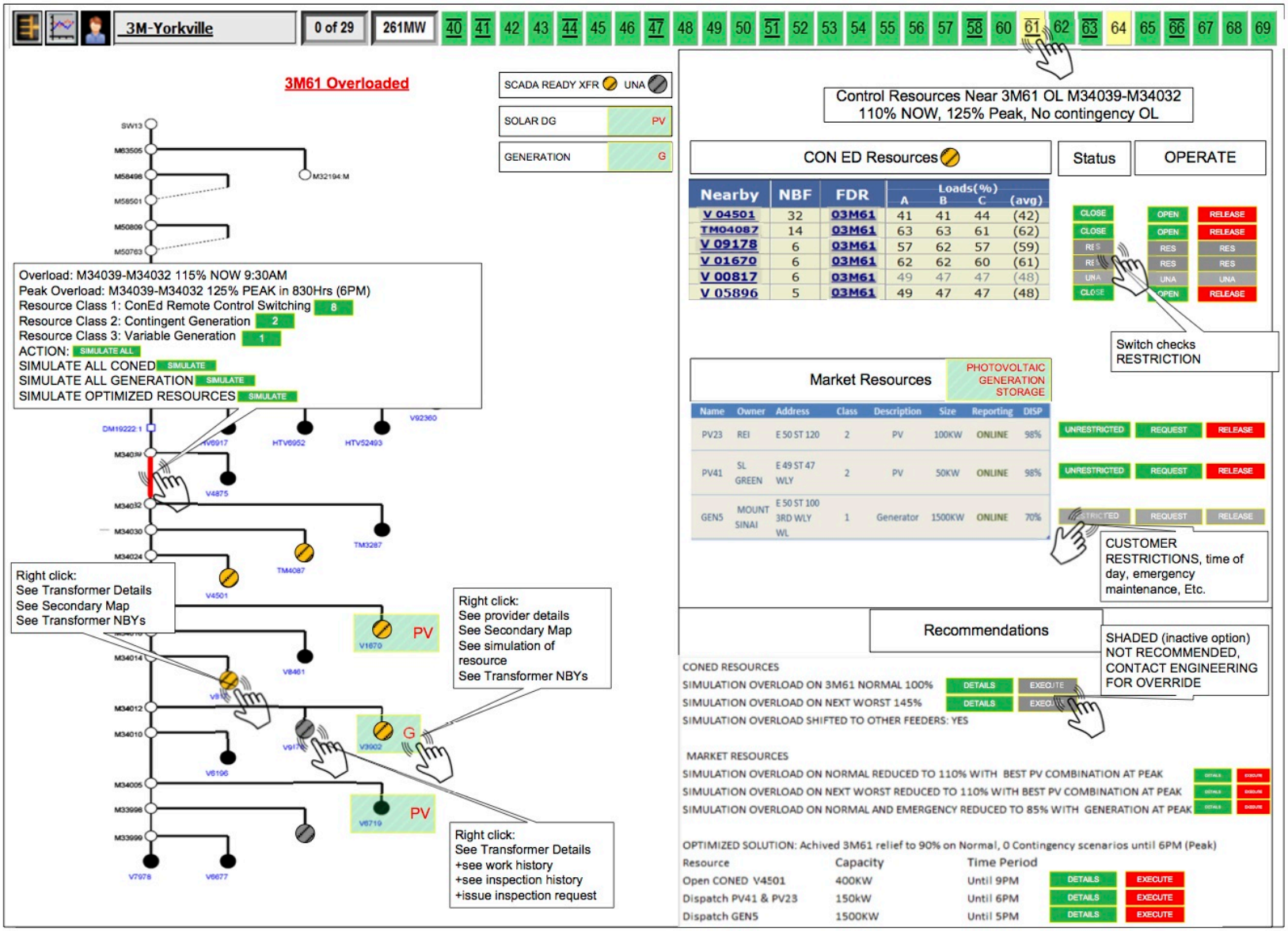

Figure 51 - Illustrative Operator View of DER in the Yorkville Network

2. Interconnection

A streamlined interconnection process and tools are critical to facilitate the integration of DERs in Con Edison's service territory. Prior to the REV Initiative, Con Edison had been working on improving the interconnection approval processes for both internal and external stakeholders. The following summarizes the Company's efforts to improve on the existing interconnection processes to improve customer and contractor satisfaction, streamline processing efforts for the Energy Services and System Design Teams, and meet the Track One requirements for interconnection. The updates to the interconnection process are largely driven through enhancements made to the three tools used throughout the process: Project Center, Customer Project Management System (CPMS), and the Distributed Generation website. These enhancements have a long lead time associated with them due to the required system changes.

The Track Two Order[124] and the NYS SIR Order[125] have prompted the Company to consider additional capabilities needed to continuously enhance its interconnection process. CPMS is currently being used by the Company to process all requests for electric and gas service, and is also used to process interconnection requests. However, as a result of the NYS SIR order, Track Two Order, and the rigorous reporting requirements of the NYS SIR, the Company is evaluating the best approach to better manage the interconnection process. To address this challenge the Company is conducting an analysis to reevaluate its reliance on CPMS in managing the interconnection process and to identify possible solutions to address current limitations to CPMS capabilities. As part of this assessment, the Company will consider available commercial products to provide the flexibility needed to accommodate possible future modifications of the NYS SIR and to streamline its internal interconnection process.

a) Interconnection Portal Implementation

Con Edison already provides a portal to facilitate timely DER interconnection processes (www.coned.com/dg) as well as a DG Ombudsman for customers when they have questions, concerns, or suggestions. The Company also continues to work with stakeholders, including NYSERDA which has developed the New York State Standard Interconnection Process (SIP), to reflect the latest rules and provides customers with the best web page experience possible. The systems that support applications initiated through the portal are Project Center and Customer Project Management System (CPMS).

The Company continues to improve the portal. In the near future, the improvements will include further automation around accepting and processing applications, sending automatic

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[124] 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).
[125] 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).

communications, setting project deadlines, and running reports. Specific Project Center and website improvements will include:

- Improved format and better content to help customers, contractors, and developers find the information they need to make sound business decisions.
- Direct links between informational website and the Project Center to streamline the transition between interest in DG and application for interconnection.
- Streamlined and clarified application fields to create a better user experience and shorten application time.
- Automated correspondence to inform contractors which application forms are missing with links to the required electronic forms for ease of upload.

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Online application tool and portal with automated status communications	- Initial functionality established (Project Center) - Improvements in the short term (first rollout by late June, 2016)	**Immediate (2017-2019):** - Improvements / further automation - accepting and processing applications, sending automatic communications, setting project deadlines and running reports - Integration with area station volumetric forecasting **Long-term (2020+):** - Integration with operational / market-facing forecasting, operational systems	**Immediate (2017-2019):** - Link to validate account numbers - Direct handover to the modeling tool **Long-term (2020+):** - Integration of data into operating and planning tools	**Immediate (2017-2019):** - Interconnection Portal - Project Center replacement (may be subsumed by DCX) - Ad-hoc link to PVL **Long-term (2020+):** - CIS replacement - GIS
Automated technical review (preliminary and supplemental)	Some automation aspects brought into CPMS Phase 2	**Immediate (2017-2019):** - Improvements / further automation as required by SIR **Long-term (2020+):** - Full automation - Transparency around technical reviews	**Immediate (2017-2019):** - Automated preliminary screen **Long-term (2020+):** - An integrated solution to feed interconnection data into operations and planning tools - Enhanced reporting capability	**Immediate (2017-2019):** - Manual screens / workarounds - Other improvements based on expected changes to SIR **Long-term (2020+):** - Link between Project Center (or replacement)/CPMS, operating, and planning tools (PVL) - Add-on reporting solutions
Queue management	- Maintained in CPMS - All entries are time-stamped	**Immediate (2017-2019):** - Reporting on project's place in each feeder's queue **Long-term (2020+):** Same	**Immediate (2017-2019):** - Reporting capability **Long-term (2020+):** Same	**Immediate (2017-2019):** - A link to DCX to publicly display the queue **Long-term (2020+):** Same
Integration into planning process	- Access database used to track installs - Currently looking for an SQL server or co-host with PVL	**Immediate (2017-2019):** - Improvements / further automation - Integration w/ planning tools/process and automated screens - Incorporate implications into hosting capacity calculations **Long-term (2020+):** - Integration with forecasting to identify potential problem areas and initiate solutions	**Immediate (2017-2019):** - Additional tools to house and use increased volumes of data **Long-term (2020+):** - An integrated solution to feed interconnection data into operations and planning tools	**Immediate (2017-2019):** - SQL servers - Solutions similar to Clean Fleet (Clean Power Research) or Solar Retina **Long-term (2020+):** - GIS - Link between Project Center (or replacement)/CPMS, operating, and planning tools (PVL)

Table 68 - Interconnection Technology Needs

- Automated emails sent to the customer and the contractor with information on next process steps and specific links for more information.

The immediate technology gaps also include a link to validate customer account numbers and a direct handover to the modeling tool. The Company is looking to an interface to its planning tool (PVL) to provide the required technical analysis capabilities.

In the long term, the interconnection portal will have the DER that are initiated and validated through the interconnection process provide input to all mapping and load flow databases so they can be integrated into the utility forecasting, planning, and operations process. This will involve integration with area station volumetric forecasting and will likely require the replacement of the Customer Information System (CIS), as well as an enterprise-scale GIS solution.

b) Technical Review Automation

Some process automation aspects are currently being implemented as part of Phase 2 of CPMS. Further improvements are likely based on possible changes to the NYS SIR.

In the long term, Con Edison envisions continuing automation of the review process, which will require an integrated solution to feed interconnection data into operations and planning tools, along with enhanced reporting capabilities. In addition to establishing interfaces between Project Center and CPMS, operating and planning tools, the following specific functionality upgrades will be required:

- Project Center upgrades to provide only completed applications reach Energy Services representatives, reducing re-work and improving efficiency.
- CPMS to automatically pull load and network system data from other internal systems to allow system planners a full picture of the DG system impacts at the customer's location.
- Automated prompts to the contractor when cases have been given the approval to proceed to construction but experience long periods of inactivity.
- Internal CPMS reporting functions to alert Energy Services Representatives when individual milestone timelines are approaching a deadline to take action.
- Automatic reporting of billing codes for net metering or standby customers to the billing system operators for completed projects.
- Automatic reporting of DG system information to Con Edison's regional mapping groups for inclusion on electric distribution maps.
- Interface between CPMS and Tableau programs to provide business analytics and oversight of project milestones on an enterprise level.
- DG System details automatically routed to the PVL Modeler for load flow analysis and addition to a pending DG queue database file for load flow analysis.

- Automated emails for systems that pass the PVL Modeler approving the DG system for construction as soon as the next business day.
- Notifications for systems that do not pass the PVL Modeler screen of the need for further study along with information regarding the nature of the failed screen criteria, again as soon as the next business day.

c) Queue Management

The interconnection queue is currently maintained in CPMS, and all project submissions are time-stamped. In the short term, the Company will focus on enhancing its reporting capabilities to provide reporting on project's place in each feeder's queue. To provide this functionality, a link to DCX to publicly display the queue will be required.

d) Integration with planning tools and processes

Currently, Con Edison uses an Access database used to track interconnections. The Company is looking for an SQL server or co-hosting solution with the planning tool (PVL). Additional short-term improvements include further automation by using SQL solutions along with additional tools to house and use increased volumes of data.

In the long term, the Company will need to develop methodologies and solutions to feed interconnection queue data into operations and planning tools, including hosting capacity calculations. This would likely require the replacement of the Customer Information System (CIS), an enterprise-scale GIS solution, as well as interfaces with Project Center (or replacement), CPMS, operating, and planning tools (PVL).

3. VVO

In the near term, the implementation of VVO solutions by Con Edison will be limited to voltage optimization for system protection and for peak shaving or demand management, an effort referred to as Conservation Voltage Optimization (CVO). Ultimately, the Company will transition to dynamic VVO to achieve system-wide efficiencies. The capabilities that fall under the VVO umbrella include peak demand management through voltage reduction and continuous voltage optimization to deliver specified voltage more efficiently and optimizing VARs to improve power factors throughout the load cycle.

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Real-time VVO	- Monitoring and voltage supporting infrastructure on existing equipment limited - CVO to be employed as part of utility non-traditional solutions in BQDM	**Immediate (2017-2019):** - Static CVO and dynamic VAR control implementation in BQDM **Long-term (2020+):** - Dynamic VVO	**Immediate (2017-2019):** - Automated CVO - Additional voltage monitoring devices **Long-term (2020+):** - Advanced controls and revenue - grade metering at area station level - Real time data on customer voltage and load - Analytics and management solution for data received from AMI	**Immediate (2017-2019):** - Engineering solutions such as new tap changing transformers, local capacitors, and SCADA controls to remotely manage CVO functions - AMI **Long-term (2020+):** - Data analytics / programming tools - Additional controls systems to dynamically implement VVO (substation infrastructure: controls / metering) - Management software platform to integrate granular AMI data - Management system for distributed reactive power to make use of smart inverter technology

Table 69 - VVO Technology Needs

a) Current State

The current Company infrastructure does not provide full visibility into the system as needed for CVO/VVO, but can be deployed locally through targeted monitoring (planned for the BQDM project). The Company's current infrastructure has limitations as it pertains to CVO/VVO. The Company is now beginning to implement SCADA-capacitor banks. SCADA controls offer the ability to override automatic controls of the bank to provide voltage or VAR support. The current usage of voltage reduction is at the discretion of the system operator with no opportunity (nor need) for third-party involvement.

b) CVO Implementation

In the near future, the Company will implement static Conservation Voltage Optimization as part of BQDM. The goal is to eventually expand the program so that CVO can be deployed both across the service territory and more dynamically. Implementing CVO will require targeted monitoring infrastructure, including additional voltage monitoring devices and engineering solutions such as new tap changing transformers, smaller localized capacitors, and SCADA controls to remotely manage CVO functions.

Advanced Metering Infrastructure (AMI) will be an essential component to implementing CVO on the Company's system because it provides real-time load information at customer locations. This will provide control room operators with the data necessary for system operation at optimal voltage levels. While AMI is a necessary enabler of CVO, AMI alone is insufficient for dynamic CVO/VVO as additional management systems are necessary to make use of the new data streams.

The Company recognized the need for these advanced CVO capabilities as REV Track One was taking shape and included investments to build the CVO/VVO capabilities of the Distribution System Platform in its current electric rate filing.[126] The investment will provide various engineering solutions such as new tap changing transformers, local capacitors, and SCADA controls to remotely manage CVO functions. These investments will be informed by the use of CVO in targeted areas as part of BQDM.

c) Transition to Dynamic CVO / VVO

Upon the initial implementation of CVO, the Company will begin transitioning towards dynamic CVO/VVO. Dynamic VAR control at the local level will be piloted in the BQDM area in 2016 and 2017 and the program will be ultimately expanded system-wide.

In order to achieve improved levels of efficiency toward optimization throughout the load cycle, Con Edison will be required to coordinate the real-time operation of its automated voltage and VAR

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[126] Case 16-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Testimony of Electric Infrastructure and Operations Panel, pp. 33-34.

supporting devices, like area substation capacitors or load tap changers, with third-party DER/DG equipment. Dynamic CVO / VVO will rely on real-time customer voltage and load data and will require infrastructure upgrades including new controls and revenue-grade metering at the area station level, an analytics and management solution to integrate granular data received from AMI, and SCADA communications that provide status data to system operators. The Company R&D group is exploring software solutions for dynamic CVO.

Con Edison is still in a learning mode when it comes to smart inverters, as the Company will need to better understand the interaction of multiple smart inverters on the distribution system. There are currently no project plans for third-party VVO support. However, the Company is open to third-party VVO providers. When such a need presents itself, 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 DER Management System to monitor and potentially manage and signal third-party VVO equipment. Ultimately a market that adequately accounts for locational value of VVO, may determine the manner and degree to which DER may provide VVO functionality.

F. Data Sharing

Increased DER penetration in conjunction with the evolution of markets 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 usage data, the granularity and visibility of which will increase their ability to make informed decisions about products and services, and adjust their consumption patterns to reduce their energy bills. As a result, customers may choose to participate in new programs and rates. Provision of the data to third parties will enable the development of tools and products to facilitate new market-based solutions, and in that way will also support customer behavior changes.

REV Functionality	Current State	Future State	Con Edison Functionality Gap	System Needs
Individual customer access and sharing of data	- Customers can obtain information regarding their energy usage through the monthly bill, the My Account web portal, the Customer Care portal, and the Corporate Customer Group Experience Centers. - The type and granularity of the information available through each channel is determined by the customer's service class and / or metering configuration	**Immediate (2017-2019):** - Ability for customers to share usage data automatically with authorized third parties - Access to interval data for some customers (consistent with meter rollouts) **Long-term (2020+):** - Access for third parties to additional customer data, beyond usage	**Immediate (2017-2019):** - Electronic consent process for GBC - Collection and integration of interval data as metering infrastructure is rolled out - A tool to allow customers to share their usage data with third parties **Long-term (2020+):** - Tools to collect / share additional data based on market needs	**Immediate (2017-2019):** - Green Button Connect (GBC) - Digital Customer Experience (DCX) - AMI **Long-term (2020+):** - Enhanced solutions as data exchange needs are further defined - Potential CIS enhancement - Encryption, secure storage, and other customer privacy and cyber security-related solutions
Providing customer data to third parties	- Data provided to authorized third parties through RAIS, Customer Care, Corporate Customer Group Website, and EDI - Manual / implied consent process as determined by the receiving party - No interval data provided through EDI - The Company uses ISO Reconciliation to reconcile customer usage data on a daily and monthly basis with NYISO	**Immediate (2017-2019):** - Billing cycle interval customer usage data provided through EDI (possibly for a fee) GBC consent process and authorization control - Retain current processes around implied customer consent per PSC guidance **Long-term (2020+):** - Increased frequency of data downloads by third parties	**Immediate (2017-2019):** - Existing EDI cannot be used to transfer additional or different data - A tool to streamline processes around customer consent Process to share additional customer data sets with authorized third parties **Long-term (2020+):** Same	**Immediate (2017-2019):** - Green Button Connect - Digital Customer Experience (DCX) - AMI - TODRS NG Interface - Revised EDI protocols for data transfer or new RESTful APIs to transfer data to ESCOs with implied consent **Long-term (2020+):** Same
System data sharing	- Some system data shared with third parties via the Con Edison website, rate case and compliance filings, capital budgets, and RFIs / RFPs - Third-party access under NDA, through an established application process defined by FERC for Critical Energy Infrastructure Information - Secure file transfer protocols - Static presentation (PDF) of hosting capacity or transformer icons for networks, including historic load curves available for the underground network	**Immediate (2017-2019):** - An interactive hosting capacity for the underground network and non-network system - Minimum / peak 24-hour load curves by network / load area - Interactive map with integrated load curves **Long-term (2020+):** - More frequent updates to hosting capacity - Upcoming projects reflected in hosting capacity determinations - Integration of planning / forecasting (esp. weather) data	**Immediate (2017-2019):** - Visualization solution for an interactive map that can be 'drilled down', including radial system **Long-term (2020+):** - Integration of inputs from the DER Management System, interconnection queue, and the mapping system	**Immediate (2017-2019):** - Registration portal for interactive maps (depending on granularity and sensitivity of data) - Mapping solution - Access and subscription management solution (as needed) **Long-term (2020+):** - GIS to replace many discrete mapping tools (may continue to rely on existing system models) - Real-time tracking of DER - Integration with PVL modeling software, CPMS, DER Management System, and the interconnection portal

Table 70 - Data Sharing Technology Needs

1. Sharing Customer Data

a) Current State

Con Edison customers can obtain information regarding their energy usage through a variety of online resources. These resources include the My Account web portal, the Customer Care portal, and the Corporate Customer Group Website. Individual customers can access their monthly bill (including historic usage data) through My Account, and share usage data through the Green Button Download My Data tool. For qualifying corporate customers, the Corporate Customer Group Website provides a means to view consolidated usage and charges across multiple accounts in a summary bill format, as well as individual account information. The Customer Care portal is designed to provide interval metered customers their usage, demand, kVAR, power factor, and load factor information. It also allows interval metered customers to perform various modeling exercises with their interval data and generate custom usage reports that can be run on a set schedule and sent to the customer's email address.

It is Con Edison's policy that vendors and third parties are only given customer-specific information at the customer's request, and with consent of the customer via a signed letter of authorization. Con Edison provides individual customer usage data to authorized third parties, such as ESCOs, through the Retail Access Information System (RAIS). ESCOs also obtain customer account and usage information through Electronic Data interchange (EDI). RAIS allows third parties to query individual customer information while EDI is capable of processing large-batch requests and provides additional transactional functionality required to administer the retail choice market. In New York State interval data is currently only available to third parties through RAIS (ESCOs) and Customer Care, provided that the third party has a letter of authorization from the customer to access their data.

b) DCX and Green Button Connect Implementation

The Company's current information channels and associated systems were each built and refined over time for a specific need or market function. As such, these channels and systems contain inherent limitations and overlap in places, making their expansion to a significantly larger group of customers and/or large volumes of interval data a sub-optimal solution. The Company's Digital Customer Experience (DCX) project will enhance the customer's ability to obtain, share, and utilize energy usage information by providing customers with critical information, tools, and analytics. The DCX program will be rolled out in phases starting in 2016 through 2020, coinciding with the Company's AMI rollout with a total estimated project cost of $47M in capital and $11M in O&M expenses. Additional information on the DCX program, including detailed budget and timeline descriptions, can be found in the Customer Operations Panel testimony filed on January 29, 2016, by the Company in its current electric rate Case 16-E-0060.

Part of the DCX functionality will include Green Button Connect (GBC) My Data, a data-sharing solution that uses 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 (RESTful 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, on 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 personally identifiable information (PII).

As data exchange needs are further defined, sharing protocols for GBC may include data beyond usage. To accommodate such data, Green Button Connect functionality may need to be expanded. This will require a staged approach to developing any additional solutions that may be required, as well as close coordination amongst all New York utilities to develop common specifications.

c) Other System Needs

In the short term, the Company will need to revise existing EDI protocols, or create new ones, to accommodate transfer of additional data (including interval data) to third parties. Per the AMI Order, Con Edison is developing an EDI monthly usage transaction to provide billing period interval data to a customer's ESCOs. This is a time- and labor-intensive process that will require development and testing with the ESCO community before being put into production. This process will have to be made in close coordination with the JU in order for EDI to remain a uniform standard. The Company will also be providing ESCOs with the ability to request a customer's interval usage data history through RESTful APIs. The Company's Engagement Plan for AMI, due on July 29, 2016, will further identify data needs and alternatives, to the extent that they are known.

Sharing sensitive customer and system information will require additional cyber security and privacy infrastructure, including encryption, secure storage, and other solutions. As part of its Customer Engagement Plan for AMI, Con Edison is conducting an assessment to identify privacy principles for handling AMI data. The Company will continue to assess its cyber security and data privacy needs as REV-related technology infrastructure and markets take shape.

2. Sharing System Data

The Company publicly discloses some of its system data via the Con Edison website, rate case and compliance filings, capital budgets, and RFIs/RFPs. In addition, third-party access to non-public system data is granted under appropriate non-disclosure agreements through an established application process defined by FERC for Critical Energy Infrastructure Information. Secure file transfer protocols are used to transmit system data to third parties.

As noted in the DSIP Order, it is expected other ongoing proceedings will discuss UBP,[127] fees for additional value added data and insightful information,[128] and additional locational benefit

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[127] Case 15-M-0180, *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products*, Notice of Technical Conference (issued April 21, 2015).

information,[129] along with a robust stakeholder engagement and associated technical conferences to inform expansion of system data and insightful information. The JU Supplemental DSIP filing will introduce and expand on the establishment of standards and protocols for sharing information with customers and DER providers, while at the same time taking into account physical security, cyber security, and customer privacy issues.

As described in the System Data section of this DSIP, going forward, the Company may share the following distribution level data for each load area: 24-hour peak load duration forecasts and 24-hour minimum load historical curves, and underlying historical 8760 load data. The Company will also share network-level maps of Phase 1 hosting capacity determinations, highlighting network locations where sufficient minimum load exists to enable DER interconnection with little to no additional cost. Capabilities and functions of hosting capacity may be further enhanced through ongoing stakeholder engagement and as uniform methodologies are developed through the JU Supplemental DSIP. As the Company continues developing infrastructure for expanded sharing of customer and system data, it may need to supplant initial DSP funding with fee revenues. Depending on the complexity of fee structures and payment models, the Company may need to implement access and subscription management solutions.

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[128] 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.151.
[129] 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).

VIII. Appendices

A. Appendix A – Acronyms

Acronym	Description
A/C	Air Conditioning
ABF	Alive on Backfeed
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
ARIMA	Autoregressive Integrated Moving Average
BCA	Benefit Cost Analysis
BCAH	Benefit Cost Analysis Handbook
BCEMD	Branch Circuit Energy Management Device
BES	Bulk Energy System
BIR	Business Incentive Rate
BQDM	Brooklyn Queens Demand Management
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CAP	Contingency Analysis Program
CCG	Corporate Customer Group
CDG	Community Distributed Generation
CECONY	Consolidated Edison Company of New York
CEF	Clean Energy Fund
CESIR	Coordinated Electric System Interconnection Review
CHP	Combined Heat and Power
CINDE	Computerized Inspection of Network Distribution Engineering
CIS	Customer Information System
CPMS	Customer Project Management System
CRM	Customer Relationship Management
CSR	Customer Service Representative
CSRP	Commercial System Relief Program
CSS	Customer-side Solutions
CUNY	City University of New York
CVO	Continuous or Conservation Voltage Optimization
CVR	Conservation Voltage Reduction
DBC	Direct Buried Cable
DC/AC	Direct Current/Alternating Current
DCX	Digital Customer Experience
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DERS	Distributed Energy Resource System

DG	Distributed Generation
DLC	Direct Load Control
DLRP	Distribution Load Relief Program
DM	Demand Management
DMAP	Demand Management Analytics Platform
DMP	Demand Management Program
DMS	Distribution Management System
DMTS	Demand Management Tracking System
DOB	Department of Buildings
DP	Distribution Planning
DPS	Department of Public Service
DR	Demand Response
DRI	Distributed Resource Integration
DRMS	Demand Response Management System
DSIP	Distributed System Implementation Plan
DSM	Demand Side Management
DSP	Distribution System Platform
EAM	Earnings Adjustment Mechanism
EDI	Electronic Data Interchange
EDRP	Emergency Demand Response
EE	Energy Efficiency
EEPS	Energy Efficiency Portfolio Standard
EMS	Energy Management System
EPRI	Electric Power Research Institute
ESCO	Energy Service Company
ETIP	Energy Efficiency Transition Implementation Plan
EV	Electric Vehicle
FDNY	Fire Department of New York
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
GBC	Green Button Connect
GBD	Green Button Download
GIS	Geographic Information System
GO	Generation Owner
GOP	Generation Operator
GWh	GigaWatt Hour
ICAP	Installed Capacity
IDSM	Integrated Demand Side Management
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator, or International Standardization Organization

IT	Information Technology
JU	Joint Utilities
KIAC	Kennedy International Airport Cogeneration
kV	kilo-Volt
kVAR	kilo-VAR
LEC	Live End Cap
LMI	Low to Middle Income
LMP	Locational Marginal Price
LMP+D	Locational Marginal Price plus the Value of Distribution
LSE	Load Serving Entity
LSR	Large Scale Renewable
LTC	Load Tap Changer
LTE	Long Term Emergency
M&V	Measurement and Verification
MDM	Mobile Device Managers, or Meter Data Management
MEG	Mobile Emergency Generators
MHP	Mandatory Hourly Pricing
MVA	Apparent Power
MVAR	Reactive Power
MW	Megawatts
NDA	Non-Disclosure Agreement
NERC	North American Electric Reliability Corporation
NOC	Network Operations Center
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NRI	Network Reliability Indicator
NWA	Non Wires Alternatives
NY-BEST	New York Battery and Energy Storage Technology
NYC	New York City
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPD	New York Police Department
NYSEIA	New York Solar Energy Industries Association
NYSERDA	New York State Energy Research and Development Authority
NYSRC	New York State Reliability Council
O&M	Operations and Maintenance
O&R	Orange and Rockland Utility
OA	Open Automatic
OBD	Onboard Diagnostic
OMS	Outage Management System
OOE	Off on Emergency
OT	Operational Technology

P.U.	Per Unit
PAD	Portable ABF Device
PADX	Permanent ABF Device
PII	Personally Identifiable Information
PQ	Power Quality
PSC	Public Service Commission
PSR	Platform Service Revenues
PTO	Pressure Temperature and Oil
PV	Photovoltaic
PVL	Poly-Voltage Load Flow Modeling
R&D	Research and Development
RAIS	Retail Access Information System
RESTful API	Representative State Transfer Application Program Interface
REV	Reforming the Energy Vision
RFC	Request for Comments
RFI	Request for Information
RFP	Request for Proposal
RIM	Rate Impact Measure
RMS	Remote Monitoring System
RMSPTO	Remote Monitoring System and Pressure Temperature and Oil
RNY	Recharge New York
RPM	Reliability Performance Mechanism
RPS	Renewable Portfolio Standards
RTF	Reactance to Fault
S&TO	System and Transmission Operations
SAIFI	System Average Interruption Frequency Index
SBC	System Benefits Charge
SBDI	Small Business Direct Install
SC	Service Classifications
SCADA	Supervisory Control and Data Acquisition
SCR	Special Case Resources
SCT	Societal Cost Test
SDLC	Software Development Life Cycle
SEPA	Solar Electric Power Association
SIP	Secondary Inspection Program
SIR	Standardized Interconnection Requirements
SNRI	Secondary Network Reliability Index
SSO	Substation Operations
STE	Short Term Emergency
T&D	Transmission and Distribution
TDM	Targeted Demand Management
TDRP	Targeted Demand Response Program

TDSM	Targeted Demand Side Management
TO	Transmission Owner
TOD	Time of Day
TODRS	Transmission Owner Data Reconciliation System
TV	Temperature Variable
TVP	Time Varying Pricing
TWG	Technical Working Group
UBP	Uniform Business Practices
UFLS	Under Frequency Load Shedding
USS	Utility Sided Solutions
VARS	Volt Ampere Reactive
VCAP	Visual Contingency Analysis Program
VPP	Virtual Power Plant
VTOU	Variable Time of Use
VVC	Volt/VAR Control
VVO	Volt/VAR Optimization
WAP	Weather Adjusted Peak
WMS	Work Management System
WTC	World Trade Center

B. Appendix B – Demonstration Projects

REV demonstration projects are intended to demonstrate new business models, *i.e.,* new revenue stream opportunities for third parties and the electric utilities. In that regard, the projects will inform decision makers related to developing Distributed System Platform (DSP) functionalities, measure customer response to programs and prices associated with REV markets, and determine the most effective implementation of Distributed Energy Resources (DER). Further, as demonstration projects, they are intended to test new technology and approaches to assess value, explore options, and stimulate innovation before committing to full-scale implementation.[130] In order to inform DSP development and measure and predict customer response to innovative new programs, Con Edison has proposed three demonstration projects: Connected Homes, Building Efficiency Marketplace, and Virtual Power Plant. A brief overview of the projects is found below, with more detail regarding the hypotheses, goals, budgets, and schedules of the projects in the linked implementation plans.

Connected Homes - The Connected Homes Platform, in partnership with Opower, Inc., Enervee Corp., and Bridgevine, Inc., will engage customers through multiple channels to participate in DSM activities.

Building Efficiency Marketplace - The Building Efficiency Marketplace in partnership with Retroficiency, Inc. will examine how interval meter data analytics can be leveraged to facilitate commercial customers' ability to make energy efficiency and demand reduction modifications.

Clean Virtual Power Plant - The Clean Virtual Power Plant, in partnership with SunPower Corp., and Sunverge Energy, LLC (battery storage), will examine how residential customers can participate as a DER providing system capacity.

Filing Links

Implementation Plans

The details for the test statements, project design, structure, governance, schedule, and budgets of each project are contained within the implementation plans for each project:

Connected Homes	(filed January 29, 2016)
Building Efficiency Marketplace	(filed November 20, 2015)
Clean Virtual Power Plant	(filed December 11, 2015)

[130] Source: DPS Staff Demonstration Project landing site, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

Quarterly Reports[131]

Progress and learnings to date are filed for each project on a quarterly basis. The most recent filing at the time of this DSIP filing is May 2016 for the first quarter of 2016:

Connected Homes	(filed May 2, 2016)
Building Efficiency Marketplace	(filed May 2, 2016)
Clean Virtual Power Plant	(filed May 2, 2016)

Future Demonstration Projects

In 2016, the Company is pursuing development of three additional demonstration projects in three key areas: utility-scale storage, affordability and accessibility for LMI (low-to-moderate income) customers, and electrification of transportation. Each RFI will solicit ideas for both Con Edison/O&R.

To facilitate this process, the Company will release Requests for Information (RFIs) in each of these three areas sequentially over the first three quarters. The goal of each RFI is to identify and refine a third- party partnership opportunity for submission as a REV Demonstration Project. The sequential release will allow lessons learned to be incorporated on a going-forward basis such that the quality of the RFIs and the evaluation and selection process improve each cycle. The Company believes that an RFI process will improve transparency and communications with stakeholders, broaden the potential solution set, maintain focus on established priorities, increase efficiency of the demonstration project process and, most importantly, lead to actionable projects that align with customer and shareholder interests:

- **Improve transparency and communications**: Open access to RFI. Key stakeholders – vendors, Commission, customers – aware of Con Edison commitment and process via highly visible process with clearly communicated strategic priorities
- **Broaden the solution set**: Public RFI release expands potential service providers and technologies beyond Con Edison, NYSERDA, and PSC personal networks
- **Use time efficiently:** RFI filters for relevance, capabilities, and constructive interactions with Con Edison and DPS Staff
- **Sets priorities/maintains focus:** RFI(s) released only on areas of highest importance for Con Edison

A successful RFI process requires an RFI structure that clearly defines the problem to be solved, sufficiently bounds the solutions sets, and solicits responses of sufficient rigor and development to

[131] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Con Edison - REV Demo Projects - 1st Quarter Report (filed May 2, 2016).

evaluate the opportunity for all key stakeholders: participating customers, non-participating customers, shareholders, and partner companies.

C. Appendix C – Stakeholder Engagement

The Company believes that a meaningful stakeholder engagement process will be a critical component to developing the distributed system platform (DSP). The Company is leveraging its unique experience and expertise, collaborating with the JU, and conducting stakeholder engagement sessions to engage interested third parties. The collaboration with the JU is a fundamental component to establishing shared operating tools 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 the JU and stakeholders to develop these algorithms, processes, and tools will be instrumental to defining the Distributed System Platform (DSP). The JU held their first stakeholder engagement session regarding an electric system overview on February 29, 2016. The main topics addressed were:

1. System planning is complex, difficult, and unique to each system, so adding resources in an optimal, customer-value-enhancing way requires analysis in context.
2. Utility budgets are driven by the need to provide safe and reliable service; there are some areas where DER integration may defer utility investments, but not everywhere.
3. The Joint Utilities are actively working toward achieving REV goals, are open to stakeholder ideas and interests, and want to be partners in DER integration and DSP development.

The session also 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 planning, underground distribution system planning, utility capital expenditures, and the JU stakeholder engagement process. The event was an overall success, and 89 percent of the stakeholders agreed that the goals of the session were met.

The Company has also taken a proactive approach to hold a Stakeholder Summit jointly with O&R that covered the 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 with 21 of 24 survey respondents indicating that the session fulfilled its goal of providing information about the content of Con Edison & O&R's initial DSIP filings. This event was also a success, where 90 percent of the participants who answered the survey agreed that the goals were met. The Table below shows the highest ranked presentations.

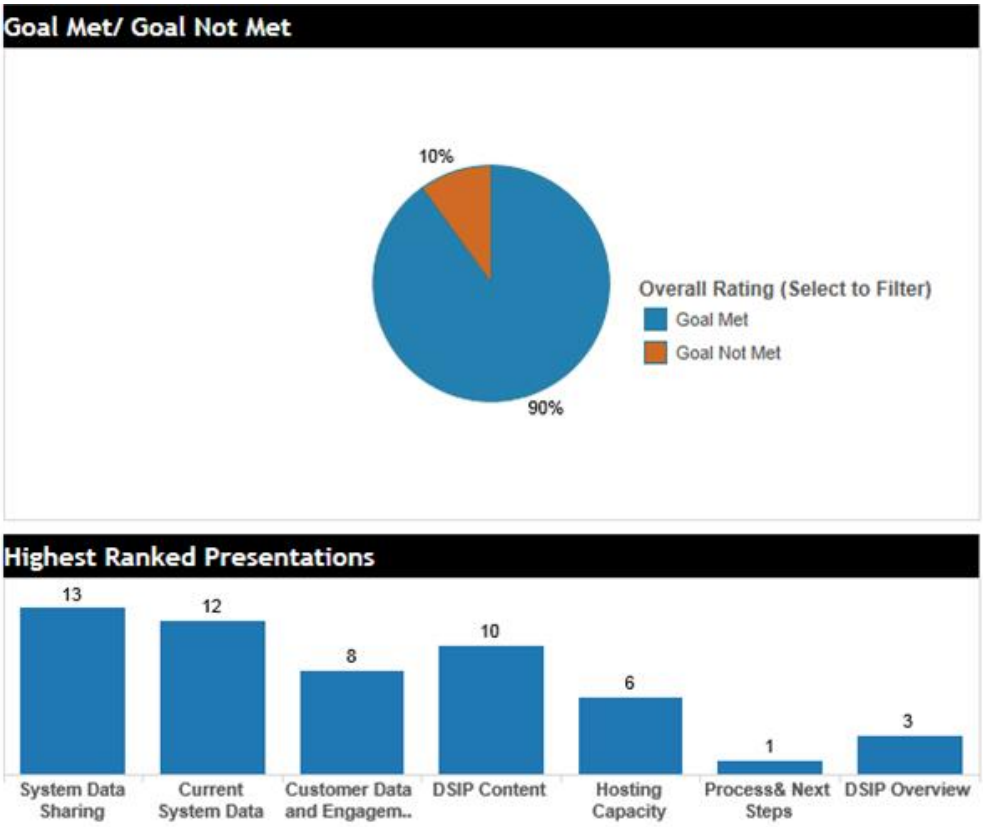


Figure 52 - Survey Responses as to Whether the 5/13/16 Con Edison and O&R Stakeholder Summit Goal Was Met and Breakdown of Favorite Topics

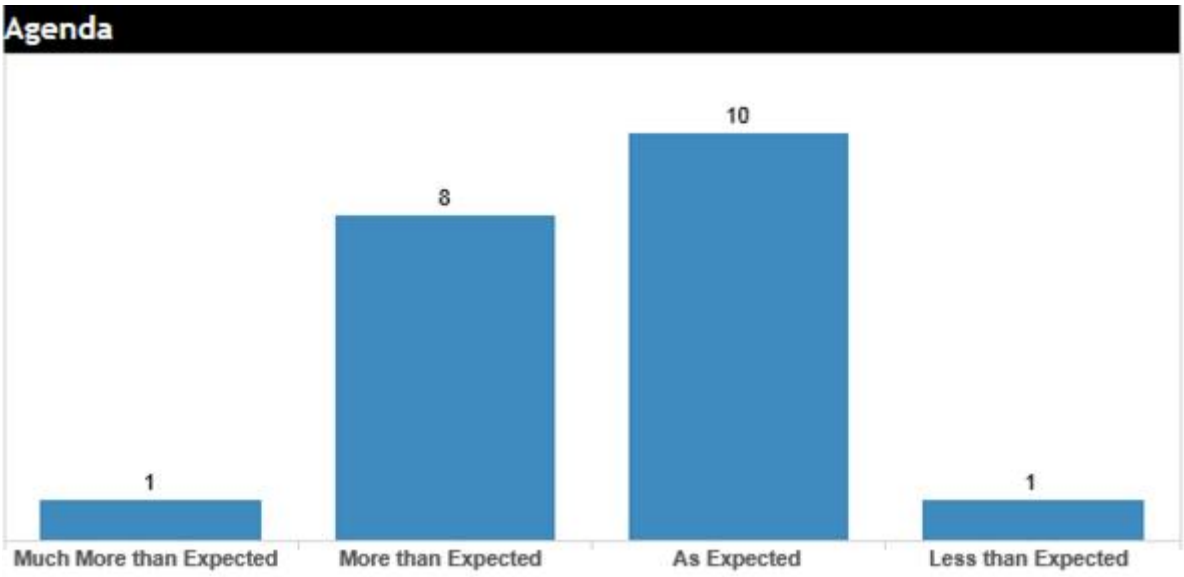


Figure 53 - Survey Responses as to Whether the 5/13/16 Con Edison and O&R Stakeholder Summit Agenda Met Expectations

D. Appendix D – Voltage Standards

NOMINAL (Volts)	NORMAL CONDITIONS WITH ALL SUPPLY FACILITIES AVAILABLE (Volts)	FIRST CONTINGENCY (Volts)	SECONDARY CONTINGENCY (Volts)
120	114 - 126	110 - 126	105 - 126
208	198 - 218	191 - 218	182 - 218
240	228 - 252	220 - 252	210 - 252
265	252 - 278	243 - 278	232 - 278
460	437 - 483	422 - 483	402 - 483

Table 71 - Voltage Standard Table – Normal Conditions and Contingencies

E. Appendix E – Detailed Project and Program Objectives

1. System Expansion Project and Program Objectives

Woodrow Load Area Autoloop: create additional autoloops

This project involves the creation of an additional 13 kV autoloop within the Woodrow Substation load area. As identified by engineering load analysis, the Company requires the additional autoloop to deload existing 13 kV autoloops which are approaching 100 percent of their normal rating. There exist two mini-loops supplied from 33kV to 13 kV stepdown transformers which experienced heavy loads during the summer of 2015. The emergency load of these loops approached 170 percent of normal rating and over 200 percent of emergency. These loops supply a region of Staten Island which continues to grow. New commercial development is expected to further strain the load availability per the NYC Economic Development Corporation (EDC). To accomplish this, approximately 20 MW from three existing autoloops 5R10:5R18, 5R14:5R24, and 5R27:5R28, and two mini-loops, will be transferred to two new auto-loops. These two new 13 kV autoloops will be established in 2017. This added capacity will address New Business projects in the area that have upcoming service dates.

Part of Pennsylvania (74 MW): create Midtown West network (COMPLETED MAY 2016):

Transfer 75 MW from the West 42nd Street No. 1 Substation to the West 42nd Street No. 2 Substation prior to the summer of 2016 to avoid overloading West 42nd Street No. 1. This will be accomplished by establishing a new network, to be named the Midtown West network. The Midtown West network will be created by carving out the northeast portion of the Pennsylvania network. The boundaries of the new network will be West 43rd Street to the north, West 38th Street to the south, Sixth Avenue to the east, and Dyer Avenue to the west. The secondary mains and transformers will be reinforced to provide adequate support in the vicinity of the new network fringe areas. The completion of this work will result in the West 42nd Street No. 1 Substation having a loading of 194 MW versus a capability of 262 MW (74 percent) for the summer of 2016.
Based on an analysis of the area substations and sub-transmission feeders in the W.49th Street load pocket, it is projected that the W.42nd Street No. 1 Substation will exceed its capability by the summer of 2016. As reported in the 2014-2023 Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program, the Pennsylvania network will reach 269 MW by the summer of 2016, which exceeds the 262 MW capability of the W.42nd Street No. 1 Substation by 7 MW (103 percent).

This project will result in West 42nd Street No. 1 Substation operating within its capability and maintaining capacity for future load growth. This proposed transfer utilizes the vacated station cubicles at West 42nd Street No. 2 which resulted from the transferring of the Herald Square network to the new Astor Substation in 2009.

This project was completed in May 2016.

Pennsylvania Network: create new feeders for Hudson Yards

Based on an analysis of the projected new business loads in the Pennsylvania Network, which is supplied by W.42nd Street No. 1 Substation, it is projected that six feeders will exceed their emergency breaker

limitations of 1,200 amps between 2017 and 2019. The six feeders will initially supply the Hudson Rail Yards, East Platform loads. The load for the Hudson Yards towers will begin to come online by mid-2015 and will continue through the early 2020's. To avoid overloading these feeders, six new feeders from W.42nd Street No. 1 Substation will need to be established. These new feeders will be extended from the Substation to the Hudson Yards footprint and this load pocket will be transferred to the new feeders.

As part of this project, four substation cubicles at W.42nd Street No. 1Sbustation will need to be built out: 24-N, 24-S, 44-N, and 44-S. In addition, two spare cubicles will be utilized that already have breakers and primary cable installed: 11-S and 31-N.

This project is forecasted to be completed in 2019.

Part of Richmond Hill/Brownsville (12MW): BQDM Traditional Solution (COMPLETED):

The forecasts for the Brownsville networks (Ridgewood, Crown Heights, and Richmond Hill) have loads that will cause the sub-transmission feeders supplying the Brownsville load pocket (feeders 38B01, 38B02, 38B03, 38B04, and 38B05) to experience overloads. One of the traditional solutions that support the BQDM NWA was to transfer 12MW out of the Brownsville load pocket before the summer of 2016.

The 12 MW involved transferring three customers from Brownsville No.1 Substation (Ridgewood and Crown Heights networks) to Glendale (Maspeth network) and Water St. Substations (Williamsburg network). The Woodhull Hospital (6 MW) was transferred in the spring of 2016 and completes all of the 12MWs that were required and the Wyckoff Hospital (4 MW) and NYCTA (2 MW) that was transferred from the Ridgewood network to the Maspeth network in the spring of 2015.

This project was completed prior to summer 2016.

Sheridan to Canal:

This Project transfers 12 MW of load from the Leonard Street No. 1 Substation to the Leonard Street No. 2 Substation prior to the summer of 2017, which is needed to avoid overloading Sheridan Square Network feeders. This will be accomplished by extending six feeders from the Canal Network north into the Sheridan Square Network. Over the past several years, over 33 MW of new business load has been added to the Sheridan Square network. This has resulted in several feeders operating very close to their capability limitations. Based on the latest new business forecast, it is projected that several distribution feeders within the network will be overloaded by 2016. Regional Engineering proposes the transfer of a 12 MW spot load from Sheridan Square into the adjacent Canal network which has spare capacity. The spot load is served by ten (10) 2500 kVA transformers. The transfer will be accomplished by extending six feeders from the Canal Network into the current footprint of the Sheridan Square Network. These six feeders will be extended along three streets: West Street, Washington Street, and Greenwich Street.

This project is forecasted to be complete in 2017.

Part of Cooper Square (30 MW):

Based on an analysis of the area substations and sub-transmission feeders, as reported in the 2014-2024 Area Substation and Sub transmission Feeder Ten-Year Load Relief Program (which includes EE, DG, and DR), it is projected that the 69 kV feeder supply to Avenue A Substation will exceed the operating capability of 257 MW (102 percent) by the summer of 2016. This project will result in Avenue A operating within its capability and maintaining capacity for future load growth through 2024.This project involves the transfer of 20 MW of load from the Cooper Square network (fed by Avenue A Substation) to the City Hall network (fed by Cherry Street Substation) by April 1, 2017 and ultimately 22 MW realized by new business load by the summer of 2019. This project was previously scheduled to be completed by June 2015 as a 15 MW transfer, however, the project was deferred due to significant anticipated changes to the load forecast and revisions to the operating capability of transmission feeders sources. To accomplish this transfer, a larger portion of the Cooper Square network needs to be cut, transferred, and placed into the City Hall network. A total of 40 MW needs to be transferred in order to avoid Cooper Square network exceeding its capability of 257 MW.

This project is forecasted to be complete in 2017.

Cable Crossing (XW Riverdale & BQ Flushing):

This program will reinforce cable crossings in the Flushing and Riverdale networks and in two radial areas consisting of City Island in the Bronx and the Village of Croton-on-Hudson in Westchester County. Issues occurring in these cable crossing include primary feeder cables approaching there capacity limits, a lack of opportunity to replace the cables with higher capacity cable, a lack of any spare conduits to install additional cable sections or a cable failure that would comprise the overall reliability and capacity of the crossing.

The forecasted schedule for cable crossing is shown in the table below.

Completion Year	Scheduled Project
2016	Paerdegat basin
2017	Harlem River
2018	Roosevelt Ave. and Grand Central Parkway
2019	Croton River
2020	Northern Blvd and Flushing River
2021	City Island

It is anticipated that this program will extend beyond the 10-year horizon with additional cable crossing projects.

59th Street Bridge Crossing:

The purpose of this project is to replace six feeders that are routed over the 59th Street Bridge (Ed Koch Queensboro Bridge) that supply Roosevelt Island. The existing feeders consist of mostly PILC aerial cable that is hung on messengers on the outer roadways of the bridge. This project reviewed viable alternatives to install a more reliable and safe cable system over the span of the bridge. The

selected design, from all the viable options, is to replace the existing cable system with a new cable system in conduit using the existing bridge location. This design will provide safety to the public and enhanced reliability for the electrical system supplying Roosevelt Island.

There will be a total of two new conduit systems, each consisting of 6-5" steel conduits, which will include risers, and new manholes. These two new conduit systems will house the 6-13kV active feeder cables, four energized spare feeder cables, and two spare conduits. This proposed conduit system will provide enough infrastructure for eight active feeders in the future. These eight feeders will be further isolated into four independent feeder bands with one spare conduit for each band for a total of 12 conduits. This configuration will provide sufficient infrastructure capacity on the bridge to meet the future growth in the island and the Roosevelt Network.
This project is forecasted to be completed in 2016.

Yorkville Crossings and Feeder Relief:

To sustain the expected load growth in the Yorkville Network, while maintaining the required design criteria (EO-2073: Network Feeder Contingency Design), a comprehensive load-relief plan must be developed and implemented. The traditional solution is to utilize the full breaker capability of the station by bifurcating the feeder from the station to the load via a new duct system in order to decrease duct occupancy and increase the ratings of the feeders.

As part of this plan, two new crossings must be created from the Bronx to Manhattan. The anticipated capital expenditure for the proposed work is $35 million over six years.

Part of Ridgewood/Brownsville to Glendale (60MW) BQDM Traditional Solution:

Based on the current forecast, the Brownsville networks have projected loads that will cause the transmission feeders supplying the Brownsville load pocket (feeders: 38B01, 38B02, 38B03, 38B04, and 38B05) to experience overloads beginning in 2015. Due to scope and outage requirements, this permanent load relief solution cannot be implemented until 2019. An interim plan (BQDM) involving a total of approximately 52 MW consisting of non-traditional utility-side (11MWs) and customer-side solutions (42MWs) will provide temporary load relief until this project can be implemented.

Glendale Substation, which supplies Maspeth, has the excess MW capacity to support the temporary load relief. This option is most cost-beneficial because of Glendale Substation's proximity to the cut-line of the load transfer. The extent of conduit and cable installation would be minimized compared to load transfer to alternative substations such as Newtown or North Queens.

As part of the load relief for Brownsville sub-transmission feeders, BQDM is already utilizing a total 52 MW of CSS and utility-sited solutions (USS). Deferral of this project for another year through CSS and USS would become cost-prohibitive.

To de-load the Brownsville sub-transmission feeders, the Company plans a transfer of approximately 60MW from Brownsville No. 1 Substation to Glendale Substation. The northern portion

of the Ridgewood (5B) network was selected as the most viable option to transfer the 60MW because of its geographical location. The design involves extending 12 network feeders from Maspeth to the Ridgewood network. Fifteen feeders in the Ridgewood network will be split to accommodate the transfer.

To establish the new network the Company plans to install: 93,000 feet of conduit, 680 sections of primary cable, 273 structures, 12 network transformers, and 123 sections of secondary cable.

This project is forecasted to be completed in 2019.

Primary Feeder Relief:

This program funds reinforcement (load relief) work on primary distribution feeders that have been projected to operate above their thermal ratings during the summer peak load period. The limits are any primary feeder with a loading greater than 100 percent during normal or 100 percent during second contingency. This applies to both normal/continuous (all equipment in service) and contingency/emergency (up to two network/load-area feeders out-of-service) conditions. Reinforcement projects may include cable replacement, transferring load between feeders, balancing load on a given feeder, bifurcating an existing feeder, and establishing new feeders.

Each year the distribution system is evaluated for load relief to determine specific system reinforcement needs based on the Area Substation and Sub-Transmission Feeder Ten-Year Load Relief program. These studies incorporate recent summer peak load data with location-specific information about customer growth and projected demand forecasts. The studies also factor in any new construction expected to be in-service that year. The primary feeder relief plan is then developed after every network's primary feeder capacity has been reviewed, based upon both the previous summer's loading and the upcoming summer forecasted load. This review occurs annually.

The primary feeder relief program is focused on proactively reinforcing distribution feeders that are projected to be overloaded during the upcoming summer peak periods.

See table below for the current forecast for primary feeder relief.

	2016 Forecasted Units	2017 Forecasted Units	2018 Forecasted Units	2019 Forecasted Units	2020 Forecasted Units
Underground Structures	25	23	22	37	36
Sections of Cable	182	335	342	527	535
Feet of Conduit	2,771	4,046	4,540	5,304	4,815

Table 72 - Forecast for Primary Feeder Relief

This is an annual program.

Network Transformer Relief:

This program funds the installation costs associated with providing relief to network transformers whose projected load exceeds their rating. The Con Edison electric distribution system utilizes approximately 42,000 network transformers to step down the primary distribution voltages (33kV, 27kV, 13kV, and 4kV) to customer-level voltages. Transformers and associated equipment are designed to operate within loading limits as described by Con Edison engineering specification EO-2002: Loading Limits for Network.

Transformers and Associated Protectors:

This program funds the implementation of load relief projects that address transformer overloads. Relief projects include replacement of existing low rated transformers with new transformers of the same design, but a slightly higher rating; replacing an existing transformer with a larger transformer with a significant higher rating; or installing a new vault and transformer to reduce the loading on the nearby transformer.

Each year the distribution system is evaluated to determine if any transformer load relief is required. These studies incorporate recent summer peak load data with location-specific information about customer growth and projected demand forecast. Any new construction with a projected service date for that year is then added. The Poly Voltage Load Flow application is then used to study each network. The transformer load relief plan is then developed after network transformer capacity has been reviewed.

Transformer load relief projects are prioritized based on Con Edison engineering specification EOP-5314 Electric Operations – Engineering and Design: ED-1 Budget Prioritization. Higher priority is given to transformer loaded above 100 percent of normal rating and/or above 115 percent of emergency rating.

See table below for the current forecast for transformer relief.

	Year				
Region	**2016**	**2017**	**2018**	**2019**	**2020**
Manhattan New	1	2	2	2	2
Manhattan Replace	0	0	0	0	0
BQ New	17	25	25	25	25
BQ Replace	0	0	0	0	0
BW New	5	5	8	6	11
BW Replace	3	4	6	4	8

Table 73 - Forecast for Transformer Relief

This is an annual program.

Non-Network Feeder Relief (Open Wire):

As system load grows, individual feeders may exceed their design limits. Feeder peak loads and calculated feeder ratings are used to determine if a feeder needs reinforcement. The process for rating a feeder is specified in EO-2048 Determination of Distribution Feeder Ratings 60 Cycle Systems. If the projected feeder load for the in-service year is greater than the feeder rating for that year, then reinforcement of the feeder is required. According to EO-2072 Method of Planning Reinforcement of Network and Radial Feeders Operating at 13, 27 & 33 kV, when an overload is determined, plans for eliminating the overload must provide a reasonable margin to cover three years (the next in-service year, and two years into the future). Reinforcement plans generally call for eliminating small-size cables, establishing new feeders, or transferring load by rearranging feeders. With an increase in wire and equipment size, existing poles and fixtures may not have the capability to support additional weight and may require replacement as well. Many of the feeders are reaching a point where all other relief options have been exhausted and the only way to de-load is to create a new feeder.
This is an annual program.

Overhead Transformer Relief:

Overhead transformers are operated according to specification EO-2000. The current process is to identify potentially overloaded transformers before the peak summer period, and design jobs to relieve those transformers. The goal of this program is to reduce the potential number of overhead transformer CSP trips that result in customer outages and to protect the transformers from damage caused by overheating. An additional benefit to this load relief is having available capacity with new transformers to support neighboring circuits in the event of a loss of a transformer and the need to supply customers on a temporary basis. In addition to loading studies done on overhead transformers, an annual review of all customer outages with a CSP trip or customer complaints of an overhead transformer oil leak is completed. If the root cause is determined to be an overloaded/overheated transformer, the transformer is added to the list of overhead transformers requiring relief/replacement.

This is an annual program.

Secondary Main Relief:

This program funds work per Company guidelines on secondary mains where loading is projected to exceed loading capability based on the forecasted system electric load growth and customer expectations including emergency response. Secondary mains replacements are prioritized based primarily on loading, voltage issues, past performance, age, conductor size, and type. Additional analysis factored in to the prioritization of reinforcement projects includes impact to system performance including SAIDI, CAIDI, and Network Reliability Index (NRI). The Con Edison electric distribution system is designed to operate safely and reliably under the N-1 (non-network) and/or N-2contingency (network) standards in each of the respective regions without system component failure. These Company design standards require annual studies of electric network distribution system models that would enable identification of locations to be considered an overload or undervoltage. As per the operation guideline EOP-5314: ED-1 BUDGET PRIORITIZATION for the secondary low-voltage distribution network grid of cables, load relief work on underground AC low-voltage mains and services should be

initiated for reported overloads that are greater than or equal 125 percent of that set of mains' or services' first or second contingency thermal ampacity rating as per EO-6039: Standard Ampacity Ratings for 600 Volt Ac Underground Service Cables In Ducts, and Service Take-Offs from Multi-Bank Transformer Installations and EO-6040: Standard Ampacity Ratings for 600 Volt AC Mains Cables Installed Underground in Ducts, as stated in Bulletin B-207. This percentage is based on results from the Low-Voltage Cable Thermal Capability project and helps operations and planning prioritize work. An additional benefit from this program, along with other secondary reliability programs, is to reduce the risk of stray voltage caused by defective cable, manhole events, and customer outages as well. Relief projects include replacing the overloaded secondary cable sections with a new secondary cable of higher rating, installing additional secondary cable sections in order to decrease the load on the sections to a level where it is no longer overloaded, and to install transformers in order to take load off of the secondary grid and mains. Existing vacant secondary ducts would be utilized for the installation of additional secondary cable sections if available. In certain cases, additional structures may be installed or existing ones enlarged to accommodate the additional secondary cable. Secondary ducts will also be installed when insufficient vacant exist.

This is an annual program.

2. Risk Reduction Program Objectives

179th St Area Substation Reconstruction:

The East 179th Street Substation is the source of supply that feeds the Fordham Network in the Bronx. The construction of the Area Substation program is meant to modernize critical equipment and is a proactive effort to upgrade aging equipment with the intent of improving substation and network reliability. The Fordham Network is a Bronx Region network serving approximately 107,000 customers. Over the next eight years, the network's 24 distribution feeders will require modification following the Area Substation equipment changes from the old standard single-synchronous bus design to the more reliable double-synchronous bus design. When each minor bus section is established, the new starting point, or the feeder breaker cubicle, for all of the distribution feeders must be transferred and rebuilt.

Osmose (C Truss):

Pole inspections are performed to monitor and maintain the reliability of installed poles and safety of the public as referenced in the U.S. Department of Agriculture Bulletin 1730B-121, Pole Inspection & Maintenance, Utilities in Decay Severity Zone 2 (New York Area). As inspections are completed and it is determined that pole strength does not meet requirements, they either must be replaced or restored to full strength and functionality by way of C-trussing. Installing C-trusses defers the need to replace poles and is more cost-effective as compared to pole replacement. This program funds the installation of C-trusses or braces to secure utility poles where decreased strength requires the installation of additional support. The C-truss provides temporary external bracing for poles that do not pose an immediate threat to the safety of the public or the distribution system. The three-year average from 2012 – 2014 for poles requiring additional support is 371 per year.

Aerial Cable Replacement:

The Aerial Cable Replacement program targets vintage cables on poorly performing feeders supplying network and non-network feeders. The program targets aerial cable sections that have experienced a number of failures. Replacing poorly performing cable such as Okonite aerial cable with new primary cable will reduce the frequency of customer interruptions due to aerial cable failures. Proactive replacement of this troublesome cable with and in accordance with standard Aerial Cable (3-1c500 kcmil copper with EPR insulation, Con Edison specification 7558E) will increase reliability and decrease the frequency of feeder outages caused by aerial cable failures. It will also decrease the duration of feeder outages following a cable failure. This program selects aerial cable sections for replacement based on feeder failure rate and cable condition; feeders with the worst performance and most degraded cable are given the highest priority for replacement.

This program will end in 2016, and depending upon the primary feeder will be addressed in either the primary feeder reliability program or non-network reliability program.

Vented Service Box Covers:

The installation of vented covers helps reduce the buildup of combustible gases associated with events on the low-voltage secondary system thereby reducing the severity of underground events and enhancing public safety. The installation of vented composite, *i.e.*, electrically insulating, covers on the sidewalks will enhance public safety by mitigating stray voltage in addition to facilitating the escape of combustible gases. Since the inception of the program in 2004, underground structure events have been reduced by 22 percent (2013), while Company related electric shock reports have been reduced by 78 percent. Property damage associated with manhole events has also been reduced (15 percent reduction). This program funds the installation of vented metal covers on structures located in the streets and vented composite covers on structures located in sidewalks. The program entails replacing all solid covers with vented composite covers on sidewalks and a installing a minimum of one vented cover panel on selected structures located in streets. The program plan is to install vented cover panels on approximately 25,000 structures per year. Of the 233,500 structures on the Con Edison system (67,000 manholes and 166,000 service boxes), approximately 6,060 manholes and 68,400 service boxes remain to be vented. At this time, a modification to the program is pending. This modification may include the use of latching covers for the balance of covers to be installed. Once a determination is made a new schedule for completion of this program will be made.

Underground Secondary Reliability Program:

Damage to the secondary system is generally harder to identify compared to the primary system due to the redundancy of the secondary grid and the lack of remote monitoring equipment beyond the network transformer. As a result, adverse conditions are typically not found until they result in a customer outage, manhole event (smoke, fire, and explosion), or stray voltage condition. These conditions can lead to hazards to the public or prolonged outages; therefore, maintaining the reliability of the secondary grid is a priority. As of 2013, there have been a total of 2,145 manhole events. A damaged secondary cable on the networks can also reduce the reliability of the secondary network

system, stress remaining transformers and secondary mains, and expose customers to a higher risk of outages. The Company will target areas to improve the reliability and performance of the secondary grid. The Company will also employ extensions of secondary burnouts where practical, when it has been determined that the existing secondary layout can result in potential problems. This is an existing program that is being expanded to include the replacement of underground secondary service and main cable and the addition of a testing component to the otherwise visual-only defect identification process in underground structures. This program reinforces the underground secondary network infrastructure by replacing underground structures, conduit, transformers, and cable.

The underground secondary main replacement sub-program will focus on replacing aluminum and 4/0 main cables, structures that have experienced an Underground Secondary Event (UGSE) within the last three years and wood or wood-fiber conduits. Replacements are prioritized into three levels based on the presence of one or more of these attributes:

- Priority 1 replacements include structures with recent UGSEs, aluminum or 4/0 cable, and wood(fiber) conduit
- Priority 2 replacements include strictures with recent UGSEs and aluminum or 4/0 cable, but no wood(fiber) conduit
- Priority 3 replacements include structures without recent UGSEs but that do contain aluminum or 4/0 cable and wood(fiber) conduits

Where possible, this sub-program will retire in-place aluminum and 4/0 cable.

The overall goal is to reduce the five-year manhole event average by 15 percent by 2020. Spending for this program is expected to increase yearly.

A secondary model (Secondary Network Reliability Index-SNRI) has been created to prioritize main replacement. Use of the SNRI helps levelize the performance of all secondary mains across all regions and provides an asset management based approach to projects that are generated.

Non-Network Reliability:

Customers experience interruptions on average once every two-to-three years discounting storms. The Company is currently utilizing the Non Network Reliability Index in order to review circuit design of specific non-network circuits based upon historical performance. The goal this work to improve service to the customers each circuit supplies as measured by SAIFI/CAIDI statistics.

The Non-Network Reliability Index (NNRI) is a measure used to evaluate and manage the reliability of all non-network feeders on the Con Edison distribution system. It is used to rank non-network circuits including 4 kV primary grids and 13/27 kV autoloops based on their reliability (SAIFI, CAIDI) so that resources could be used to target the worst performing ones. The NNRI ranking process takes into consideration the failure rates of each individual component or segment as well as dominant failure contributors and produce circuit-specific reliability improvement options and recommendations

based on proper cost-benefit studies. Circuits will be prioritized in order based on the blue –sky-day NNRI rankings.

The Company will implement strategies to enhance non-network feeder performance and improve system resiliency during blue-sky and overhead storm events. In addition to removing poorly performing components, other reliability projects that will improve a circuit's score include Overhead Distribution Equipment Upgrade and Retrofitting.

- Deploy Strategic Smart switches
- Improve source reliability
- Improvement of Non-Network Feeder Reliability via reconfiguration of circuit
- Harden the existing overhead system to prevent damage
- Double Wood Remediation

Use of the NNRI application in this program helps levelize the performance of all non-network feeders across all regions and provides an asset management based approach to projects that are generated.

Transformer Vault and Structure Modernization:

Severe structural deficiencies must be addressed due to the following:

- Public safety risks related to slips, trips or falls, sunken roofs, or structural collapses
- Employee injury risk due to falling concrete or structural collapses
- Reliability risk due to damaged transformers and cable from falling debris
- Fines from New York City due to settled structures and cracked concrete
- Impact to customers due to water intrusion at customer service entrances
- A negative public image of Con Edison due to unsightly or unattended repairs

At locations where temporary steel plates and barricades are installed, these plates present trip/fall hazards along with the potential for city fines. In addition, steel plates prevent air-flow to structures reducing the capability of transformers may affect system performance during summer peak periods.

This program provides funding for proactive repair of structural deficiencies in deteriorated transformer vaults, manholes, and service boxes. If unrepaired, structural deficiencies in deteriorated vaults present a risk of collapse that can be a hazard to the public and can compromise system reliability by causing damage to electric infrastructure. Program funding has been increased in order to reduce the number of on-hand structures identified with deficiencies.

The program objectives are to identify and prioritize structures with defects and proactively repair those defects. Proactive repair of structures is significantly less costly than repair after collapse.

Remote Monitoring System Third Generation:

This ongoing work is required to comply with the Reliability Performance Mechanism (RPM) associated with the Remote Monitoring System mandated by the PSC. The RPM requires 90 percent of all transformers within a network to report real-time equipment information once a month. Failure to comply with the Remote Monitoring System RPM metric will result in a revenue adjustment of $10 million per violation and up to $50 million annually. This program provides funding for the installation of new Remote Monitoring System (RMS) third generation (generation) transmitters at various network transformer vault locations throughout all regions. This includes all new transformer installations, transmitter replacements, and Remote Monitoring System Pressure, Temperature, and Oil level sensor (RMSPTO) field conversions. An average of 1,950 units will be installed per year by Company regional I&A (Installation and Apparatus) equipment personnel.

Pressure, Temperature and Oil Sensors:

This program funds the installation of Pressure, Temperature, and Oil level (PTO) sensors on Con Edison's network distribution transformers. In-service transformer failures are a public safety concern and a corporate ERM, and PTO sensors help mitigate such concerns by identifying a suspect transformer prior to failure. Network transformers used by Con Edison are installed in underground vaults and manholes in public areas.

The PTO program is one of the transformer failure mitigation programs that have contributed to an 86 percent reduction in transformer failures since 2005. In 2014, 104 transformers were preemptively removed from service due to problems detected via PTO sensors.

All network transformers connected to the Remote Monitoring System (RMS) are targeted to have sensors installed by December 2019 completing this program.

Shunt Reactors:

This program is for the installation of Shunt Reactors to provide compensation within the Brooklyn/Queens and Staten Island load areas. Shunt Reactors are required to be installed on selected 27kV and 33kV feeders as per Company specification EO-2069. The installation of these reactors is required in order to prevent over voltages from damaging Company and customer equipment during back feed conditions. The goal is to have the proper compensation for each 27 KV network feeder in the Brooklyn/Queens region by 2028.

URD Cable Rejuvenation/Fault Indicator:

The program funds the rejuvenation of Underground Residential (URD) cable sections and installation of fault indicators. Cable rejuvenation is a rehabilitative process of restoring deteriorated solid dielectric cable to near new dielectric strength by removing contaminants and moisture and in-filing voids with insulation. Fault indicators are lights installed in pad-mount transformers that alert crews to the location of a cable fault and reduce restoration time.

The scope of work, mainly in the Bronx / Westchester region, is to target direct buried (4kV and 13kV) cable for rejuvenation, as well as transformer locations for fault indicator installations. The scope of this work involves the following tasks:

- Testing and evaluating the integrity of the population of field aged URD direct buried cable
- Prioritizing cables by likelihood of failure
- Rehabilitating cables at risk of failure injecting them with restorative fluid
- Installing fault indicators on URD and pad-mount transformers without them

This program is projected to end in 2016.

ATS Installation USS Reliability:

This program addresses the installation of new Automatic Transfer Switches (ATS), prioritized based on overload severity to the 4kV unit transformer or individual 4kV feeders. The unit substations will also be prioritized based on the impact to the 4kV grid in the event that two adjoining stations are out-of-service at or near peak load times. Adding an ATS as a backup in these first contingency design areas will help mitigate the potential risk of cascading 4kV feeder outages and grid collapses.

This program will end in 2016, and will be addressed in the non-network reliability program.

Primary Feeder Reliability:

This program addresses the reliability of the primary feeders that supply the 65 secondary networks on the system. The Network Reliability Index (NRI) application is used to evaluate and manage the reliability of all 65 networks on the Con Edison distribution system. The program is used to evaluate performance against the goal of having networks operate below 1.0 per unit. This was achieved in 2015. Going forward the NRI application will be used to maintain the reliability of the networks. Factors that impact network scores include component failure rates, as well as load growth causing higher component loading. Each year these values are updated, the scores each network receives are subject to change and may score higher than the initial 1.0 per unit goal. In order to maintain each network's reliability, projects will be generated to improve a network's score. Reliability projects include the removal of poorly performing components. Examples of poorly performing primary components include PILC (Paper Insulated Lead Covered) cable, PILC stop joints, and vintage Cross Linked Polyethylene (XLPE) primary cable that was manufactured and installed between the years of 1970 and 1975, or the first

generation of underground sectionalizing switches that were motor-operated three-phase SF6 (sulfur hexafluoride) gas-insulated switches.

The NRI application is utilized to maintain network reliability and prioritize feeder reliability projects. Use of the NRI helps levelize the performance of all networks across all regions and provides an asset management based approach to projects that are generated.

Modernization and Other:

This program addresses the reliability of the 239 4kV unit substations on the system and is comprised of four sub-programs.

Tap Changer Position Indicator:

This program funds the installation of new tap changer position indicators on 4 kV unit substation transformers and their interconnection to the Unit Substation Automation (USA) System to enable remote indication and control. In order effectively implement voltage reduction that reduces system demand during critical load periods, the 4 kV unit substations must have their tap changers placed in the remote manual position. This is needed to prevent automatic operation of the tap changers, which counter the desired voltage reduction. The tap changer position indication system is essential for this function. The forecast is to install the remaining 15 stations with tap changer position indicators at a rate of three installations per year starting in 2017. The work is expected to conclude in 2021.

USS Transformer Temperature Gauges:

This program calls for the replacement of existing temperature gauges with new temperature monitoring units at the Company's Unit Substations. The existing gauges can provide inaccurate or unreliable temperature readings. Incorrect temperature readings could result in unit substation transformers operating beyond their temperature limits, resulting in loss of transformer life, and increased risk of failure. Inaccurate temperature readings may also result in unnecessarily removing a transformer from service due to erroneous high temperature readings, producing unnecessary customer outages. Real-time archived temperature data provided by new monitoring units will allow for the implementation of dynamic ratings, which will help optimize the use of transformer capacity. The installation of 75 new temperature monitoring units was completed over the last seven years. There are approximately 60 locations left that require temperature monitoring units. The work scope includes equipment installation (cabinets, conduits, cable), programming and testing of temperature monitoring units.

USS (Unit Sub-Station) Switchgear House Replacement:

This program will replace unit substation switchgear houses with new selected switchgear houses in their entirety (including the circuit breakers they house, which will be upgraded to vacuum circuit breakers) in the non-network system. Structural members of switchgear houses have deteriorated due to aging and environmental conditions. These factors have resulted in circuit breakers

that do not fit into their cubicles properly. In many instances, pinch bars are used to force the breakers into the cubicles. Forcible insertion or removal of a circuit breaker into or out of its cubicle due to structural degradation often requires de-energization of the unit substation's 4 kV bus and all feeders. This typically results in a delay in station availability of two or three days. The Company began utilizing a model/matrix in 2016 to calculate a health index for its unit substation switchgear houses. Based upon that model/matrix, units that have a score outside of the target are recommended for replacement. A unit substation switchgear house with a health index score above the goal runs the risk of an in service mis-operation that would lead to extended repair and having that breaker/feeder out-of-service for an extended time compromising reliability. There are currently 20 unit substation switchgear houses that are recommended for replacement based upon their health index score. The USS model is utilized to maintain USS 4kV switchgear reliability and prioritize reliability projects. Use of the model helps levelize the performance of all 4kV switchgear across all regions and provides an asset management based approach to projects that are generated.

USS Transformer Replacement Program:

This program will replace unit substation transformers with new unit substation transformers. There are 239 4kV Unit Substation Transformers and 45 4kV High Tension Vaults in Con Edison distribution system (total of 284 4 kV transformers). They carry about 10 percent of the total system load and play an important role in overall system reliability of the non-network distribution systems. Over the past 20 years, a third of these transformers were replaced with new larger banks to compensate for growing load under the Load Relief Program. In the past six years, there have been no USS transformer replacements needed for load relief. The Company began utilizing a USS transformer model/matrix in 2016 to calculate a health index for its USS transformers. Based upon that model/matrix, units that have a score outside of the target are recommended for replacement. A USS transformer with a health index score above the goal has an increased risk of an in-service failure. The model/matrix utilizes the following factors in its health index calculation: DGOA (Dissolved Gas in Oil Analysis), Furan test results, transformer loading, apparent corrosion, oil leaks, LTC (Load Tap Changer) functionality, environmental impact, proximity to public, and age. The Company plans to replace all USS transformers that have a score above the goal. Use of the model helps levelize the performance of all 4kV transformers across all regions and provides an asset management based approach to projects that are generated.

3. Replacement Program Objectives

Primary Cable Replacement OA's: The Primary Cable Replacement OA's program addresses emergency repair work on primary feeders (these repairs can include splicing, cable, and installation of new conduit) for the following conditions:

- Component failures (cable, splice, termination) that cause an in-service outage (OA, Open-Auto)
- Component failures caused by post maintenance High-Voltage Withstand/Hipot tests (FOT, Fail-On-Test)
- Component failures that result in a post maintenance Ammeter-Clear test failure (FOT, Fail-on-test)

- Serious degraded components that are classified as “C” or “D” faults

Units per Year:

Number of applicable feeder component repairs averaged over five years:

o OA,	932
o FOT,	297
o C&D Faults (two year average)	796
o Total	2,025

This is an annual program.

Overhead Emergency Response:

The Overhead Emergency Response program addresses failures on Con Edison’s non-network overhead and underground residential distribution (URD) infrastructure. The distribution systems covered by this program are predominantly first contingency design. Failures on these systems are addressed as they occur and impending failures may be scheduled for future repair.

Due to the nature of the non-network overhead and URD systems, faults that occur on these systems are in close proximity to customers. Some of the possible faults include downed wires, hit poles, and damaged/ leaking transformers. These present an immediate hazard to public safety and the environment. All faults on these systems are addressed when they occur.

In addition to emergency work Con Edison conducts diagnostic testing such as infrared, ultrasonic, and visual inspections on these systems. These inspection programs are covered under Con Edison specifications EO-10644, EO-10336, and EO-10345. These inspections and testing cycles allow for proactive identification of imminent failures. By identifying weak spots before they develop into a fault the Company is able to improve reliability as well as reduce the number of potentially hazardous conditions to the public. Feeders or equipment removed from service and repaired in this manner are based on the nature of the impending failure, danger to the public, crew availability, and impact on supported loads.

Repairs due to emergencies are addressed as they arise and the goal is to maintain first contingency design. Defects discovered by diagnostic testing programs can be scheduled for future repair.

This is an annual program.

Service Replacements:

Service cables and conduit connect Con Edison’s distribution system to the customer. These cables are the umbilical cord between the customer and the utility. Without a service connection, customers and businesses do not receive electricity from the utility and service connections are of zero contingency. For this reason maintaining the service connection is of paramount importance.

A service can require replacement for a number of reasons including damage from weather, age, or loading. When a service initially fails an attempt is made to make a permanent repair. The ability to make a permanent repair is circumstantial and primarily based on the nature of the required repair and crew availability. If a service repair is unsuccessful or must be deferred a temporary repair is made to return service to the customer. Temporary repairs occur either by installing a bridge on the electric service (where the damaged service leg is cut clear and remaining customer electric load is jumped to the remaining service leg) or a service shunt is installed (a temporary cable installed). These temporary repairs will be removed when the permanent repair is made. The Service Replacements program provides the funding to remove these temporary service shunts and perform permanent repairs on underground services.

When a temporary repair is made it is placed in a working backlog until a permanent repair is scheduled. Con Edison specification EOP-5033 provides a guideline for managing and eliminating temporary service shunts. Due to the importance of the service connection a temporary service shunt is required to be replaced with a permanent repair within 60 in the summer period or 90 days in the winter period of the temporary repair. This eliminates the ability for long-term scheduling. Other scheduling obstacles can include alternate side of the street parking or construction over a structure required to be accessed. Additionally, there are instances where the permanent service repairs require excavation. Some of these instances include a structure being paved over, an obstructed service conduit, or the conduit being too small for the new service cable. It should be noted that anytime an excavation is require the local municipality requires specific street opening permits which take time to file and receive back from the municipality. The goal is to end the year with no higher than a three-month backlog. The current work plan is to reduce the backlog to this level by the end of 2019.

Temporary Services	Year-End Projections - Cable Units With Conduits				
	2016	2017	2018	2019	2020
Starting Backlog	4,990	4,213	2,913	1,873	673
Projected Incoming	8,928	9,300	9,300	9,300	9,300
Total Completion	8,255	9,150	8,890	9,050	7,700
Backlog	5,663	4,363	3,323	2,123	2,273
Additional Units to reduce backlog	1,450	1,450	1,450	1,450	0
Backlog With Reduction	4,213	2,913	1,873	673	0

Table 74 - Year End Backlog Projections

Streetlights:

Streetlights have become an increasingly important public safety concern for the New York City Department of Transportation (NYCDOT) and Westchester municipalities. These lights keep city and municipality streets illuminated at night. Con Edison works with local agencies to make repairs when a streetlight problem is discovered. The Streetlight program addresses the replacement of secondary cables that provide service to streetlights and associated conduit. NYCDOT and municipality agents routinely patrol and collect complaints from the public to determine which lights are not working. Con

Edison receives approximately 8,000 streetlight requests annually from these agencies. These lights are then tested to determine whether Con Edison or the local agency has the responsibility to make the required repairs. Based on four years of historical data, approximately 5,100 of the streetlight requests require cable replacement. Due to the impact a streetlight outage has on public safety repairs are made as soon as possible and only a short-term backlog is kept. During the summer months the goal is to complete 80 percent of all jobs within 45 days. During the winter months the goal is to complete 90 percent of all jobs within 90 days.

This is an annual program.

Transformer Installation:

The Transformer Installation program seeks to replace electrical distribution equipment (primary underground network transformers and their associated cable, conduit, and structures) that are found to be defective. If transformers fail while they are in service there is the potential hazard that jeopardizes public safety and system reliability. To mitigate this hazard Con Edison seeks to proactively detect and replace network transformers that exhibit symptoms of impending failure.

Network transformers are identified for removal based on equipment condition. The condition of units is assessed by visual inspection, dissolved gas in oil analysis, and remote sensors which monitors a transformer's pressure, temperature, and oil level. If a potentially hazardous condition is discovered the associated transformer is removed from service and scheduled for removal. Prioritization of transformer replacement is based on a risk of failure analysis. Since 2005, Con Edison has been able to improve its analyses and dramatically reduce the number of transformer failures from 148 in 2005 to 20 in 2014. Of the units that failed in-service, Con Edison also achieved reductions in the number of units that ruptured from 18 in 2005 to 3 in 2014. These reductions are directly correlated with the results of the failure mitigation programs and the Company's focus on removal of at-risk equipment prior to failure. When a transformer is removed from service the hazard is eliminated. The transformer replacement or repair is then scheduled. These out-of-service transformers will remain on a backlog until addressed. A transformer removed from service is no longer able to support the load in its surrounding area. As a result, nearby transformers are required to support the additional load. The increased stress on other transformers and supporting equipment like primary feeders and the secondary distribution system can reduce the equipment's expected life. It is for this reason that the backlog should be addressed in a timely manner. The table below shows the projected number of transformers to be taken out-of-service, the expected number that will be repaired, and the expected backlog.

Transformer Installation Yearly Projections					
	2016	2017	2018	2019	2020
Starting Backlog	532	539	447	379	250
Projected Incoming	2325	2075	2075	2075	2075
Projected Total Comp.	2318	2168	2145	2203	2101
System Backlog	539	446	377	251	224

Table 75 - Transformer Installation Backlog Projections

The total number of transformer replacement/repairs is expected to steadily decrease. This is because technologies deployed in the past have exposed transformer problems that otherwise would not have been discovered. As the increased workflow begins to stabilize the Company expects to see a reduced and steadier number of new jobs. The goal is to reduce the backlog units to no higher than a three month backlog. A working backlog is due to logistical reasons associated with transformer replacement including scheduling, permits, and access issues.

Secondary Open Mains:

The Secondary Open Mains program replaces, repairs, or reinforces secondary cables, joints, and conduit that have failed due to either overloads or damage. The distribution grid, or network, is made up of interconnected secondary mains that designed to a second contingency. These secondary mains allow power supplied from multiple sources to support customer loads. If one of the sources is removed from service, the customer does not see an interruption because the other sources are able to supply the load through secondary mains. It is this network configuration that allows Con Edison to maintain the level of reliability that customers expect.

An open main is defined as a non-conducting section of secondary cable. Some of the usual reasons a main can become open is damage on the secondary cable or a blown fuse, called a limiter, on the network system. When a main becomes open it is no longer able to carry current. This shifts the flow of current and results in an increased burden on the surrounding mains. The increased burden can cause these surrounding mains to carry more load than they are designed to handle and become overloaded. As a result, open mains can also lead to network transformer overloads, low voltage conditions, radially fed customers, manhole events, coordination problems, and power quality issues. Prioritization of open main repairs is covered in EO-10308. The impact they have to the surrounding area determines when the work will be scheduled. The Priority 1 and 2 open mains will continue to be the focus of this program. Open mains waiting to be addressed remain in a backlog. Historically, Con Edison receives approximately 5,300 open mains per year. The expected backlog of work and yearly forecast is shown in the table below.

Open Mains Yearly Projections					
	2016	2017	2018	2019	2020
Starting Backlog	2,891	3,034	3,080	3,111	3,289
Projected Incoming	5,228	5,254	5,254	5,254	5,254
Projected Completion	5,085	5,208	5,223	5,076	5,388
Year End Backlog	3,034	3,080	3,111	3,289	3,168

Table 76 - Open Mains Backlog Projection

Targeted Primary Direct Buried Cable (DBC) Replacement :

The Targeted Primary DBC Replacement program has been developed to replace problematic DBC. DBC is primary and secondary cable that is not placed in a conduit but buried directly in the ground. This increases the cable's exposure to the environment. From 2003 through 2013, an average of 5,840 underground residential distribution (URD) customers each year in Westchester County and Staten Island experienced a service interruption due to a problem with DBC. In addition, it takes 20 percent longer to locate and repair a fault when it occurs on DBC than it does to repair a fault that occurs on the same cable installed in a conduit. Higher quality DBC is expected to have a reduced number of failures compared to the current, in-service DBC.

The Targeted Primary DBC Replacement program will target failure-prone DBC cable over a 20-year period and will replace primary and secondary DBC with higher quality jacketed DBC to improve the reliability of the supply to URD customers. Work is prioritized based on a ranking system which takes into account the age of the cable and the interruption rate. This program began in 2009 and is forecasted to complete by 2029.

F. Appendix F - T&D Historical Spending and Forward Budgets

Transmission and Distribution	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Emergency Response	$ 432,910	$ 449,262	$ 490,354	$ 487,635	$ 513,179	$ 466,696	$ 494,513	$ 494,716	$ 498,830	$ 490,748
Public Works (Interference)	$ 57,103	$ 77,221	$ 77,691	$ 64,018	$ 71,500	$ 85,500	$ 77,501	$ 77,168	$ 70,394	$ 46,185
Other (IT)	$ 28,816	$ 41,619	$ 51,993	$ 39,381	$ 22,678	$ 44,114	$ 32,526	$ 17,193	$ 16,145	$ 15,489
Resiliency	$ -	$ -	$ 66,018	$ 138,126	$ 230,347	$ 297,711	$ 34,700	$ 17,700	$ 10,000	$ 7,119
Risk Reduction	$ 228,805	$ 216,802	$ 223,777	$ 253,874	$ 176,102	$ 247,509	$ 352,830	$ 356,271	$ 323,071	$ 291,310
New Business	$ 209,137	$ 236,691	$ 245,054	$ 208,569	$ 241,975	$ 243,250	$ 225,102	$ 224,423	$ 228,263	$ 226,254
System Expansion	$ 107,078	$ 70,279	$ 70,908	$ 42,587	$ 47,432	$ 99,398	$ 190,349	$ 154,039	$ 89,269	$ 67,675
TOTAL	$ 1,063,849	$ 1,091,874	$ 1,225,795	$ 1,234,190	$ 1,303,214	$ 1,484,178	$ 1,407,521	$ 1,341,510	$ 1,235,972	$ 1,144,781

G. Appendix G - IT Historical Spending and Forward Budgets

IT	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Transmission (SSO + S&TO)	$ 970	$ 214	$ 438	$ 1,276	$ 1,681	$ 1,087	$ 1,081	$ 1,077	$ 1,077	$ 1,077
Dist IT	$ 27,846	$ 41,405	$ 51,555	$ 38,105	$ 20,997	$ 43,027	$ 31,445	$ 16,116	$ 15,068	$ 14,412
T&D IT	$ 28,816	$ 41,619	$ 51,993	$ 39,381	$ 22,678	$ 44,114	$ 32,526	$ 17,193	$ 16,145	$ 15,489
Common IT	$ 210,292	$ 242,609	$ 171,847	$ 208,806	$ 230,767	$ 334,742	$ 456,837	$ 442,882	$ 300,531	$ 300,531
Electric Portion of Common IT	$ 174,542	$ 201,366	$ 142,633	$ 173,309	$ 191,537	$ 277,836	$ 379,175	$ 367,592	$ 249,441	$ 249,441
Total IT	$ 203,358	$ 242,985	$ 194,626	$ 212,690	$ 214,215	$ 321,950	$ 411,701	$ 384,785	$ 265,586	$ 264,930

H. Appendix H – Substation and Sub-transmission Load Relief Projects 2016-2025

CATEGORIES		SERVICE YEAR	PROJECT COST (Millions)
BQDM (Traditional)			
Farragut to Brownsville	Transfer 12 MW total load out of Brownsville (Wyckoff and Woodhull Hospitals)	2016	$7
Farragut to Brownsville	Install capacitors equivalent of 3 MW on 4 kV system	2016	-
		TOTAL	**$7.00**
BQDM (Utility Sided Solutions - NWA)			
Utility Sided Solutions - NWA	Battery installation, Voltage Optimization, Brownsville Area PV Pilot, Platwood Fuel Cell	2016 and beyond	$50.00
		TOTAL	**$50.00**
Projects - 50% or greater allocated funds spent			
Cooper Square	Transfer 20 MW to Cherry St.	2017	$12.00
Parkchester No. 2	Bus section upgrade - Parkchester No. 2	2017	$4.92
Plymouth Street	Bus section upgrade - Plymouth	2017	$5.45
Plymouth Street	Install transformer cooling on all transformers	2017	$4.88
East 179th Street	Replace area substation transformers, switchgear and buses (double syn bus design with 5 transformers)	2021	$60.00
East 179th Street	De-bifurcate 8 network feeders to improve the reliability of the Fordham network	2021	$3.00
East 179th Street	Install fans for the bus, breaker and reactor associated with Transformer No. 4	2017	$0.75
East 179th Street	Install water spray for Transformer No. 5	2017	$0.98
East 179th Street	De-bifurcate Feeder 3X61 and establish Feeder 3X82	2017	-
		TOTAL	**$91.96**
Eligible for NWA deferral (Including BQDM)			
Farragut to Brownsville	Transfer 60 MW to Glendale	2019	$106
Glendale	Install fifth transformer & 138 kV supply Feeder 38Q05 from Vernon East	2019	$134
Vernon to Glendale	Upgrade three cable sections plus risers associated with Feeder 38Q03	2019	$7.40
Vernon to Glendale	Upgrade two cable sections plus risers assoc. with Feeder 38Q04	2019	$7.93
BQDM Customer Sided Solutions	SBDI Adder, Multifamily EEPS Adder, Other EE, Energy Storage, DR, Fuel Cells, CHP	2016 and beyond	$150.00
West 65th St. No. 1	Uprate syn bus sections, or install AC cooling for both North & South syn buses	2020	$5.85
		TOTAL	**$411.16**

I. Appendix I – Distribution Load Relief Projects Eligible for NWA Comparison

CATEGORIES	5 Yr. Total (Millions)
Ongoing Programs	
Primary Feeder Relief	$54.05
Network Transformer Relief	$72.02
Non-Network Fdr Relief (Open Wire)	$33.67
Overhead Transformer Relief	$10.93
Secondary Main Relief	$16.01
	$186.68
Projects - 50% or greater allocated funds spent	
Woodrow Load Area Autoloop	$14.52
Part of Penn network (74 MW)	$3.00
Sheridan to Canal (12 MW)	$3.20
Part of Cooper Square (30 MW)	$3.50
59th Street Bridge Crossing	$16.00
	$40.22
Eligible for NWA deferral	
BQDM Distribution work	$98
Yorkville Crossing	$20.00
Penn Network New feeders for Hudson Yards	$19.70
Sherman Creek, Cable Crossings (BQ Flushing)	
Cable Crossing: Long Isl. Expy - College Point	$3.80
Cable Crossing: North Northern Blvd - Flushing River	$1.80
Cable Crossing: Roosevelt Avenue - Flushing River	$7.60
Cable Crossing: Roosevelt Avenue - Grand Central Pkwy	$4.00
Cable Crossing: Northern Blvd - Grand Central Pkwy	$6.30
Cable Crossing: 44th Ave - Grand Central Pkwy	$3.10
	$164.30

J. Appendix J – NPV Analysis of CVO Efficiency Benefits

							Total			
	Fuel		CO_2		Capacity		Low		High	
	1.0% Peak Reduction & 1.5% Avg Reduction	1.25% Peak Reduction & 2.25% Avg Reduction	1.0% Peak Reduction & 1.5% Avg Reduction	1.25% Peak Reduction & 2.25% Avg Reduction	1.0% Peak Reduction & 1.5% Avg Reduction	1.25% Peak Reduction & 2.25% Avg Reduction	1.0% Peak Reduction & 1.5% Avg Reduction	1.25% Peak Reduction & 2.25% Avg Reduction	1.0% Peak Reduction & 1.5% Avg Reduction	1.25% Peak Reduction & 2.25% Avg Reduction
NY State	$342,246	$513,369	$63,400	$95,100	$262,283	$327,876	$405,646	$608,469	$667,929	$936,344
CECONY	$253,032	$379,548	$39,386	$59,080	$262,283	$327,876	$292,418	$438,628	$554,701	$766,503

K. Appendix K – Data Shared through SIR Pre-Application Report

DG project Information: (Provided to Utility by Applicant)
Customer name
Location of Project: (Address and/or GPS Coordinates)
DG technology type
DG fuel source configuration
Proposed project size in kW (AC)
Date of Pre-Application Request
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)

L. Appendix L – Advisory Community Data Sharing Survey Key Findings and Recommendations

- **Virtually all customers view their data usage, mostly preferring to look at their bill.**

- **The majority of customers surveyed would appreciate a website/portal to view data usage, with Con Edison being deemed the logical entity to host it.**

- **Customers expect to achieve energy efficiency and cost/bill reductions as a result of receiving energy savings information and the ability to conduct comparative analysis of usage:**
  - Over time
  - Versus other like households/businesses

- **Despite the fact that many customers are willing to share their data with Con Edison as they consider it a solid, trustworthy organization; customers are still leery of data sharing and are generally concerned with privacy protection.**
  - The proposition of data aggregation somewhat increasing customers' willingness to share, and anonymity is even more ideal, when sharing with third parties.

- **Only a very small portion of those surveyed currently employ renewable source energy technology (solar panels the most noteworthy)**.

- **There appears to be considerable interest in receiving information about these technologies and learning more about alternative energy providers.**
  - The idea of saving money coupled with helping the environment is the biggest motivator for this interest.

- **Although not as compelling as the energy usage website/portal, there is interest in being able to input energy usage data in a website/portal that would connect customers with Energy Efficiency and Renewable Energy Source companies and service providers.**
  - Having the information in one place would be convenient as many don't really know where to start to explore these.

- **While customers overall have very limited knowledge of Green Button Connect, customers want to learn more and become better educated in order to see cost savings.**

Energy Usage Portal

Con Edison should move forward with the energy usage portal as customers have expressed an interest in this type of website. They feel the "one-stop-shop" feature is something that will greatly benefit in terms of achieving energy efficiency and consequently savings on their bills.

- **The portal should:**
  - Be informational;
  - Be user friendly;
  - Provide customers with the ability to see both current and historical usage data for comparative analysis purposes; and
  - Include energy savings tips and recommendations based on their data.

- **The data usage portal should allow for a two-step authentication process as customers mentioned this to be an extra privacy safeguard.**
  - Additionally, consider aggregation of data or keeping it anonymous.

- **It was expressed that manually inputting in data by the used would not be appealing and would even dissuade customers from using the portal.**

Interconnection Portal

Given customers interest in having access to energy efficiency/renewable source information, further explore the interconnection portal to connect customers with energy/renewable source companies.

- **The portal should minimally provide customers with two key elements:**
  - **<u>Education and information about alternative energy and providers, including:</u>**
    - Company history/ratings
    - Technologies employed
    - Residences/dwellings suitable for technology
    - Customer testimonials

  - **<u>Ability for a comparative pricing and energy efficiency analysis:</u>**
    - Matrix or calculator-based type of query
    - Historical current technology vs. proposed technology

- **It was expressed that manually inputting in data by the used would not be appealing and would even dissuade customers from using the portal.**

- **Allow for a two-step authentication process as customers mentioned this as an extra private safeguard.**

Con Edison's Role

Trust in Con Edison and their leadership in the energy industry make it the best entity to host the new portals and should help alleviate customers' concern over data sharing and safeguarding their privacy.

- **When considering which entity is best to host, Con Edison seems like the most logical host and it is preferred over other entities:**
  - Customers generally feel Con Edison is a trustworthy company.
  - Con Edison's past performance (e.g., positive customer service interactions, website familiarity, etc.) is indicative of the level of protection and quality customers expect to receive in such a portal.

As much of the data is already in Con Edison's "capable hands," this may streamline the process by alleviating some initial steps to make this happen.

M. Appendix M – Cybersecurity and Privacy Strategy Framework

The Company, O&R, 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.

Executive Summary

The NY Reforming the Energy Vision (REV) Cybersecurity and Privacy Framework ("Framework") focuses on ensuring that adequate attention is given to cybersecurity and customer privacy challenges to address new and emerging threats introduced by the NY Reforming the Energy Vision (REV) order. This Framework provides a common language for understanding and managing cybersecurity risk. The Framework enables all NYS utilities to align their cybersecurity activities while considering individual utility business requirements, risk tolerances, and resources.

The Framework enables NYS utilities regardless of size, degree of cybersecurity risk, or cybersecurity sophistication to apply the principles and best practices of risk management to improving the security and resilience of critical infrastructure.

The Framework incorporates cybersecurity best practices and industry standards that are consistent with leading cybersecurity authorities, such as NERC, NIST, and other related agencies, that will help NYS utilities identify, implement, and improve cybersecurity practices. (See appendix 3.1). It creates a common language for addressing cybersecurity and privacy threats ("threats") to the NYS utility sector. The proposed framework is designed to evolve with changes in cybersecurity threats, processes, and technologies. This Framework envisions effective cybersecurity as a dynamic and evolving response to threats. As a result, NYS utilities that adopt this Framework would be better positioned to comply with 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;

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.

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.

Information Security Management
Risk Methodology
Vendor Assurance
People Process Technology
Security Design Principles
Privacy Management
Cybersecurity Capabilities to Manage Risk
Cybersecurity & Privacy Controls
Identify
Asset Management
Business Environment
Governance;
Risk Assessment
Risk Management Strategy
Detect
Access Control
Awareness and Training
Data Security
Information Protection Processes and Procedures
Maintenance; and Protective Technology
Protect
Anomalies and Events
Security Continuous Monitoring
Detection Processes
Respond
Response Planning
Communications
Analysis
Mitigation
Improvements
Recover
Recovery Planning
Improvements
Communications

Information Security Management

Each participating utility shall adopt a formal cybersecurity program and plan based on an accepted industry recognized framework to insure Confidentiality, Integrity, and Availability (CIA) of systems, information, and assets. This component will position each utility to comply with the NYS DSIP. Information Security Management is based on ISO/IEC 27001, which is an industry known standard providing requirements for an information security management system (ISMS) and is noted as an informative reference within the NIST Cybersecurity Framework.

Information Security Management requires that all businesses and operating companies within the regulated NYS utilities, including third party contractors and business partners, develop cybersecurity policies and standards that will properly mitigate the risks identified by each NYS utility as part of implementing a risk management strategy (described in more detail in Section 2.2 below). These cyber policies and standards exist to protect assets in use and to govern REV related projects and activities. Third party contractors and business partners must work with each NY Utility to ensure that they have adequate information security management practices, which is discussed in more detail in Section 2.6 below.

During the course of NY REV Grid modernization effort, any existing information security management policies or standards should be periodically reviewed, amended, and appropriately communicated to ensure the relevance and accuracy to any business or functional change via a risk-based approach.

Risk Methodology

Each participating NYS utility organization shall adopt a formal risk management program that identifies, acts on, and mitigates risks based on an industry approved risk methodology framework (approved list of frameworks in Appendix 3.1). 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.

Security Design Principles

The foundation of any desired security architecture is a set of design principles intended to serve as 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.

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.

Cybersecurity and 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.

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.

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.

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

APPENDIX - Cybersecurity

Industry Standards and Best Practices

Cybersecurity Industry Standards and Guidelines leveraged to inform development of Cybersecurity and Privacy Joint Utility Framework

- NIST Cybersecurity Framework
- NISTIR 7628: Guidelines for Smart Grid Security
- NIST SP 800-53: Security and Privacy Controls for Federal Information Systems and Organizations
- NIST SP 800-30: Guide for Conducting Risk Assessments
- NIST SP 800-161: Supply Chain Risk Management Practices for Federal Information Systems and Organizations
- NIST 800-144: Guidelines on Security and Privacy in Public Cloud Computing
- NIST IR 8062: Privacy Risk Management for Federal Information Systems
- Fair Information Practice Principles (FIPPs)
- Electric Sector Cybersecurity Capability Maturity Model (ES-C2M2)
- DOE DataGuard Energy Data Privacy Program
- AICPA Generally Accepted Privacy Principles
- ISO/IEC 27001 Information Security Management
- ISO/IEC 27002 Code of Practice for Information Security Controls
- ISO/IEC 27005 Information Security Risk Management
- ISO/IEC 27018 Code of Practice for Protection of PII in Public Cloud
- ISO/IEC 29100 Privacy Framework
- ISO/IEC 29101 Privacy Architecture Framework
- ISO/IEC 29134 Privacy Impact Assessment
- DOE voluntary code of conduct
- Information Security Forum General Information Security Practices

Definitions

- **Access Control**: Access to assets and associated facilities is limited to authorized users, processes, or devices, and to authorized activities and transactions.
- **Analysis**: Analysis is conducted to ensure adequate response and support recovery activities.
- **Anomalies and Events**: Anomalous activity is detected in a timely manner and the potential impact of events is understood.
- **Asset Management**: The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.
- **Availability:** is generally considered the next most critical security requirement, although the time latency associated with availability can vary.

- **Awareness and Training**: The organization's personnel and partners are provided cybersecurity awareness education and are adequately trained to perform their information security-related duties and responsibilities consistent with related policies, procedures, and agreements.
- **Business Environment**: The organization's mission, objectives, stakeholders, and activities are understood and prioritized; this information is used to inform cybersecurity roles, responsibilities, and risk management decisions.
- **Communications (Recover)**: Restoration activities are coordinated with internal and external parties, such as coordinating centers, Internet Service Providers, owners of attacking systems, victims, other CSIRTs, and vendors.
- **Communications (Respond)**: Response activities are coordinated with internal and external stakeholders, as appropriate, to include external support from law enforcement agencies.
- **Confidentiality**: is generally the least critical for actual power system operations, although this is changing for some parts of the power system, as customer information is more easily available in cyber form: Privacy of customer information is the most important =general corporate information, such as human resources, internal decision-making, etc.
- **Cybersecurity**: is the protection required to ensure confidentiality, integrity and availability of the electronic information communication system.
- **Data Security**: Information and records (data) are managed consistent with the organization's risk strategy to protect the confidentiality, integrity, and availability of information.
- **Detection Processes**: Detection processes and procedures are maintained and tested to ensure timely and adequate awareness of anomalous events.
- **Governance**: The policies, procedures, and processes to manage and monitor the organization's regulatory, legal, risk, environmental, and operational requirements are understood and inform the management of cybersecurity risk.
- **Integrity**: is generally considered the most critical security requirement for power system operations, and includes assurance that:
    - Data has not been modified without authorization
    - Source of data is authenticated
    - Timestamp associated with the data is known and authenticated
    - Quality of data is known and authenticated
- **Improvements (Recover)**: Recovery planning and processes are improved by incorporating lessons learned into future activities.
- **Improvements (Respond)**: Organizational response activities are improved by incorporating lessons learned from current and previous detection/response activities.
- **Information Protection Processes and Procedures**: Security policies (that address purpose, scope, roles, responsibilities, management commitment, and coordination among organizational entities), processes, and procedures are maintained and used to manage protection of information systems and assets
- **Maintenance**: Maintenance and repairs of industrial control and information system components is performed consistent with policies and procedures.
- **Mitigation**: Activities are performed to prevent expansion of an event, mitigate its effects, and eradicate the incident.

- **Personal information**: Information that is about, or can be related to, an identifiable individual that a NYS Utility has a relationship with.
- **Privacy**: The rights and obligations of individuals and organizations with respect to the collection, use, retention, disclosure and disposal of personal information.
- **Protective Technology**: Technical security solutions are managed to ensure the security and resilience of systems and assets, consistent with related policies, procedures, and agreements
- **Recovery Planning**: Recovery processes and procedures are executed and maintained to ensure timely restoration of systems or assets affected by cybersecurity events.
- **Response Planning**: Response processes and procedures are executed and maintained, to ensure timely response to detected cybersecurity events.
- **Risk Assessment**: The organization understands the cybersecurity risk to organizational operations (including mission, functions, image, or reputation), organizational assets, and individuals.
- **Risk Management Strategy**: The organization's priorities, constraints, risk tolerances, and assumptions are established and used to support operational risk decisions.
- **Security Continuous Monitoring**: The information system and assets are monitored at discrete intervals to identify cybersecurity events and verify the effectiveness of protective measures.

REV DPS Orders

- Add links of all the orders that are relevant to the REV initiative (need to provide proper references)
- The NYS Order Adopting Distributed System Implementation Plan Guidance.
- Reference to the orders specific to NYS REV: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument

PSC Order 13-M-0178 Security for the Protection of Personally Identifiable Customer Information:http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B28CDF9EB-8661-491C-B2C2-E6E527297EE0%7D

N. Appendix N – Benefit-Cost Analysis Handbook (BCAH)

Benefit Cost Analysis Handbook

June 30, 2016

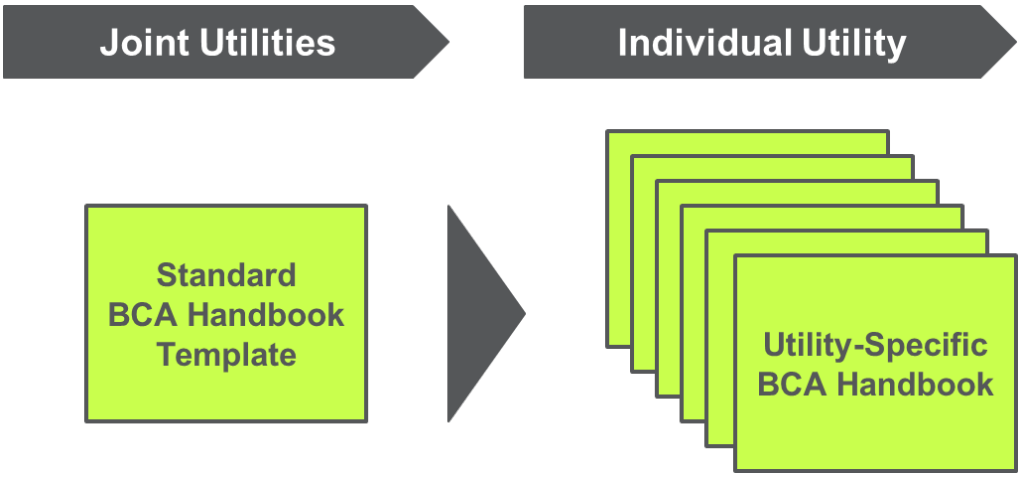
VERSION HISTORY

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	Con Edison BCA Handbook - v1.0	06/30/16	Con Edison	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. Navigant Consulting, Inc. (Navigant) facilitated the development of the standard BCA template at the request of the New York Joint Utilities. By design, the key assumptions, scope, and approach for a BCA included herein are largely consistent amongst all utilities' BCA Handbooks.

Figure 1-1. Relationship between Standard BCA Handbook Template and Individual Utility BCA Handbooks



Source: Navigant

The Handbooks 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 present 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. Where applicable, Con Edison has customized the handbook to account for utility specific assumptions and information.

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I. 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

1.1 Introduction

The New York Public Service Commission (NYPSC) directed the Joint Utilities (JU)[1] 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*)*.[2] 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.[3]

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:[4]

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection[5]
3. Procurement of DER through tariffs[6]
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 is reflected in the BCA Handbook.[7] The 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.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

1.2 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

[1] For the purpose of this document, Joint Utilities include 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.
[2] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Establishing the Benefit Cost Analysis Framework (BCA Order) (issued January 21, 2016).
[3] REV Proceeding, Order Adopting distributed System Implementation Plan Guidance (DSIP Guidance Order) (issued April 20, 2016), p. 64.
[4] REV Proceeding, BCA Order, pp. 1-2.
[5] These are also described as non-wires alternatives (NWA).
[6] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).
[7] REV Proceeding, BCA Order, p. 2.

procurement of DER through tariffs, and to be specifically applicable to procurement of DER 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 theBCA 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[8]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model[9]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[10]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[11]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[12]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 2[13]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[14]

[8] 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

[9] 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.

[10] 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 JU will work with DPS Staff to determine the appropriate values to use for the September ETIP filing and otherwise.

[11] 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.

[12] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[13] 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.

[14] 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	CECONY Electric Case 13-E-0300 *(twelve months ending December 31, 2016)*
Losses	Con Edison's 2007 Electric System Losses Study
Marginal Cost of Service	Consolidated Edison 2016 Rate Case Filing DAC-3 Schedule 1
Reliability Statistics	DPS: Electric Service Reliability Reports[15]

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.

1.3 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.[16] Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.4 Structure of the Handbook

The four remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

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.

[15] The latest Annual Electric Service Reliability Report is available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/D82A200687D96D3985257687006F39CA?OpenDocument

[16] REV Proceeding, DSIP Guidance Order, p. 64.

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 DER.

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.

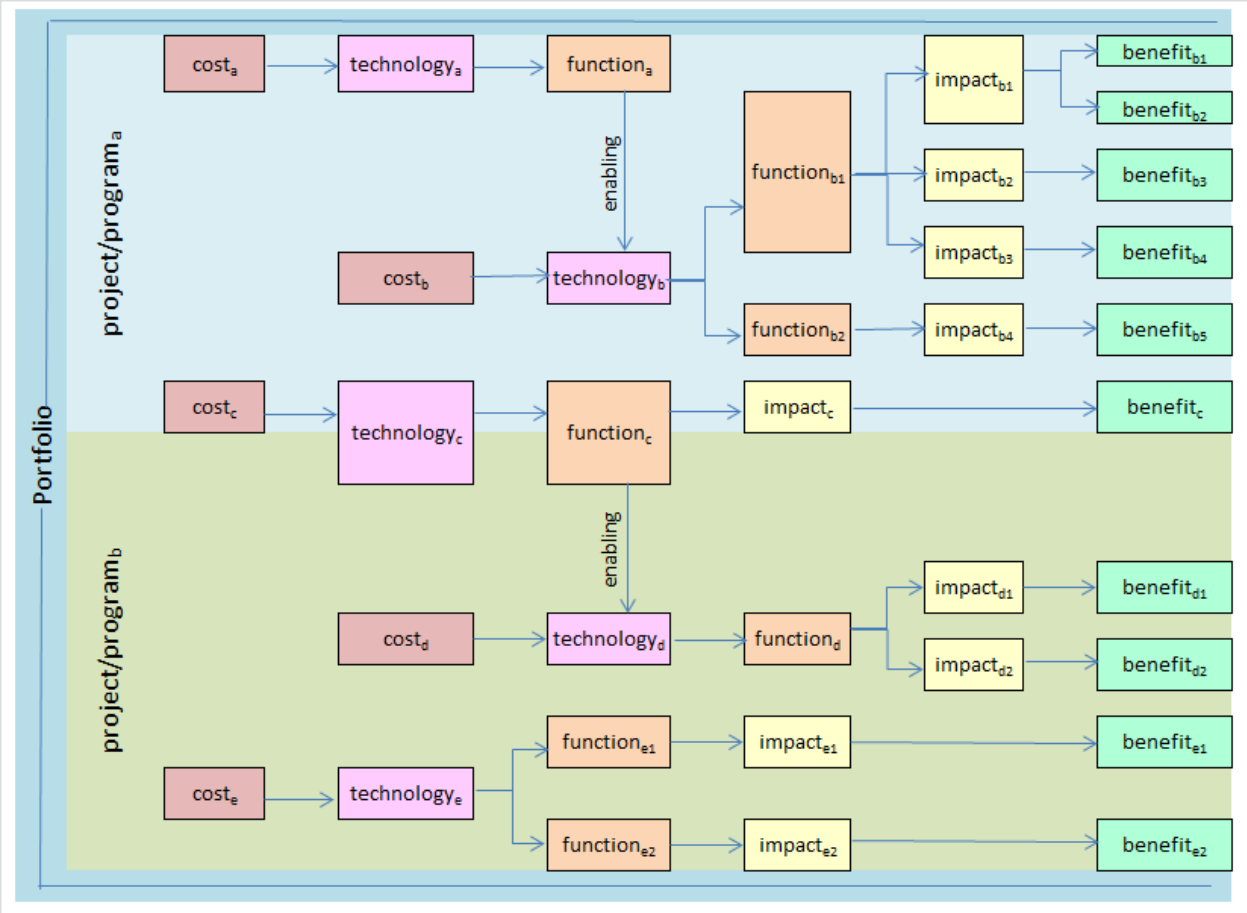
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

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. Over time, 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."[17]

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.

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.

[17] REV Proceeding, BCA Order, Appendix C, p. 18.

Table 2-1 provides a list of potentially overlapping AGCC and Avoided LBMP benefits.

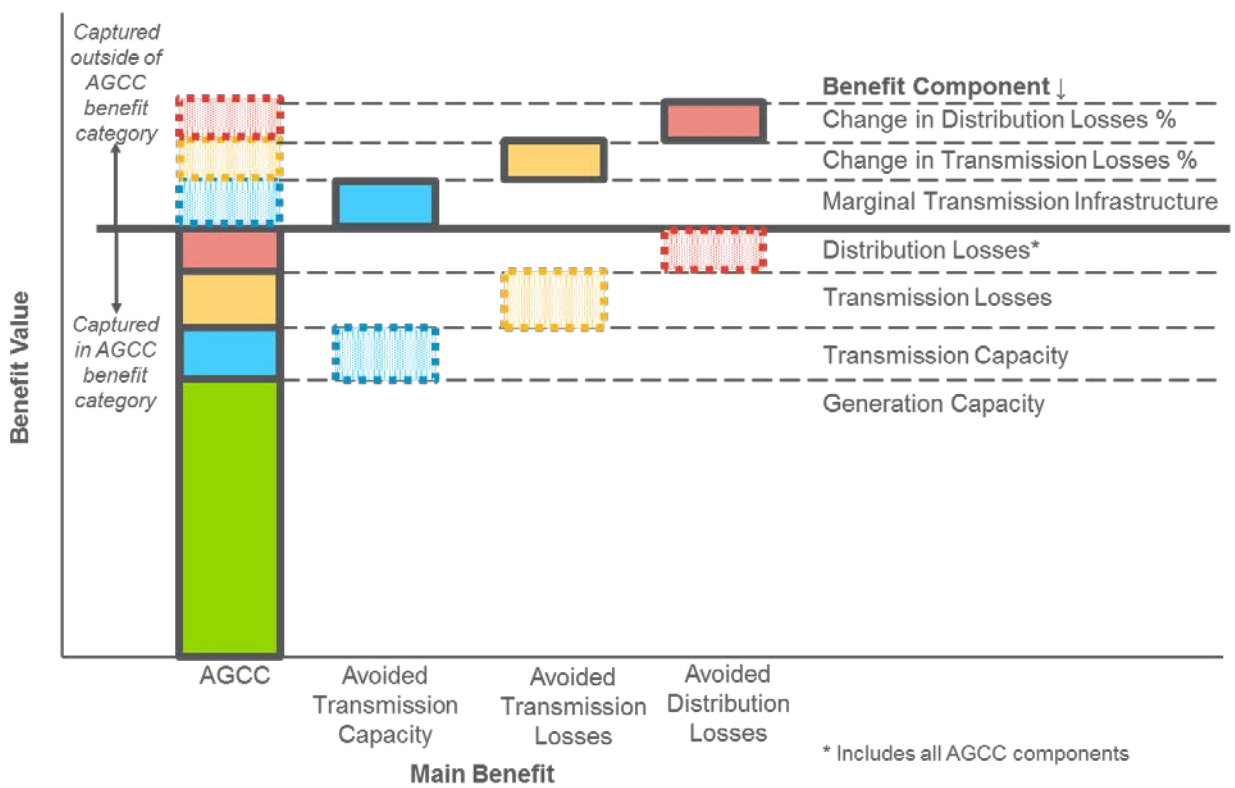
Table 2-1. Benefits with Potential Overlaps

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

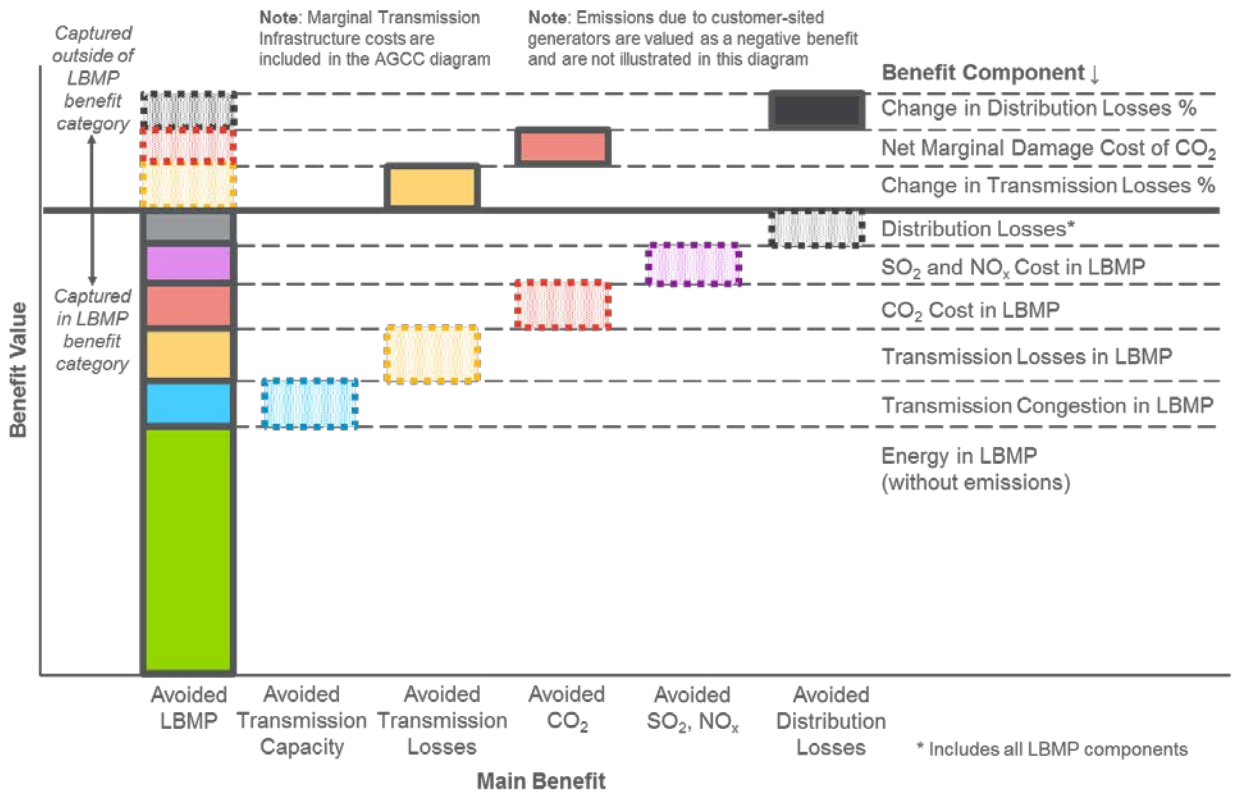
above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission losses.[18] Additionally, distribution losses can affect the calculation of AGCC, depending on the project location on the system.[19] The AGCC calculation accounts for these distribution 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

[18] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[19] 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.

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.[20] 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[21] 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:

- “r” subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[22]

[20] 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.

[21] 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.

- "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 $\mathrm{Loss\%_{b\rightarrow r}}$ 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-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

[22] Transmission in this context refers to the distribution utility's sub-transmission and internal transmission.

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.[23]

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.”[24] 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%.

[23] REV Proceeding, BCA Order, p. 2.
[24] REV Proceeding, BCA Order, Appendix C, p. 31.

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.[25]

[25] REV Proceeding, BCA Order, p. 25.

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”.[26]

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.

[26] REV Proceeding, BCA Order, p. 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.[27]

[27] REV Proceeding, BCA Order, p. 24.

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

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,[28] 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 and costs,[29] it is assumed that impacts generate benefits/costs in the following year of the impact. For

[28] 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, Avoided Restoration, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO_2, Net Avoided SO_2 and NO_x, 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.

[29] 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.

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.[30] 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

$\Delta\text{PeakLoad}_{Z,Y,r}$ **(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

[30] 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.

(e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$AGCC_{Z,Y,b}$ ($/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.[31] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[32] 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

[31] 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

[32] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

Section 2.1.2.1 for details on how the methodology avoids double counting between this benefit and others.

4.1.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-2 presents the benefit equation for Avoided LBMP:

Equation 4-2. Avoided LBMP

$$\text{Benefit}_{\text{Y}} = \sum_{\text{Z}} \sum_{\text{P}} \frac{\Delta\text{Energy}_{\text{Z,P,Y,r}}}{1 - \text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}} * \text{LBMP}_{\text{Z,P,Y,b}}$$

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

$\Delta\text{Energy}_{\text{Z,P,Y,r}}$ **(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 $Loss\%_{Z,b\rightarrow r}$ parameter. This input is project or program-specific. A positive value represents a reduction in energy.

$\text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}$ **(%)** 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.

$\text{LBMP}_{\text{Z,P,Y,b}}$ **($/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

$$\text{Benefit}_{Y+1} = \sum_{C} \frac{\Delta\text{PeakLoad}_{Y,r}}{\text{Loss}\%_{Y,b\rightarrow r}} * \text{TransCoincidentFactor}_{C,Y} * \text{DeratingFactor}_{Y} * \text{MarginalTransCost}_{C,Y,b}$$

The indices[33] of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system[34]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\mathbf{PeakLoad}_{\mathbf{Y,r}}$ **(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.

$\mathbf{Loss}\%_{\mathbf{Y,b\rightarrow r}}$ **(%)** 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.

$\mathbf{TransCoincidentFactor}_{\mathbf{C,Y}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an

[33] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[34] If system-wide marginal costs are used, this is not an applicable subscript.

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.

$\mathbf{DeratingFactor_Y}$ **(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. Con Edison 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

$$\text{Benefit}_{Y+1} = \sum_{Z} \text{SystemEnergy}_{Z,Y+1,b} * \text{LBMP}_{Z,Y+1,b} * \Delta\text{Loss\%}_{Z,Y+1,b\rightarrow i} + \text{SystemDemand}_{Z,Y,b} * \text{AGCC}_{Z,Y,b} * \Delta\text{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\text{Loss\%}_{Z,Y,b\rightarrow i} = \text{Loss\%}_{Z,Y,b\rightarrow i,\text{baseline}} - \text{Loss\%}_{Z,Y,b\rightarrow i,\text{post}}$$

The indices[35] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[36])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\text{SystemEnergy}_{Z,Y+1,b}$ **(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

[35] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[36] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

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 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"[37] 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.

$\mathbf{\Delta Loss\%_{Z,Y,b\rightarrow i}}$ **(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.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,baseline}}$ **(%)** 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.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,post}}$ **(%)** 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.

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.

[37] "Transmission level" represents the bulk system level ("b").

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 DER that are willing and qualify to provide ancillary services to NYISO. NYISO could purchase ancillary services from these DER 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 DER 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 DER. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DER 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 DER 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

$\mathrm{Capacity_Y}$ (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

$$\text{Benefit}_Y = \text{Capacity}_Y * n * \text{CapPrice}_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$\mathbf{Capacity_Y}$ (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.

$\mathbf{CapPrice_Y}$ ($/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.[38] LBMP impact will be calculated for each NYISO zone. AGCC price impacts are characterized using Staff's ICAP Spreadsheet Model.

4.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

Equation 4-7. Wholesale Market Price Impact

$$\text{Benefit}_{\text{Y+1}} = \sum_{\text{Z}} (1 - \text{Hedging\%}) * (\Delta\text{LBMPImpact}_{\text{Z,Y+1,b}} * \frac{\Delta\text{Energy}_{\text{Z,Y+1,r}}}{1 - \text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}} + \Delta\text{AGCC}_{\text{Z,Y,b}} * \text{ProjectedAvailableCapacity}_{\text{Z,Y,b}})$$

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K[39])
- 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.

$\Delta\mathbf{LBMPImpact}_{\mathbf{Z,Y+1,b}}$ **(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.

$\Delta\mathbf{Energy}_{\mathbf{Z,Y+1,r}}$ **(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.

$\mathbf{Loss\%}_{\mathbf{Y,b\rightarrow r}}$ **(%)** 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.

$\mathbf{WholesaleEnergy}_{\mathbf{Z,Y,b}}$ **(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.

$\Delta\mathbf{AGCC}_{\mathbf{Z,Y,b}}$ **(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

[38] REV Proceeding, BCA Order, Appendix C, p. 8.
[39] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

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.[40] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\text{ProjectedAvailableCapacity}_{Z,Y,b}$ (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.

4.1.6.2 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.

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.[41]. 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.

4.2.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation 4-8. Avoided Distribution Capacity Infrastructure

$$\text{Benefit}_{Y} = \sum_{V}\sum_{C} \frac{\Delta\text{PeakLoad}_{Y,r}}{1 - \text{Loss\%}_{Y,b\rightarrow r}} * \text{DistCoincidentFactor}_{C,V,Y} * \text{DeratingFactor}_{Y} * \text{MarginalDistCost}_{C,V,Y,b}$$

The indices of the parameters in Equation 4-8 include:

[40] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

[41] The one-year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[42]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\mathrm{PeakLoad}_{Y,r}$ **(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.

$\mathrm{Loss}\%_{Y,b\rightarrow r}$ **(%)** 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.

$\mathrm{DistCoincidentFactor}_{C,V,Y}$ **(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.

Network systems comprise a significant portion of Con Edison's distribution system. When considering DER for relieving overloads on network distribution elements such as a primary feeder or a network transformer, the location of the DER relative to the overloaded element directly affects the percentage contribution of the DER to relieving that overload. As the electrical distance from the DER to the point of need increases, the value of the DER in reducing the specific overload quickly lessens. DER on the network system have diffuse impacts because the power flows in the network move in so many directions.[43]

Radial systems comprise a smaller portion of Con Edison's distribution system. Similarly, when considering DER for relieving overloads on such systems, the location of the DER with respect to the point of need is also of importance. In radial systems, a DER must be located "downstream" of the point of need (relative to the substation) to contribute to resolving the respective overload.

In Con Edison's system, Area Substations and sub-transmission feeders supply the distribution systems such as those mentioned above. When considering a DER (or portfolio of DER) to resolve sub-transmission feeder and Area Substation overloads, DER located anywhere in the respective distribution system would provide load relief benefits that would "roll upstream" to the respective point of need.

$\mathrm{DeratingFactor}_{Y}$ **(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.

[42] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.
[43] Electric Power Research Institute, *Time and Locational Value of DER: Methods and Applications,* Report No. 3002008410 (pending finalization).

$MarginalDistCost_{C,V,Y,b}$ ($/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 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.

4.2.1.2 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 DER 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

$$\text{Benefit}_{\text{Y}} = \sum_{\text{AT}} \Delta\text{Expenses}_{\text{AT,Y}}$$

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

$\Delta\text{Expenses}_{\text{AT,Y}}$ (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 DER may be limited to instances where DER 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

$$\text{Benefit}_{\text{Y+1}} = \sum_{\text{Z}} \text{SystemEnergy}_{\text{Z,Y+1,b}} * \text{LBMP}_{\text{Z,Y+1,b}} * \Delta\text{Loss\%}_{\text{Z,Y+1,i}\rightarrow\text{r}} + \text{SystemDemand}_{\text{Z,Y,b}} * \text{AGCC}_{\text{Z,Y,b}} * \Delta\text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r}}$$

Where,

$$\Delta\text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r}} = \text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r,baseline}} - \text{Loss\%}_{\text{Z,Y,i}\rightarrow\text{r,post}}$$

The indices[44] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[45])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$SystemEnergy_{Z,Y,b}$ (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.

$LBMP_{Z,Y,b}$ ($/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 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.

$SystemDemand_{Z,Y,b}$ (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.

$AGCC_{Z,Y,b}$ ($/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.

$\Delta Loss\%_{Z,Y,i\rightarrow r}$ (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.

[44] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[45] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,baseline}}$ **(%)** 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 fix 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. 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

$$\text{Benefit}_{\text{Y}} = -\Delta\text{CrewTime}_{\text{Y}} * \text{CrewCost}_{\text{Y}} + \Delta\text{Expenses}_{\text{Y}}$$

Where,

$$\Delta\text{CrewTime}_{\text{Y}} = \#\text{Interruptions}_{\text{base,Y}} * (\text{CAIDI}_{\text{base,Y}} - \text{CAIDI}_{\text{post,Y}} * (1 - \%\text{ChangeSAIFI}_{\text{Y}}))$$

$$\%\text{ChangeSAIFI}_{\text{Y}} = \frac{\text{SAIFI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}}}{\text{SAIFI}_{\text{base,Y}}}$$

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 utilized for localized and geographic specific projects that exhibit more 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.

$\Delta\mathbf{CrewTime_{Y}}$ **(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

$\mathbf{CrewCost_{Y}}$ **($/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

$$\mathrm{Benefit_Y} = \mathrm{MarginalCost_{R,Y}}$$

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

$\mathbf{MarginalDistCost_{R,Y}}$ **($/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 installed/built; 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

$$\text{Benefit}_{\text{Y}} = \sum_{\text{C}} \text{ValueOfService}_{\text{C,Y,r}} * \text{AverageDemand}_{\text{C,Y,r}} * \Delta\text{SAIDI}_{\text{Y}}$$

Where,

$$\Delta\text{SAIDI}_{\text{Y}} = \text{SAIFI}_{\text{base,Y}} * \text{CAIDI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}} * \text{CAIDI}_{\text{post,Y}}$$

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

$\text{ValueOfService}_{\text{C,Y,r}}$ ($/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.

$\text{AvgDemand}_{\text{C,Y,r}}$ (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.

$\Delta\text{SAIDI}_{\text{Y}}$ (Δhr/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.[46] Baseline system average reliability metrics can be found in the Company's annual Electric Service Reliability Reports. A positive value represents a reduction in SAIDI.

$\text{SAIFI}_{\text{post,Y}}$ (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.

[46] SAIDI = SAIFI * CAIDI

$\mathbf{CAIDI_{post,Y}}$ **(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.

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[47] 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 are the full marginal damage cost less the cost of carbon embedded in the LBMP.

[47] 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.

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

$$\mathrm{Benefit_Y = CO2Cost\Delta LBMP_Y - CO2Cost\Delta OnsiteEmissions_Y}$$

Where,

$$\mathrm{CO2Cost\Delta LBMP_Y} = \left(\frac{\Delta\mathrm{Energy_{Y,r}}}{1-\mathrm{Loss\%_{Y,b\to r}}} + \Delta\mathrm{Energy_{TransLosses,Y}} + \Delta\mathrm{Energy_{DistLosses,Y}}\right) * \mathrm{NetMarginalDamageCost_Y}$$

$$\Delta\mathrm{Energy_{TransLosses,Y}} = \mathrm{SystemEnergy_{Y,b}} * \Delta\mathrm{Loss\%_{Y,b\to i}}$$

$$\Delta\mathrm{Energy_{DistLosses,Y}} = \mathrm{SystemEnergy_{Y,b}} * \Delta\mathrm{Loss\%_{Y,i\to r}}$$

$$\Delta\mathrm{Loss\%_{Z,Y,b\to i}} = \mathrm{Loss\%_{Z,Y,b\to i,baseline}} - \mathrm{Loss\%_{Z,Y,b\to i,post}}$$

$$\Delta\mathrm{Loss\%_{Z,Y,i\to r}} = \mathrm{Loss\%_{Z,Y,i\to r,baseline}} - \mathrm{Loss\%_{Z,Y,i\to r,post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions_Y} = \Delta\mathrm{OnsiteEnergy_Y} * \mathrm{CO2Intensity_Y} * \mathrm{SocialCostCO2_Y}$$

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 $Loss\%_{b\to r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\to r}}$ **(%)** 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.

$\mathbf{\Delta Energy_{TransLosses,Y}}$ **(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.

$\mathbf{NetMarginalDamageCost}_{Y}$ **($/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.

$\Delta\mathbf{Loss\%}_{Z,Y,b\rightarrow i}$ **(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.

$\mathbf{Loss\%}_{Z,Y,b\rightarrow i,baseline}$ **(%)** 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.

$\mathbf{Loss\%}_{Z,Y,b\rightarrow i,post}$ **(%)** 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.

$\Delta\mathbf{Loss\%}_{Z,Y,i\rightarrow r}$ **(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 represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%}_{Z,Y,i\rightarrow r,baseline}$ **(%)** 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"). Thus, this reflects the distribution loss percent post-project, which is found in Table A-2.

$\Delta\mathbf{OnsiteEnergy}_{Y}$ **(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[48].

$\mathbf{SocialCostCO2}_{Y}$ **($ / 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

[48] 1 metric ton = 1.10231 short tons

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."[49]

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

$$\text{Benefit}_{\text{Y}} = \sum_{\text{p}} \text{OnsiteEmissionsFlag}_{\text{Y}} * \text{OnsiteEnergy}_{\text{Y,r}} * \text{PollutantIntensity}_{\text{p,Y}} * \text{SocialCostPollutant}_{\text{p,Y}}$$

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.

[49] REV Proceeding, BCA Order, Appendix C, p. 16.

$PollutantIntensity_{p,Y}$ (ton/MWh) is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$SocialCostPollutant_{p,Y}$ ($/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

$$\mathrm{Cost_Y} = \sum_{\mathrm{M}} \Delta\mathrm{ProgramAdminCost_{M,Y}}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

$\Delta\mathrm{ProgramAdminCost_{M,Y}}$ 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 has 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 *Order Adopting Regulatory Policy Framework and Implementation Plan* (REV Track One 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."[50]

The acquisition of most DER 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

[50] REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), p. 33.

considered in any SCT evaluation.[51] Company competitive solicitations for DER 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 *The Benefits and Costs of Net Energy Metering in New York* (E3 Report).[52] In this report, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in New York 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$/kW-AC)[53]	4,430
Fixed Operating Cost ($/kW)	15

Note: These costs would change as DER project-specific data is considered.

1. **Capital and Installation Cost:** Based E3 Report'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 the E3 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

[51] REV Proceeding, BCA Order, Appendix C, p. 18.

[52] E3 [Energy+Environmental Economics], *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(E3 Report)(December 11, 2015) The E3 Report was issued in Case 15-E-0703, *In the Matter of Performing a Study on the Economic and Environmental Benefits and Costs of Net Metering Pursuant to Public Service Law Sec 66-n*, Letter to Secretary Burgess from Deputy Markets and Innovation Weiner (dated December 17, 2015).

[53] 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 the E3 Report.

from the EPA's *Catalog of CHP Technologies*[54] 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.

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.[55]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[56]

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)	$140

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.

[54] United States Environmental Protection Agency and Combined Heat and Power Partnership, *Catalog of CHP Technologies* (EPA Catalog of CHP Technologies)(March 2015) is available at https://www.epa.gov/chp/catalog-chp-technologies.
[55] EPA Catalog of CHP Technologies, pp. 2-15.
[56] EPA Catalog of CHP Technologies, pp. 2-17.

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 DER 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 DER 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 DER 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	**ΔEnergy (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	**ΔEnergy (annual)** **ΔAGCC**
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[57]
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

Table 5-5 further describes the key parameters identified in Table 5-4.

[57] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table 5-5. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[58] 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[59]	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.[60]

[58] This parameter is also used to calculate the Wholesale Market Price Impact benefit.

[59] 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.

[60] 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

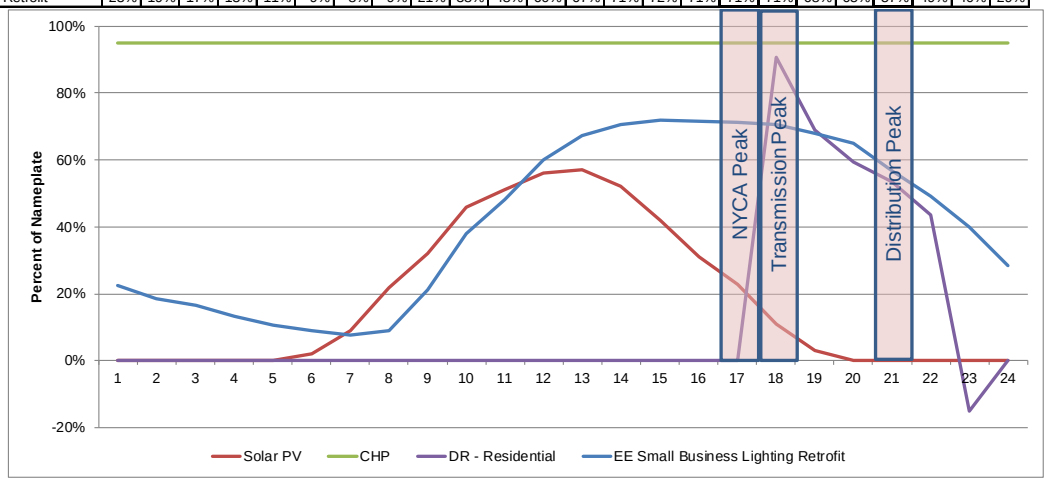
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DER; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the 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.[61]

[61] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DER, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DER and distribution

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 the E3 Report, described above, 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.

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.

The E3 Report 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

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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 DER, 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.

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%
ΔEnergy (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.[62] 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.[63] 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. **ΔEnergy (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. 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

[62] New York Independent System Operator (NYISO), Installed Capacity Manual 4 (June 2016), p.4-23.
[63] *See* E3 Report, *supra*, p. 49.

electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's *Catalog of CHP Technologies*.[64]

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.[65]

The carbon and criteria pollutant intensity can be estimated using the EPA's publically-available CHP Emissions Calculator.[66] CHP Technology, Fuel, Unit Capacity' and Operation were the four inputs required. An example is 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.

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).

[64] https://www.epa.gov/chp/catalog-chp-technologies.
[65] EPA Catalog of CHP Technologies, . p. 2-20.
[66] EPA CHP Emissions Calculator, https://www.epa.gov/chp/chp-emissions-calculator.

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.[67] 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.[68] 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

[67] Some DR programs may be "dispatched" or scheduled by third-party aggregators.
[68] These factors are specifically from the July 15 – 19, 2013 heat wave.

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.

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..**ΔEnergy (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 example is 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.

6. 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. Benefit and Cost streams should be discounted at the Weighted Average Cost of Capital (WACC) unless specified otherwise.

Table A-1. Utility Weighted Average Cost of Capital

Regulated Rate of Return
6.91%
Source: CECONY Electric Case 13-E-0300
For twelve months ending December 31, 2016

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

Portion of T&D Delivery System	Voltage Segment	Loss Type	
		Fixed	**Variable**
Transmission	500 kV	0.00%	0.00%
	345 kV	0.32%	0.52%
	138 kV	0.34%	0.50%
	69 kV	0.03%	0.05%
	TOTAL	**0.69%**	**1.07%**
Distribution	Primary	0.02%	1.12%
	Secondary	0.00%	1.56%
	Metering	0.18%	0.00%
	Equipment	0.78%	0.39%
	TOTAL	**0.69%**	**1.07%**
Unaccounted For		0.00%	0.65%
TOTAL		**1.67%**	**4.79%**
Source: Con Edison's 2007 Electric System Losses study			

Utility-specific system average marginal costs of service are found in Table A-3. Utility-specific system average marginal costs of service are found in Table A-3 Utility System Average Marginal Costs of Service in terms of $/kW-year. The nominal costs post 2024 can be estimated by escalating the costs by 3% annually.

Table A-3. Utility System Average Marginal Costs of Service

Year	Transmission ($/kW-yr)	Primary Distribution ($/kW-yr)	Secondary Distribution ($/kW-yr)
2016	$1.53	$76.07	$85.11
2017	$10.29	$128.82	$87.67
2018	$10.63	$133.20	$90.30
2019	$2.41	$153.90	$93.01
2020	$31.27	$159.75	$95.80
2021	$32.70	$169.06	$98.67
2022	$34.06	$175.63	$101.63
2023	$34.64	$184.33	$104.68
2024	$38.34	$193.14	$107.82

Source: Consolidated Edison 2016 Rate Case Filing DAC-3 Schedule 1

To estimate yearly values beyond the last year, escalate the final year values by 3%