CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
ELECTRIC CASE TESTIMONIES
VOLUME 3

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL

I. Introduction

A. Introduction and Qualifications of Panel Members

Q. Would the members of the panel please state their names and business addresses?

A. Robert Schimmenti, Milovan Blair, Patrick McHugh, Walter Alvarado, Hugh Grant, and Matthew Sniffen. The business address for all panelists is 4 Irving Place, New York, NY 10003.

Q. By whom are you employed, in what capacity, and what are your backgrounds and qualifications?

A. (Schimmenti)

I am Robert Schimmenti, Senior Vice President of Electric Operations. I have been employed by Consolidated Edison Company of New York, Inc., ("Con Edison" or "the Company") for 31 years. I have held senior level positions in Electric Operations, Electric Construction, Control Center Operations and Substation Operations, including Vice President, Engineering and Planning, Electric Operations, Chief Engineer of Engineering and Planning, General Manager of Electric Construction, and General Manager of Substation Operations. I currently have overall responsibility for Con Edison's Electric Distribution Operations, Engineering and Planning, and Con Edison's Energy Services organization, which coordinates all aspects of the delivery of electric service to customers.

I earned a Bachelor of Engineering degree in electrical engineering from Hofstra University and a Master of Science degree in management technology from Polytechnic University. I have also completed the Transmission Systems program from Siemens PTI (Power Technology International).

(Blair)

I am Milovan (Milo) Blair, Senior Vice President of Central Operations for Con Edison. My responsibilities include the planning, design, operation and maintenance (O&M) of the Company's electric transmission system, substations, primary control center, electric and steam generating plants, and steam distribution system. I am also responsible for the Company's engineering and construction activities. I joined Con Edison in 1991 as a Management Intern and have served as General Manager, Substation Operations-Northern region, General Manager, System Operations; Vice President, System and Transmission Operations and Vice President Brooklyn/Queens Electric Operations.

I hold a MBA in Information Systems from St. John's University and a Bachelor of Science degree in Electrical Engineering from the City University of New York. I have completed the Senior Executive Program at Columbia University and the Siemens PTI Power Technology course and am licensed as a System Operator by the North American Electric Reliability Corporation ("NERC"). I currently serve on the executive board of the YMCA Bedford Stuyvesant Chapter and as a leadership council member of the City College of New York Grove School of Engineering.

(McHugh)

I am Patrick G. McHugh, vice president of Engineering & Planning for Con Edison. I assumed this responsibility in September 2014, after serving as vice president of Brooklyn/Queens Electric Operations. My responsibilities include overseeing energy services, engineering, and quality assurance. Engineering & Planning is also responsible for designing and monitoring the performance of the electric distribution system.

I have been with the Company for over 27 years after joining in 1991 as a management intern, and have held various positions with increasing responsibility including

Chief Engineer of Distribution Engineering, General Manager Protective Systems Testing, Senior System Operator, and Chief District Operator. I hold a Bachelor of Science degree in electrical engineering from Clarkson University, a Bachelor of Arts degree in physics from Plattsburgh State University, and a master's degree in electrical engineering from Clarkson University. I have also completed the Siemens PTI Transmissions course.

(Alvarado)

I am Walter Alvarado, Vice President of System & Transmission Operations for Con Edison. My responsibilities include the planning, maintenance, and operation of the electric transmission system; I am also responsible for the operation of the steam system. I joined Con Edison in 1992 as a Management Intern and have served as General Manager, Manhattan Electric Construction; General Manager, Brooklyn Queens Electric Operations; and Vice President, Staten Island and Electric Services.

I hold a Master of Science in Computer Science and Bachelor of Science in Mechanical Engineering from NYU Tandon School of Engineering (formerly Polytechnic University). I have completed Siemens PTI courses in electric distribution and transmission. I currently serve on the board of directors for North American Transmission Forum (NATF), and on the board of directors and stewardship committee of Teatown Lake Reservation. I have also served on the board of directors for the Staten Island Economic Development Corporation.)

(Grant)

I am Hugh Grant, Vice President of Substation Operations for Con Edison. I have been with Con Edison for a little over 19 years. I started with Con Edison in May 1999 and have held various management positions in Steam, Substations, Central Engineering and System and Transmission Operations. From 2010 to 2013, I served as the General Manager of Transmission Operations. From 2013 to 2015, I served as the General Manager for Construction Services. After my position with Construction services, I was General Manager of System Operation through August of 2017. Since September of 2017, I have been the Vice President of Substation Operations.

In my current role, I provide leadership and oversight in maintaining and operating all of Con Edison’s 101 substations. In addition I am responsible for the capital portfolio for Substation Operations.

I have a BS in Electrical Engineering from Florida International University and an MS in Information Systems from Pace University. I am currently pursuing an MBA from Columbia University, through their executive program.

(Sniffen)

I am Matthew Sniffen, Vice President of Emergency Preparedness for Con Edison. I joined Con Edison in 1982 as a Management Intern and subsequently served in various supervisory roles in Electric Distribution, including Department Manager of the Manhattan Electric Control Center.

My current responsibilities include, but are not limited to, the development of emergency response plans inclusive of drills and exercises designed to ensure readiness for corporate emergencies for all commodities.

Prior to my current role, I held the position of Chief Engineer of Regional Engineering. In that role, I was responsible for developing Electric Distribution's asset investment strategy and justifying its capital projects and programs in support of the Company's budget and general rate case processes. I was also a central figure in Electric Distribution's post-Sandy storm hardening program. I hold a Bachelors of Science in Mechanical Engineering from Manhattan College.

B. Purpose of Filing

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

A. Our purpose is to present the Company's required electric projects and programs, and their respective funding requirements. Specifically, our testimony covers the Capital and O&M funding requirements for the Company's transmission, distribution, and electric production functions. The transmission funding requirement – which includes the System and Transmission Operations ("S&TO") and Substation Operations ("SSO") groups – and the Electric Operations ("Distribution") funding requirements are described together and are collectively referred to as Transmission and Distribution ("T&D"). The Electric Production funding requirement, the costs of which are shared with the steam system, is presented separately in Section VI of this testimony.

In presenting these initiatives, the Company's focus remains on the continued provision of safe and reliable electric service, operational excellence, maximizing customer experience, and further integrating clean energy resources into the electric system. The main purposes of the Company’s planned electric investments are to: 1) maintain and enhance system safety, reliability, and resilience for customers while reducing environmental impacts; 2) enhance customers’ experience and further engage customers in managing their energy use; 3) support the growth of clean energy solutions, including energy efficiency and electric vehicles; and 4) advance grid innovation and the distributed system platform. Each program and project for which the Company seeks funding is described in a “white paper” that includes scope of work, cost, schedule, and justification, including discussion of alternatives.

Q. What time period does this testimony cover?

A. This testimony presents the projects and programs planned for the 12-month period ending December 31, 2020 (“Rate Year” or “RY1”).

Q. Does your testimony look beyond Rate Year 1?

A. Yes. This testimony also addresses the capital plant additions and other programs and initiatives planned for the two years following the Rate Year. For the sake of convenience, we will refer to the twelve-month periods ending December 31, 2021 and December 31, 2022 as “RY2” and “RY3,” respectively. As the Company’s Accounting

Panel explains, the Company is not proposing a multi-year rate plan in this filing, but is interested in pursuing one in settlement discussions with Staff and interested parties.

Q. What is the Company’s total capital expenditure for T&D and Electric Production in RY1, RY2, and RY3?

A. The Company’s total capital expenditure for T&D and Electric Production is $1,687.2 million in RY1, $1,958.9 million in RY2, and $1,977.9 million in RY3.

Q. Why are the Company’s capital investments in its electric system infrastructure increasing during the proposed term of this rate case?

A. The main drivers are increased investment in new equipment and technologies that support the advancement of clean energy and a reduction in the Company’s carbon footprint, increased investment in projects that both reduce reliability risks and protect the environment, and continued investments that improve storm resiliency in the Con Edison service territory. We will discuss these areas briefly here, and then in greater detail later in this testimony.

Q. Please describe the planned investments in new equipment and technologies that support reliability and the advancement of clean energy.

A. These programs and projects are part of the Company’s Grid Innovation efforts, a suite of initiatives involving the use of advanced technologies that are foundational and/or enable the Distributed System Platform (“DSP”). They also develop or enhance safety, reliability, resiliency, efficiency, and automation of the electric distribution system. One key component of this suite of investments is the implementation of an enterprise-wide Geographic Information System (“GIS”). When complete, this platform will offer one consolidated mapping and visualization system across electric, gas, and construction and will support the Company’s ability to integrate DER on the system.

Q. What is the projected spending associated with these initiatives for RY1 through RY3?

A. The total projected spend for these items in this timeframe is $260 million.

Q. What are the primary capital investments that both reduce risks to system reliability and protect the environment?

A. The Company plans to replace two of its 138kV dielectric oil-filled feeders in Staten Island, as well as significant portions of two 345kV dielectric feeders in Manhattan, with solid/oil-free dielectric feeders. The existing feeders have a history of oil leaks and proactively replacing them will improve the feeders' reliability and eliminate the potential for future oil leaks in an environmentally sensitive area. In addition, the Company is starting a program that will replace switches, bus sections, and ancillary equipment at existing gas-insulated substations to both improve the reliability of the substations and reduce sulfur hexafluoride ("SF6") leaks. SF6 is a greenhouse gas with approximately 23,000 times the potency of carbon dioxide that is used as an insulating medium inside these substations. Finally, Con Edison plans to significantly increase spending in its existing Substation EH&S Risk Mitigation Program based on lessons learned from recent spill events at one of the Company's substations. This program provides operational enhancements and site improvements, such as modifications to secondary containment structures around oil-filled equipment, installation of oil/water separator systems, and site drainage upgrades. These upgrades are required to manage and mitigate the risks of potential oil release to the environment, which will also protect the health and safety of the public and Con Edison employees.

Q. What is the projected spending associated with these items for RY1 through RY3?

A. The total projected spend for these items in this timeframe is $889 million.

Q. What are the primary capital investments associated with storm resiliency?

A. The Company plans an increase in spending related to storm resiliency, primarily due to lessons learned from winter storms Riley and Quinn. As a result of its post-storm review, the Company plans to enhance the resilience of its non-network circuits by replacing open wire with new stronger wire, adding breakaway service connectors for more customers, reconfiguring 13kV auto loops, and performing additional targeted undergrounding of overhead wire.

Q. What is the projected spending associated with this storm resilience work for RY1 through RY3?

A. The total projected spend for these items in this timeframe is $355 million.

Q. What is the Company’s O&M expenditure for the Historic test year (the period October 1, 2017 through September 30, 2018) for T&D and Electric Production?

A. The Company’s total O&M expenditure for the Historic test year for T&D and Electric Production is $497.8 million.

Q. What are the Company’s O&M program cost change totals for T&D and Electric Production in RY1, RY2, and RY3?

A. The RY1 O&M expense is $481.9 million after subtracting $44.8 million for normalization over the Historic test year and reductions, and adding $28.9 million for program changes. The RY2 O&M expense is $470.0 million after subtracting $12.4 million for reductions and adding $0.6 million for program changes. The RY3 O&M expense is $441.1 million after subtracting $28.9 million for reductions.

Q. Does the Company’s T&D budget contain Capital and O&M funding for municipal infrastructure interference work?

A. Yes. The basis for this funding is explained in separate testimony provided by the Company’s Municipal Infrastructure Support Panel.

C. Key Themes

Q. What are the principles driving the Company’s funding request?

A. The Company selected the projects and programs for which it seeks funding based on four principles: safety, customer experience, operational excellence, and clean energy.

Q. Please elaborate on the Company's objective of maintaining and improving safety.

A. The Company is absolutely committed to maintaining and improving safety for its customers, employees, and the general public. As a necessary part of that effort, the Company replaces infrastructure that has either reached the end of its useful life or that it has identified as presenting a risk. In addition, the Company invests in improvements for cyber and physical security to protect its system from attacks.

Q. Please explain how the Company's commitment to safety includes the secondary system.

A. Through its Secondary Open Mains program, Underground Secondary Reliability program, and Monitoring Device and Application program, the Company continues to invest in the secondary system to reduce manhole events, which can affect both safety and reliability.

Q. Please elaborate on the Company's objective of improving the customer experience.

A. Customers are always at the center of Con Edison's investment decisions. The Company believes that the best possible customer experience begins by providing customers the service and reliability they expect. For example, the Company's recent capital investments and O&M expenditures have reduced its service response time, led to higher rates of resolving issues on the first attempt, and resulted in faster issue resolution overall. In this respect, enhancements to the Company's Customer Project Management System have reduced the duration of the service work life cycle by 7.7%. In addition, the Company's storm hardening and primary energy delivery system investments have improved grid reliability and reduced the risk of service interruptions during both blue sky days and extreme weather events. The Company is also focusing on improving its secondary distribution system.

The planned investments presented in this testimony will continue these efforts. For example, the Company will continue to improve system resilience in the face of severe weather events, particularly with respect to the Company's overhead system. We describe individual projects and programs in the capital and O&M categories of Section V.

The Company is also enhancing its Customer Project Management System to, among other things, allow customers to self-schedule inspection appointments and accomplish a number of case-related tasks using a mobile phone. Additional upgrades include a new customer inquiry feature to manage and track customer questions and new analytic tools. Our testimony and the Customer Operations Panel testimony describe additional initiatives to enhance the customer experience by improving service, communications, and customer processes.

Q. Please elaborate on the Company's objective of enhancing operational excellence.

A. The Company is committed to upgrading its electric system so that it can respond to changing customer needs and an increasingly diverse resource mix. These upgrades will require: 1) new physical infrastructure, such as communications networks, upgraded relaying, increased distribution automation, and enhanced monitoring of field equipment; and 2) the information technology ("IT") infrastructure to manage the associated data so as to maintain a safe and reliable electric delivery system.

The Company also supports operational excellence by replacing degraded infrastructure with newer, more capable assets. These types of replacements, such as the modernization of network protectors, maintain and improve reliability while preparing the system to better integrate new distributed energy resources ("DER").

The Company also maintains operational excellence by investing in the solutions necessary to serve localized load growth. The Company is experiencing significant load growth in specific localized areas despite system-wide load growth being relatively flat. In locations where non-wires solutions ("NWS") are unable to meet all or part of the increased demand, the Company invests in traditional infrastructure to meet system needs. Additional information on load growth drivers and related projects can be found in the New Business section of this testimony.

Q. Please elaborate on how the Company is integrating clean energy.

A. The Company is committed to integrating clean energy into its system. For example, it is investing in infrastructure that supports the use and deployment of electric vehicles, battery storage technology, and flexible non-traditional resources. The Company is also making the necessary investments for increased DER penetration and continues to make foundational and/or DSP-enabling investments. We discuss the Company's efforts to promote and integrate clean energy in the Grid Innovation section of this testimony. Additional information can be found in the testimony of the Customer Energy Solutions Panel.

D. Testimony Format

Q. Please describe how the remainder of this testimony is organized.

A. Section II describes the Company's T&D electric system to provide context for the Company's planned projects and programs. Section III covers the Company's Business Cost Optimization efforts impacting Electric and Central Operations. Section IV provides a summary of planned T&D capital and O&M expenditures. Section V covers the individual T&D projects and programs organized by categories of spend and then by type of work within each category. Section VI describes planned Electric Production projects and programs. For sections V and VI, the Company provides a description of each spend category, lists all programs and projects in each category, and typically describes the higher dollar programs and projects in testimony. Additional detail on each program and project can be found in the respective white paper located in the EIOP exhibits. Section VII addresses work performed for the Metropolitan Transportation Authority. Finally, Section VIII discusses special issues such as Reliability Performance Mechanism changes, storm reserve, and charges for special services. Each special issue discussed in Section VIII is listed in the Table of Contents.

II. Electric System Description

A. Importance of Electric Infrastructure to Service Area

Q. Please describe the importance of the Company's electric infrastructure to its customers and to its service territory.

A. Con Edison is proud of the fundamental role it has played and continues to play in the history, growth, and future of its service territory. The Company distributes electricity to approximately 3.46 million customer accounts in New York City ("City") and Westchester County, which have a combined population of nearly ten million people. The Company's service territory is home to two of the five largest cities in New York State – the City and Yonkers, and to businesses that are leaders in national and international commerce, finance, culture, sporting events, and entertainment. The City is also an important center for international affairs as the host for the United Nations headquarters.

Electric system reliability is important to the safety and economic health of the service territory, which is comprised of high-rise buildings, extensive subway and rail transportation systems, and major health care facilities.

Electricity is also critical to our customers' health and well-being. It enables food storage and preservation, water delivery and purification, wastewater treatment, communications, entertainment, and the conveniences of everyday life.

Because Con Edison understands how important electricity is to our customers and our region, it continuously seeks to deliver it safely and reliably. This requires the Company to make ongoing investments in its electric infrastructure. Con Edison prides itself on excellence, provides a high level of reliability to its customers, and was recently recognized by PA Consulting as the recipient of the 2018 ReliabilityOne Award for Outstanding Reliability Performance in the Northeast Region. Con Edison is also making investments to transition to a new electric delivery system that will enable the new more interactive customer relationship that customers expect.

B. Description of T&D Systems

Q. Please provide a general overview of Con Edison's electric energy delivery systems.

A. Con Edison's electric service territory covers 604 square miles and includes all of New York City, except the fifth ward (Rockaway Peninsula) in Queens, and approximately two-thirds of Westchester County. The electric delivery system is comprised of approximately 96,300 miles of underground T&D lines and over 34,400 miles of overhead lines. The Company's underground T&D system is the largest in the United States. Con Edison's service territory, while relatively small geographically, represents approximately 40 percent of New York State's peak electricity demand.

The Company's T&D systems are classified into three major categories: 1) the transmission system (S&TO); 2) transmission and area substations (SSO); and 3) the distribution system (Distribution). Con Edison also has a small portfolio of facilities associated with its steam system that generate electric power, as discussed in Section VI.

C. Transmission System

Q. Please describe the Company’s transmission infrastructure.

A. The transmission system includes both underground and overhead infrastructure. Con Edison's underground transmission system is the largest underground transmission system in the United States and delivers electric energy at 69 kilovolts (“kV”), 138kV, 230kV, 345kV, and 500kV from generating sources to Company substations located throughout its service territory. About 85 percent of the underground transmission system is comprised of underground pipe-type cables, the largest system of its kind in the world. This type of cable system is composed primarily of steel pipe that houses three paper-insulated cables and is filled and pressurized with 8.3 million gallons of dielectric fluid. The dielectric fluid provides insulation as well as cooling for the cables. Over 200 facilities, located throughout the system, pressurize, circulate, and cool the dielectric fluid. In addition to pipe-type cable, the remaining 15 percent of Con Edison's underground transmission system consists of other types of cable, such as self-contained, fluid-filled, and solid dielectric. The overhead transmission system, located in Dutchess, Putnam, Westchester, and Richmond Counties, consists of 1,220 towers that support 355 circuit miles of cable situated along 113 miles of right-of-way. The Company also owns or jointly owns 387 structures that support 81 circuit miles in Orange and Rockland counties.

The transmission system is subject to high loading as well as a physically challenging underground environment. Accordingly, the Company must maintain, restore, and programmatically upgrade and replace system components in order to provide a safe and reliable system.

D. Transmission and Area Substations

Q. Please describe the Company's transmission and area substation infrastructure.

A. Substations consist of components (circuit breakers, transformers, phase angle regulators, switches, relay systems, and communications systems) that are used to transform, sectionalize, control, and direct power on the electrical power system. On the Con Edison system, these substations are referred to as transmission stations and area substations or stations. Typically, transmission lines and generating units are interconnected to transmission stations, which step the voltage down through the use of transformers, to deliver electric power to the area substations. Area substations receive power from the transmission stations and further step the voltage down to deliver electric power to the distribution system. Currently, the Con Edison system has 39 transmission stations and 62 area substations. The transmission stations are operated at 345kV, 138kV, and 69kV. Of the 39 transmission stations, Academy, Mott Haven, and West 49th Street are indoor Sulfur hexafluoride ("SF6") insulated stations; Dunwoodie is an outdoor SF6 insulated station; and all others are outdoor open-air insulated stations.

With the exception of some of the older stations, most of the 62 area substations are indoor facilities, except for their power transformers. The area substations are operated at 33kV, 27kV, and 13kV.

As described in more detail in the T&D Programs/Projects section, the Company must expand certain substations because they will have increased capacity requirements. The Company must also maintain, refurbish, and programmatically upgrade and replace components in each substation to continue to provide a safe and reliable system.

E. Distribution System

Q. Please describe the Company's distribution infrastructure.

A. The electric system's 62 area substations supply 65 networks and 19 non-network load areas. The distribution system is composed of network and non-network systems operating at voltages of 4kV, 13kV, 27kV and 33kV. Staten Island systems operate at 4kV, 13kV, and 33kV; Brooklyn and Queens at 4kV and 27kV; Bronx and Westchester at 4kV and 13kV; and Manhattan at 13kV. Approximately 2,300 primary voltage distribution feeders supply network and non-network load.

Con Edison's underground distribution system is the largest underground, low-voltage, network system in the world. It includes approximately 266,000 manholes and service boxes; 25,400 conduit miles of duct; 96,300 miles of underground cable; and 42,500 underground transformers that further step the voltage down from 33kV, 27kV, or 13kV to 120/208 volts to supply the low-voltage secondary distribution system.

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

The Company’s (non-network) overhead distribution system includes 192 auto loops; 217 unit substations; 13 multibank substations; approximately 198,700 poles; 51,800 overhead transformers; and approximately 34,300 miles of overhead wire including primary, secondary, and service wire. The non-network system uses a first contingency design, i.e., it is designed to sustain the loss of one distribution feeder under peak load conditions without any feeder or transformer overloads or adverse impact on service to customers.

The Company’s distribution system must be maintained, upgraded, and expanded when necessary in order to provide safe, reliable electric service to its customers.

F. Distributed Energy Resources

Q. Please describe the DER on the system today.

A. The term DER covers a wide range of resources including energy efficiency (described in the Customer Energy Solutions panel testimony), demand response ("DR"), and distributed generation ("DG") that includes combined heat and power ("CHP") generators, battery storage, and renewable energy such as solar.

Con Edison has over three decades of experience implementing programs and interconnecting these devices. Over this time, the Company has worked with its customers to increase the amount of DER connected to its system. Since January 1, 2016, the amount of installed solar capacity connected to Con Edison's distribution system has doubled to over 200 MW and is expected to reach 650 MW by the end of 2023. Today, the Company has over 20,000 rooftop solar installations in its service territory. The Company is also facilitating growth in other DER markets, including combined heat and power, which is expected to grow nearly 50 percent by 2023 to 260 MW, and energy storage, which is currently poised for further growth. The Company continues to support the energy transition through its work to make the interconnection process easier, more efficient, and further increase the level of DER penetration.

As discussed in this testimony, the Company has and will continue to work with its customers to increase these resources through its initiatives. Additional information on DER can be found in the Customer Energy Solutions panel testimony.

III. Business Cost Optimization

Q. Please describe Electric Operations' efforts to support the Company's Business Cost Optimization ("BCO") initiative.

A. The Company has several BCO initiatives to optimize Electric Operations' costs while continuing high levels of safety and reliability. The BCO initiatives that Electric Operations is pursuing include the following areas:

- Condition Based Maintenance/Prioritization
- Minimization of Field Visits and Time to Complete
- Scheduling Enhancements
- Workforce Management

The amount of savings associated with the Company's various BCO initiatives are presented in Exhibit AP-3, Schedule 16.

Q. Please describe the "Condition Based Maintenance/Prioritization" initiative.

A. This initiative addresses the current work processes associated with Computer Inspection Network Distribution Equipment ("CINDE") cycles, open main repairs, and mobile system scans. The CINDE inspection cycle will be modified to change it from a time-based inspection cycle to one that is based upon data supplied from the Pressure, Temperature, Oil, and Remote Monitoring systems. Open mains will be prioritized and repairs scheduled based upon a system need analysis that will be uniform across all networked distribution regions. O&M costs for system scanning performed through the Company's Safety Inspection program will be reduced through revision of the current vendor contract to include only the labor to perform the scans using Company equipment.

Q. Please describe the "Minimize Field Visits and Time to Complete" initiative.

A. This initiative addresses the current Electric Operations field crews' work tasks with a focus on reducing work hours and crew visits required per job. These tasks include changes to crews for flush truck support, obstructed conduit repairs, construction or operation crew coverage, and the maintenance associated with communication lines to unit substations. Flush Support Operations will add flush capabilities that can be used by field crews, reducing the need for crews to wait on a flush truck to complete their work. This will reduce the time and costs associated with multiple visits to a location by Company crews. The obstructed conduit repair process change will allow first responding crews to attempt cable removal when it is determined that a cable needs to be replaced. This process change will allow for a quicker determination of the need to repair or replace the cable conduit as well. The Westchester Electric region will combine the Overhead and Emergency groups, using both groups to provide coverage on all shifts. This change will help reduce overtime in the Emergency groups, which currently provides coverage of all shifts. Unit substations rely on copper telecommunication lines for its SCADA systems. These lines have reliability issues requiring numerous field visits with telecommunication crews to resolve the issues. These lines will be replaced at all unit substations where cellular coverage meets the station’s SCADA requirements. This will reduce troubleshooting issues with the communication lines.

Q. Please describe the “Scheduling Enhancements” initiative.

A. This initiative addresses enhancements to current work processes including development of analytics to support the planning and scheduling of jobs. One of the objectives of this initiative is to develop tools and reports to be used in the planning of work, with a focus on reducing “false starts” by field crews. Analysis of data from the work management system will enable efficiency gains in job planning and scheduling of work. Analytics will help with pre-requisite reviews prior to work being scheduled, identify least cost effective areas of spending in the work-flow and resource management, help with the bundling of work, and predict jobs that require additional support before crews arrive on the job site. Tools and reports will be created to focus on the daily planning and execution of work, which includes addressing how emergent work is inserted into the short term work schedule and eliminating the need to review and schedule these jobs on the day they are assigned to field crews. Additional tools and reports will also provide capability assessments that more appropriately match crew capability to job requirements.

Q. Please describe the “Workforce Management” initiative.

A. This initiative addresses changes to how the workforce is managed including the minimum number of people required to perform specific types of work. The initiative also addresses the current process for addressing project layout modifications and/or revisions.

Changes under this initiative will eliminate the need for company resources to perform a final service connection due to customer load expansion or electrical equipment replacement or reconfiguration. The Company will work with electrical contractors by providing procedures, training, and the hardware necessary for the contractor to complete the final service connection. This change will allow the Company to adjust crew sizes as necessary to meet needs. Emergency crews responding to damaged poles often require immediate support from Overhead crews. New shift design involves changes to the starting times of crews by staggering start times, adjusting the duration of a shift, and alignment of supervisor and crew schedules to provide more optimal coverage based upon when work is scheduled.

Projects being constructed using pre-developed construction designs often experience delays when field conditions require modifications to the design. Through changes to the design revision process that improve communication between construction and engineering, the Company will reduce the time and effort required to make these changes.

Q. What challenges does Electric Operations face in implementing its BCO-driven initiatives and realizing its cost savings?

A. First, these changes all involve substantial changes in work processes that will encounter difficulty to implement because they involve substantial change in how the Company has implemented work previously. Many of these initiatives will identify required updates to Company policies, processes, and procedures and additional training for its crews. To succeed, these initiatives will require clear and effective change and communication management programs to drive these opportunities from initiation to completion.

Current cost savings were estimated based upon various factors (when available/applicable) including historical spending, number of annual jobs, average man-hours required to complete tasks, and estimated reductions.

Q. Is Central Operations pursuing its own BCO initiatives?

A. Yes, our primary initiatives are:

- Field Work Execution
- Reorganization
- Planning & Engineering

Q. Please discuss the Central Operations organization's BCO initiatives.

A. The objective of Central Operations' BCO initiatives is to critically examine and redesign processes and employ software tools, where possible, to improve our organization's efficiency. Central Operations analyzed its current work processes to identify opportunities for implementing changes and improving efficiency. Based upon this examination, Central Operations identified and is pursuing three primary initiatives. The amount of projected savings associated with Central Operations' BCO initiatives are presented in the exhibits sponsored by the Company's Accounting Panel.

Q. Please describe Central Operations first BCO initiative.

A. The “Field Work Execution” initiative is based upon the critical examination of the Company’s maintenance and construction activities performed by Company personnel in Substation, Steam, and Transmission Operations. This initiative encompasses a thorough review of how Central Operations plans and executes work efforts. By redesigning processes, this initiative will focus on performing required preventative maintenance in a more efficient manner. The Company is in this process of implementing this initiative and expects to realize savings in RY1, RY2 and RY3.

Q. Please describe Central Operations “Reorganize Substation Operations” BCO initiative.

A. The current organizational structure of the Substation Operations function is not fully optimized. This initiative’s objective is to restructure the Substation Operations organization to enable the most efficient use of personnel and operational tools across the entire organization.

Q. Does Central Operations also have a BCO initiative for its Central Engineering Department?

A. Central Operations analyzed multiple functions within the Central Engineering department for cost savings opportunities. This initiative will focus on pre-screening Engineering Service Requests, reducing Engineering drawings, forming dedicated Engineering project teams, and employing lower cost resources for lower value Engineering functions.

Q. What challenges does the Central Operations organization face in implementing these BCO initiatives and realizing their cost savings?

A. The identified cost savings are dependent on a number of variables. The potential savings were identified by reengineering existing work processes. To achieve the identified savings will require technology enhancements that need to be further defined and developed. After the system enhancements are implemented, the work processes would be expected to lead to reduced staffing requirements. Any such reduced staffing requirements will be achieved through future attrition. The timing for implementing these technology enhancements and realizing the resulting staffing reductions will affect the timing of the projected cost savings.

Q. In addition to the direct BCO savings discussed above, are there other savings that the Company may realize within the Electric Operations and Central Operations functions?

A. Yes. We have also identified “influenced savings.” “Influenced savings” refer to savings driven by initiatives implemented by Utility Shared Services, but that are allocated to another organization. For more detail on such savings, please see the direct testimony of the Shared Services Panel.

IV. T&D Capital and O&M Summary Information

Q. What is the Company’s projected T&D capital spend for the three rate years?

A. The Company is planning to spend $1,676.6 million in RY1, $1,937.0 million in RY2 and $1,963.0 million in RY3.

Q. What is the Company’s T&D Operations and Maintenance (“O&M”) expenditure for the historic test year (the period October 1st, 2017 through September 30th, 2018) for T&D?

A. The Company’s total T&D O&M expenditure for the Historic test year for T&D is $497.8 million.

Q. What are the Company’s O&M program cost changes for T&D in RY1, RY2 and RY3?

A. The Company has calculated a $7.6 million normalization decrease in O&M expenditure over the Historic test year as well as a reduction of $37.2 million. The Company is also planning an increase of $28.9 million for program changes in RY1 and an increase of $0.6 million for program changes in RY2. Reductions in RY2 result in a $12.4 million decrease and reductions in RY3 result in an additional $28.9 million decrease. All the amounts discussed above are exclusive of escalations, which are described by the Accounting Panel.

Q. Does the Company's Electric T&D budget contain Capital and O&M funding for municipal infrastructure interference work?

A. Yes, it does. This Public Improvement/Interference work is addressed in separate testimony provided by the Company's Municipal Infrastructure Support Panel.

Q. How will you present the Company's projected T&D capital and O&M expenditure requirements?

A. Con Edison's projected T&D capital and O&M expenditure requirements are presented under the following categories: Grid Innovation, New Business & System Expansion, Risk Reduction/Reliability, Replacement, Equipment Purchases, Safety and Security, Environmental, and Information Technology.

Q. Please provide a description of each category.

A. Each of the Company's expenditure categories is described below:

1. Grid Innovation – This category contains projects and programs designed to develop or enhance capabilities that improve the reliability, resiliency, efficiency, and automation of the electric distribution system and support the Company's efforts to establish the Distributed System Platform ("DSP"). The Company will invest $62.4 million in RY1, $62.4 million in RY2, and $67.4 million in RY3 in this category.

2. New Business & System Expansion – New business consists of projects and programs that connect new customers to the Company's electric system. System Expansion consists of projects and programs that increase system capacity or address customer demand growth or supply retirements. The Company will invest $316.7 million in RY1, $339.8 million in RY2, and $345.7 million in RY3 in this category.

3. Risk Reduction – This category consists of projects and programs that support the reliability and/or

availability of a facility or an operational function and that reduce or mitigate a risk associated with a facility or operation through proactive replacement/upgrade strategies. The Company will invest $360.6 million in RY1, $582.3 million in RY2, and $661.3 million in RY3 in this category.

4. Replacement – This category consists of projects and programs to replace failed equipment or equipment that has not yet failed but has degraded performance, has become difficult or costly to maintain, or is approaching the end of its useful life. The Company will invest $474.4 million in RY1, $479.3 million in RY2, and $462.5 million in RY3 in this category.

5. Equipment Purchases - This category consists of projects and programs for the purchase of necessary equipment such as transformers, network protectors, switches, and meters. The Company will invest $126.5 million in RY1, $132.0 million in RY2, and $139.0 million in RY3 in this category.

6. Safety and Security – This category consists of projects and programs primarily intended to prevent or reduce the likelihood of injury or risk to public safety, enhance physical or cyber security, or comply

with regulatory requirements. The Company will invest $16.1 million in RY1, $16.4 million in RY2, and $16.4 million in RY3 in this category.

7. Environmental – This category consists of projects and programs primarily intended to enhance environmental performance, reduce environmental impact, or comply with environmental regulatory requirements. The Company will invest $83.4 million in RY1, $86.4 million in RY2, and $31.3 million in RY3 in this category.

8. Information Technology – This category consists of projects and programs to improve computer systems, system development, and information and communication systems. The Company will invest $43.2 million in RY1, $38.0 million in RY2, and $30.5 million in RY3 in this category.

In addition to these categories, Municipal Infrastructure Support, which is T&D Public Improvement/Interference work, is addressed in separate testimony provided by the Company’s Municipal Infrastructure Support Panel. The Company forecasts $193.0 million in RY1, $201.0 million in RY2, and $210.0 million in RY3 in this category.

Q. Was the document titled “T&D Capital and O&M Summary” prepared under your direction or supervision?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-1

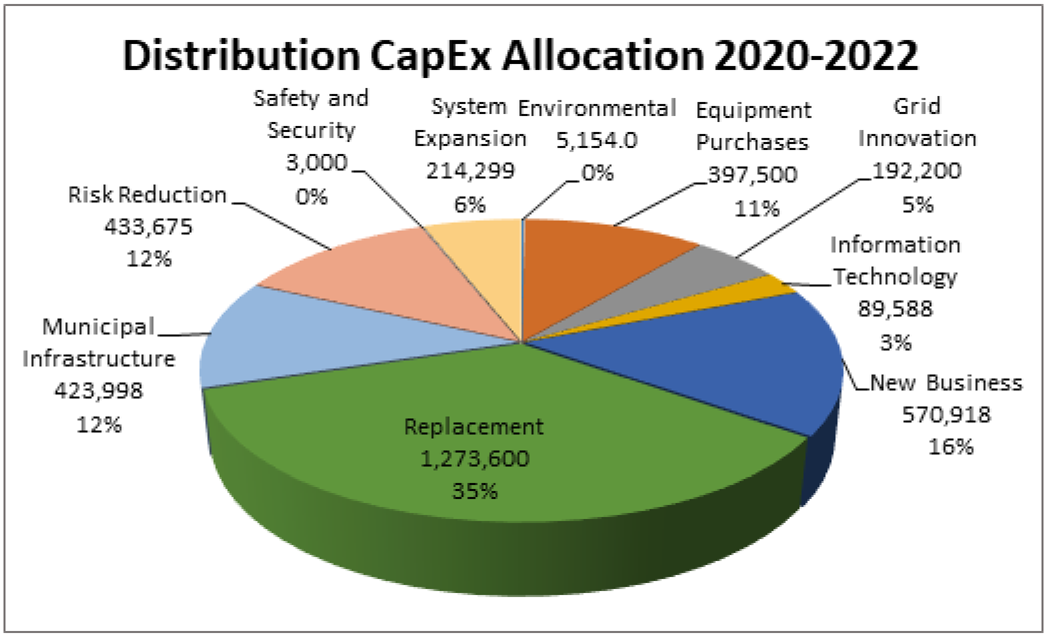
Q. What does this exhibit show?

A. This exhibit presents an overall summary of the total T&D capital expenditures that are presented in our testimony. The exhibit first presents a summary of the Company’s planned capital and O&M expenditures for each of the rate years, for the S&TO, SSO, and Electric Operations organizations. The exhibit also shows planned capital expenditures for each of the rate years for common capital expenditures that are charged to the electric business. The exhibit also shows planned O&M expenditures by organization and a summary of program changes. Note that this Exhibit does not reflect any escalation in expenses in the calculations of the total rate year forecasts for each item. Escalation is discussed by the Accounting Panel.

Q. Please provide an overview of capital expenditures for the rate years.

A. The expenditure details are described in their respective sections of the testimony, but we provide a general overview here. Exhibit EIOP-1, Schedule 1 shows the rate year capital T&D budgets for S&TO, SSO, and Electric Operations. For the purposes of this overview, we describe S&TO and SSO collectively as the Transmission budget.

First, Electric Operations’ spend in the Replacement category represents approximately 35% of its planned capital expenditure. The need for increased replacement work results from an increased focus on this area and work remaining after the recent harsh winters. The Company would need to complete this work regardless of load growth. The full breakdown for Electric Operations is shown in this pie chart in Exhibit EIOP-1, Schedule 3 (dollars are in thousands):



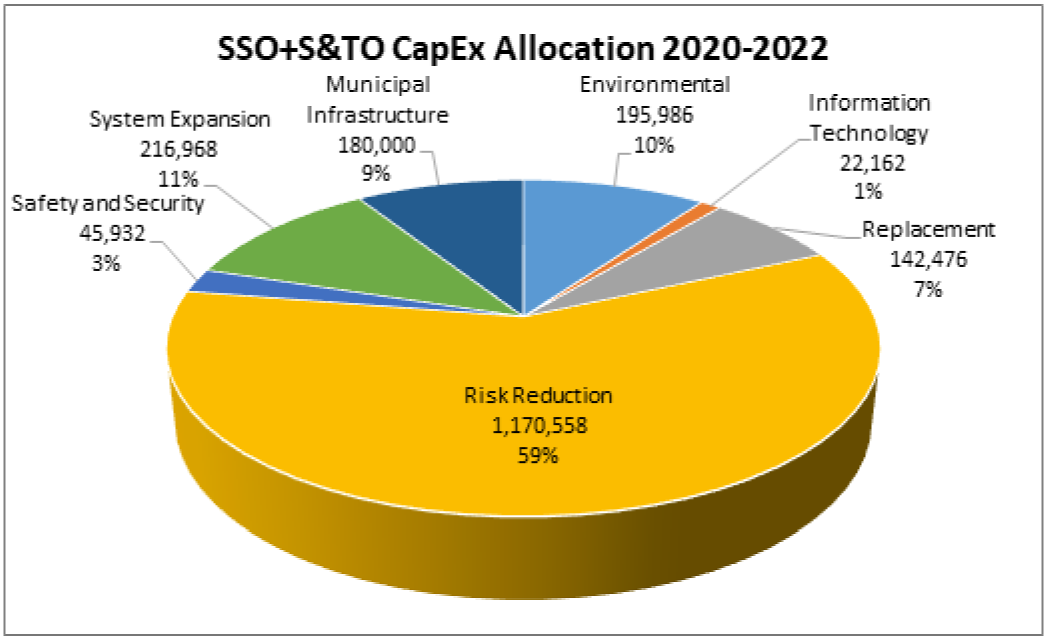
We note here that replacement here doesn't mean just replacement with the same technology. Wherever there is an opportunity, we replace old technology with newer technology that provides additional benefits for customers. For example, should a paper insulated lead covered ("PILC") primary feeder section fail while in service, it is replaced with non-oil containing cable.

Q. Please describe the Company's strategy for investments in its electric distribution system to improve secondary system reliability and reduce manhole events.

A. As described in more detail in the Risk Reduction section, the Company will focus on improvements to its distribution system that will involve installation of sensors in structures that can detect defects or failing components as well as the replacement/repair work on targeted secondary cables based upon their failure rate. These investments will reduce failure events that cause stray voltage and manhole events on the network system. Although the Company does not have complete control over manhole events, because they are weather related and influenced by salt usage, the goal is to reduce the five-year manhole event average. These are important investments because public safety will benefit from a reduced number of manhole events and stray voltage conditions found and repaired.

Q. Please continue with a description of Transmission investments.

A. On the Transmission system, more of the spending is for Risk Reduction, which represents approximately 59% of its capital expenditure. For the Transmission system, the Company typically replaces equipment before an in-service failure because the replacement is for a small amount of equipment that affects a large number of customers. In addition, System Expansion constitutes approximately 11% of the planned electric capital expenditures for transmission. System Expansion activities are needed for multiple reasons, including to address pockets of load growth in the service territory that require expansion. The full breakdown for Transmission is shown in this pie chart that is in Exhibit_EIOP-1, Schedule 3 (dollars are in thousands):



Q. Please provide an overview of the O&M increases for the rate years.

A. Exhibit EIOP-1, Schedule 2 shows the rate year O&M T&D budgets for S&TO, SSO, and Electric Operations. The major driver of O&M increases during the rate years is the Safety Inspection program. This program, which funds the inspection of distribution equipment in order to identify conditions that can lead to safety hazards or adverse impacts on system performance, requires a significant increase in funding during the rate years. This funding increase is required due to the increased number of flush units required associated with the inspections of underground structures required in each of the remaining years (six, seven, and eight) of the eight-year underground inspection cycle. The Company is proposing to modify the current pilot to reduce the amount of the increase required for flushes under the Safety Inspection program. The panel discusses the details of this proposal in the Special Issues section.

V. Detail of T&D Programs/Projects

A. Grid Innovation Capital Expenditure Requirements

1. Overview

Q. Was the exhibit titled, "T&D Grid Innovation" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-3

Q. What does Exhibit EIOP-3 show?

A. Exhibit EIOP-3, Schedule 1 lists the capital program and project funding requirements required to support the company's Grid Innovation work conducted by Electric Operations for RY1, RY2, and RY3. O&M funding requirements associated with Grid Innovation are part of a larger program change to the "O&M Engineering and Other Services" program and are described in the Risk Reduction section of this testimony. In addition, the exhibit contains white papers that provide more detailed information on each of the programs/projects in this category.

Q. Please describe how the Company defines Grid Innovation.

A. Grid Innovation is a set of important initiatives involving the use of advanced technologies — some of which may be considered Distributed System Platform ("DSP") enabling — that develop or enhance capabilities that improve the safety, reliability, resiliency, efficiency, and automation of the electric distribution system. Such initiatives include:

- The sensors, data, and communications networks that enable enhanced visibility and understanding of the state and behavior of the electric network;
- Technologies and equipment that facilitate greater customer engagement regarding energy usage and alternatives; and
- The underlying systems, data management, and analytics that facilitate situational awareness,

asset management, contingency and risk analysis, outage management and restoration.

These necessary core investments underpin the Company's focus on safety and operational excellence. They also provide the engineering basis for increased operational flexibility of a bidirectional grid, which will enable the energy transition and our efforts to achieving state policy goals – such as the integration of various types of DER. They are beneficial for any resource mix.

Q. What are the drivers for Con Edison's Grid Innovation portfolio of investments?

A. The Company developed a Grid Innovation roadmap in response to several important industry trends, including increasing customer expectations for choice, increased DER penetration, and technology advances. Customer expectations for choice and information to use energy how and when they would like is increasing in an on-demand world, driven by technologies like mobile phones and online shopping. With lower prices and policies contributing to the increased penetration of DER, the grid is transitioning from one-way electric delivery to two-way power flows and a 'prosumer' approach where a customer can be both a supplier and a consumer.

Technology advances in computing power, telecommunications, and sensing and control devices enable Con Edison engineers and operators to collect and apply data from points throughout the system to manage a more dynamic grid. The deployment of non-traditional resources has been accelerated by customer demand and policy support for DER technologies, EVs and associated charging infrastructure, and battery storage. Managing a more dynamic grid, that adjusts not only for customer electricity demand but also the supply of DER, requires greater distribution sensing, control, and automation to safely and reliably deliver power, which is essential if these changes are to benefit Con Edison's customers. Given the convergence of drivers described above, Con Edison seeks to execute this plan now to properly position the Company to evolve the electric distribution system for the future.

Q. How will Con Edison's Grid Innovation program benefit its customers?

A. Con Edison's Grid Innovation program benefits customers in several ways. The investments the Company proposes will enable it to continue to deliver power safely and reliably, with enhanced flexibility to enable the delivery of power from a cleaner, more diverse and distributed resource mix. In addition to these benefits, our proposed investments in data analytics will provide long-term benefits associated with reduced transformer failures, improved capital allocation, remote inspections offsetting manual inspections, and improved engineering efficiency for monitoring inspection results.

Q. What has the Company already done to modernize its distribution system?

A. Con Edison has been progressively pursuing modernization of its distribution system for some time now. Several recent examples of these efforts include:

- Deployment of AMI – AMI is a foundational investment for Grid Innovation, enables voltage optimization, produces more timely and granular data, provides visibility into customer energy usage and system performance, improves outage detection and awareness, and provides a telecommunication backbone to enable distribution automation and advanced sensing. The ongoing deployment of AMI is discussed further in the Customer Energy Solutions panel's testimony.

- Accelerating deployment of technologies for greater distribution automation and grid edge visibility – This work includes the deployment of communicating smart switches and sensors, enables the development of advanced capabilities needed to meet Company goals, including DER integration.
- Developing the capabilities of the DSP – Current and proposed Grid Innovation investments, such as communications infrastructure and a Geographic Information System ("GIS"), are foundational prerequisites for DSP investments as well and help facilitate the development of DSP capabilities. The Company's DSP investments are described in more detail in the DSP section of the Customer Energy Solutions panel testimony.

Q. How has Con Edison structured its Grid Innovation program?

A. Con Edison has developed a twenty-year roadmap for Grid Innovation investments required to build the capabilities needed to meet Company goals. The investments are grouped into four five-year phases to provide optionality and guide future investment decisions. As the program progresses, the Company will evaluate certain sign posts

– such as policy direction, technology developments, and penetration of DERs and EVs – that may dictate a change in direction. This deliberately agile approach provides checkpoints to align the Company’s strategy to develop system capabilities in a manner that continues to provide the greatest benefit to customers.

The first phase of the roadmap begins in 2020 (RY1) and is focused on developing foundational systems and infrastructure. This phase will also focus on piloting a number of smaller investments to begin to achieve defined capabilities and identify scalable programs for future investment. The Company expects these initial investments to deliver early successes where ready-to-deploy technology can provide additional grid visibility, intelligence, and control.

2. Required Investments

Q. What type of investments comprise the Grid Innovation roadmap?

A. The Company has eight projects and programs that are part of its Grid Innovation roadmap and the Company plans to invest in during the rate plan years. Details on each of these programs/projects can be found in their respective white papers in Exhibit EIOP-3, Schedule 2.

- “Advanced Employee Safety Tools” ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- “Communications Infrastructure” ($15.0 MM RY1, $15.0 MM RY2, $20.0 MM RY3)
- “Cybersecurity Test Environment” ($2.0 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- “Data Analytics Use Cases” ($2.0 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- “GIS” ($30.0 MM RY1, $30.0 MM RY2, $30.0 MM RY3)
- “Non-network Resiliency with FLISR” ($2.1 MM RY1, $2.1 MM RY2, $2.1 MM RY3)
- “Smart Sensors” ($6.3 MM RY1, $6.3 MM RY2, $6.3 MM RY3)
- “Underground Network Resiliency” ($4.0 MM RY1, $4.0 MM RY2, $4.0 MM RY3)

Q. Please provide an overview of the Company’s GIS project.

A. The Company proposes to implement an enterprise-wide GIS system (“Enterprise GIS”) to consolidate multiple current mapping and visualization systems, and to set the foundation for its Grid Innovation efforts. The Company plans to upgrade from its static mapping systems that include department-specific GIS applications to a single dynamic Enterprise GIS available to all departments within the Company. An Enterprise GIS will catalog and record the specific location and operating characteristics of all grid-connected assets, whether Company-owned or third-party DERs, and the Company's gas and steam infrastructure. This information will enable the Company to develop a single, up-to-date model of its electric, gas, and steam distribution systems.

Q. How did the Company develop the GIS project?

A. In 2014, the Company undertook a Phase 0 Planning project. This Phase 0 project informed the design requirements and cost estimates of the phases of the Enterprise GIS project. Since then, an Enterprise GIS is a core project on Con Edison's Information Technology ("IT") roadmap and the Company is now ready to begin a phased implementation of an Enterprise GIS.

Q. Why is the Company unable to use its existing mapping system to achieve its Grid Innovation goals?

A. The Company's current mapping system was not designed to facilitate the Grid Innovation goals described in this testimony, and maintaining it instead of investing in an Enterprise GIS would significantly hinder or possibly halt the Company's progress toward those goals.

For example, the Company's current mapping system is a combination of several "core" systems and dozens of ancillary systems developed for specific purposes. These systems use 15 distinct and proprietary coordinate systems, have dated graphical user interfaces, and are difficult and costly to enhance and maintain. In addition, sixteen Company departments have developed their own GIS related capabilities for their own use. Some of these GIS related applications are supported by specialized business led IT teams and are limited by the specific department need that required them. None of the existing GIS-related applications provide an interconnected model for use across the engineering departments and operational systems. This departmental level approach does not effectively leverage resources and increases total cost of ownership.

And because there are multiple systems and proprietary coordinates, it is difficult to integrate all the required technology together – both within the Company and with respect to third-party systems (e.g., New York City). As a result, the continued use of the present mapping and visualization systems significantly limits the Company's ability to use external map services, produce multi-commodity maps, perform data and map maintenance, and produce ad-hoc maps as necessary.

Q. Please discuss the benefits of an Enterprise GIS.

A. The proposed Enterprise GIS is a foundational investment necessary to unlock the benefits of the customer-focused, clean energy future that both the State and the Company are working to achieve. The Company requires an Enterprise GIS in order to fully implement its Distributed Energy Resource Management System ("DERMS"). Con Edison currently has over 23,000 DER (like rooftop solar) on our grid with the expectation of an exponential increase to achieve environmental policy goals. As explained by the Customer Energy Solutions Panel, DERMS will be an essential tool for monitoring, forecasting, dispatching, and planning for this existing and new DER. Similarly, the Company must implement its proposed Enterprise GIS in order to implement an Advanced Distribution Management System ("ADMS"), which will continuously run load flow calculations to optimize system configuration and provide greater situational awareness. Without an investment in an Enterprise GIS now, customers will lose out on the benefits that future investments like DERMS and ADMS will offer.

In addition, the proposed Enterprise GIS will assist the Company in producing more advanced DER hosting capacity maps, and is required for the Company to map many of the new assets it expects to be added to its system including AMI access points, AMI relays, and upgraded network protectors. The proposed Enterprise GIS will also benefit customers by improving the Company’s storm response through outage mapping and damage assessments. Finally, the proposed Enterprise GIS has benefits for the gas system, as discussed by the Gas Infrastructure and Operations Panel.

Q. Does the Enterprise GIS provide financial benefits?

A. Yes. In addition to its essential role in unlocking the benefits of the Company’s Grid Innovation roadmap, developing an Enterprise GIS will result in cost avoidance for licenses and support for mapping systems that can be retired, and efficiency gains associated with electric and gas spatial analysis, improved regional engineering processes, enhanced vegetation management, and increased implementation of demand side management resources. An Enterprise GIS platform will also improve the system model and accuracy and reduce the risk of conflicting information by having a single system of record for data collection and reconciliation. These financial benefits are discussed in the business plan in Exhibit EIOP-3, Schedule 2.

For all of these reasons, an Enterprise GIS provides immediate benefits today and also enables future capabilities needed to achieve the goals of the Grid Innovation initiative.

Q. Did the Company do a Benefit Cost Analysis for the Enterprise GIS?

A. Yes. While present estimates indicate that the Enterprise GIS would be BCA neutral, the Company anticipates additional benefits and will continue to refine its analysis in the future as this project progresses.

Q. Please describe the Company’s implementation approach.

A. The Company is proposing a phased approach to developing an Enterprise GIS. Phase 1 will focus on replacing the VISION Electric and Gas system and will combine the Company’s low-tension electric and gas maps into a single, state of the art GIS system. Phase 2 focuses on integrating the electric primary feeders and high-tension maps into the new GIS system. Phase 3, which is outside the horizon of the Company’s 2019 rate filing, integrates the Company's steam system and electrical conduits, including vacant and obstructed conduits into the new mapping system, and will provide enhanced capabilities to all systems.

Q. Please provide an overview of Smart Sensors.

A. During the upcoming rate period, the Company intends to implement a Smart Sensors program to enable grid sensing at the edge of the electric system. The Smart Sensors program deploys advanced technology to provide visibility of structures, cable equipment, and network protectors in order to analyze performance and identify issues early. The Company requires smart sensors and visibility of the edge of the electric system in order to, 1) better understand the impacts of third parties connecting to the Company's distribution system, 2) allow the increased penetration of DER, and 3) allow automation of certain tasks and inspections normally done in field. Each type of sensor is described below:

- Structure Observation System is an environmental sensor that monitors combustible gasses, stray voltage, overheating, and visible deterioration in structures, like Company manholes and service boxes. The Structure Observation System also can be configured as a collection point for additional data, which it then securely transmits back to be analyzed for appropriate next actions

- Embedded sensors in cable equipment such as splices collect electrical data (e.g., current, phase angle, temperature) of primary and secondary cable
- Pressure sensors similar to those currently being deployed on distribution transformers will be used to provide visibility into network protector conditions. These sensors will help to determine if there are leaks or faults in the network protector housing that would lead to failed operations.

Q. What is the justification for the Smart Sensors program?

A. The additional situational awareness provided by the smart sensor program will improve public and employee safety, enhance system reliability, and over time will likely lead to cost savings by enabling a transition to condition-based inspections.

Safety benefits are realized through earlier detection, root cause identification, and response to emergent hazardous conditions on the electric system or within manhole structures, which offers the opportunity to proactively address these conditions before they evolve to rare but dangerous events.

Smart Sensors also provide reliability benefits through greater visibility of equipment performance. For example, the embedded sensors in secondary cable joints provide visibility to blown limiters, which were previously undetectable. Blown limiters can eliminate the redundancy of service to customers, potentially impacting reliability. Similarly, deploying Structure Observation System has demonstrated the ability to avoid equipment failures as part of a pilot to safeguard and maintain utility service for the subway system[1].

Finally, through greater visibility, the Company is laying the groundwork for virtual inspections and condition-based maintenance, which would provide an opportunity to reduce costs related to the current manual inspection process and unplanned maintenance. Smart

[1] Case 17-E-0428, In the Matter of an Investigation into the April 21, 2017 Metropolitan Transportation Authority Subway Power Outage and Consolidated Edison Company of New York, Inc.’s Restoration Efforts, Order Directing Steps to Safeguard and Maintain Adequate Utility Service to the Subway System, issued November 10, 2017, pp. 13.

sensors need to be deployed now and in the future to proactively identify and correct problems in our subsurface structures.

The annual equipment deployed in this program includes approximately 2,250 Structure Observation System sensors, 1,070 smart secondary crabs, 250 smart primary slices, and 300 network protector housing pressure sensors.

Q. What investments is Con Edison planning during the rate period to enable greater distribution automation?

A. During the upcoming rate period, the Company intends to implement and expand upon programs related to underground resiliency and non-network resiliency with Fault Location, Isolation, and Service Restoration ("FLISR") respectively, which will provide greater distribution automation capabilities. These programs both deploy SCADA-capable automated switching devices to detect faults and isolate portions of feeders to mitigate the impact of faults and more rapidly restore impacted sections.

Q. What is the justification for the underground resiliency program?

A. The ability of the underground breakers to reduce the portions of networks in contingency and reduce stress on secondary cable will improve the resiliency and reliability of the system. In developing the technology, Con Edison modeled the replacement of all switches in a network with the underground breaker and calculated a resulting 10% improvement in the Network Reliability Index ("NRI") score. The SCADA control of these breakers will also enable greater operational flexibility. The breaker will reduce the risk of system events that jeopardize the reliability of the network. Con Edison's service territory includes over 2,200 primary distribution feeders. While not all feeders will be targeted for this program, the Company anticipates that the deployment of this program will extend well beyond this rate period. Benefits will accrue on a feeder by feeder basis as the underground feeders are bisected or network and non-network portions of hybrid feeders are split.

Q. How will the deployment locations for this project be prioritized?

A. Underground interrupters will be deployed on a targeted basis, with 8-24 interrupter installations per year, starting with areas of the grid where reliability gains can be made at the least expense. Locations will be chosen based on the system design (network and hybrid feeders), reliability performance, and cost to implement.

B. New Business and System Expansion Capital and O&M Expenditure Requirements

Q. Please describe how content in this section is organized.

A. This section contains four subsections: 1) Load Growth Forecast, which describes the Company's forecast and load growth drivers; 2) Investment Approach Overview, which provides a high-level description of how the Company approaches system expansion investment decisions; 3) Non-Wires Solutions, which contains an overview of how non-wires solutions are used to address load growth; and 4) Utility Solutions, which contains a description of the traditional utility solutions required to address load growth.

1. Load Growth Forecast

Q. Was the exhibit titled, "Electric Peak Demand Forecast" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-2

Q. Please describe the load growth and electric demand forecasts for Con Edison's service territory.

A. Total electric demand in Con Edison's service territory is expected to grow at approximately 0.1 percent per year over the next five years (2019-2023). The electric peak demand forecast takes into account commercial, residential, governmental, and other new business growth (electric vehicles and steam to electric chiller conversions) and load modifiers such as CHP, storage, solar, conservation voltage optimization (“CVO”), and organic Energy Efficiency/codes and standards. It also includes the demand side savings expected to result from the various State and Company Demand Side Management (“DSM”) programs, discounted for free ridership.

Q. Please describe what is shown in Schedule 1 of Exhibit EIOP-2.

A. Exhibit EIOP-2, Schedule 1 shows the effect on the current electric system forecast of peak demand reductions projected to occur as a result of DSM initiatives in the rate years and beyond. However, as discussed in the Customer Energy Solutions panel, the Company’s DSM forecast used in this rate filing is subject to change if the Company changes its proposed program. The upper line in this exhibit represents the Con Edison service area peak demand forecast for the years 2019 through 2028 without the impact of DSM programs. The lower line in this exhibit represents the service area peak demand forecast, including the impact of 223 MW of DSM in RY1, 331 MW in RY2, and 461 MW in RY3 (DSM values are incremental to the 2018 baseline). The DSM programs reflected in the difference between the upper line and the lower line in the exhibit include Con Edison’s proposed Energy Efficiency program, demand response (“DR”) that is enrolled only in Con Edison programs, the Company’s Demand Management program, the Brooklyn-Queens Demand Management program, targeted non-wires solutions, New York State Energy Research and Development Authority’s (“NYSERDA”) energy efficiency programs, and the New York Power Authority’s (“NYPA”) energy efficiency programs. All together, the Company forecasts that these proposed programs will deliver approximately 1,445 MW of system coincident peak demand reductions between 2019 and 2028. These reductions do not include the New York Independent System Operator (“NYISO”) DR programs, which are considered to be supply side bulk system reliability event programs and will not necessarily be called to address a need when Con Edison requires distribution peak load reduction measures on its distribution system.

Q. Please discuss in more detail the Company's projection for load growth and its impact on this rate filing.

A. While overall electric system load growth is 0.1 percent annually, load growth in many individual load areas is projected to be higher. Load growth in these areas is driven by certain residential neighborhoods, such as those in various electric networks in Brooklyn and Queens, including Ridgewood, Williamsburg, and Borough Hall, and mixed-use neighborhoods, such as those located within the Pennsylvania Network in Manhattan. In these growth areas, the Company considers both traditional solutions as well as non-wires solutions ("NWS") to address the need for load relief.

Growth in these areas drives the need for electric delivery expansion. In total, as described in Exhibit EIOP-2, Schedule 2, there are 27 electric network areas that are projected to have compounded annual load growth rates of 1.0 percent or higher for each of the next 5 years, and in some of these networks, much higher than 1.0 percent. For example, the Company forecasts 11.4% annual growth over the next 5 years for the Pennsylvania

Network. The significant load growth in this network is due to the redevelopment of the west side of Midtown Manhattan.

The Hudson Yards Redevelopment is contributing to this localized load growth and is 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 next phase of Hudson Yards has started engineering design and will be residential, office/commercial and school loads, at approximately 37 MVA with service dates starting in 2021. Additionally, there are various developments planned across the same area including Brookfield’s Manhattan West, 30 Hudson Blvd., 35 Hudson Blvd., 50 Hudson Blvd, and 66 Hudson Blvd, which all vary from mix-use commercial/residential buildings with trade floors that will add an additional 116 MVA.

New construction projects in the Company’s service territory include large commercial and residential developments, renovations, and expansions as well as most of the large transportation and municipal projects currently underway. As described in more detail later, the Company anticipates that New Business projects - major and retail - will require it to invest more than $498 million over the next three years.

2. Investment Approach Overview

Q. Was the exhibit titled, "T&D New Business and System Expansion" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-4

Q. What does Exhibit EIOP-4 show?

A. Exhibit EIOP-4, Schedules 1 and 2 list the capital program and project funding requirements and O&M program changes required to support New Business and System Expansion work conducted by S&TO, SSO, and Electric Operations for RY1, RY2, and RY3. The exhibit also contains white papers for each capital and O&M program/project in this category that provide more detailed information, such as program and project work description, justification, alternatives, estimated completion date, current status, and forecasted funding.

Q. Please discuss the Company's plans to reinforce its T&D system to support new business and the associated load growth.

A. As stated previously, the forecasted increase in customer demand in certain networks results in forecasted capacity constraints that the Company must address. The Company must invest in its transmission system, substation infrastructure, and local distribution system 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 through non-wires solutions; 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.

3. Non-Wires Solutions

Q. Please describe how the Company engages customers to reduce demand.

A. When the Company identifies a system constraint driven by customer demand it evaluates the ability of a non-wires solution (“NWS”) to meet that need.

Q. How does the Company define NWS and how may they be used to address increased demand?

A. The Company worked with Staff and stakeholders to define NWS. We define NWS as a cost-effective portfolio of non-traditional, typically customer-side, solutions that enable the offset or deferral of traditional utility asset investments while continuing to maintain the same high levels of reliability for its customers. NWS portfolios are generally comprised of a variety of distributed energy resources ("DER") that collectively satisfy an identified reliability need in place of a traditional asset investment.

Q. How does the Company identify NWS opportunities and consider them as part of its capital planning process?

A. The Company starts by identifying areas of its system that have forecasted overloads and require load relief to maintain reliability. The Company then determines whether the identified need is a suitable candidate for a NWS by assessing it against the Company's NWS suitability criteria. The suitability criteria identify projects that: 1) are for load relief, 2) have enough lead time to pursue a NWS without foreclosing the opportunity to install a traditional solution if needed, and 3) offer enough capital deferral or displacement to overcome transaction costs and scale issues. Projects that pass the Company's suitability criteria enter the procurement process. The Company conducts a competitive solicitation for non-traditional solutions to determine if a NWS portfolio is feasible and cost-beneficial.

Q. Has the Company identified any NWS opportunities to-date for implementation in the near term?

A. Yes. The Company has identified two potential NWS opportunities that it plans to implement: 1) Water Street, and 2) Plymouth Street. Additional detail on the Company's NWS processes and these specific opportunities can be found in the Customer Energy Solutions panel.

4. Utility Solutions

Q. How does the Company identify the appropriate utility solution to use, when required?

A. As discussed previously, the Company considers multiple approaches to mitigate capacity constraints on the system at the lowest cost while maintaining reliability. During the rate plan years for this filing, the Company has projects in the following traditional system expansion categories: 1) upgrade or replace existing assets with ones that have higher capacity ratings; 2) install additional assets to increase system capacity, and 3) transfer load to other areas with spare capacity.

Q. Please describe how upgrading or replacing existing equipment is used to alleviate capacity constraints.

A. Where feasible, the Company will replace limiting cable, bus, and/or transformers with new equipment that has a higher capacity and/or higher rating.

Q. What upgrade or replacement projects is the Company pursuing?

A. The Company is pursuing the following projects. Details on each of these projects can be found in their respective white papers.

- "E179th Switchgear and Bus Replacement" ($12.2 MM RY1, $10.4 MM RY2, $22.2 MM RY3)
- "Network Transformer Relief" ($12.4 MM RY1, $12.4 MM RY2, $12.4 MM RY3)
- "Non-Network Feeder Relief" ($7.3 MM RY1, $7.3 MM RY2, $7.3 MM RY3)
- "Overhead Transformer Relief" ($2.3 MM RY1, $2.3 MM RY2, $2.3 MM RY3)
- "Primary Feeder Relief" ($10.8 MM RY1, $10.8 MM RY2, $10.4 MM RY3)
- "Queensboro Bridge Riser Replacement" ($1.6 MM RY1, $10.6 MM RY2, $5.5 MM RY3)

- “Secondary Main Relief” ($2.5 MM RY1, $7.0 MM RY2, $7.0 MM RY3)

Q. For the “Queensboro Bridge Riser Replacement” project, please describe the need for this work.

A. The Company supplies power to Roosevelt Island through six network distribution feeders that are supplied via two riser cables attached to each side of the Ed Koch Queensboro Bridge. Since 2004, there have been fifteen failures and emergency repairs to the distribution riser cables attached to the bridge. Each time a riser cable failure occurs, the capacity to supply Roosevelt Island is reduced until time-consuming repairs can be made, which increases the risk of a power loss to the island.

To address these concerns, the Company previously initiated in 2011 the “59th Street Bridge Crossing” project designed to upgrade the infrastructure supplying Roosevelt Island. The project scope included replacement of the existing messenger wires and aerial paper feeder cables on the main bridge spans with new conduit systems, feeder cables, and riser cables. However, due to field conditions and the rigidity of the armored riser cables, the Company attempted, but was unable, to install new riser cables in the existing riser conduit. Field conditions required the Company to develop a new approach for installation of the new riser cables. Through this project, the Company plans to begin construction in 2021 and complete installation and commissioning of the new riser conduit and cable in 2023, based on the revised design for this work.

Q. Because it is an important ongoing program, please elaborate on “Network Transformer Relief.”

A. This program identifies and proactively addresses potential transformer overloads that could affect capacity on the roughly 27,000 network transformers supplying power to the 65 secondary grid networks that comprise the Company’s underground network distribution system. Each fall, the Company inputs updated data from the summer into its Poly Voltage Load Flow program and models load on its network transformers. Based on this analysis, the Company designs projects to relieve the projected transformer overloads and targets completion of the projects prior to the summer peak load period.

Q. How many such projects does the Company anticipate that it will identify through this program?

A. The Company projects, based on the three year historical average, that it will need to complete approximately 14 transformer relief projects each year during the rate plan years. These may include replacing a transformer with a higher capacity transformer, transferring load and transformers between feeders, balancing load through secondary main reconfiguration, or installing a new transformer.

Q. Please continue by describing the next type of traditional utility solution used to address load growth, installing additional equipment.

A. In cases where capacity constraints cannot be relieved through demand reduction or equipment replacement, the Company will install additional equipment to handle the increased load and relieve capacity constraints. This category includes the installation of additional assets required to connect new customers.

Q. What installation projects is the Company pursuing?

A. Projects in this category are listed below. They include work to install additional equipment on primary feeder cables, transformers, secondary cables and wires, and underground and overhead services. The list also includes programs to connect new customers. Details on each project can be found in their respective white papers.

- “Cable Crossing – XW Riverdale and BQ Flushing” ($5.0 MM RY1, $2.7 MM RY2, $1.0 MM RY3)
- “Hudson Avenue Distribution Switch Station” ($34.2 MM RY1, $68.4 MM RY2, $69.4 MM RY3)
- “Meter Installation” ($24.3 MM RY1, $24.3 MM RY2, $24.3 MM RY3)
- “Nevins St. Battery Storage” ($5.0 MM RY1, $5.0 MM RY2)
- “New Business Capital” ($165.0 MM RY1, $165.0 MM RY2, $168.0 MM RY3)
- “YorkVille Crossings and Feeder Relief” ($8.5 MM RY1, $7.7 MM RY2, $7.7 MM RY3)

Q. Because it is the Company’s sole program for connecting new customers, please discuss “New Business Capital.”

A. When the Company connects new load, it often finds that its distribution system is at or beyond its capability and that it cannot serve the new load by simply extending a service lateral from its distribution system. In fact, many new residential and commercial projects require the Company to make extensive infrastructure investments such as reinforcing secondary mains, extending primary feeders, and installing transformer vaults. The New Business Capital program is the vehicle for these investments. Without these investments, the Company would not be able to fulfill its obligation to serve new customers within its service territory.

Q. Does the Company need a New Business Capital program given its relatively flat load growth forecast?

A. Yes. The need for new infrastructure to support load growth is driven by conditions within very specific local areas of the overall system. This means that the Company is required to invest in additional capacity to meet localized needs, despite system-wide load growth being relatively flat.

Q. Please describe some of the new business projects driving the need for investment under the "New Business Capital" program.

A. The Company is experiencing growth in numerous areas of the five boroughs from new commercial and residential developments, rail and air transportation projects, universities and technical schools, and residential growth within existing communities.

In Manhattan, a mix of new developments and public transportation projects are driving load growth. With respect to new developments, the Eastern and Western Hudson Rail Yards developments are expected to add approximately 50 MVA of load over the rate case years. In addition, the Company is aware of several planned mix-use commercial/residential buildings with trade floors, which will add an additional 116 MVA. The service dates for these developments vary from 2019 to 2021.

With respect to public transportation, the Company will have to invest in infrastructure to support the East Side Access and the Second Avenue Subway extension projects. The East Side Access project is the first expansion of the Long Island Rail Road ("LIRR") in over 100 years and is the largest project of its type in the country. It will connect the LIRR's Main and Port Washington lines in Queens to a new LIRR terminal beneath Grand Central Terminal in Manhattan, with a targeted start in December 2022.

Phase two of the 2nd Ave. Subway project has started construction to extend the current 2nd Ave. subway line northward; establishing new stations located at 106th, 116th, and 125th Streets, which will add approximately 20 MVA of load to the YorkVille and Triboro networks.

Q. What type of projects are driving load growth outside of Manhattan?

A. In the Brooklyn/Queens Service territory, there are several large-scale projects scheduled for development over the next five years. The Pacific Park Project (AKA “Atlantic Yards”) consists of 14 mixed-use buildings, of which eight remain to be completed. The remainder of the project is expected to add approximately 13 MVA.

The Domino Sugar waterfront property consists of a five phase commercial and residential development in which phase one is complete and phase two has begun construction. Phase three is in the design phase and involves restoring Domino’s Sugar landmark refinery building and creating over 400,000 square feet of new commercial and office space, with a projected service date in 2021. The complete five phase complex will have an estimated load of 14MVA.

The Brooklyn Navy Yard and longtime tenant Steiner Studios are redeveloping its waterfront property. The Navy Yard has requested an increase in its electric service as it plans to add more than two million square feet of commercial space including office and research lab facilities. In conjunction, Steiner Studios is developing its portion of real estate by re-purposing long abandoned hospital facilities to be converted into filming studios and commercial real estate and is in the design phase on more than 1.5 million square feet of new construction. Both projects have a target service date starting in 2023 with an estimated demand of 16 MVA.

The Port Authority of New York and New Jersey is currently proceeding with an extensive program to modernize and expand its facilities at LaGuardia Airport. Two major redevelopment plans for the airport are the LaGuardia Development Program and the Delta Expansion Program. The combined additional load for both programs is expected to be approximately 28 MVA.

The Port Authority of New York and New Jersey is also planning to redevelop John F. Kennedy airport. The total additional load from this development project is expected to be 10 MVA over next several years.

There are also projects in Westchester driving load growth. The New York City Department of Environmental Protection will be constructing the Kensico - Eastview Connection Tunnel, which is a deep rock tunnel boring project between Valhalla and Eastview in Westchester County. Once the project is completed and the tunnel is in operation, the Company expects an ongoing load of

1.4MVA. The project is currently in the planning stages with construction expected to begin in 2023.

Lastly, there are two projects in the Company’s Staten Island service territory driving load growth. The DEP has plans to revamp its Waste/Water Treatment plants and the Staten Island Railway will continue bolstering its system by adding two additional traction power substations. In addition, the Company anticipates other major projects including a new substation for the College of Staten Island, the new Sanitation garage, and the continued development of the West Shore warehouse/ logistics site.

Q. In addition to the New Business Capital program, you mentioned the “Hudson Avenue Distribution Switch Station” project as an example of an installation project that addresses capacity constraints. Please describe these Brooklyn projects.

A. The aforementioned NWS opportunities for Plymouth Street and Water Street Substations are projected to solve capacity needs at these stations through 2021. After 2021 the Hudson Ave Distribution Switch Station will need to be put in service or additional NWS will be needed to fully alleviate substation capacity constraints. The

Company’s load flow and forecast analyses project that the Water St. area substation and Farragut substation transformers supplying the Water St. area substation will develop 11 MW and 15 MW capability shortfalls respectively in 2022, and that these shortfalls will increase in subsequent years. Furthermore, the Plymouth Street area substation is projected to have a 6 MW shortfall starting in 2025. Projected load growth in the area served by these substations requires a substantial increase in the capability of the substations.

To address this issue, the Company plans to install two 138/27kV transformers supplied from the 138kV Hudson Ave. East transmission station. This project will create an additional supply source for the Plymouth and Water St. stations prior to the projected capability shortfall in the summer of 2022. This project will provide the capacity needed at the least cost and is expected to meet the station’s capability needs through 2038. Please refer to the project’s white paper for additional detail.

Q. Please continue with a description of the final traditional utility solution type, load transfers, and how they are used to alleviate capacity constraints.

A. Load transfers involve shifting load from an overloaded, or soon to be overloaded, substation, transmission feeder, or network to an adjacent network that has spare capacity. Load transfers allow the Company to maximize use of its existing infrastructure and are done when the Company finds them to be more cost effective than building new substation capacity. This option, however, is becoming increasingly difficult as spare substation capacity decreases.

Q. Is the Company planning to invest in any new load transfer projects?

A. Yes, the Company plans to invest in the two load transfer projects listed below. While we describe these projects below, additional details can be found in their respective white papers.

- "Load Transfer Newtown to North Queens" ($24.0 MM RY1, $1.8 MM RY2)
- "Load Transfer W42nd St. to Astor" ($1.5 MM RY1, $4.0 MM RY2, $8.0 MM RY3)

Q. Because load transfers are typically larger investments, please describe both of these projects starting with "Load Transfer W42nd St. to Astor."

A. Based on the Company's 10-Year Load Forecast, it projects that the area substations and sub-transmission feeders in the West 49th Street load pocket will exceed their capability by the summer of 2023. This situation is driven mainly by new business load growth in the Pennsylvania Network, which includes the Hudson Rail Yards, Brookfield Properties, and several skyscrapers along the newly constructed Hudson Blvd. In addition, it is also expected that the No. 7 Subway Line extension to W.34th St. and 11th Ave. will play a significant role in the area's load growth by attracting new tenants.

To avoid overloading the W.42nd St. No. 1 substation, which supplies the Pennsylvania network, the Company plans to transfer 55 MW of load from the W.42nd St. No. 1 substation to the Astor substation prior to the summer of 2023. This load transfer will reduce loading at the W.42nd St. No. 1 substation to 84% of capacity, while leaving the Astor substation at 88% of capacity for the summer of 2023.

Q. Please continue with a description of "Load Transfer Newtown to North Queens."

A. The Company must complete this project to avoid overloads to both the Newtown substation and the sub-transmission feeders supplying it. Load projections indicate that the Newtown area substation and the 138 kV sub-transmission feeders supplying the Vernon/Glendale/Newtown load pocket will exceed their capabilities by the summer of 2021. The overloads are projected to occur as result of load growth in the Borden network, causing the Newtown substation load to increase to 248 MW by summer of 2021. If left unaddressed, this load would exceed the 244 MW capability of the substation by 4 MW. This load transfer will require extending ten network feeders from the Long Island City network to the Borden network, splitting ten feeders in the Borden network, and reconfiguring impacted secondary networks.

Q. Has the Company excluded any capital expenses related to infrastructure needs in its revenue requirements because the infrastructure is being deferred or eliminated through a Non-wires Solution?

A. Yes, the Company has not included capital expenses related to Plymouth Street and Water Street projects, discussed further in the "Targeted Initiatives to Defer Electric Infrastructure" portion of the Customer Energy Solutions panel testimony, because the Company is developing a NWS, i.e., a cost-effective portfolio of customer-side solutions, to defer or eliminate the infrastructure need. The Company will include the costs of NWS in its preliminary update after it has more certainty of the amount and timing of the payments for customer-side solutions. If, however, the Company determines that the NWS projects are not feasible, then the Company will include the cost of the traditional project in its preliminary update.

5. O&M Program Changes

Q. Is the Company proposing any O&M changes related to its system expansion programs?

A. Yes, the Company is proposing three O&M program changes.

Q. Please describe one of these changes.

A. One of the Company's proposed O&M changes is necessary to support the new Cricket Valley Substation. Cricket Valley plans to construct a nominal 1,177 MW combined cycle, natural gas-fired generating facility in Dover, New York ("Facility"). The Facility will consist of three sets of combined cycle units, each with one combustion turbine generator and one steam turbine generator, and will interconnect to Con Edison transmission facilities that are part of the New York State Transmission System. The point of interconnection will be at a new 345 kV substation configured as a six breaker ring bus on Con Edison’s Line 398. The Company will assume ownership and operating responsibilities for the new Cricket Valley substation in 2020.

The incremental operations and maintenance expenses associated with the expansion of the Con Edison transmission facilities include weekly operator coverage, regular preventative and scheduled maintenance, and limited facilities and corrective maintenance. This program change requires an increase of $400 thousand in RY1. For additional information on this change, please reference the corresponding white paper.

Q. Is the Company proposing any other O&M program changes related to its System Expansion programs?

A. Yes the Company is proposing two additional O&M program changes, which are listed below. Details for these O&M program changes can be found in their respective O&M program change white papers.

- “Emergent Survey - Specialized Transmission Planning Studies” ($100 thousand increase in RY1)
- “Survey 345 kV and 138 kV Shunt Reactor Priority Study” ($200 thousand increase in RY1 and $200 thousand decrease in RY2)

C. Risk Reduction/Reliability Capital and O&M Expenditure Requirements

Q. Was the exhibit titled, "T&D Risk Reduction" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-5

Q. What does Exhibit EIOP-5 show?

A. Exhibit EIOP-5, Schedules 1 and 2 list the capital program and project funding requirements and O&M program changes required to support the company's Risk Reduction and Reliability work conducted by S&TO, SSO, and Electric Operations for RY1, RY2, and RY3. In addition, the exhibit contains white papers that provide more detailed information on each of the capital and O&M programs/ projects in this category.

Q. Please provide an overview of this category of work.

A. Con Edison's Risk Reduction programs and projects are designed to maintain the operational capability, reliability, and safety of the transmission, substation, and distribution systems.

The Company's programs in this category address near-term reliability issues. The Company analyzes, assesses, and adjusts its capital programs to best focus expenditures on systems and components most in need of attention. Where deemed necessary and appropriate, Con Edison programmatically upgrades and proactively replaces system components before they become degraded or obsolete.

Risk reduction/reliability projects and programs are divided into four sub-categories for this rate filing:

- System Resilience
- Transformers, breakers, and other energy delivery equipment
- Monitoring, supervisory, protection, and auxiliary systems
- Structures, housings, buildings, and other miscellaneous assets

1. System Resilience

Q. Please describe the System Resilience category.

A. Investments in the System Resilience category are designed to strengthen the Company's electric distribution system, reducing the amount of damage sustained during severe weather events and improving the Company's ability to repair damage and restore service after the events.

Q. What work is the Company performing for the resiliency of its electric distribution systems?

A. Extreme weather can threaten lives, disable communities, and devastate electric utilities' distribution systems. The Company's efforts to "harden" both its underground and overhead distribution systems focus on prevention, recovery, and survivability. Survivability is the ability to maintain some basic level of electrical functionality if there is a loss of electrical service from the distribution system. Con Edison leverages innovative technologies to bolster resiliency.

Q. Did the Company experience any severe weather events in its service territory in 2018 that caused significant damage to its electric system?

A. Yes, in March 2018 the Company's service territory was hit by two consecutive Nor'easters. The first storm, Riley, struck on March 2, 2018. The second storm, Quinn, struck on March 7, 2018, while the Company's Riley restoration was ongoing. Riley produced strong sustained winds of 18-51 mph lasting more than 36 hours, and gusts from 48-67 mph. Quinn was a snow event that dropped up to 14 inches of heavy, wet snow in Westchester County.

Q. Please describe the impact these storms had on the Company's electric system.

A. Riley and Quinn caused extensive damage to the Company's overhead electrical facilities, particularly in Westchester County, which experienced prolonged winds that were at times tropical storm force. The storms damaged 61 transformers and 471 poles, resulted in 2,457 downed wires, and caused 693 roads to be closed. In addition, the storms caused nearly 210,000 customer outages, which is the second highest number of outages in the Company's history, second only to Superstorm Sandy, which required the Company to perform 7,000 rebuild repair jobs to restore power to customers. By comparison, Hurricane Irene caused approximately 204,000 customer outages, but required 2,500 repair jobs.

Q. Did the Company perform work to strengthen its electric system after Superstorm Sandy?

A. Yes. Following Sandy, Con Edison invested approximately $1 billion between 2013 and 2016 in storm hardening and resilience projects across its service territory.

Q. Please describe the storm hardening work performed on the overhead distribution system.

A. The Company invested $121 million, hardening all aspects of its overhead distribution system, including converting select sections of the system from overhead to underground. The Company installed approximately 1,650 larger and stronger Class 1 and Class H1 utility poles, which are 22% and 46% stronger, respectively, than the previous standard pole. The Company also replaced 879 sections, or nearly 21 miles, of aerial electric cable with a new type of cable that is nearly three times stronger than the previously installed aerial electric cable. The Company also reduced the segment size on 115 4kV primary feeders and 59 auto loops in the Bronx and Westchester County, which reduced the maximum number of customers per segment that can lose power from storm damage to a particular line. This required installing 1,756 fuses and fused bypass switches, and 654 sectionalizing switches. In addition, the Company worked with its municipal partners in New York City and Westchester County to identify and harden key infrastructure in their communities. This work targeted Police Departments, Fire Departments, ambulance companies, Town Hall facilities, hospitals, sanitation facilities, wastewater treatment facilities, waterworks facilities, heating and cooling facilities, and other facilities specifically identified by the Company’s municipal partners. Among other things, the Company installed automatic transfer switches and redundant supply sources for these locations to reduce the likelihood of power outages during storms. In total, the Company completed 34 projects across 25 municipalities, from the Bronx to the northern border of Westchester.

Q. Did the Company's post-Sandy storm hardening mitigate the Riley and Quinn power outages?

A. Yes. The Company's storm hardening investments reduced the number of customers that lost power, and the number of key municipal facilities that lost power during the storms. For example, 31 of the 34 key municipal facilities that the Company worked on after Sandy did not experience any service interruptions during Riley or Quinn, and only one lost power, even though the storms damaged feeders that serve 19 of the facilities.

The Company estimates that its storm hardening investments prevented 60,000 customer outages in Westchester County. The Company calculated these estimates by using its outage management models to compare the pre and post-storm hardening system configurations for circuits damaged by the storms. The Company also notes that it estimates that its storm hardening has prevented approximately 370,000 customer outages since 2016, including the Riley and Quinn outages.

Q. Did the Company conduct post-storm reviews after Quinn and Riley?

A. Yes. The Company conducted an internal review.

Q. What initiatives were created as a result of the review?

A. The Company identified a number of initiatives to reduce system damage and customer outages and to improve restoration efforts and customer outreach, including:

- Developing an approach to Mutual Aid that best positions the Company to augment its crews with the right type and amount of resources at the right time for each severe weather event.
- Continuing to invest in storm resiliency that expands options and opportunities for overhead hardening and moving overhead infrastructure underground, with an emphasis on key municipal infrastructure.
- Re-evaluating its tree management program, including focusing on customer engagement and trees in and out of the utility Right-of-Way.
- Addressing customer experience and improving customer satisfaction by improving the accuracy of

estimated times of restoration ("ETRs"). This will be described in the IT section of this testimony.

- Integrating systems and devices to increase storm restoration efficiency. Two systems targeted for integration are the Company's Advanced Metering Infrastructure ("AMI") and Outage Management Systems ("OMS"), which will yield greater functionality in the Company's OMS. Although Con Edison already planned to integrate these two systems, it prioritized them for integration after the storms. This will be described in the IT section of this testimony.
- Improving the Company's interaction with municipalities by bolstering the relationship with municipalities and the County during blue-sky days and improving the Municipal Liaison Program ("MLP") in order to more effectively communicate and coordinate with municipalities during an event.
- Establishing a prioritization for road closures that closely coordinates with the municipalities.

Q. Please discuss in detail the Company's proposed efforts to prevent storm damage.

A. First, the Company has increased the scope of its Non-Network Reliability program to include increasing the resiliency of its overhead distribution system. As part of this program, the Company will: replace certain existing utility poles with H1 class construction poles, upgrade specific sections of overhead wires, de-load and split large auto loops into smaller auto loops, replace targeted open wire spans on auto loops with more resilient cable, and incorporate breakaway hardware and detachable service cable into the overhead system, reducing the likelihood of pole and customer equipment damage during storms.

Second, the Company will expand its “Tree Trimming” program to include preemptive removal of 1,400 hazardous/danger trees each year, which are trees on or off the right of way that could contact electric supply lines. As has been demonstrated during major storms, electric facilities are subject to significant damage from fallen trees. Following Winter Storms Riley and Quinn, a study commissioned by the Company determined that 77 percent of the surveyed damage in the hardest hit areas was caused by privately owned trees outside of the Company’s right of way. In October 2018, the Company instituted a pilot program to remove hazardous trees in the Town of Cortlandt. The Company selected Cortlandt for the pilot because of the significant tree damage that occurred in Cortlandt during the storms. The pilot has been welcomed by residents and municipal officials because the Company uses an arborist to identify sick trees that could be harmful to the electric grid. Removal of these trees reduces the risk of tree-caused outages. The Company plans to continue and expand this pilot during the rate plan.

Third, the Company will prevent damage to its underground distribution systems through its Underground Secondary Reliability and Vented Service Box Cover Programs. Heavy snow and road salt damages the Company’s underground system by causing corrosion and allowing water to intrude in compromised cable or splices, which leads to manhole events. On average, there are 2,800 manhole events each year in the underground distribution systems. The Company’s goal is to reduce this number by installing new monitoring devices and vented service box covers that include a latch feature, and by removing poorly performing distribution cables and splices. Vented covers have successfully contributed to a 10%

reduction in CO evacuations normalized to salt dispersion over a five year period of years. The Company plans to install additional vented covers in areas that provide the highest benefit to public safety.

In addition, the Monitoring Device and Application program will use innovative technologies to detect conditions in the underground system that could lead to a manhole event. The Company will introduce new sensors into underground structures that will detect anomalies. These new sensors will monitor underground structures for energized objects and changes that are precursors to manhole events, and will provide visible and non-visible (infrared) inspections and defect detection. The scope of this program only includes priority locations and the grid innovation portion of these sensors addresses the expansion of this program to other locations.

Q. How did the Company determine the priority locations?

A. Priority locations targeted for sensor installation will include structures and areas with a high manhole event generation rate or structures that meet an asset design criteria based upon the number of assets present or specific types of assets located in the structure.

Q. What specific resilience projects does the Company plan to invest in for the rate plan period?

A. The Company plans to invest in the projects listed below. Additional detail on each of these projects can be found in their respective white papers.

- “Monitoring Device and Application Program” ($5.0 MM RY1, $5.0 MM RY2, $5.0 MM RY3)
- “Non-Network Reliability – Overhead Reliability” ($29.5 MM RY1, $35 MM RY2, $27.7 MM RY3)
- “Underground Secondary Reliability Program” ($45.0 MM RY1, $55.0 MM RY2, $55.0 MM RY3)
- “Vented Service Box Covers” ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)

Q. Are there any O&M program changes required to support the Company’s efforts to prevent storm damage?

A. Yes, there is one. Changes to the Company’s “Tree Trimming” program, described previously, require an increase of $2.0 million in RY1. Additional details on this program change can be found in the corresponding white paper.

Q. Please continue by describing the two largest capital programs in this category starting with “Non-Network Reliability - Overhead Reliability.”

A. The overhead distribution system is comprised of non-network circuits including 4 kV primary grids and 4kV, 13kV, and 27 kV auto loops. The Company ranks the reliability of these circuits by standard industry metrics, including SAIFI and CAIDI, so that it can identify and target the worst performing ones for remediation.

The Company uses three primary approaches for improving the reliability of the non-network system: 1) addressing source reliability, which involves replacing aerial and underground feeder cables; 2) rebuilding the overhead network, which includes replacing poles and conductors supplied by feeder cables; and 3) reconfiguring circuits by adding new segments and associated equipment, which typically includes poles, wires, and switches.

Q. Please describe the “Underground Secondary Reliability Program.”

A. Damage to the secondary system is generally harder to identify than damage to the primary system due to the redundancy of the secondary grid, the number assets that comprise this system and limited presence of remote monitoring equipment. As a result, the Company discovers many conditions in the secondary system only when a customer reports an outage, it receives a call about a manhole event, or it finds a stray voltage condition during a routine scan. Because of the risk to public safety from these events, this is an important program.

The Underground Secondary Reliability Program involves replacing and upgrading underground secondary equipment and facilities, such as structures, conduits, transformers and cable, as required to properly maintain reliability. The program has four subcomponents: 1) System Design, 2) Secondary Rebuild, 3) Secondary Service Replacement, and 4) Emergent Reliability.

System Design work is associated with maintaining the Company’s highly reliable network design basis. System design considerations include contingency, reinforcement, and proper equipment operation. Through its Secondary Rebuild work, the Company proactively replaces secondary equipment and mains in order to reduce the number of energized objects (street lights, manhole covers, etc.), outages, and manhole events. The Secondary Service Replacement program focuses on the replacement of service cables selected on the basis of performance or inspection. Lastly, Emergent Reliability includes work associated with new initiatives, including enhanced inspection for non-visible defects and changes to the system design basis.

Q. Please continue with a description of the next component of the Company's approach to create a more resilient system by describing its efforts to improve how it recovers from storms.

A. The Company will enhance its storm recovery efforts by focusing on three key areas: rapid damage assessment, prompt crew deployment (including mutual aid and contracted overhead resources in addition to Company resources), and improvements to its Outage Management System ("OMS"). In support of this effort, the Company has one capital project and two O&M program changes. The Company's capital project is "OMS IT System Hardening," which is designed to increase the accuracy of the Estimated Time of Restoration ("ETR") customers receive and by promoting consistent messaging to customers through a redesign of the OMS Customer Communication Interface. As this is an IT project, it is covered in detail in the IT section of this panel.

Q. Please describe the two O&M program changes.

A. The first of the two O&M program changes we will discuss is to the Company's "Emergency Response" program and is designed to improve mutual aid response. Con Edison will sign retainers with overhead contractors that will guarantee the Company up to 101 overhead line FTE's for use during severe weather events. Proactively recruiting contractors for faster response after severe storms and securing access to bucket trucks for mutual aid crews as soon as the crews arrive will greatly improve the effectiveness of the Company's mutual aid response. Additional O&M changes to the "Emergency Response" program and the net financial impacts are described under the heading "O&M Program Changes" at the end of the Risk Reduction section.

Q. Please describe the second O&M program change.

A. The second O&M program change is to the "Engineering and Other Services" program. Through this program the Company plans to make a change in support of its ARCOS project, which involves software that will more effectively automate crew callout and resource management. This change will enable the Company to more rapidly deploy resources, including damage assessment resources, during severe weather events. Additional O&M changes to the

"Engineering and Other Services" program and the net financial impacts are described under the heading "O&M Program Changes" at the end of the Risk Reduction section.

Q. Please continue by describing the final component of the Company's proposal on system resilience which will improve system survivability.

A. The Company will increase survivability in its overhead distribution systems through the Critical Facility program. This program involves the Company, working with local municipalities, identifying and hardening critical facilities located and fed via non-network distribution circuits. Critical facilities may include fire departments, police departments, municipal buildings used in a command and control capacity during severe weather events, pumping stations, and strategic major food retailers.

The "Non-Network Reliability" program will also introduce additional automatic transfer switches ("ATS") and supply feeders to underground residential distribution ("URD") developments to help avoid customer outages during severe weather events. In addition, the Company will work with local municipalities during large capital sewer/water projects to determine the feasibility of undergrounding overhead distribution assets.

Q. What specific resilience projects does the Company plan to invest in?

A. The Company plans to invest in the project noted below. Additional detail on this project can be found in its white paper.

- “Critical Facility Program” ($2.0 MM RY2, $2.0 MM RY3)

2. Transformers, Breakers, and Other Energy Delivery Equipment

Q. Please provide an overview of programs and projects focused on transformers, breakers, and other energy delivery equipment.

A. The Company’s T&D systems transmit power through equipment located within substations and above or below the streets of New York City and Westchester County. Each type of equipment has its own purpose, historical performance, and functional lifecycle. This rate filing contains projects and programs to address: 1) proactive upgrades and replacements of these assets; 2) equipment replacement because, based upon asset management methodologies, it is the optimal time to replace; 3) projects designed to enhance reliability through the installation of additional equipment; and 4) replacements or upgrades when the equipment will exceed its design basis.

Q. Please describe the Company's proactive equipment replacement/upgrade programs and projects.

A. The programs in this category address equipment that has an elevated risk of failure or that is no longer supported by manufacturers.

The projects listed below involve proactive equipment replacement. Details on each of these projects can be found in their respective white papers in Exhibit EIOP-5, Schedule 3.

- "Circuit Switcher Replacement Program" ($1.4 MM RY1, $1.4 MM RY2, $1.4 MM RY3)
- "Gas Insulated Substation Replacement Program" ($25.0 MM RY2, $25.0 MM RY3)
- "High Voltage Test Set" ($2.5 MM RY1, $4.4 MM RY2, $6.5 MM RY3)
- "Mobile Control Center" ($1.0 MM RY3)
- "Other Capital Equipment Upgrades" ($2.5 MM RY1, $2.3 MM RY2, $2.3 MM RY3)
- "Reinforced Ground Grid Program" ($3.0 MM RY1, $1.6 MM RY2, $4.9 MM RY3)

- "U Type Bushing Replacement Program" ($2.3 MM RY1, $2.5 MM RY2, $4.7 MM RY3)

Q. Please describe the largest investment in this category, the "Gas Insulated Substation Replacement Program."

A. A gas-insulated substation is a high voltage substation where the major structures are contained in a sealed environment that uses sulfur hexafluoride ("SF6") gas as the insulating medium. The clearance required for phase-to-phase and phase-to-ground for all equipment is much lower in a gas-insulated substation than in a conventional air insulated substation. The total space required for a gas-insulated substation is roughly 10% of that needed for a conventional substation, which makes a gas-insulated substation an attractive option for our dense urban locations where the space for a conventional substation is unavailable. The Company has four of these on its transmission system at the W49th Street, Dunwoodie, Academy, and Mott Haven substations.

The purpose of this capital program is to proactively replace selected switchgear, in prioritized order, at the Company's gas-insulated substations with current technology the Company has successfully used to improve station reliability and reduce SF6 emissions. Of the Company’s four gas-insulated substations, West 49th Street has the highest rates of SF6 leakage and forced outages due to moisture ingress, creating both environmental and reliability concerns. Specifically, the 138kV sections of GIS equipment at this station have been prioritized for replacement under this program. This project will reduce SF6 emissions and improve station reliability.

Engineering for the W49th Street Project will begin in 2020 and procurement and construction will begin in 2021. Due to the complexity of outage scheduling, equipment lead times and construction requirements, the W49th Street project is expected to continue through 2025.

Also, based on ongoing condition assessments, the Dunwoodie 345kV Substation may be prioritized for partial or full switchgear replacement under the program during the rate years.

Q. Please continue with a description of the next Risk Reduction subcategory.

A. The next subcategory covers how the Company uses asset management methodologies to identify component replacement dates. Con Edison uses various asset management analysis tools to determine the ideal replacement prioritization and funding levels to cost-effectively reduce failure risks. Substation Operations, Electric Operations, and Transmission Operations use these tools as inputs for their Risk Reduction programs. The Company determines the performance metrics against which it will evaluate each asset class and then uses its asset management tools to evaluate the health of each asset class and the relative priority for addressing any identified issues.

Q. What projects and programs does the Company have in this regard?

A. The Company has 10 projects and programs that are designed to assess the health of various asset classes and address identified issues. These programs include identification and resolution of issues with T&D feeders, secondary network infrastructure, unit substation switchgear houses, circuit breakers, transformers, and disconnect switches. Details on each of these programs can be found in their respective white papers in Exhibit EIOP-5, Schedule 3.

- "4kV USS Switchgear House Replacement" ($6.8 MM RY1, $15.0 MM RY2, $15.0 MM RY3)

- “Area Substation Phased Replacement Program” ($6.0 MM RY2, $28.0 MM RY3)
- “Disconnect Switch Capital Upgrade Program” ($3.3 MM RY1, $2.1 MM RY2, $2.1 MM RY3)
- “Feeder 38R51 and 38R52 Replacement Project” ($23.0 MM RY1, $92.8 MM RY2, $92.8 MM RY3)
- “High voltage Circuit Breaker Capital Upgrade Program” ($10.5 MM RY1, $10.5 MM RY2, $14.5 MM RY3)
- “Partial Replacement of Feeders M51 and M52” ($67.3 MM RY2, $168.2 MM RY3)
- “Pressure, Temperature, and Oil Sensors” ($2.0 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- “Primary Feeder Reliability” ($7.5 MM RY1, $10.8 MM RY2, $13.8 MM RY3)
- “Substation Transformer Replacement Program” ($71.7 MM RY1, $76.6 MM RY2, $58.1 MM RY3)
- “Unit Substation Transformer Replacement” ($6.5 MM RY1, $3.9 MM RY2, $3.9 MM RY3)

Q. Please describe the largest ongoing program in this group, “Substation Transformer Replacement Program.”

A. This program is designed to proactively replace transformers that the Company has determined are nearing the end of their useful lives and cannot be maintained in reliable operating condition. There are 422 power transformers on the Con Edison system, of which 181 have been in service for over 40 years. As these units age, there is an increase in the amount of required corrective maintenance and the likelihood of malfunction. Replacing problematic transformers prior to failure improves reliability and is more cost effective than emergency replacement. This program is required to help the Company keep in-service transformer failure rates low, which contributes to system reliability, employee and public safety, and environmental responsibility.

As part of this program, when the Company replaces a transformer it also installs a moat system in the transformer vault to contain potential transformer oil spills, a new fire protection system, and a monitoring system. To reduce the risk of not having replacement equipment when needed, this program also provides for procurement of transformers with long lead times that are required for future replacements.

Q. Please continue with a description of the “Area Substation Phased Replacement Program” and what makes this program approach unique.

A. The Company typically approaches equipment upgrades in substations at the asset level through the use of capital programs. Under most circumstances this is the most efficient way to maintain the reliability of an individual station. However, in order to maintain system reliability standards, some substations are in need of an approach that is more holistic than the programmatic approach. The Company performed an assessment of power carrying, auxiliary, and structural equipment at a group of area substations and determined that certain locations require capital investment beyond the scope of existing capital programs.

In order to maintain individual locations, it is important to look beyond individual asset health and recognize conditions that present a systemic risk to the reliability of the substation. Degradation of individual assets can be addressed with corrective maintenance and or capital upgrade programs. However, when a substation is exhibiting degradation across multiple, interrelated systems, there is a greater reliability risk and a different approach is required. This program will prioritize capital projects at area substations that are in need of switchgear replacement, control and indication upgrades, and civil improvements. This top to bottom approach will improve the reliability of the candidate stations and complete the upgrades in the most efficient manner.

Through this program, the Company will replace 13kV, 27kV, or 33kV (medium voltage) equipment at various area substations based on condition assessments. The scope of the program may also include civil work associated with the switchgear, direct current control cable system replacements, and the addition of automation packages for overall station control. The scope of individual projects under this program will be evaluated along with other capital programs, such as 13/27kV Breaker Retrofits, to leverage outage and construction synergies.

Through assessments of medium voltage equipment, switchgear housing condition, and direct current control cable failures at various area substations, E63rd Street Substation has been prioritized under the program. Area substation locations beyond E63rd Street Substation will be evaluated for similar projects in the future.

Engineering and procurement for this program will begin in 2021 and construction will begin in 2022. Due to the complexity of the outage requirements for the East

63rd Street project, construction is expected to continue beyond 2023.

Q. Because it is a particularly large project, please describe “Replacement of Feeders 38R51 and 38R52.”

A. Feeders 38R51 and 38R52 are oil filled, direct buried cables supplying power to one of the Company’s area substations. This project will replace the feeders with oil-free solid dielectric cable installed in protective duct banks, which will significantly reduce the environmental and reliability risks associated with the feeders.

The Company has identified several issues with the feeders. First, both feeders use an outdated technology that is supported by only one manufacturer, creating a risk that parts will be unavailable when maintenance is needed. Second, the feeders are direct buried cables, meaning they are not protected against digging by contractors. In fact, the feeders previously incurred a fault due to excavation work by a third-party contractor. Third, both feeders are routed through an environmentally sensitive area and are prone to dielectric oil leaks. When there is a leaking joint, the Company must remove the leaking feeder from service for repair, which removes one of the only two feeders to the supplied area substation. In addition, the two feeders share a manhole, which increases the risk that the Company will have to remove both from service at the same time to perform maintenance work. This is a problem because the feeders are the only two sources of supply to one of the Company's area stations. Lastly, these feeders require significantly more maintenance than other fluid filled feeders and as they are unique and require a specialized skill set to perform the maintenance work.

In addition to addressing these issues, the Company expects this project to eliminate 300-400 hours of annual maintenance work, reduce unplanned outages, improve environmental performance, and help standardize labor expertise and spare inventory.

The Company anticipates that engineering activities for this project will begin in 2020 and that it will complete construction by the end of 2023.

Q. Please describe the "Partial Replacement of Feeders M51 and M52" project, which also represents a large investment.

A. Feeders M51 and M52 are each over 17 miles long and go through significant portions of Westchester, the Bronx, and Manhattan. Within the past ten years, these feeders have had over 180 leaks totaling roughly 18% of the total volume of dielectric fluid contained in the two feeders. The Pipe Enhancement Program, which restores the integrity of the cable pipe, has been the primary method used to reduce the frequency of dielectric fluid leaks on these feeders. Although Pipe Enhancement has reduced the frequency of dielectric fluid leaks in many areas along these feeders, unique challenges along the Manhattan portion of these feeders, such as stray current, have reduced the performance and longevity of the repairs.

To address the persistent leaks on the Manhattan portion of these feeders and the associated reliability and environmental risks, the Company plans to replace approximately 8 miles of the Manhattan portion of these high pressure fluid filled (“HPFF”) cables with approximately 11 miles of cross-linked polyethylene insulated (“XLPE”), non-fluid filled cable. A portion of the new XLPE cable will be submarine cable routed under the Harlem River to avoid congestion issues along a section of the current cable route, driving the increased length of the replacement cable over the current cable. The project will also install a gas-insulated substation to transition between the HPFE and XLPE cable sections. Engineering activities for this project will begin in 2021 and construction is estimated to be completed by the end of 2025.

Q. Please continue with a description of the “Unit Substation Transformer Replacement” program.

A. This program is designed to proactively replace unit substation transformers that are identified as having an increased risk of failure. The Company identifies transformers to replace by assigning an asset health index score that factors in Dissolved Gas in Oil Analysis (“DGOA”), Furan test results, transformer loading, apparent corrosion, oil leaks, Load Tap Changer (“LTC”) functionality, environmental impact, proximity to the public, and age. The Company’s asset class model for all of its unit substation transformers shows that it needs to replace four transformers each year to prevent the current transformer failure rate from increasing. This model also shows that a run-to-failure strategy would lead to failure rates doubling in the next ten years and quadrupling in the next 20 years.

Failures during high electric load periods could jeopardize reliability and system stability, and would increase replacement costs, which are typically higher for reactive work.

Q. Please proceed to the next Risk Reduction category by describing investments the Company plans to make to enhance the reliability of its assets through the installation of additional equipment.

A. In order to enhance the reliability of various parts of the transmission system, the Company periodically adds new components. These new pieces of equipment may improve switching flexibility and contingency response, fault clearing, or improve system stability. The Company has four projects/programs in this category. Additional detail on these investments can be found in their respective white papers in Exhibit EIOP-5, Schedule 3.

- “Area Substation Reliability” ($14.1 MM RY1, $11.5 MM RY2, $10.8 MM RY3)
- “Elmsford - Add 138kV Disconnect Switches on TR5, 38W24 and 38W14” ($1.1 MM RY2)
- “Ramapo – Install New Surge Arrestors” ($1.5 MM RY1)
- “SSO Loss Contingency Area Station Rapid Recovery Transformer Resiliency” ($19.4 MM RY2)

Q. Please describe the largest investment in this group, the “Area Substation Reliability” program.

A. This program provides for the upgrade of fault clearing capability in transformer vaults at area substations in accordance with the Company's current design standards. Con Edison modified its substation designs in 1991 to provide for more reliable high speed clearing of transformer secondary faults and reduce the possibility of losing area substations during protracted fault incidents.

The new fault clearing capability will be achieved either through the installation of high voltage equipment, such as a circuit switchers and/or interrupters for local clearing, or installation of relay equipment in the form of digital transfer trip ("DTT") protection schemes. The addition of circuit switcher and/or interrupters or DTT protection schemes will provide for more reliable and redundant systems for high speed clearing of transformer secondary faults at area substations.

The Company has 134 transformers remaining to be addressed under this program, not all of which will be completed during RY1-RY3, and will install local clearing devices in approximately 54 transformer vaults and schemes in approximately 80 vaults.

Q. Please describe the final Risk Reduction subcategory, which addresses assets that have exceeded their design basis.

A. The Company must address risks associated with equipment that no longer meets the design basis, including by adding new equipment. The Company has five capital projects in this category. Details on each of these projects can be found in their respective white papers in Exhibit EIOP-5, Schedule 3.

- "179th St. Area Substation Reconstruction" ($488 thousand RY1, $488 thousand RY2, $488 thousand RY3)
- "Retrofit Overdutied 13kV and 27kV Circuit Breaker Programs" ($14.8 MM RY1, $14.8 MM RY2, $12.5 MM RY3)
- "Shunt Reactors" ($1.3 MM RY1, $2.5 MM RY2, $2.5 MM RY3)
- "Unit Substation Tap Changer" ($36 thousand RY1, $38 thousand RY2, $38 thousand RY3)
- "Unit Substation Temperature" ($95 thousand RY1, $100 thousand RY2, $100 thousand RY3)

3. Monitoring, Supervisory, Protection, and Auxiliary Systems

Q. Please provide a general overview of this category.

A. To reliably operate its T&D assets, the Company maintains monitoring, supervisory, protection, and auxiliary systems. The Company’s monitoring, alarm, and supervisory systems provide operators information with which to make real-time operational decisions and maneuvers. In addition, these systems provide asset condition data that enable operators and engineers to proactively address emerging equipment related risks and aid in the prevention of catastrophic failures. Con Edison’s protective systems provide an automated means of detecting and isolating abnormal electrical system events to mitigate damage. The Company’s auxiliary systems do not directly transmit or distribute power but facilitate the operation of such bulk power equipment.

Q. Please describe the Company’s planned investments to its performance monitoring systems.

A. The Company maintains systems that monitor the condition of critical assets in its electric system. These systems monitor, measure, and communicate key parameters of operating performance to engineers and operators, who use this data to proactively identify equipment maintenance issues and/or early stages of failure.

The Company has five capital projects to support the development and upgrade of its monitoring systems. Details on each of these projects can be found in their respective white papers.

- “138kV Disturbance Monitoring Program” ($2.1 MM RY2, $2.4 MM RY3)
- “Condition Based Monitoring” ($14.1 MM RY1, $14.1 MM RY2)
- “Dynamic Feeder Rating System Program” ($1.5 MM RY1, $1.5 MM RY2, $1.5 MM RY3)
- “Remote Monitoring System 3rd Generation” ($3.2 MM RY1, $3.2 MM RY2, $3.2 MM RY3)
- “Unit Substation PTO/Unit S/S Modernization” ($500 thousand RY1, $500 thousand RY2, $500 thousand RY3)

Q. Please describe the largest investment in this group, the “Condition Based Monitoring” program.

A. The purpose of this program is to install monitoring equipment on the Company’s power transformers to identify incipient faults and respond to equipment problems prior to failure. Through this program, the Company plans to install monitoring equipment that will reduce the number of unanticipated transformer faults, improving reliability and safety while reducing the chance of releasing transformer oil into the environment and the costs associated with catastrophic transformer failures.

To achieve this, the Company plans to install an additional 400 Kelman gas monitoring units over the next three years to reach 100% monitoring on its substation transformer fleet. This work includes installation of the monitoring units, setting up a central server to support, store, and process data from the units, and establishing remote communication with the existing and new Kelman gas monitoring units. This work will allow the Company to review data, perform data trending analysis, diagnostic analysis, and establish fleet-wide monitoring. In addition, the Company will need to establish a new Data Acquisition Network with enhanced cyber security features to handle the communication of data from the monitoring devices to the central server.

Currently, the primary means of monitoring levels of dissolved gas-in-oil is through periodic sampling by the Company’s Chemistry Lab, which occurs one to six times per year. Online monitoring through the Kelman units will allow for continuous monitoring, which facilitates early fault detection and mitigating actions by the Company.

In addition to the monitoring system projects just described, the Company plans to make the following two investments in its alarm and indicator systems.

- “Category Alarms Various” ($2.2 MM RY1, $1.8 MM RY2, $2.2 MM RY3)
- “Pothead Pressure Alarm Program” ($150 thousand RY1, $150 thousand RY2, $150 thousand RY3)

Q. Please describe the investments being made in the Company’s supervisory systems.

A. Supervisory systems include automation systems for substation operators and systems that aid operators in reacting to system events, faults, and contingencies while balancing changes in generation and electrical demand. The Company has three projects/programs in this category. Additional detail on these investments can be found in their respective white papers.

- “East River Automation - Upgrade The 69KV Yard” ($4.0 MM RY2, $3.0 MM RY3)
- “RTU Upgrade Program” ($2.2 MM RY1, $2.6 MM RY2, $2.5 MM RY3)
- “Transmission Station Metering and SCADA Upgrades” ($3.1 MM RY1, $3.1 MM RY2, $3.1 MM RY3)

Q. Please elaborate on the “Transmission Station Metering and SCADA Upgrades” project.

A. In an effort to drive down the number of outstanding deficiencies and faulty pieces of equipment on the Company’s system, Con Edison plans to perform surveys of its substations to verify existing metering deficiencies and determine if any additional deficiencies exist that require mitigation. These deficiencies could potentially impact the reliable operation of the Company’s electric system.

Q. Could these metering deficiencies have an impact on customer bills?

A. No, these deficiencies do not impact customer bills.

Q. Please continue the discussion on evaluating the scope of deficiencies.

A. Surveys performed under this program will allow the Company to understand the scope and type of issues requiring mitigation, prioritize them for mitigation, develop appropriate mitigation measures, and execute the required work. Equipment targeted for evaluation and mitigation includes Coupling Capacitor Potential Devices, Potential Transformers, Current Transformers, Bushing Potential Devices, transducers, and associated wiring.

Identified deficiencies will be categorized based on the cause of the issue and the Company’s mitigation approach. Categories include, but are not limited to:

- Unavailability of devices: Includes all metering devices, instrument transformers, and wiring that is malfunctioning, obsolete, or had been previously removed or retired in place.
- Lack of accuracy: This category includes aging and underrated equipment that no longer meets metering accuracy requirements and must therefore be replaced with equipment that meets both operational and regulatory requirements.
- New metering points: Includes operational performance metering that does not currently exist on the Company’s system. Work in this category includes design and implementation of new metering infrastructure.

The Company plans to start these surveys with substations on its Bulk Electric System that have a history of metering issues, as reported through the Company’s work management system. Substations currently prioritized for survey and upgrade include, E179th Street, Farragut, Sherman Creek, Sprainbrook, Goethals and Dunwoodie 345kV/South/North.

In addition, the Company plans to invest in its Energy Control Center ("ECC") through the following two projects.

- "EMS Reliability AECC and ECC" ($300 thousand RY2, $300 thousand RY3)
- "Operations Network for EMS" ($293 thousand RY1, $300 thousand RY2, $300 thousand RY3)

Q. Please describe the Company's planned investments in protection equipment.

A. To reliably operate its substation and transmission system, the Company uses over 60,000 protective relays, which sense system disturbances and irregularities and automatically intervene to remove equipment from service that may be at risk of damage or failure. The Company makes investments annually in its protective relay systems to improve their operation, maintain regulatory compliance, and reduce specific risks that may contribute to transmission system forced outages.

Q. Why is it important for the Company to invest in its protective relay systems?

A. While robustly designed and well maintained, the Company’s substation and transmission system is operated at high voltage and carries very high levels of energy. During normal operation, the system is designed to reliably transmit electricity. However, various events may cause system instability or faults, potentially damaging equipment and creating risk for both employees and the public. The Company’s protective relays are designed to sense instabilities in delivery of electric power and, in combination with interrupting devices like circuit breakers and switchers, de-energize components and remove them from service before faults can cause damage to equipment and/or cascade to affect greater areas of the transmission system.

Q. What kinds of investments is the Company planning to make in its relay and other protective systems?

A. The Company is planning three investments in this area. Additional detail on these investments can be found in their respective white papers.

- “Fire Suppression System Upgrade” ($6.5 MM RY1, $3.5 MM RY2, $10.9 MM RY3)
- “Relay Modifications Program” ($12.1 MM RY1, $12.1 MM RY2, $12.1 MM RY3)

- “Relay Protection Communication Upgrade Program” ($3.0 MM RY1, $3.5 MM RY2, $3.0 MM RY3)

Q. Please describe the Company’s planned investments in its auxiliary systems.

A. The Company’s auxiliary systems facilitate the operation and monitoring of various components of the transmission system and include direct current systems that provide control power to switching and protection equipment, pressurization systems that help maintain the dielectric properties of transmission feeders, and Capacitive Coupling Potential Devices (“CCPD”) that measure system voltages and power flow. The Company has four projects/programs in this category. Additional detail on these investments can be found in their respective white papers in Exhibit EIOP-5, Schedule 3.

- “Bus Auxiliary Equipment Program” ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- “DC System Upgrade Program” ($5.1 MM RY1, $5.1 MM RY2, $5.1 MM RY3)
- “LP Reservoir Replacement Program” ($1.4 MM RY1, $2.5 MM RY2, $2.5 MM RY3)
- “Pumping Plant Improvement Program” ($5.5 MM RY1, $3.9 MM RY2, $3.9 MM RY3)

4. Structures, Housings, Buildings, and Other Miscellaneous Assets

Q. What is the next category of Risk Reduction/Reliability work that you will be discussing?

A. The next type of equipment within the Risk Reduction/Reliability category includes non-power carrying assets that house or structurally support energy delivery, supervisory, communication, or protection assets, or that support general T&D operations.

Q. Please describe the Company's projects and programs in this category.

A. The Company is planning to invest in such systems to proactively address degraded structural support systems that, upon failure, would pose a risk to maintaining the availability of important energy delivery equipment. In addition, many of these projects enhance the safety and security of the Company's employees and the public. The Company's equipment, feeders, cables, and wires require structural support systems to maintain proper electrical clearances and support substantial assets such as power transformers.

The Company plans to invest in the eight projects listed below to address risks associated with these assets. Details on each of these investments can be found in their respective white papers in Exhibit EIOP-5, Schedule 3.

- “Hellgate Dock Refurbishment” ($2.4 MM RY1, $2.5 MM RY2; O&M program increase of $800 thousand RY1, decrease of $85 thousand RY2, decrease of $715 thousand RY3)
- “Osmose – C-Truss” ($2.3 MM RY1, $2.3 MM RY2, $2.3 MM RY3)
- “Roof Replacement Program” ($2.1 MM RY1, $2.1 MM RY2, $2.1 MM RY3)
- “Stabilization of Pothead Stand Supports/Settlement” ($1.5 MM RY1, $2.5 MM RY2, $2.5 MM RY3)
- “Structural and Infrastructure Upgrades” ($6.6 MM RY1, $7.9 MM RY2, $8.2 MM RY3)
- “Substation Enclosure Upgrade Program” ($2.3 MM RY1, $1.9 MM RY2, $1.9 MM RY3)
- “Transformer Vault and Structure Modernization” ($15.4 MM RY1, $15.4 MM RY2, $15.4 MM RY3)
- “USS Upgrade and Improvement” ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)

Q. Because it is a larger project that contains both capital and O&M impacts, please describe the “Hellgate Dock Refurbishment Project.”

A. Hellgate wharf, located in the Bronx, supports Electric Operations' flush truck facility for wastewater barges and Substation Operations' heavy lift area for transformers delivered via barges. This project will remediate identified structural deficiencies, restore the full functionality of the dock, and extend the high capacity loading area deck to allow for the use of longer multi-axle trailers for offloading transformers.

The Company's review and analysis of the wharf identified numerous structural issues that the Company plans to address. In the heavy lift area, the concrete encased beams exhibit corrosion, spalling, and/or cracking. Currently all ten pier walls within this vicinity show signs of significant deterioration, including concrete spalling and erosion and steel rebar corrosion. Conditions in this area of the wharf have diminished load capacity, restricting use of the wharf to lighter loads.

The Flush Truck Facility portion of the wharf exhibits similar deficiencies to those identified in the heavy lift area. The northernmost of the three bays is missing mooring hardware and fenders and the Company has deemed it unsafe for personnel to access.

The full list of specific repairs and installations can be found in the corresponding white paper.

As part of this effort, the Company proposes an O&M increase of $800 thousand in RY1, a decrease of $85 thousand in RY2, and a decrease of another $715 thousand in RY3 to support restoration of the structural steel and restoration, modification, and repairs to the concrete. Additional details on this O&M program change can be found in the corresponding capital white paper.

Q. Please describe the projects and programs that relate to systems that house, support, or protect the Company’s energy delivery equipment and supervisory, communication, and protection assets.

A. The Company plans to invest in these assets in both its underground and overhead systems. The Company will invest in the underground system through the “Underground Transmission Structure Modernization” program. This program proactively mitigates concerns with structures that the Company has identified as requiring major or non-routine upgrades. These structures contain Transmission Feeder splices along with auxiliary piping and valves. Structural deficiencies, especially at the end walls where feeder pipes enter the manhole and water enters because of structural issues, jeopardize the integrity of the feeder pipes and lead to dielectric fluid leaks each year. This program will provide increased reliability, extend the useful life of the existing structures, and prevent leakage of dielectric fluid into the environment.

Q. What type of investments does the Company plan to make in its overhead system to maintain its steel lattice transmission towers?

A. Con Edison plans to invest in its overhead system through its "Overhead Transmission Structures Program." This program will upgrade specific 345 kV steel lattice towers that the Company has selected based on feeder criticality, engineering analysis, and accessibility. The Company performs an analysis on a corridor-by-corridor basis and gives priority to critical corridors that are specified by System Operations and Transmission Planning. Reinforcement of these overhead towers increases structural capacity and system reliability and prevents situations in which multiple towers collapse due to the collapse of a single tower. The Company's current transmission tower design criteria call for towers to be able to withstand the breakage of all transmission wires on one side of the tower without causing the tower to collapse. This program will continue to identify potential failure scenarios in order to prioritize work for future years. Based on this ongoing evaluation, the Company will identify selective tower element reinforcement projects that mitigate the possibility of tower failures or severe cascading events.

The Company plans to invest in the two projects below to address risks in its underground and overhead structural support assets. Details on each of these investments can be found in their respective white papers in Exhibit EIOP-5, Schedule 3.

- "Overhead Transmission Structures Program" ($2.0 MM RY1, $2.0 MM RY2, $1.7 MM RY3)
- "Modernization Program CECONY Electric Feeder Structure" ($1.9 MM RY1, $2.0 MM RY2, $2.0 MM RY3)

5. O&M Program Changes

Q. Is the Company proposing any Risk & Reliability O&M program changes that have not already been addressed in this section of testimony?

A. Yes. The Company is proposing changes to three O&M programs in this category, its Emergency Response, Engineering and Other Services, and Roof and Structural Repairs programs.

Q. Please start by describing changes to the Emergency Response program.

A. This program change has several components, two of which have already been described in this section, Hellgate Wharf and the Mutual Aid Retainer, both of which represent cost increases. The Hellgate O&M increase that is part of the Emergency Response program is in addition to the O&M increase described with the capital project. In addition, there is another cost increase from a change to the Company’s Flush Allocation methodology. The Company uses a specialized truck to remove debris and water from its structures. The Company is changing its flush allocation methodology from one based on its retired “DOCS” work management system to one based on its current “Logica” work management system. In the past, some flush work was charged directly to jobs requiring flush work while other flush jobs were charged based upon an allocation table. The Company believes that direct charging of all flush work directly to the job is a more accurate representation of costs per job. The new allocation methodology will charge all flush work directly to jobs and eliminate use of the allocation table. The Company collected several years of data through its Logica work management system to develop and support this change. This will result in an increase in O&M cost for flush related activities but a decrease in capital cost for flush related activities.

Mitigating the impact of these cost increases, there are cost decreases driven by the implementation of AMI. The Company’s AMI will allow it to better manage load on its distribution transformers, helping to prevent overloads and failures that drive repair and replacement costs. The AMI system will also reduce costs related to outage management by improving outage identification and restoration efforts. Outage management benefits are driven by a reduction in field visits for “false outages,” the identification and correction of power quality issues prior to receiving customer calls, and reductions in outage duration, which increases revenue.

The net effect of these cost increases and decreases is an increase in the Emergency Response O&M funding requirement of $5.6 million in RY1, a reduction of $0.7 million in RY2, and a further reduction of $1.5 million in RY3. Additional detail on these changes can be found in the corresponding white paper.

Q. Please continue with a description of the Engineering and other services program.

A. The Company is proposing a funding change for its Engineering and Other Services program based on changes to support its OMS IT system hardening efforts, Communications infrastructure for Grid Innovation, and ARCOS, which was previously described in this section of testimony.

The impact of these changes is an increase in O&M funding requirement of $4.6 million in RY1, $0.2 million increase in RY2, and $0.5 million increase in RY3. Additional detail on these changes can be found in the corresponding white paper.

Q. Please continue by describing proposed changes to the Roof and Structural Repairs Program.

A. The Company has an ongoing program to inspect each of the 554 substation roofs approximately once every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year. These inspections identify candidates for the capital Roof Replacement program as well as potential repairs where applicable. This O&M program addresses repairs that would alleviate current deteriorated roofs that are not currently candidates for a full replacement.

Central Engineering has also established an inspection program to monitor and assess the structural condition of substation facilities (external and internal) to provide for the safety of the public, company employees, and the equipment in the facilities. In this request, the Company proposes to establish a comprehensive maintenance program that will correct material issues it can no longer address through routine maintenance. The program will affect major sections of the structure, both interior and exterior, that are too significant to be addressed with minor repairs.

The Company estimates that the operations and maintenance expense to repair five roofs and one façade per year requires a program change of $650 thousand in RY1. Additional detail on this program change can be found in the corresponding white paper.

D. Replacement Capital Expenditure Requirements

Q. What is the next category of work?

A. The next category of work is “Replacement.”

Q. Was the Exhibit titled, “T&D Replacement” prepared under your direction?

A. Yes it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-6

Q. What does Exhibit EIOP-6 show?

A. Exhibit EIOP-6, Schedule 1 lists the capital program and project funding requirements that support replacement work planned by S&TO, SSO, and Electric Operations for RY1, RY2, and RY3. The exhibit also contains white papers for each capital program and project in this category that provide more detailed information such as program and project work descriptions, justifications, alternatives, estimated completion dates, current status, and forecasted funding.

Funding for each program under the Replacements category is based on the historical failure or degraded performance rates of each component covered by the program. The exhibit normalizes the historical rates to account for any circumstances that may have caused a major deviation to the equipment failure rate in any given year. These programs do not include proactive replacement of components before they experience degraded performance or fail.

Q. Please provide an overview of the work performed under the Replacement category.

A. Through this program, the Company replaces failed transmission and substation equipment, including transmission and sub-transmission class feeders, transformers, reactors, and phase angle regulators. The program also funds the replacement of potheads, circuit breakers, bus enclosures, instrument transformers, and equipment monitoring and control devices. In addition, the program funds the replacement of distribution system equipment, including 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 (AKA “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 work covered by this program include repair and upgrade of overhead poles, wire, and equipment that fails during storms or other emergencies.

Q. Has weather contributed to or affected the volume of work seen in any of these Replacement programs?

A. Yes. It has increased both the volume of work and the program funding requirement. The winter of 2017-2018 saw numerous rain and snow storms that produced 40 inches of snow, over 18 inches of rain, and strong winds. In March 2018, the system experienced three major storms: Nor'easters Quinn, Riley and Toby. In addition to snow and rain, wind gusts exceeded 50mph. 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 were higher than the historical average. Funding for these programs is necessary to maintain system reliability and supports the Company's goal to reduce the number of outstanding repairs.

Q. What programs and projects does the Company plan to invest in to support required replacement work?

A. The Company plans to invest in the following projects. Additional detail on each of the projects below can be found in their respective white papers.

- "Failed Substation Transformer Program" ($30.0 MM RY1, $30.0 MM RY2, $30.0 MM RY3)
- "Other Failed Substation Equipment" ($6.5 MM RY1, $6.5 MM RY2, $6.5 MM RY3)

- “Overhead” ($39.8 MM RY1, $40.6 MM RY2, $38.8 MM RY3)
- “Primary Cable Replacement – OA’s” ($93.0 MM RY1, $93.0 MM RY2, $93.0 MM RY3)
- “Secondary Open Mains” ($153.0 MM RY1, $153.0 MM RY2, $153.0 MM RY3)
- “Service Replacements” ($68.0 MM RY1, $68.0 MM RY2, $60.0 MM RY3)
- “Street Lights – Incl. Conduit” ($27.2 MM RY1, $27.2 MM RY2, $20.2 MM RY3)
- “Targeted Primary DBC Replacement” ($10.0 MM RY1, $14.0 MM RY2, $14.0 MM RY3)
- “Transmission Feeder Failures” ($10.0 MM RY1, $10.0 MM RY2, $10.0 MM RY3)
- “Transmission Failures – Other” ($0.98 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- “Transformer Installation” ($35.9 MM RY1, $35.9 MM RY2, $35.9 MM RY3)

Q. Please elaborate on the largest program in this group, Secondary Open Mains.

A. The Secondary Open Mains program involves replacing and reinforcing secondary cable to maintain system reliability and safety. Secondary cables can fail - becoming an “open secondary main” - as a result of physical damage to the cable insulation. Such failures most often occur in the winter when salt is used to melt snow and ice. They also occur in the summer because of higher loads.

Secondary cables that have failed can result in the overload of other secondary cables in the vicinity. If left unaddressed, overloaded secondary cables can result in low voltage conditions, manhole events, equipment coordination problems, and overheating. The Company classifies Secondary Open Mains based on their priority, which is determined by their impact on the system and customers. In addition, the Company uses statistical event risk and cost benefit analysis to further categorize and prioritize work.

E. Equipment Purchase Capital and O&M Expenditure Requirements

Q. Was the Exhibit titled, “T&D Equipment Purchases” prepared under your direction?

A. Yes it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-7

Q. What does Exhibit EIOP-7 show?

A. Exhibit EIOP-7, Schedules 1 and 2 list the capital program/project funding requirements and O&M program changes that support Equipment Purchases for Electric Operations for RY1, RY2, and RY3. The exhibit also contains white papers for each capital and O&M program/project in this category that provide more detailed information, such as program and project work description, justification, alternatives, estimated completion date, current status, and forecasted funding.

Q. Please discuss the Company's programs for purchasing transformers and meters used on the distribution system.

A. 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 Public Service Commission ("PSC") approved electric revenue meters and associated equipment, such as revenue grade instrument transformers. The Company requires approximately 167,000 new electric meters and associated electric metering devices per year, incremental to the replacement occurring as part of the Company’s AMI program. The Company installs meters in new customer locations and in existing customer locations that received an upgrade. The Company also replaces mechanical meters, which require more frequent testing.

Q. What are the equipment purchase programs for which the Company is seeking funding?

A. The Company is seeking funding for the following three programs:

- “Meter Purchases” ($5.5 MM RY1, $6.0 MM RY2, $8.0 MM RY3)
- “Sarnoff Equipment” ($5.0 MM RY1, $5.0 MM RY2, $5.0 MM RY3)
- “Transformer Purchases” ($116.0 MM RY1, $121.0 MM RY2, $126.0 MM RY3)

Q. Please describe the new program in this group, “Sarnoff Equipment."

A. Con Edison is required by the PSC to perform annual underground system scans in the City, New Rochelle, Yonkers, and White Plains using mobile contact voltage detection technology – per “Order Establishing Rates for

Electric Service," issued March 25, 2008 in Case 08-E-0539 and "Order Adopting Changes to Electric Safety Standards," issued December 15, 2008 in Case 04-M-0159. This program reflects a change in the business model followed in the past where the 12 mobile scans done on the system were performed under an O&M program, using contractor equipment and labor. The Company is changing this model to use capital funds to procure the required equipment including the required scanning sensors, associated software, and vehicles to which the sensors are mounted to perform the inspections. Through this change, which now uses contractor labor to perform the inspections with Company equipment, Con Edison is able to lower the O&M cost associated with the 12 mobile scans as mentioned in the prior Business Cost Optimization section of this testimony.

Q. Are there any O&M program changes to discuss in the Equipment Purchase category?

A. Yes. There is one O&M program change, which is to the Meters and Other Customer Equipment program.

Q. Please describe this change.

A. Due to benefits from the installation of AMI meters and their impact on the Company's interval metering work, the

O&M funding requirement for this program is decreasing. Interval metering is used to support the Company's Mandatory Hourly Pricing Program, which requires customers who incur 30 minute demand of 500kW or more to be billed at the hourly price rate. Costs associated with the communication and data management aspects of this program will be reduced through the use of AMI meters and the associated Meter Data Management System, as will labor costs associated with manual meter reading.

As a result of these cost reductions, the funding requirement for this program will decrease by $0.3 million in RY1, $0.9 million in RY2, and $1.1 million in RY3 for a total reduction of $2.3 million over the three rate case years. Additional details on this program change can be found in the corresponding white paper.

F. Safety and Security Capital and O&M Expenditure Requirements

Q. What is the next category of work?

A. The next category of work is "Safety and Security."

Q. Was the Exhibit titled, "T&D Safety and Security" prepared under your direction?

A. Yes it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-8

Q. What does Exhibit EIOP-8 show?

A. Exhibit EIOP-8, Schedules 1 and 2 list the capital program and project funding requirements and O&M program changes required to support Safety and Security work conducted by S&TO, SSO, and Electric Operations. In addition, the exhibit contains white papers for each capital program/project and O&M program change in this category that provide more detailed information, such as program and project work descriptions, justifications, alternatives, estimated completion dates, current status, and forecasted spending.

Q. Please describe the Company's capital safety program.

A. Con Edison maintains a high level of safety and holds safety as a paramount consideration in each and every task. Many of the projects described in this testimony have safety benefits; the ones discussed here are primarily driven by safety.

Con Edison closely monitors and actively manages the risks that have arisen in the last decade related to physical and cyber security. Businesses have seen an alarming rise in attempted cyber-attacks. Like many major businesses, Con Edison is devoting more resources to protect against cyber and physical attacks. The Company is addressing the cyber risk through compliance with NERC Critical Infrastructure Protection ("CIP") Standards. These standards provide a cyber-security framework for the identification and protection of Critical Cyber Assets ("CCA") to support the reliable operation of the Bulk Electric System ("BES").

- "Cable Termination Platform Program" ($1.1 MM RY1, $1.1 MM RY2, $1.1 MM RY3)
- "Cap and Pin Insulator Replacement Program" ($0.69 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "Critical Infrastructure Protection - Security Upgrade" ($975 thousand RY1, $975 thousand RY2, $975 thousand RY3)
- "Cyber Security" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "Distribution Electric Control Center Cybersecurity" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "ECC Facility Security Enhancement" ($390 thousand RY1, $400 thousand RY2, $400 thousand RY3)
- "Overhead Tower Rapid Rail Program" ($0.97 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "Substation Security Enhancements" ($10.0 MM RY1, $10.0 MM RY2, $10 MM RY3)

Q. Due to the importance of the program, please describe in detail “Cyber Security.”

A. The Company’s T&D System relies heavily on its cyber assets for operation, analysis, and day-to-day business. Nearly every tool used to operate Con Edison's electric system, and support that operation, is dependent on its cyber assets.

Through this program, the Company will improve cybersecurity, increase its ability to detect system threats and attacks, enhance its response to cybersecurity incidents, improve its ability to recover from system damage, expand its ability to find new and latent vulnerabilities in current systems, and maintain its ability to comply with increasing cybersecurity regulatory requirements. Con Edison will continue to evaluate and implement advancements in Intrusion Detection / Protection Systems. The Company will also implement a recently acquired centralized backup system that will dramatically improve disaster recovery and lay the foundation for making operational its Mobile Control Center.

Q. Please describe how physical security is addressed through the “Substation Security Enhancements” project.

A. This program is required to systematically upgrade substation security systems in the City’s five boroughs and Westchester, Rockland, and Dutchess Counties. These security upgrades are necessary to address the threat of sabotage, terrorism, vandalism, theft, and unauthorized access to Company facilities per Con Edison’s security specifications and regulatory requirements.

Based on previous physical attacks to electric infrastructure in the U.S., the Federal Energy Regulatory Commission directed the North American Electric Reliability Corporation to develop reliability standards to address risks due to physical security threats and vulnerabilities. The New York Public Service Commission also recommended that Con Edison put additional security measures in place to enhance protection and increase deterrence of attacks against its facilities.

Security upgrades made through this program include the installation of fencing, video surveillance systems, access control systems, and perimeter intrusion detection systems, allowing the Company to meet both its internal security specifications and regulatory requirements. The program began prior to the current rate plan and the

Company anticipates that it will continue through this rate plan.

Q. Please describe how the “Cap and Pin Replacement Program” improves safety.

A. The Con Edison transmission system contains porcelain cap and pin insulators that support substation bus sections at various voltages. In the past twelve months, these insulators have failed multiple times, causing both reliability and safety concerns. Broken insulators have resulted in high-voltage electric short circuits requiring the emergency removal of equipment and some have fallen into work areas below, creating a potential safety issue.

This replacement program will address high-risk areas, increasing the reliability of networks supplied by stations using these insulators and mitigating employee safety hazards.

Q. Is the Company proposing any O&M changes related to its safety and security programs?

A. Yes, the Company is proposing two O&M program changes, one related to safety and one to security.

Q. Please describe the Company’s O&M program change associated with safety.

A. The Enhanced Safety Inspection and Repair program identifies and repairs conditions on underground distribution structures and overhead distribution poles that could lead to safety hazards or negatively impact system performance.

Structures covered under this program require inspection at least once in the defined 8-year cycle period for all company owned underground structures. It also requires inspection at least once in the defined 5-year cycle period for all company owned Overhead structures. This program also is responsible for Mobile scanning. The Company uses contractors to perform many of these inspections, but not the repairs. As reflected in this rate filing, the Company plans to use contractors in all years of the eight-year program.

Q. Please explain the challenge to this program posed by debris and dirt.

A. The Company has approximately 285,000 distribution manholes, service boxes, transformer vaults, and URD facilities. In order for the Company to inspect an underground structure, including secondary mains, services and splices need to be visible and free of debris and or dirt. If debris or dirt would impede an inspection, the Company must take the additional step of flushing the structure to clear the debris and dirt.

The Company has recently seen a significant increase in the number of structures that require flushing. In 2018, which corresponds to year four of the current eight-year UG/URD cycle, the Company had to flush almost half (46%) of the total number of structures inspected during years one through four. Based on its experience thus far, the Company estimates that it must flush an additional 45,809 units before the end of the current eight-year program.

Q. What accounts for the increase in structures that require flushing?

A. In the 2018 inspection cycle, 46 percent of Company structures required flush work in order to perform inspections, which represents an increase over the previous two inspection cycles. The number of vented covers utilized on the system is a contributing factor to this.

Q. How has the program been affected by its revised scope that requires more flushing?

A. Because of the program’s revised scope, the Company had to renegotiate with its contractor. The new contract, effective May 29, 2018, separates inspections and flushes, which were formerly combined as a single product. While the cost per inspection has decreased, the Company estimates that costs to complete flushes in the remaining years of the current inspection cycle will increase because of the increase in the number of required flushes as described above. We forecast that this increase will substantially outweigh the decrease in cost per inspection. However, these increased costs are being offset to a large degree by a proposed change to the inspection program that is expected to improve performance of the inspection program and reduce costs. The proposed changes are described in detail in the Special Issues section of this testimony. Based on making the proposed changes to the inspection program, the impact to the O&M funding requirement is an increase of $2.3 million in RY1, increase of $3.6 million in RY2, and a reduction of $5.4 million in RY3. This represents an increase of $8.8 million over the three rate years. Because RY3 is the final year of the current eight year inspection cycle, there will be a reduction in the number of inspections performed. For additional information on this O&M change, please reference the corresponding white paper.

Q. Please describe the Company's O&M program change related to Security.

A. The Company proposes enhancements to its Cyber and Physical Security program. Specifically, the Company is seeking funds to license and maintain new physical and cyber security tools and systems to protect its critical cyber assets and high value networks at the Energy Control Center and Alternate Energy Control Center and to comply with regulatory requirements. Details on this program change can be found in the O&M white paper. This change requires an increase of $370 thousand in RY1.

G. Environmental Capital and O&M Expenditure Requirements

Q. What is the next category of work?

A. The next category of work is "Environmental."

Q. Was the Exhibit titled, "T&D Environmental" prepared under your direction?

A. Yes it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-9

Q. What does Exhibit EIOP-9 show?

A. Exhibit EIOP-9, Schedules 1 and 2 list the capital program/project funding requirements and O&M program changes required to support Environmental work conducted by S&TO, SSO, and Electric Operations. In addition, the exhibit contains white papers for each capital program/project and O&M program change that provide more detailed information, such as program and project work descriptions, justifications, alternatives, estimated completion dates, current status, and spending.

Q. Please provide an overview of the Company’s environmental work category.

A. The environmental work category focuses on work designed to minimize the Company’s environmental footprint. Specifically, the Company strives to reduce the number and impact of dielectric fluid (“oil”) spills and sulfur hexafluoride (“SF6”) gas emissions to the environment. The Company uses oil in its electric system as an insulating and cooling medium and also uses SF6, which is a greenhouse gas when it leaks, for insulation and current interruption in electric transmission, substation, and distribution equipment. In the rate case years for this filing, the Company’s SF6 leak mitigation work is part of a larger effort that also addresses risk reduction and is described in the Risk Reduction section of this testimony. The capital programs discussed here are focused on preventing oil spills, detecting and responding to oil spills, and upgrading facilities and containments so that oil leaks or spills can be captured before they affect the environment.

Q. Please describe the capital programs within the environmental work category.

A. The Company has three capital programs within the environmental work category, all of which are designed to reduce the risk of dielectric fluid release from the underground transmission system by addressing potential leaks in transmission feeder cable pipe, substation equipment, and distribution equipment.

The programs listed below address leak prevention, detection, and containment. Details on each of these projects can be found in their respective white papers.

- “Environmental Enhancement Program” ($586 thousand RY1, $600 thousand RY2, $600 thousand RY3)
- “Oil Minders” ($0.7 MM RY1, $3.7 MM RY2, $0.7 MM RY3)
- “Pipe Enhancement Program” ($25.0 MM RY1, $25.0 MM RY2, $25.0 MM RY3)
- “Substation EHS Risk Mitigation Program” ($57.1 MM RY1, $57.1 MM RY2, $5.0 MM RY3)

Q. As one of the larger projects in this group, please elaborate on the “Pipe Enhancement Program.”

A. The Pipe Enhancement Program is a proactive program designed to reduce dielectric fluid leaks and increase the availability of transmission facilities. It focuses on addressing corrosion on the pipe-type transmission feeder system and includes the large-scale installation of welded barrels or carbon fiber wrap to encase heavily corroded pipe sections, the installation of new pipe coatings, and the associated required excavation, coating removal, inspection, and backfill/restoration tasks.

Dielectric fluid leaks in pipe-type cable are a problem from both an environmental and reliability perspective. Mitigating the release of dielectric fluid to the environment is a critical component of the Company’s efforts to achieve environmental excellence.

In addition, dielectric fluid leaks can result in the Company removing feeders from service. If the leak rate exceeds the flow rate capability of the fluid pressurization pumps, the Company might need to take an extended outage to complete repairs. In cases where fluid pressure can be maintained, a feeder with a large leak may still be forced out of service to clamp and repair the leak. These issues can have detrimental effects on overall system reliability, especially during high load periods.

This program provides increased reliability, extends the useful life of existing pipe-type feeder facilities, and prevents or reduces the likelihood of dielectric fluid release from the pipe-type feeder system.

Q. Please describe the largest project in this group, “Substation EHS Risk Mitigation.”

A. This project is designed to establish system-wide unit containment of all oil-filled equipment, which helps to mitigate risks associated with potential oil release to the environment from substation equipment. These projects are also required to comply with regulatory requirements such as Spill Prevention Control and Counter measures 40CFR112 and New York Department of Environmental Conservation State Pollutant Discharge Elimination System.

The O&M portion of this project includes the below-ground interconnection and installation of flame arrestors between existing transformer moats and requires an increase of $11.9 million in RY1, $1.5 million decrease in RY2, and $10.5 million decrease in RY3.

Additional details on this O&M change can be found in the corresponding capital white paper.

H. Information Technology Capital and O&M Expenditure Requirements

Q. Please explain the Company’s plans to incorporate technology to enhance how it manages the operation of its electric T&D systems.

A. Con Edison uses a number of sophisticated technology applications. The Company continues to explore opportunities to employ the latest technologies in order to improve performance and streamline work processes. The Company’s initiatives in this rate filing focus on two key areas, improving operator visibility and improving process efficiency. Improving operator visibility enhances the information and analytics available to system operators and engineers required for making timely decisions. Improving process efficiency supports system reliability and improved productivity through adding functionality to existing work management systems, supporting operator training, and streamlining work processes. The objective for both these projects is the same – to enable Con Edison employees to leverage critical data for the greatest benefit.

Q. Was the Exhibit titled, "T&D Information Technology" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-10

Q. Please describe the Exhibit EIOP-10.

A. Exhibit EIOP-10, Schedules 1 and 2 list the capital program/project and O&M program change funding requirements that support Information Technology initiatives planned by S&TO, SSO, Central Engineering, Maintenance and Construction, and Electric Operations for RY1, RY2, and RY3. The exhibit also contains white papers for each capital program/project and O&M program change in this category that provide more detailed information, such as program and project work description, justification, alternatives, estimated completion date, current status, and forecasted funding.

Q. Please begin by describing IT programs and projects designed to improve operator visibility.

A. Programs and projects in this category will enhance performance during everyday operations and emergency conditions, such as storms. Specifically, they will help the Company gather more granular, real-time data, better analyze system data, and more effectively respond to system conditions. The programs will also help the Company better integrate and analyze the more granular levels of data that will be available to the Company through AMI. This will help the Company present system data in a format that enables quick analysis and improves decision-making.

The Company plans to invest in the six IT projects listed below to improve operator visibility. Details on each of these projects can be found in their respective white papers.

- “DECC Alarm Manager” ($250 thousand RY1, $250 thousand RY2, $250 thousand RY3)
- “Distribution Ops Training Simulator” ($250 thousand RY1, $150 thousand RY2, $150 thousand RY3)
- “Electric Distribution SCADA Enhancement” ($1.2 MM RY1, $2.2 MM RY2, $1.0 MM RY3)
- “Electronic Feeder Sign On” ($351 thousand RY1, $351 thousand RY2, $351 thousand RY3)
- “Emerging IT” ($3.8 MM RY1, $11.3 MM RY2, $10.0 MM RY3)
- “Integrate Machine Learning Models-CAP” ($250 thousand RY1, $250 thousand RY2, $250 thousand RY3)

Q. Due to the importance of the Company’s SCADA systems, please elaborate on the “Electric Distribution SCADA Enhancement” project.

A. This project upgrades the software and hardware for the General Electric XA21 (PowerOn) SCADA application, which operates SCADA-enabled devices deployed on the distribution system. In addition to enhancing functionality, these upgrades will increase the capacity of the SCADA IT system, which has reached its limit for the number of devices it can support, enabling the Company to connect additional devices as part of both the grid modernization initiative and overhead system resiliency efforts undertaken in the non-network reliability program. Currently, Control Center and Regional Engineering personnel use this application to analyze system conditions and reconfigure the system during scheduled and unscheduled feeder outages and equipment operations. This project supports the Company’s ability to collect and analyze distribution system data and operate its distribution system.

Q. Please continue with a description of the second IT investment category, programs and projects to improve process efficiencies.

A. Projects in this category will increase efficiency by reducing manual effort and the time currently spent on tasks. The projects and programs include the management of specific work activities and processes, both customer-facing and internal, as well as the overall body of work that is managed through the corporate Work Management system. These gains in efficiency will enable the Company to deploy its resources to other important on-hand work. Details on each of these projects can be found in their respective white papers.

- “AutoCAD“ ($0.5 MM RY1, $0.7 MM RY2, $1.0 MM RY3)
- “Construction – Survey Mapping” ($520 thousand RY1, $520 thousand RY2, $520 thousand RY3)
- “CPMS Customer Knowledge Self Service” ($3.0 MM RY1, $3.0 MM RY2, $3.0 MM RY3)
- “Distribution Order Enhancements” ($293 thousand RY1, $300 thousand RY2, $300 thousand RY3)
- “District Operator Task Management” ($390 thousand RY1, $400 thousand RY2, $400 thousand RY3)
- “EMS Replacement AECC and ECC” ($4.6 MM RY1)
- “Field Smart Forms” ($250 thousand RY1, $250 thousand RY2, $250 thousand RY3)

- “OMS IT System Hardening” ($10.0 MM RY1, $10.0 MM RY2, $5.0 MM RY3)
- “Operation Management System Enhancement” ($390 thousand RY1, $400 thousand RY2, $400 thousand RY3)
- “OSS Phase 3” ($2.8 MM RY1)
- “Outage Management System - Phase 3 and 4” ($2.5 MM RY1, $2.5 MM RY2, $1.7 MM RY3)
- “Plant Information System” ($250 thousand RY3)
- “Rogue Employee (GRC)” ($200 thousand RY1, $200 thousand RY2, $200 thousand RY3)
- “Substation Technology Improvements Program” ($1.1 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- “System Operation Enhancements” ($293 thousand RY1, $300 thousand RY2, $400 thousand RY3)
- “WMS Phase II and Enhancements” ($7.2 RY1)
- “WMS Sustainability” ($3.0 MM RY1, $3.0 MM RY2, $3 MM RY3)

Q. Please elaborate on the “CPMS Customer Knowledge Self Service” project to provide an example of this project category.

A. Through this project, the Company will improve the Customer Project Management System (“CPMS”), which went live in 2013. Con Edison’s customers interact with the Company through the CPMS system when they have new service requests or need to increase the capacity of their existing service. The CPMS has streamlined and refined a number of these processes. For example, customers can now self-schedule inspections, and accomplish a number of case-related tasks using a cell phone. There is also a customer inquiry feature to manage and track customer questions and analytics tools.

This project will enhance self-service capabilities, flexibility, transparency, and customer control functionality while adding 24/7 availability and machine learning capabilities. These investments will help the Company better serve its customers and provide additional resources for customers to find the information they need.

For example, the project includes Omni Channel Communication, which aggregates all customer interactions into a single stream of content that is managed by a single customer interaction “layer” in the current case management platform, allowing the Company to quickly find relevant customer information and better respond to their inquiries.

Another improvement being made through this project is the use of Answer Bots and Chat Bots to quickly address common customer inquiries. Answer Bots are designed to automate routine tasks, such as reading incoming customer emails, determining the content of the email, and providing an appropriate response. Chat Bots are an artificial conversational entity that engages the customer as the first line of response before human intervention is required. The Company will use Machine Learning to better respond to customer inquiries. When an auto response fails to adequately answer an inquiry, the system will "learn" to provide a more accurate answer through feedback loops built into the system.

To make information easier for customers to find, this project will implement an Index Management Crawler (IMC) that will make documents (e.g., engineering specifications, Blue Book, Yellow Book, and Customer Service Procedures) in network repositories readily available to the customer for search and classification.

Q. Please elaborate on the "OMS IT System Hardening" project that was previously mentioned as required to support the Company's system resilience efforts.

A. After Nor'easters Riley and Quinn, the Company had an independent assessment of its response performed by an outside consultant. This assessment identified several areas for improvement in Information Technologies and Systems that can enhance the Company's performance in comparable weather events in the future. IT systems important to the Company's storm response were installed for a variety of largely standalone applications, such as Outage Management, control of electrical devices through Supervisory Control and Data Acquisition (SCADA) systems, and Outage Communication Dashboards.

To improve the Company's ability to meet its customer's expectations for ETR accuracy, the Company will need to enhance and integrate a number of its IT systems and platforms. Through this project, the Company will enhance its OMS to improve both its customer service performance in major weather events and the accuracy of estimated restoration times. The Company will need to replace or upgrade several platforms in its current OMS, including the Obvient and iFactor platforms. The Company will enhance distribution system computer models in order to achieve improved outage prediction performance and will integrate SCADA telemetry data into the OMS. The

Company will also re-architect its Customer Communication Interface to promote consistent messaging to customers through their preferred communication channel.

Q. Please elaborate on the "Substation Technology Improvements Program."

A. This program funds technology improvements required to upgrade, enhance, automate, and/or establish substation processes. Many of the Company's processes and procedures designed to promote safe operation and maintenance of its equipment involve data collection, transfer, and storage and are supported by IT assets. Work performed under this program is integral to Con Edison's efforts to continually improve process efficiency and the reliability of the electric system. The use of technology to streamline processes results in more efficient completion of tasks and better resource utilization. Better data collection and storage facilitates enhanced data analysis and trending, which ultimately leads to improved reliability and equipment performance.

As technology advances, the Company works to identify and take advantage of opportunities to improve the efficiency of its processes by leveraging new technology and improving the way data is collected, transferred, and/or stored. This includes the incorporation of mobile technology, which has a quickly expanding role in the work place.

As the use of technology in the workplace grows, funding requirements for this program increase as larger amounts of technology assets require upgrade or replacement and new technology solutions are identified and implemented.

In the current rate plan years, the Company is focused on improvements to its data acquisition network (“DAN”) and an upgrade to its Maximo system. The goal of the DAN improvements is to establish a standard for housing data acquisition applications on a secure and dedicated infrastructure environment and to migrate existing systems onto the platform. The establishment of a secure, dedicated network for data collection applications will enable the Company to install and use remote equipment monitoring devices to monitor equipment condition.

Upgrades to Maximo will be achieved through the addition of software, such as DataSplice and Engage, and will enhance Maximo performance and functionality. DataSplice provides functionality not available in Maximo by allowing the Company to better track and trend equipment conditions. Engage works Maximo to facilitate maintenance resource management, planning, scheduling, and work assignment. Engage is part of an integrated asset management platform that links disparate asset management databases and functions to improve maintenance and engineering efficiency.

Additional detail on specific IT projects funded through this program can be found in the corresponding white paper.

Q. Due to the importance of the Company’s control centers, please describe the “EMS Replacement ECC and AECC” project.

A. The ECC houses the Company’s Energy Management System (“EMS”) and the employees responsible for monitoring and operating the Company’s T&D systems. The Company also maintains a fully-equipped backup, the Alternate Energy Control Center (“AECC”). The Company is planning upgrades to systems at both the ECC and AECC.

Q. Why is it important for the Company to invest in these systems at the ECC and AECC?

A. The ECC and AECC are essential to reliable operation. The Company operates the bulk power system from these facilities in coordination with NYISO. Additionally, the ECC coordinates all planned and emergency work to avoid adverse system impacts.

Q. Are there any O&M changes to IT programs?

A. Yes, the Company proposes to increase funding to support Outage Scheduling System ("OSS") Maintenance. The OSS is used to submit, review, and approve outage requests on the electric system. The Company implemented the current OSS on a web based Pega platform in 2016 and 2017. The Pega licensing model allows up to an agreed number of cases to be created or re-opened each year. There are annual license costs associated with the Pega software and with the IBM WebSphere servers that host the application and database. Details for this program change can be found in the O&M white paper. To support this work, the company proposes an increase of $237 thousand in RY1.

VI. Electric Production

A. Electric Production Overview

Q. Please describe the Company's Electric Production facilities.

A. The Electric Production facilities are: 1) cogeneration unit East River 6/60, which is comprised of Turbine

Generator 6 and Boiler 60; 2) cogeneration unit East River 7/70, which is comprised of Turbine Generator 7 and Boiler 70; and 3) six gas turbines ("GT"s), one located at the 59th Street Generating Station ("59th Street"), two located at the 74th Street Generating Station ("74th Street"), and three located at the Hudson Avenue Generating Station ("Hudson Avenue"). Electric Production also covers O&M for East River Units 1 and 2 combustion turbine generators (also referred to as the East River Repowering Project ("ERRP")).

B. Summary

Q. Was the document titled "Electric Production" prepared under your direction or supervision?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-11

Q. What does this exhibit show?

A. Exhibit EIOP-11, Schedule 1 presents a summary of the Company's projected capital expenditures for Electric Production for each of the rate years. The exhibit also includes white papers for all capital expenditures listed in this section of testimony. There are no O&M program changes for Electric Production in the rate case years.

Q. Please briefly describe the planned capital spending for Electric Production.

A. The Company projects to spend approximately $10.6 million in RY1, $21.9 million in RY2, and $14.9 million in RY3. The Company’s proposed Electric Production capital spending varies based on the outage schedule for East River 6/60 and 7/70. As Boiler 60 upgrades are planned to be complete in 2019, there is a decrease in the total capital expenditure for Electric Production in RY1. Major boiler tube projects are planned for Boiler 70 in RY2, which results in a capital expenditure increase in RY2. The planned expenditure levels decrease again from RY2 to RY3, as there are no major boiler outages currently scheduled for RY3.

Q. Please describe each Electric Production project category for this rate filing.

A. The Company is requesting funding for projects in four categories to support Electric Production: 1) Replacement, 2) Risk Reduction, 3) Environmental, and 4) Safety and Security.

Replacement contains projects and programs to replace failed equipment or to replace equipment that has not yet failed but has degraded performance, has become difficult or costly to maintain, or is approaching the end of its useful life. The Company will invest $0.5 million in RY1, $17.9 million in RY2, and $3.0 million in RY3.

Risk Reduction projects and programs support the reliability and/or availability of a facility or an operational function, and reduce or mitigate a risk associated with a facility or operation through proactive replacement strategies. The Company will invest $7.3 million in RY1, $1.4 million in RY2, and $4.8 million in RY3.

Environmental projects and programs are primarily intended to enhance environmental performance, reduce environmental impact, or comply with environmental regulatory requirements. The Company will invest $1.9 million in RY2, and $6.5 million in RY3.

Safety and Security contains projects and programs primarily intended to prevent or reduce the likelihood of injury or risk to public safety, enhance physical or cyber security, or comply with regulatory requirements. The Company will invest $2.8 million in RY1, $0.8 million in RY2, and $0.6 million in RY3.

C. Detail of Programs/Projects

1. Replacement

Q. Please describe the planned capital expenditures for the Company's Replacement projects.

A. The Replacement category contains projects and programs to replace failed equipment or equipment that has not yet failed but has degraded performance, has become difficult or costly to maintain, or is approaching the end of its useful life. Capital Replacement projects supporting Electric Production are organized in three programmatic subcategories, which are listed below. The Company plans to track and report on its Electric Production Replacement capital spending under these programs going forward:

- Mechanical Equipment
- Electrical Equipment / Control Systems
- Civil / Structural

Q. Please describe the Mechanical Equipment subcategory for Electric Production equipment replacement.

A. This subcategory includes the replacement of boilers, pumps, valves, heat exchangers, air compressors, and tanks. Boilers are integral to the process of generating the steam required to drive the Company's turbine generators and produce electricity and account for a significant portion of the total work performed in this subcategory on Electric Production assets. Both Boiler 60 and Boiler 70 were installed in the 1950’s and require ongoing work to maintain safe and reliable operations.

The furnace walls within boilers are lined with banks of tubes that help maximize the efficiency of converting water to steam. These tubes degrade over time. In order to maximize the efficiency and reliability of the boilers, the Company must replace degraded tubes. The capital work that the Company has currently planned for the boilers involves replacing these tubes along the furnace walls in Boiler 70, and is based on the schedule for Boiler 70 capitalized maintenance.

Q. Please describe each of the major anticipated Replacement projects related to the Mechanical Equipment subcategory.

A. Projects in this subcategory are focused on Boiler 70 and represent typical projects that would be captured in the Mechanical Equipment program going forward. Details on each of these projects can be found in their respective white papers.

- “Boiler 70 Super-heater Elements” - The project will replace the Boiler 70 super-heater tubing because it has developed stress fractures, which have led to tube misalignment and sagging. The Company will invest $6.5 million in RY2.

- “Boiler 70 Re-heater Elements” - The project will replace the Boiler 70 re-heater tubing because it has developed stress fractures, which have led to tube misalignment and sagging. The Company will invest $0.5 million in RY1, and $3.3 million in RY2.
- “Boiler 70 Rear Wall Hopper Slope” - The project will replace the Boiler 70 Rear Wall Hopper Slope tubes because they are degraded from long term corrosion and are susceptible to metal fatigue. The Company will invest $3.3 million in RY2.
- “Boiler 70 Rear Wall BRILC” - The project will replace the Boiler 70 bricks/tiles, refractory, insulation, lagging, and casing (“BRILC”) because they have deteriorated and are failing. The Company will invest $2.0 million in RY2.

Q. Please describe the next Replacement subcategory, Electrical Equipment / Control Systems.

A. This subcategory typically includes the replacement of electrical equipment such as switchgear, transformers, batteries, uninterruptible power supplies, inverters, breakers, motors, cables and backup generators. The Company has identified a number of these systems — including load centers, emergency battery systems, and uninterruptable power systems (“UPS”) — for capital replacement because they are nearing the end of their useful life. Load centers and their associated switchgear comprise the electric supply for critical station equipment, such as circulator pumps (“CP”), boiler feed pumps (“BFP”), and forced draft (“FD”) and induced draft (“ID”) fans. Load centers and switchgear power many of the plant’s primary and auxiliary components. In the event a plant’s auxiliary power supplies are interrupted, certain plant equipment and systems must have access to a temporary, back-up power supply for safety and emergency processes. The battery systems and UPS systems provide a reliable source of emergency power in the event of such auxiliary power supply losses.

This subcategory also includes the replacement of control systems, including transmitters, digital control systems, control panels and terminals, monitoring instrumentation, and wiring. The Company will periodically identify control equipment and systems such as protective relays, instrumentation, and programmable logic controllers (“PLCs”) that are obsolete or present a cyber or operational risk. The Company upgrades or replaces these systems to also reduce the likelihood or impact of forced outages.

Q. Please describe each of the planned Replacement projects in the Electrical Equipment/Control Systems subcategory.

A. Replacement projects related to a number of auxiliary electrical systems are listed below and represent typical projects that would be captured in the Electrical Equipment/Control Systems program going forward. Details on each of these projects can be found in their respective white papers.

- “Replace 6CP Unit Substation” ($1.0 MM RY2, $1.5 MM RY3)
- “ER 71 Circulator Switchgear Replacement” ($200 thousand RY2)
- “ER 72 Circulator Switchgear Replacement” ($200 thousand RY2)
- “73 Boiler Feed Pump Substation Replacement” ($500 thousand RY2, $500 thousand RY3)
- “60-FDE Unit Substation Replacement” ($500 thousand RY3)

- “60-FDW Unit Substation Replacement” ($500 thousand RY3)
- “Battery Replacements” ($30 thousand RY2)

Q. Please explain the Civil/Structural subcategory.

A. This subcategory contains projects that include facility upgrades for heating, ventilating, and air-conditioning (“HVAC”) systems and structural building elements. These projects are required to maintain a proper operating environment for both critical plant equipment and Company personnel.

Q. Please describe each of the planned Replacement projects in the Civil/Structural subcategory.

A. Replacement projects in the Civil/Structural subcategory are listed below and represent the typical projects that would be captured in the Civil/Structural program going forward. Details on each of these projects can be found in their respective white papers.

- “Roof Replacement Over Unit 6/60 Fans” ($700 thousand RY2)
- “Replace Control Room HVAC” ($200 thousand RY2)

2. Risk Reduction

Q. Please describe the Company’s planned capital expenditures on Risk Reduction projects.

A. Risk Reduction projects and programs support the reliability and/or availability of a facility or an operational function, and reduce or mitigate a risk associated with a facility or operation through proactive replacement strategies. The Company’s capital Risk Reduction projects for Electric Production are organized in three programmatic subcategories, which are listed below. The Company plans to track and report on its Electric Production Risk Reduction capital spending going forward:

- Mechanical Equipment
- Electrical Equipment/Control Systems
- Civil/Structural

Q. Please explain the Mechanical Equipment subcategory for Risk Reduction and the risks being addressed.

A. This subcategory includes the replacement of boilers, pumps, valves, heat exchangers, air compressors, and tanks. It also covers the capital spending associated with aquatic life preservation. To avoid the likelihood of potential derating or unit shutdowns, overhauls to replace and refurbish major equipment components of boilers and turbines are systematically planned based on manufacturer and industry guidelines, actual length of operation, unit performance, inspections, and engineering assessments. Additionally, equipment improvements are required to address malfunctions and failures that could potentially lead to unreliable operations and contribute to plant unavailability.

Q. Please describe the Company's planned investments in the Mechanical Equipment subcategory.

A. The Company currently has five Risk Reduction projects for Mechanical Equipment. The details on these projects can be found in the associated white papers and represent typical projects that would be captured in the Mechanical Equipment program going forward.

- "Boiler 60 Chemical Clean Modifications" ($2.1 MM RY3)
- "Replace the Unit 7/70 Circulating Water Pumps" ($500 thousand RY3)
- "Purchase Spare Traveling Screen" ($800 thousand RY2)
- "Replace Traveling Screens 4 & 5" ($1.5 MM RY3)
- "Traveling Screen No. 8 Overhaul" ($700 thousand RY3)

Q. Please explain the need for the aquatic life preservation projects, which include: Purchase Spare Traveling Screen, Replace Traveling Screens 4 & 5, and Traveling Screen No. 8 Overhaul.

A. The New York State Department of Environmental Conservation (“NYSDEC”) modified the State Pollutant Discharge Elimination System (“SPDES”) permit for the East River Generating Station (SPDES Permit NY-0005126) on June 1, 2010. The modification specified the installation of Best Technology Available (“BTA”) for the reduction of marine life impingement mortality and entrainment associated with the plant Cooling Water Intake Structure that supplies 370 million gallons per day of cooling water for East River 6/60 and 7/70. In response to this NYSDEC permit modification, Con Edison completed capital project number 22047-06 - Aquatic Life Preservation Project over the period of 2012-2013, and installed traveling water screen equipment in accordance with the NYSDEC's BTA requirement. In recent years there have been significant failures of two of the screens, requiring complete refurbishment or replacement. Furthermore, it has been discovered that the original design of the traveling water screens is susceptible to corrosion caused by marine microbes, referred to as Microbial Influenced Corrosion. To mitigate this, the

Company must remove the screens and coat them with a corrosion resistant material.

Q. Please describe the Electrical Equipment/Control Systems subcategory for Risk Reduction and the risks being addressed.

A. This subcategory typically includes upgrades of electrical equipment such as switchgear, transformers, batteries, uninterruptible power supplies, inverters, breakers, motors, cables and backup generators. It also includes the upgrades to control systems, including transmitters, digital control systems, control panels and terminals, monitoring instrumentation, and wiring. Proper operation and dependability of the electrical supply systems is a cornerstone to the overall reliability and performance of the Electric Production assets. Failures of electrical system components could result in forced outages and deratings. Additionally, the Company will periodically identify control equipment and systems such as protective relays, instrumentation, and programmable logic controllers ("PLCs") that are obsolete or present a cyber or operational risk. The Company upgrades or replaces these systems to also reduce the likelihood or impact of forced outages.

Q. Please describe the Company's planned investments in the Electrical Equipment/Control Systems subcategory.

A. The Company currently has five Risk Reduction projects for Electrical Equipment/Control Systems. The details of these projects can be found in their associated white papers and represent typical projects that would be captured in the Electrical Equipment/Control Systems program going forward.

- "TR-7E Replacement" ($7.0 MM RY1)
- "East River Units 60 and 70 O_2 Trim" ($500 thousand RY2)
- "Replace Legacy Control Systems" ($300 thousand RY1)
- "Replace Steam Pressure Control Valve" ($100 thousand RY2)
- "Replace GT1 GE Relays" ($100 thousand RY3)

Q. Please provide additional details regarding the TR-7E Replacement project.

A. This project will replace the 13/69kV Generator Step-Up ("GSU") Transformer 7E dedicated for East River 7/70. The Company has identified Transformer 7E as one of its top candidates for replacement due to a history of oil leaks. The Company has attempted to mitigate these leaks with repairs, however, the repairs have proven unsuccessful.

3. Environmental

Q. Please describe the capital expenditures under Environmental.

A. In general, projects in this category are intended to enhance environmental performance, reduce environmental impact, or comply with regulatory requirements. The Company currently plans to implement projects in this category designed to convert current backup fuel assets to use a cleaner burning fuel and to reduce the risk of oil leaks into the environment. These projects are representative of projects that will be captured in the Environmental program moving forward.

Q. Please describe the Company's plans to convert its Electric Production assets to use a cleaner burning backup fuel source.

A. The New York City Department of Environmental Protection ("NYCDEP") has prohibited the use of No. 6 fuel oil as of January 1, 2020, unless a fuel oil user agrees to go to No. 2 or lighter fuel oil by January 1, 2022; it has also prohibited the use of No. 4 fuel oil as of January 1, 2025. Pursuant to PSC, NYISO, and Con Edison gas tariff requirements and to maintain reliable operations year round, the Company maintains a backup fuel for its electric and steam production facilities. The Company has determined, based on fuel oil prices and conversion costs that it is in the customers' best interest for the Company to convert to No. 4 oil as an interim step prior to 2020 and then convert to No. 2 oil prior to 2025.

The affected stations are: East River 6/60 and 7/70, East River South Steam Station ("ERSSS"), 59th Street, 74th Street, and the Ravenswood A-House ("RAV"). The specific affected assets impact both Electric and Steam rate payers—Electric Production and Steam Production.

Q. Please discuss the conversion plan for the East River Electric Production assets.

A. In Fall 2018, the Company converted the backup fuel for East River Electric Production Units 6/60 and 7/70 from No. 6 to No. 4 oil. The Company is now planning its conversion to No. 2 oil. Detailed engineering for this process will begin in 2019 to meet the January 1, 2025 regulatory deadline.

Q. What is involved in converting to No.2 oil?

A. Any fuel oil conversion involves three considerations: 1) delivery/storage, 2) forwarding/conditioning, and 3) combustion efficiency. Fuel delivery and storage takes into account contracts, piping, tank capacity, tank condition, and environmental and safety hazards. Fuel oil forwarding and conditioning includes pump design, pump capacity, heating requirements, and metering. Boiler combustion efficiency involves evaluating how fuel is applied to the furnace.

Q. Please describe the conversion process.

A. First, the Company will pump down, clean, and inspect the fuel oil storage tanks at East River. Second, the Company will install equipment required for the conversion. Lastly, the Company will commission, test and tune the equipment to optimize operation. The Company’s fire risk assessment determined that it must upgrade the East River Tank Farm to store No. 2 oil; specifically, it must upgrade the tank internal foam system, the external foam monitor system, the fire detection system, and install a redundant water supply from a separate city water main.

The Company must also install new pumps at the tanks to shuttle, recirculate, and forward fuel oil from the tanks to the boilers. The pumps are required to establish and maintain the minimum flows and pressures needed to get the appropriate amount of fuel to each boiler. The existing pumps will not work because of the consistency of No. 2 oil. In addition, the pumps are submerged and continuously touched by the fuel oil. The change to No. 2 oil requires a change in pump and seal material to resist chemical attack.

When the Company used No. 6 oil, it needed heaters to maintain the proper conditions for burning. While No. 4 oil is much less viscous than No. 6 oil, it still has the potential to become very thick in low temperatures. The heaters were retained during the No. 4 oil conversion to mitigate this potential scenario. No. 2 oil is a much lighter fuel than both No. 6 oil and No. 4 oil and the viscosity will not become so high in low temperatures that combustion cannot be maintained. Consequently, the Company will remove and retire the four East River fuel oil heaters located on top of fuel oil storage tanks No. 2 and No. 3. This involves capping, closing, and retiring the steam piping supplies and returns, and adding fuel oil piping where the fuel oil heaters are located.

Burner changes are also necessary for conversion to No. 2 oil. The control stations that regulate the fuel to each boiler were originally designed for a much thicker, denser fuel. The systems are not adequately sized to effectively control the fuel flow to each boiler. Each burner has an oil gun and/or oil gun tip that regulates the flow of fuel to each burner. The Company must also replace these oil guns and/or tips to ensure adequate combustion. These mechanical changes require controls tuning to address the valve, piping, and instrumentation upgrades for safe and reliable operation.

Q. What does the Company project to spend to complete the oil conversion work?

A. The Company will invest $0.8 million in RY2 and $6.5 million in RY3, with additional spending planned after RY3 for the completion of this project. Additional details can be found in the associated oil conversion white paper.

Q. Please explain the Environmental projects that reduce the risk of oil leaks.

A. The Company currently has two Environmental projects planned that will reduce the risk of oil leaks. The details on each project can be found in their respective white papers.

- “Replace Dock Transformer” ($1.0 MM RY2)

- “Cable Cooling Dielectric Leak Detection” ($100 thousand RY2)

4. Safety and Security

Q. Please describe the capital expenditures under the Safety and Security category.

A. Safety and Security contains projects primarily intended to prevent or reduce the likelihood of injury or risk to public safety, enhance physical or cyber security, or comply with regulatory requirements. Projects in the Safety and Security category typically involve hazard protection system upgrades, facility safety upgrades, and personnel access improvements and represent the types of projects that would be captured in the Safety and Security program moving forward.

Q. Please describe each of the major anticipated Safety and Security projects.

A. The Company’s Electric Production Safety and Security projects are listed below. Details on each of these projects can be found in their respective white papers.

- “Fire Alarm System in Unit 6/7 Plant Areas” ($1.5 MM RY1)
- “Install Access Platforms” ($1.3 MM RY1)
- “Update ER Emergency Evacuation System” ($500

thousand RY2)

- “Repair Slabs Under Transfer House” ($300 thousand RY2)
- “Lube Oil Room Ventilation” ($600 thousand RY3)

VII. Metropolitan Transportation Authority

Q. Does the Company’s proposed revenue requirement in this rate filing include certain costs of complying with the Commission’s directives in Case 17-E-0428 “Order On Consent Directing Steps To Safeguard And Maintain Adequate Utility Service To The Subway System,” issued August 16, 2017 (“August 2017 Order”), and the Order Directing Steps To Safeguard And Maintain Adequate Utility Service To The Subway System issued November 10, 2017 (“November 2017 Order”)?

A. Yes.

Q. What does the rate filing revenue requirement include?

A. The revenue requirement request includes certain MTA related costs that the Company incurred to comply with the Commission’s two Metropolitan Transit Authority (“MTA”) orders. As described in more detail in the Accounting Panel’s testimony, the Company proposes to recover the cost of this Commission-ordered work on MTA facilities over five years.

Q. What did the Commission direct in Case 17-E-0428?

A. On June 29, 2017, Governor Cuomo declared a disaster emergency in the five boroughs of New York City, Westchester County, and the remaining six counties that comprise the MTA region. Subsequently, in the August 2017 Order, the Commission exercised its emergency authority and directed the Company to take specific enumerated steps “to safeguard and maintain adequate utility service to the MTA subway system.” As part of this work, the Commission directed the Company to accelerate its planned deployment of smart meters at MTA locations, formalize communication protocols with the MTA, and establish an inventory of dedicated emergency generators for dispatch to subway signal power locations as needed.

Pursuant to the Commission’s order, the Company inspected and repaired its facilities that provide service to the MTA subway, replaced vulnerable cable, and improved redundancy of its electric feeds at targeted subway stations. The Company inspected approximately 1,000 structures that supply MTA signals, and installed sensors in underground structures that supply MTA signaling facilities in the Company’s service territory.

The Company replaced approximately 250 sections of aluminum cable that supply MTA signaling facilities, and improved redundancy to signal services at 67 subway stations. In general, and as described in more detail in the Accounting Panel’s testimony, the Company has not included cost recovery of this work in this rate filing because it mostly involved work on the Company’s facilities that the Company managed as part of its existing rate plan capital and O&M expenditures.

Q. Did the Commission direct additional work in Case 17-E-0428?

A. Yes. On November 10, 2017, the Commission issued the November 2017 Order that increased the Company’s scope of work to include additional substantial work on the MTA’s system. The Commission ordered the Company to inspect and repair MTA-owned energy distribution rooms, trackside signal equipment, and switches, and to assume an existing MTA contract to replace 74 automatic transfer panels and install 162 emergency generator connections. The November 2017 Order also directed the Company to hire contractors to purchase and install voltage sag compensators at MTA subway signal locations and replace signal cable. The Company had worked with EPRI and the MTA to identify solutions to mitigate the effect of power quality disturbances on MTA signaling equipment. The full scope of the work the Commission ordered in the November 2017 Order is included as an appendix to that order.

Q. Did the Commission address cost recovery in the November 2017 Order?

A. The Commission stated as follows in its November 2017 Order (at 10):

> “This order does not address or provide for any cost recovery. The August 16, 2017 Order and this order will result in a change in Con Edison’s annual electric costs or expenses not anticipated in the forecasts and assumptions on which rates in the current rate plan are based. Because in this instance the ten (10) basis point annual deferral threshold in the rate plan creates a perverse incentive for Con Edison to delay work, the Commission will entertain waiving it in this instance if Con Edison can demonstrate that it has sufficiently expedited the emergency work in a cooperative and prudent manner. By compliance with the ordering clauses Con Edison does not waive any of its rights to recover or seek recovery of any prudently incurred costs, and the Commission reserves all of its rights to approve or deny such costs in any future rate case. Any deferral will be considered in light of the level and nature of spending within existing rate allowances.”

The Accounting Panel discusses the application of the Commission’s language and the revenue requirement impact. We note that in the Accounting Panel’s testimony, waiving of the ten basis point annual deferral threshold, as discussed in the

Order, is not required except for a smaller amount of dollars that the Company forecasts it will spend in 2019 that, as currently forecasted, would not exceed the threshold.

Q. If necessary, is waiver of the threshold for 2019 justified?

A. As the Commission noted in its November 2017 Order, the threshold should be waived if Con Edison has sufficiently expedited the emergency work in a cooperative and prudent manner. This is exactly what Con Edison did. The Company performed a large amount of work in a relatively short time to improve the electricity supply for the MTA system as ordered by the Commission. The full scope of the work completed is documented in the final monthly report that Con Edison filed in 17-E-0428 on January 14, 2019 (the December 2018 Monthly Report), which and is available on the Commission website. This report shows all of the work completed. The vast scope of work performed shows that Con Edison dedicated significant resources to complete this work in a relatively short time period. In addition, Con Edison cooperated through the entire work process with DPS Staff and the MTA, meeting with them once each week to review work performed to date and plan future work. Finally, the Company at all times proceeded in a prudent manner, working with the MTA to use its qualified contractors for the work performed on its system. The Company used competitive processes throughout -- to the extent feasible given the Order’s requirement that the work be completed expeditiously -- to minimize costs for customers.

The Company completed a vast amount of work, as ordered by the Commission, in a relatively short time period at a reasonable cost to customers.

VIII. Special Issues

A. Reliability Performance Mechanism

Q. Does the Company propose to modify any of the performance metrics of the current Reliability Performance Mechanism (“RPM”)?

A. Yes. The Company proposes to: 1) replace the Network Outages per 1,000 customers served metric with System Average Interruption Frequency Duration (“SAIFI”); 2) replace the Network Outage Duration metric with System Average Interruption Duration Index (“SAIDI”) metric; and 3) replace the non-network Customer Average Interruption Duration Index (“CAIDI”) with SAIDI, as modified by excluding heat waves, for network and non-network systems, that are above the design criteria of the electrical system.

Q. Please explain SAIFI, SAIDI, and CAIDI.

A. SAIFI measures the average number of customer account interruptions annually. The formula is the number of customer accounts (hereinafter in this section customers) that have lost power during the year divided by the number of customers served at the end of the previous year. CAIDI measures the average time that an affected customer is out of service. The formula is the total customer hours of lost power divided by the number of customers that have lost power. SAIDI measures the average amount of time a customer is out of service during the year. The formula for SAIDI is the customer hours of lost power divided by the number of customers served at the end of the year. SAIDI can also be derived by multiplying SAIFI by CAIDI.

Q. Have you considered current industry practice in proposing these changes?

A. Yes, the Company reviewed the electric service reliability metrics used in performance-based ratemaking ("PBR") across the country. The Company also reviewed relevant literature, including a series of papers from the National Regulatory Research Institute (“NRRI”), an arm of the National Association of Regulatory Utility Commissioners (“NARUC”), and publications from utility management/economic consultants, especially O’Neill Management Consulting, LLC and Pacific Economics Group.

Q. Do you have a summary of your findings?

A. Yes. Exhibit EIOP-12, Schedule 1 shows a map of the United States colored with different shades of gray to indicate which states have PBR mechanisms that explicitly include electric service reliability measures and a table that shows the electric reliability metrics used by each state.

Q. What is the conclusion that you draw from that table?

A. The most common PBR electric reliability metrics are SAIDI and SAIFI, which is consistent with the Company’s proposal to modify its performance metrics.

1. Network Outages per 1,000 Customers Served

Q. What does the Network Outages per 1,000 customers served metric (“Network Outage metric”) measure?

A. It measures the number of network customer outage interruptions received in one year per 1,000 customers served. In contrast, SAIFI measures the average annual number of customer interruptions.

Q. How did Network Outage Metric become a metric?

A. It was adopted in 2009, in Case 08-E-0618, as a substitute for SAIFI while the Company gained experience with a new Outage Management System. As the Commission stated in Case 09-E-0428, determining network SAIFI targets requires the collection of data over multiple years. When the Network Outage metric was adopted, the Commission recommended that the Company gather enough data through its new (and current) Outage Management System to identify an appropriate target before allowing SAIFI to again be used as a metric. The Company now has ten years of data using the OMS system and proposes to revert back to SAIFI. This would bring Con Edison in line with the rest of the New York State utilities.

Q. What is the network SAIFI threshold that the Company proposes?

A. The Company proposes that the network SAIFI threshold be set at 20.05.

Q. How did the Company calculate this threshold?

A. The Company calculated this threshold using ten years of historical performance data and statistical analysis to identify a threshold that is one standard deviation above average historical performance for the ten year period.

The use of historical performance data is standard practice in the industry. We used ten years of data to account for performance variability in the data set, including variations caused by heat waves and other weather variables. In addition, the use of ten years is consistent with the Commission's recommendation in Case 09-E-0428 to collect multiple data points over multiple years. The Company used statistical analysis to calculate the threshold because it is a more sophisticated method for calculating variability in a data set than using a fixed percentage. Data used in the Company's threshold calculation is displayed in the table below.

Network SAIFI without Storms	
Year	**SAIFI**
2008	14.31
2009	14.65
2010	19.14
2011	21.03
2012	12.08
2013	12.44
2014	13.96
2015	16.12
2016	16.18
2017	16.72
Average Performance Plus One Standard Deviation	**20.05**

2. Adoption of SAIDI Metric

Q. Please describe the cases in which the Company would like to change existing metrics for SAIDI.

A. There are two cases. First, the Company proposes to replace its Average Outage Duration ("AOD") metric with SAIDI. Second, the Company proposes to use SAIDI instead of CAIDI as its non-network performance metric.

Q. What is the AOD metric and how did it become a metric?

A. AOD measures the duration of interruptions, and was intended to work in conjunction with the Network Outage metric. AOD is calculated by dividing the sum of the duration of network outage jobs by the total number of network outage jobs. The Commission adopted AOD concurrently with the Network Outage metric as substitute for network CAIDI.

Q. Why is the Company proposing to eliminate AOD and adopt SAIDI instead of CAIDI for networks?

A. SAIDI, which measures how long the average customer experiences a sustained interruption, is a more meaningful metric than CAIDI or AOD. CAIDI measures the average duration of an interruption for the few customers that experience an interruption in a given year. While this metric is important, it provides only limited information about customer experience, especially when a high percentage (e.g., 80 to 90 percent) of customers do not experience any interruption at all.

CAIDI may also be inordinately affected by a single interruption, especially if the total number of interruptions is low. For example, in 2007 a lightning-induced transmission-substation outage interrupted service to 137,000 customers in the YorkVille and West Bronx networks for 45 minutes and 48 minutes, respectively. Before the interruption, network CAIDI was 4.49 hours. After the interruption, it dropped to 1.17 hours. The final CAIDI for that year was 1.58 hours. The lightning strike drove a record low CAIDI that was not indicative of performance prior to the event. The current AOD metric has the same flaws as the CAIDI metric.

SAIDI, in contrast, measures both frequency of interruption and duration. In other words, SAIDI measures the average of customer interruptions for all customers, taking into account that some customers experience no interruptions at all.

Q. What SAIDI thresholds is the Company proposing?

A. For the same reasons previously stated, the Company proposes the network SAIDI threshold be set at 8.09 minutes, which is one standard deviation above the Company's ten-year historical performance. The chart below shows the Company's performance over the last ten years.

Network SAIFI-CAIDI-SAIDI without Storms

	SAIFI	CAIDI Minutes	SAIDI Minutes	**SAIDI + 1 SD**
2008	0.0143	340	4.86	8.09
2009	0.0147	248	3.63	8.09
2010	0.0191	400	7.66	8.09
2011	0.0210	413	8.69	8.09
2012	0.0121	381	4.60	8.09
2013	0.0124	337	4.19	8.09
2014	0.0140	394	5.50	8.09
2015	0.0161	405	6.53	8.09
2016	0.0162	413	6.68	8.09
2017	0.0167	391	6.53	8.09
Average	**0.02**	**372**	**5.83**	

Q. Do the same reasons you just gave for SAIDI being preferable to CAIDI support the Company's proposal to use SAIDI instead of CAIDI as its non-network performance metric?

A. Yes.

Q. What Non-Network SAIDI threshold is the Company proposing?

A. The non-network CAIDI target should be replaced by SAIDI. SAIDI is calculated by multiplying SAIFI times CAIDI in minutes. The Company proposes to set the threshold at 60.59 minutes based on the current SAIFI (0.495) CAIDI (122.4 minutes) thresholds.

3. Heat Wave Exclusions

Q. What is the Company's proposal for exclusions?

A. Under the "Electric Service Reliability Performance Mechanism" Case 16-E-0060 Appendix 14, page-4, "Heat-related outages are not a major storm". The Company's electrical system is designed to withstand a certain amount of heat but not extreme heat. Con Edison is asking for heat waves above the design criteria of the system design to be classified as excludable events, similar to major storm exclusions.

Q. Have you conducted a study that shows the impact of extreme weather in the electrical system?

A. Yes. The "Reliability Metric Study."

Q. Was the document titled "Reliability Metric Study" prepared under your direction or supervision?

A. It was prepared as a result of one of the recommendations in the "Operations Audit of the Accuracy of New York State Utilities' Self-Reported Data Electric Reliability" requested by the NYSDPS under Case 13-M-0314 and filed July 10th, 2017.

Q. How does heat affect the overhead electrical system?

A. The Company’s Climate Change study, currently being drafted, predicts more frequent heat waves and extreme weather taking place in the future for which the Company will need to account. The overhead electrical system is designed for variable (which is a weighted average of temperature and humidity over days) of 85^{0}F (because the average includes wet bulb temperature, which is a measurement of humidity, the temperature measurement includes humidity). When the variable exceeds 85^{0}F, potential for cable and equipment failures increases increasing the risk of customer outages. For example, on July 22, 2011 the temperature variable was 88.7^{0}F. That day, the Company had 123 non-network outage jobs that affected service to 5,754 customers for a total of 80,593 hours. The average duration of outages due to overhead transformers was 14.01 hours. That one day increased the CAIDI from 1.96 hours to 2.12 hours, which resulted in the Company having to pay a $5 million penalty for missing the threshold that year. Again, one event dictated the CAIDI performance for the year. If SAIDI was the metric being used instead of CAIDI, the Company would not have exceeded the threshold in this year as a result of this single event and been subject to the penalty.

Q. What is the Company proposing?

A. The Company proposes an exclusion for non-network outages when the variable for the day is equal to or exceeds 85^{0}F, which is the design criterion for the overhead system.

Q. Does the Company propose a similar exclusion for the network system?

A. Yes. For the network system the design criteria is 86^{0}F. Similarly, the Company is asking for exclusion of network outages when the variable is equal to or exceeds 86^{0}F for the day.

Q. Has there been a study conducted that illustrates the adverse impact of heat in the electrical system?

A. Yes. The “Reliability Metric Study” that was performed as a result of the “Operations Audit of the Accuracy of New York State Utilities’ Self-Reported Data Electric Reliability” requested by the NYSDPS under Case 13-M-0314.

Q. What were the key findings from that report that are relevant to the Company’s proposal?

A. CAIDI is measured by the population of customers impacted by an outage and not the total number of customers served by the system as a whole. Therefore, it does not provide an accurate representation of true system performance. Hence any single outage with a large number of customers interrupted will result in a significant effect on the overall CAIDI value, not a true representation of the performance of the system for the entire year. The study also showed that there is an adverse impact on reliability resulting in a significant increase in customer interruptions and duration when temperature, measured in temperature variable, exceeds the system design basis.

4. Network Summer Open Automatics

Q. Please describe the Company’s current Network Summer Open Automatics RPM.

A. Currently, the Company pays $1.0 million dollars if the network feeder failure rate for automatic feeder trips exceeds 330 only during the summer months in that year. Summer months are June, July and August for the purposes of this metric.

Q. When was the metric introduced?

A. The Commission adopted this metric in Case 08-E-0539 when the network metric was changed to AOD and Network Outages per 1,000 customers served.

Q. What changes is the Company proposing to the RPM?

A. The Company proposes to eliminate the RPM because it does not accurately represent the network system's performance and reliability. The Company has approximately 2,200 distribution feeders that supply 65 second contingency networks. These networks are designed to serve loads with up to two feeders out of service during peak load times. Measuring individual feeder outages during the summer period does not accurately represent the reliability of these networks. During peak load periods, operational measures are enacted once a feeder opens automatically. These measures both shorten the time a feeder is out of service and reduce the probability of another feeder opening automatically.

Moreover, the Company is already subject to a different metric that better reflects network reliability, the Network Major Outage metric. Under the Network Major Outage metric, the interruption of service to 15 percent or more of the customers in any network for a period of three hours or more results in a penalty of $5.0 million to $15.0 million per event. This requirement results in the Company focusing on network reliability and events that interrupt service to customers. In contrast, the Summer Open Automatics metric is focused on events that the system is designed to handle and that do not impact customers.

Q. Does the Company have a program to monitor and address the health of its networks?

A. Yes, through the Primary Feeder Reliability program the Company both monitors and initiates projects that improve network reliability. For additional details on this program, please see the corresponding white paper in exhibit EIOP-5, Schedule 3.

5. Remote Monitoring System Reporting

Q. Please describe the current Remote Monitoring System (“RMS”) reporting requirements.

A. The Company is required to achieve a 90 percent reporting rate for the RMS in each network during the last month of each quarter or be subject to a penalty of $10 million per network.

Q. What changes to this RPM is the Company proposing?

A. The Company proposes to revise the RPM so that it must achieve a 90 percent reporting rate for the RMS in a minimum of 62 of its 65 networks on the last month of the second quarter. The Company believes it is unreasonable to subject the Company to a penalty if it fails to meet this reporting standard for one, or a small number of its networks. For example, during a scheduled load transfer, those networks will not meet the standard, and the Company must seek an exemption from the Commission. Under the Company’s proposal, the networks involved in the load transfer would be excluded. The Company believes that its proposal to only report for the last month of the second quarter is reasonable, because the end of the second quarter is the beginning of the summer and peak load electric period. This time period is the most important for the electric distribution system. The Company further proposes to reduce the Annual Revenue Adjustment exposure from $10 million to $5 million.

Q. Please explain the basis for the Company’s proposal.

A. As part of its Grid Innovation efforts, the Company is looking to migrate from the use of RMS’s current power line carrier technology to either the AMI system’s wireless network or a wireless modem. The change in communication technology will enable the Company to fully use the functionality in its latest generation of network protector relays, which includes self-diagnostics and two-way communication. Self-diagnostics functionality involves the relays monitoring their status over a designated period of time of inactivity and initiating a test to verify working status. This functionality will allow the Company to see when there is an issue that needs to be resolved instead of discovering non-functional equipment during routine feeder operations.

Due to changes currently taking place involving the communication with Network Protectors and the new features being provided by the self-diagnostic capabilities, the Company requests the change to the current RPM in order to facilitate this transition. The optimal time to have this equipment reporting is the period prior to the beginning of the summer peak load period, which is the time the Company is proposing. In order to facilitate this transition and thereafter, the Company requests the change to the current RPM.

B. Major Storm Cost Reserve

Q. Does the Company’s current electric rate plan include a major storm cost reserve that includes cost recovery for mobilization for a forecasted major storm that does not occur?

A. Yes. The Company may charge to the major storm reserve up to $3 million per calendar year for costs it incurs to obtain contractors and/or utility mutual assistance in reasonable anticipation of a storm that will affect its electric operations to the degree that it qualifies as a major storm under 16NYCRR Part 97, but which ultimately does not. The Company proposes that the major storm cost reserve be continued, with two modifications. The modifications are discussed in detail below and in the Accounting Panel.

Q. Explain how this charge to the major storm cost reserve currently applies.

A. A major storm is a period of adverse weather during which service interruptions affect at least 10 percent of the customers in an operating area and/or result in customers being without electric service for durations of at least 24 hours. The Company uses staff meteorologists who forecast a storm’s strength and its potential impact on the electric system. The Company uses a well-established storm matrix, which it has revised post Riley/Quinn, to forecast the impact on the electric system. As with any forecast, however, there will be times when the forecast of a storm's strength is incorrect and the Company will have prepared for a forecasted major storm that does not turn out to be a major storm.

Q. What modification to the major storm cost reserve does the Company propose?

A. The Company proposes to lift the $3 million cap per calendar year and charge all qualified costs to the major storm cost reserve. Qualified costs here means cost incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance, incremental employee labor, transportation, meals, lodging, and travel time (collectively, "Pre-Staging and Mobilization Costs")

Q. Why does the Company seek this change?

A. In March 2018, the Company experienced significant damage to its distribution system as a result of Nor'easters Quinn and Riley. The next month, on April 4th, the Company forecasted that a significant wind (sustained winds of 30mph with gusts as high as 45mph) and thunderstorm event would impact its service territory and mobilized and supplemented its resources with mutual aid. The April 4th storm event was actually much less severe than forecasted and had minimal impact on the distribution system. The event, however, caused the Company to spend approximately $4 million in mobilization, more than $1.0 million more than the current $3.0 million annual cap.

Q. Has the Company changed its practice concerning storm mobilization since Riley/Quinn?

A. Yes. In order to expedite restoration efforts when a Major Storm is forecast, the Company's Electric Emergency Response Plan now calls for the pre-staging of contractors and/or mutual assistance crews, taking into consideration the forecasted regional weather impact and pre-determined minimum staffing requirements. Because such contractor and mutual aid mobilization costs are reasonably incurred, the Company is proposing to charge the major storm reserve for Pre-Staging and Mobilization Costs without a cap.

Q. Are there any other modifications to the major storm cost reserve that the Company is proposing?

A. Yes, the Company is proposing to eliminate the two percent deductible.

Q. Please describe the two percent deductible that you propose to eliminate.

A. The current rate plan provides for the Company to exclude from costs chargeable to the major storm reserve an amount equal to two percent of the costs incurred (net of insurance and other recoveries) due to the occurrence of a major storm.

Q. What is your understanding of the reason for this deductible?

A. The deductible is intended to recognize that some portion of the storm restoration activities for which the Company will be compensated pursuant to the reserve mechanism will reduce by some amount the Company’s future O&M costs.

Q. Why is the Company proposing to eliminate the deductible?

A. Although the Company acknowledges that some portion of the repairs made during storm restoration may reduce future O&M expense, the two percent deductible fails to consider other factors associated with the Company’s response to storms that result in the Company having higher, unreimbursed O&M costs over the course of the year. Specifically, the application of the deductible does not account for higher costs the Company will incur to: 1) complete planned O&M work not completed because resources are diverted during storm restoration; 2) make permanent repairs to equipment on which temporary repairs were made during restoration; and 3) the additional unreimbursed O&M expense to effectuate storm restoration.

Q. Please explain why the Company incurs higher costs to complete planned O&M work not completed during the storm restoration period.

A. During storm restoration, the Company defers planned O&M work as a result of crews being reassigned to storm restoration work. Some of the uncompleted work (for example, specification driven compliance work such as transformer inspections) must subsequently be accomplished using overtime, resulting in the Company incurring higher costs than would otherwise have been incurred had storm restoration not been necessary.

In addition, timely equipment repairs typically prevent more serious problems from developing. Deferring O&M repairs because of storm related work can result in the Company being required to address a more serious condition later that is more costly. For example, postponing a patch repair to a rusted area on a transformer tank due to more pressing storm work may result in further rusting, which could thereafter require a more extensive and costly repair.

Q. Please explain the incremental costs incurred to make permanent repairs to equipment on which temporary repairs were made during restoration.

A. During restoration, the Company often makes temporary repairs in order to expedite service restoration to customers. Following restoration to all customers, the Company must make permanent repairs to the equipment on which temporary repairs were effectuated. Examples of this type of work include removing bridges that were installed on customers’ services, returning to service transformers that were cut clear, or returning a primary circuit to normal operation following a wire down, which results in the Company making an emergency tie to fix a feeder gap.

Q. Please also describe the additional unreimbursed O&M expense the Company can incur in connection with its storm restoration activities.

A. During and immediately following a major storm, the Company typically redirects Company labor from capital projects to O&M activities that comprise storm restoration. The major storm reserve excludes the recovery of the straight time labor expense associated with this additional labor assigned to storm work.

Q. Do you have any analyses that quantify these incremental unreimbursed costs?

A. We do not. We believe such a study would not be practicable because it would require myriad assumptions that may or may not be applicable depending upon the unique facts and circumstances associated with each major storm. There is also no underlying study that provides a basis for the two percent deductible, which we believe would be equally impractical to perform. But, for the reasons we explained above, we believe there is no reasonable basis to assume the cost of work that may be avoided would necessarily exceed the additional incremental costs that the Company may incur. For these reasons, we recommend that the two percent deductible be eliminated.

C. Generator Retirement

Q. Does the Company have any proposals related to third-party Generator retirements?

A. Yes. Third-party generators may retire or announce their retirements during RY 1, 2, or 3. Generators may retire as a result of market forces.They may also be affected by environmental regulations, such as the New York State Department of Environmental Conservation’s significant proposed changes to regulations on nitrogen oxides emissions which, although they may not take effect until after 2022, could force earlier generator retirements. Generator retirements or retirement announcements may create reliability needs that the Company has to address during the term of the rate plan through upgrades to itselectric delivery system. As the Company cannot know in advance whether generator retirements will occur, or the precise upgrades required, it is proposing recover the costs for any upgrades necessary to maintain reliability because of a generator retirement, to the extent not otherwise recovered, as described in more detail in the Accounting Panel.

D. Charges for Special Services

Q. Please discuss the Company's proposal to update charges for special services performed by the Company.

A. The Company is proposing to update charges for special services performed by the Company as follows:

- Reinspection Charge:
  - Increase to $241.00 (currently $109.00)
- High potential proof test
  - Per visit to the premises, up to four hours: $1,761.00 (currently $1,693.00)
  - For each additional hour or portion thereof: $440.00 (currently $423.00)

- Megger Test
    - Two people for 1 hour: $440.00 (currently $423.00)
- Dielectric Fluid Test
    - First sample: $1,161.00 (currently $1,121.00)
    - Each additional sample taken at the same time: $822.00 (currently $799.00)
    - Each sample taken by the Customer: $721.00 (currently $698.00)

Q. What is the basis for the proposed charges?

A. These charges were last updated January 1, 2017. The proposed charges reflect the Company's 2020 cost for labor, vehicles, corporate overhead, and chemical lab. The change in costs for these charges is the result of the overhead allocation to these tasks.

E. Reporting of Capital Expenditures

Q. Does the Company propose to report on electric capital expenditures?

A. Yes. Currently, the Company files an electric capital budget and expenditure report twice annually in January and February. The content of that report is established by the terms of Appendix 22 of the Joint Proposal adopted by the Commission in Cases 16-E-0060, et al. The Company proposes to modify the reporting schedule on electric capital expenditures for the rate plan commencing January 1, 2020 by eliminating the January reporting requirement.

Q. What is the current reporting schedule?

A. Under the Company's existing Rate Plan, the Company was required to file by January 15, 2017, 2018 and 2019 its most recent projected capital projects and programs list for the upcoming year and the subsequent year. In addition, the Company was or is required to file by February 28, 2018, 2019 and 2020 a report on its project and program expenditures during the prior calendar year and five-year capital budget.

Q. Why is the Company proposing to eliminate the January filing obligation?

A. The two filings are duplicative. The February report requires a five-year forecast and therefore, includes the two year forecast required by the January report. In addition, the February report is more comprehensive because the Company provides information on expenditures for the prior year.

Q. Please explain the Company's proposal for reporting electric capital expenditures for the rate plan commencing January 1, 2020.

A. The Company would file by February 28, 2021, (a) a report on capital project and program expenditures during the prior calendar year for electric transmission, substations and distribution operations, electric production, electric storm hardening, municipal infrastructure, and shared services allocable to electric and (b) an update to the five-year capital forecast.

Q. Please describe in more detail the content of the annual report.

A. The report would provide the same information as stated in Appendix 22, which is set forth below: The Report will provide 1) a list of all projects and/or programs reflected on the Project/Program List and in the Company’s annual capital budgets that were eliminated, with supporting explanation; 2) a list of all new projects and/or programs that were added, with supporting explanation; 3) for all projects and/or programs, including new and eliminated projects and/or programs, the actual amount spent as compared to the forecasted budget amounts. To the extent the amount spent on a project or program varies from the forecasted amount by more than 15 percent, for projects or programs with a forecasted cost greater than $5 million but less than $25 million, or by more than 10 percent for projects or programs with a forecasted cost of $25 million or more, the Company shall provide an explanation of the reasons for the variance.

Q. Do you anticipate that the Company’s capital plan during the rate year will be the same as the plan stated in the “Project/Program List” to be filed by February 28, 2020?

A. During the course of any budget year, planned expenditures are subject to change to address the myriad conditions that can arise during the year, including unplanned events and other circumstances outside of the Company’s control. The Company will reprioritize projects to respond to such conditions and then reallocate to optimize the Company’s overall capital expenditures. It is a long-standing feature of the Company’s rate plans that the Company has the flexibility over the term of the rate plan to modify the list, priority, nature and scope of its electric capital projects. Such modifications will be described in the annual report as discussed above. In addition, the Company plans to continue to hold quarterly budget meetings with Staff to discuss the Company’s current expectations in meeting the annual electric capital budget and, if and to the extent applicable, net plant targets.

F. Review of and Proposed Changes to Safety Inspection Pilot Program

Q. Please briefly describe the Company's Safety Inspection Program ("SIP") pilot.

A. In Electric Rate Case 16-E-0060, the Commission approved a pilot that changed the inspection cycle for all Company-owned underground/underground residential development ("UG/URD") structures from five to eight years. In addition, the Company changed its inspection process for each UG/URD structure to include enhanced inspection techniques using infrared and current readings. The Company also changed its mobile scanning schedule and augmented it with targeted mobile contact voltage scanning in higher risk areas.

Q. Did the Commission approved rate plan provide for evaluation of this pilot?

A. Yes. The rate plan provides that the Company will review the pilot and that it may be subject to prospective adjustment.

Q Have the changes implemented under the pilot been successful?

A. Yes, the pilot has been successful and the Company proposes to continue it. According to Company data, the rate of manhole events per kiloton of salt distributed on city streets declined under the eight-year inspection cycle. In winter 2017, events per kiloton of distributed salt in New York City were the lowest in the last ten years. Based on the amount of salt used in 2017, the Company's models predicted there would be 40 shocks. The number of shocks in 2017, however, was only 23. Under the pilot program, the Company targeted inspections in active zones and used infrared scanning equipment. By proactively finding energized equipment before shocks occur, the Company improved public safety. In addition, changing the inspection cycle from five to eight years has made the Company's public safety programs more efficient. Ad hoc inspections, performed along with regular utility work at Company locations, are less expensive than targeted inspections, which require a dedicated crew to inspect the structure. By increasing the cycle to eight years, the Company has been able to significantly increase the number of ad-hoc inspections and decrease the number of targeted inspections. As the Company explained in its last Rate Filing, the reduction in spending on inspections has permitted the Company to reallocate funding towards the completion of repairs. As a result, the Company was able to drive down the defect backlog by 40% since the beginning of the pilot program.

And finally, the use of thermal imaging resulted in the Company identifying and repairing over 250 additional hotspot defects in 2018. Our thermal scans have been finding defects that are not otherwise discoverable by crews conducting inspections in underground facilities. As a result, the Company is finding defects more rapidly and before the defect potentially results in an event.

Q. Is the Company proposing any modifications to the current pilot?

A. Yes. The Company proposes to modify the current frequency, geographic areas, and threshold criteria to become more effective and efficient, and ultimately safer because it will enable us to focus resources on the more significant threats to public safety. The proposed changes will better focus Company resources by increasing inspection and testing in areas of elevated risk based upon a) performance including historical energized equipment (“ENE”) and or manhole event (“MHE”) generation rates; and b) system design including structures with low secondary cable density, vented covers, and underground residential distribution ("URD"). In addition, our proposed testing criteria will segregate and focus mitigation resources on abnormal conditions that are more likely to present a public safety concern. The pilot modifications are:

- Implementing a targeted Underground SIP that creates a periodic inspection group that increases the rate of inspection for high risk and critical supply structures and a non-periodic inspection ("NPI") group for all other structures. This proposed change is included in the Company's BCO initiative.
- Implementing an optimized Mobile Contact Voltage ("CV") inspection program based upon geographical areas and seasonal activity. The existing program (Case 10-E-0271) treats all electric underground areas the same over a constant time period. Overall, the number of scans the Company will conduct on an annual basis will remain the same. Areas that historically have a high number of defects will be scanned more frequently, and therefore, those areas will see a decrease in defects more rapidly. Areas with low defects will

still be scanned, but not as frequently. We note that we are not proposing to change the manual contact voltage inspection program for areas containing overhead wires.

- Modifying the Finding threshold (CASE 04-M-0159 (2015) as defined in Appendix (A.1.f). This proposal would change the threshold from 1V using a 500 Ohm shunt resistor to 5V using a minimum 15 kOhm shunt resistor. An additional benefit of this change is that it will reduce troubleshooting and any requisite construction time. This proposed change is included in the Company's BCO initiatives.

Q. Please describe the proposed pilot changes to the existing Structure Inspection and Repair cycle that is part of the SIP.

A. The Company is proposing to optimize the Underground SIP by changing it from a fixed cycle, equal weighted approach, to an approach that assigns priority based on a structure's safety and reliability risk. The Company anticipates that this optimization will reduce the number of targeted inspections of underground structures from a peak of approximately 40,000 to approximately 15,000 a year.

Q. How does this compare to existing practice?

A. Under the current Underground SIP, the Company inspects its 280,000 underground and underground residential distribution (“URD”) structures via a mixture of ad-hoc and targeted inspections. When an underground crew enters a structure for construction or maintenance work, it performs an ad-hoc inspection. These inspections occur as part of routine work, and account for approximately 40-45% of the total unique inspections performed for the SIP program. For the approximately 160,000 remaining structures, which the Company does not visit during the cycle for routine work, the Company schedules an underground crew to perform a Targeted SIP inspection. Under the proposed pilot, of the 280,000 underground and URD structures, approximately 10,000 will require inspection bi-yearly and approximately 140,000 every eight years.

Q. Please explain how this will be accomplished.

A. The Company proposes an asset optimized based inspection program that categorizes structures into two groups: 1) Periodic Inspection Group, and 2) Non-Periodic Inspection Group. The Periodic Inspection Group would consist of two tiers with a relatively fixed number of assets. We would select these assets based on factors including critical customers, asset performance, and design. The Company would inspect each asset in this group on either a two year or eight year cycle. For example, Tier One facilities would include a structure providing service to a critical customer such as the MTA, or a structure with a history of more frequent events, and would be inspected once every two years as part of the first tier. A structure with a higher number of assets with a good performance history would not require an inspection every two years, but would still be classified as a Tier Two structure and be inspected once every eight years. All other assets would be in the Non-Periodic Inspection group. For example, a URD structure or underground structure with fewer assets and a good performance history would be in the Non-Periodic Inspection group asset because of the low level of risk for this structure. The Company would inspect facilities in the Non-Periodic Inspection group only when it performs routine work. We would, however, test all of the facilities in the Non-Periodic Inspection group for contact voltage at least once per year through mobile scanning or manual contact voltage testing programs.

Q. How will system performance and public safety be affected?

A. The Company expects its new approach will maintain public safety and system reliability levels. The Company’s analysis predicts a significant decrease from facilities in the Tier 1 Periodic Inspection group. The Tier 2 Periodic Inspection cycle remains the same at eight years. As a result, the Company does not predict any change to the frequency of events. Finally, the Company anticipates that it will see a slight increase in events for facilities in the Non-Periodic Inspection. Overall, the Company forecasts that the net effect of this change will result in no increase in events on the system. The Company’s analysis, as illustrated in EIOP-12 Schedule 2, shows the expected number of events for each of these three groups.

Q. Does the Company have a plan to improve underground inspection efficiency?

A. Yes, new technology will allow the Company to inspect a structure without physically entering it. Advancements in sensors, communication, data analytics, and mechanical packaging make remote inspections with either a borescope or monitoring device under our Structure Observation System platform a reality and the optimal method to effectively inspect underground electrical structures.

Q. Can serious defects be detected as effectively using this technology, compared to a physical inspection by a person?

A. Yes. We can identify with remote inspection tools defects such as unsealed ducts, improper end caps, cable in contact with cover, and severe structural damage. The image shown in EIOP-12 Schedule 3 was acquired using a borescope on an underground structure with sufficient image detail to verify a properly installed end cap. The image shown in EIOP-12 Schedule 4, Figure 2 is an infrared image that was reported in real time from a remote monitoring box, along with the image post repair shown in Figure 3.

Q. What additional benefits are there to doing a technology assisted inspection?

A. A change in technique, from human entry to machine entry, would have wide ranging benefits to all parties involved. The safety risk to employees would be greatly reduced as they would no longer have direct exposure to the unknown conditions. The public would also benefit from remote inspections as the inspection time and need for a full work setup is greatly reduced, thereby removing roadway obstructions that impede traffic flow and can result in increased emissions. The Company has begun to use some of this new technology and plans to eventually implement these changes system wide. This will be a long-term effort.

Q. Are there any other ways the Company can improve underground inspection efficiency?

A. Yes, inspections can be run more efficiently by eliminating non-beneficial vacuum and hydro evacuations (flushes).

Q. What is the Company's proposed change to the applicable definition of a flush for the purpose of this pilot?

A. Safety Order 04-M-1059 (1/8/2015) Section 4 states: "Where debris or water is found in an underground structure, it must be removed before commencing the inspection so that all of the facilities in the structure, and the structure itself, may be fully inspected". The Company is proposing to clarify and restrict the flush requirement to being required only when line of sight to ducts and connections from a distance of 5 feet is not possible. We proposed that if line of sight is possible, a flush is not required solely because a structure contains limited debris or water on the floor or equipment.

Q. What is the benefit from this change in definition?

A. This will eliminate the need for performing flushes as part of the inspection where line of sight is possible. Under this amended definition, inspections such as for shallow service boxes (48 inches and below) may be performed from the top of the structure. In addition, potential damage to equipment contained in the structure would be avoided as the equipment is no longer exposed to the flushing process's cleaning solution at 400 psi. This proposed change will also result in a reduction in the number of flushes required for inspections. As explained in the section titled Safety and Security Capital and O&M Expenditure Requirements, the Company accordingly is requesting a lower O&M increase for the new separate flush cost than it otherwise would have.

Q. Please explain the Mobile Contact Voltage Inspection program.

A. The Company scans the non-overhead electric system 12 times per year. The Company is scanning for defects that cause Energized Objects, which if the Company does not repair, can cause electric shocks. The program started in 2006, in response to the safety order in Case 04-M-0159. Since 2015, the Company has had a program to target areas that generate a high number of defects. Based upon the success of doing targeted scans, the Company is recommending integration into the baseline scanning.

Q. What has the Company observed from its program?

A. The data shows that approximately 10% of mobile scanned plates produced almost all electric shocks. This data shows that within the overall area scanned there are pockets that have a higher generation of energized objects due to defects. Scanning them more frequently and addressing them as they occur will improve system reliability and public safety.

Q. What conclusion does the Company draw from these statistics?

A. That the Company can optimize the CV program by integrating targeted scanning, which will reduce costs and increase effectiveness.

Q. What is the Company’s optimization proposal?

A. The Company proposes to establish high and low risk categories. The Company will scan high risk areas more frequently, and the remaining lower risk areas less frequently, while maintaining the same number of overall scans per year.

Q. What are the benefits of the Company's proposal?

A. Optimization of the mobile CV program shortens the Energized Objects' exposure time to public contact, which will reduce the potential for an ENE to cause an electric shock especially during seasonal peaks.

Q. You stated above that the Company proposes to change the threshold voltage for mitigating detected energized objects. Please provide the justification for this change?

A. Today, the Company must mitigate findings of 1.0V measured with a 500 Ohm shunt resistor, which includes guarding the object producing the measurement until it is repaired. This is a significant cost. The average cost per source mitigated is approaching $4,000. The present standard is not necessary for public safety and requires the Company to inefficiently deploy resources. The Company proposes to pilot a change to the detection threshold to 5V using a minimum 15 kOhm shunt resistor.

Q. Why does the Company believe that the current standard may not be necessary for public safety?

A. Within the secondary system there exist neutral to earth voltages between street furniture such as a fire hydrant and street light pole. These neutral to earth voltages generally do not present a safety concern to the public as a 5V design threshold is considered safe. The scientific basis for using this slightly higher voltage is detailed in two papers published by the Institute of Electronics and Electrical Engineers ("IEEE") by D. Dorr IEEE 2009 and J. Burke C. Untiedt, IEEE 2009. Practically speaking, the public can relate the risk to mobile phones that charge through a USB – these are all 5V devices. USB and similar chargers can be capable of supplying amps of current, but at only 5V the safety concern is minimal. Moreover, automotive accessory outlets are 12V with several amps of available current. As can be seen from EIOP-12 Schedule 5, over 60% of ENE's are measured between 1-5V, while 85% of Electric Shock Reports are above 5V, and the 15% of Electric Shock Reports below 5V.

Q. Is there a concern regarding allowing even a small defect to remain on the system?

A. Only insofar as a small defect might worsen over time and become dangerous. However, the Company's proposal is designed to prevent this. The Company proposes to use a higher value shunt resistor than it currently does in executing its public safety programs. Switching the value of the shunt resistor from 500 Ohms to 15 kOhms makes the measurement more sensitive to faults instead of normal system operations. As a result, this change will allow the Company to identify defective equipment that are actual hazards in the initial program testing stages.

Q. How will the Company’s proposal lead to more efficient use of Company resources?

A. Today, the Company tracks and repairs over 1900 Company ENE sources and 30 ESRs in an average year under the current criteria. This results in a drain on Company resources without a commensurate public safety benefit. Under the Company’s proposal, it will use resources more effectively by assigning them to other public safety work including mitigation of hot spots; maintenance, response and troubleshooting of structure monitors and their associated alarms; and proactive cable replacements.

Q. Does the Company’s passive guarding program in 2018 support its proposal?

A. Yes. From the initiation of the mobile CV program until January 2018, as per Case 04-M-0159 Appendix A 1.f., the

Company employed site safety personnel and mechanical barriers to guard detected energized objects until company crews arrived to make repairs.

Starting on February 1, 2018, the Company initiated a pilot program of using only mechanical barriers to guard energized objects with voltages between 1-5V (compared to locations with voltages above 5V that continue to be guarded by site safety personnel). During the pilot program, the Company tested these lower voltage objects every 48 hours to verify that the voltage did not increase to dangerous levels, (in which case site safety personnel would be called to the site). The Company found minimal voltage variation from the initial measurement. Of the approximately 3,930 passively guarded objects found between February and September 2018, only one of them increased in voltage to a hazardous level – an increase that occurred the day repair steps had started. There were no reported electric shocks due to energized object in passively guarded locations.

G. Tariff Changes

1. AMI Communications Equipment

Q. As a result of the Company’s installation of the AMI system, do new customer requirements change?

A. Yes, they do. With AMI, not only does the Company require the discretion to determine the location of the metering equipment, customers must also provide adequate space for AMI communications infrastructure so information from the AMI meter communicates with the Company. Currently, General Rule 7.1 (leaf 64) “Customer Wiring and Equipment” makes clear that the Company will determine the location, and specify the type and manner of installation and connection metering equipment and will furnish this information to customers upon request. The Company proposes to add language to General Rule 7.1 making clear that AMI communications-related metering equipment is also included in this section of the Tariff so that customers understand their obligation to accommodate the Company’s communication infrastructure.

Q. Why is this addition necessary?

A. The Company has been installing AMI metering and communication equipment throughout its AMI deployment. In some instances, because of poor signal strength, complexity or depth of building layout and equipment, or otherwise, the Company must install additional communications infrastructure to get a sufficient signal. This can include communication wiring to separate points inside or outside of the building to obtain sufficient communications signals, socket access points, or antennas. This Tariff addition will make it clear to customers that they must provide the Company with space communications equipment so that the AMI meter is properly communicating. Although the Company has been working with customers to install required communications equipment, the Company believes this clarification makes the customer's obligation clearer as it relates to metering equipment.

Q. What specific Tariff language do you propose?

A Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added to General Rule 7.1.

2. Charge for Replacement of Damaged Meters

Q. As a result of the Company's installation of the AMI system, do the charges for replacing a damaged meter need to be updated?

A. Yes. We propose to modify General Rule 16.1 (leaf 121) to update the cost of replacing a damaged meter. Currently, the Tariff imposes a charge of $205 to replace a demand meter that was damaged because the access controller to the meter did not exercise reasonable care or the meter was damaged due to tampering.

Q. Why do the costs need to be updated?

A. The Company has updated these costs to reflect the average cost of an AMI meter and average length of time for meter replacement. The cost is greater than the $205 currently in the tariff for replacement of a demand meter.

Q. What is the average cost the Company expects to incur for replacing meters damaged by customers because of a lack of care of theft?

A. The average cost is $282. This cost reflects the average cost of an AMI meter, considering that there are varying costs depending on the meter required at each customer location, average internal labor costs, and the average amount of time it takes to remove and replace a meter.

Q. What specific Tariff language do you propose?

A. Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added to General Rule 16.1.

3. Temporary Service

Q. Is the Company proposing a change to the Temporary Services section of the Tariff, General Rule 5.2.7 of (leaf 37)?

A. The Company is proposing to add language to clarify long-standing Company practices related to temporary services.

Q. Please explain.

A. The Company provides electric service to a customer at a building or premises through a single service line. Customers that request electric service at locations that are not at a building or premises are only eligible for temporary service, which includes non-permanent structures. This includes customers that request electric service for facilities that are located in the Public Right of Way as defined in the Tariff. Customer electric facilities located in the public right-of-way are non-permanent structures because: 1) the public right-of-way is the inalienable property of the municipality, and; 2) the electric structures are subject to superior municipal rights, and the municipality can require that they be moved regulations.

Q. What types of electric facilities in the public right-of-way does the Company consider to be non-permanent and require to take temporary service under the tariff?

A. To date, we have considered non-permanent structures to include newsstands, bus shelters, telephone kiosks, street kiosks, wireless telecommunication equipment and Wi-Fi and cable power supplies in public rights-of-way.

Q. How does the Company treat electric facilities that are non-permanent and temporary?

A. Pursuant to General Rule 5 of the Tariff, customers are required to pay the costs of electric service connections to non-permanent temporary structures.

Q. Please describe the proposed clarification to the tariff.

A. The Company proposes to add language to General Rule 5.2.7 to clarify any perceived ambiguity about customer's responsibility to pay the costs associated with electric service connections to customer-owned electric facilities that are installed in the public right-of-way.

Currently, although this General Rule clearly states that non-permanent structures are considered temporary, it does not define non-permanent structures. The Company's proposed revision will make clear that facilities in the public right-of-way are considered non-permanent.

Q. Are the proposed modifications a change to Company practice?

A. No. These proposed changes are of housekeeping nature, and only meant to clarify any perceived ambiguity in the Tariff. These modifications only make the Tariff more clearly consistent with the Company's longstanding practice.

Q. Why is the Company proposing this clarifying language?

A. Customers are increasingly requesting to install various types of electric facilities in the public right-of-way. Some customers have recently questioned the Company's longstanding policy of treating non-permanent facilities in the public right-of-way as temporary facilities.

Q. Do you agree with this interpretation?

A. No we do not. First, the Company's policy to require customers with facilities in the public right-of-way to pay the costs of the electric service connection has long been in place. For instance, bus shelters, kiosks, and newsstands are treated as temporary structures and required to pay for connection costs. Under the current Tariff, these customers are eligible for temporary service because the Company does not have a reasonable assurance that the customer will be a permanent customer at the location. Customers seeking to occupy the public right-of-way assume the risk that the municipal government will require the relocation of the street equipment. Moreover, there is not reasonable assurance that the customer itself may decide to move the location of the electric facility, abandoning the electric service line. Con Edison’s customers should not bear the costs for these services and any new services required by the relocation of facilities in the public right-of-way. This is why the Company has consistently determined that the customer that chooses to install its electric facilities in the public right-of-way is installing temporary equipment and should bear that risk and that cost.

Q. Please explain language the Company proposes to add to this General Rule related refunding temporary equipment installation costs.

A. Construction and building customers often require a temporary service to begin construction of new buildings or premises. At times, the temporary service can become the permanent service at the location and, therefore, the customer would be eligible for a refund of the construction costs. The Company then recovers those construction costs through rates. This new language clarifies that customers with electric facilities in the public right-of-way, under these specific circumstances, are not eligible under the temporary service provision of the tariff for refunds.

Q. What specific additional language is the Company proposing to add to the Tariff to clarify these housekeeping changes?

A. Please see the Electric Rate Panel testimony for a description of the special Tariff language.

4. High Tension Service Charge

Q. Is the Company proposing changes to its Tariff that pertain to its High Tension ("HT") Service customers?

A. Yes, the Company is proposing Tariff revisions to clarify and reinforce HT customers' existing obligation to isolate their high tension equipment from the primary feeders that supply them when those feeders are out of service. The proposed Tariff language states that during a high electric load period, an HT customer must isolate its HT equipment as soon as possible, but no later than six hours after receiving notification from the Company. If an HT customer fails to comply within six hours, the proposed Tariff language would require the customer to permit a Company-hired contractor to access and isolate the customer’s equipment. Finally, the Company proposes to add a charge to recover contractor costs. Please see attachments to the testimony of the Electric Rate Panel for the revised Tariff leaves need to implement these changes.

Q. What existing obligations do HT customers have in this regard?

A. Pursuant to the O&M specifications between the Company and its HT customers, an HT customer is already responsible for isolating its HT equipment any time a primary feeder goes out of service. This includes the customer taking steps to isolate its service from the feeder and restore it to service after the feeder is returned to service. The O&M specifications (and the tariff) do not require a specific response time, but the O&M specifications do require an HT customer to provide a qualified customer electrician and access to its facilities within a reasonable time period. The Company is proposing to reflect these obligations in the Tariff to make it easier to address customer questions when they arise.

Q. Why is it important to isolate an HT customer’s equipment when the primary feeder that supplies it is out of service?

A. For safety reasons, the Company cannot initiate work on its primary feeder until the HT customer has isolated its equipment.

Q. Why is the customer, and not the Company, responsible for isolating the customer’s HT equipment?

A. As part of the HT customer’s agreement with the Company, the HT customer owns and operates all equipment from the property line termination point (manhole or splice chamber), including cables, circuit breakers, transformers, and associated equipment.

Q. Why does the Company think a six-hour time limit in periods of high electric load is appropriate for an HT customer to isolate its equipment?

A. During high electric load periods, which often occur with high temperatures, feeder failures can occur at a higher rate. The Company expedites repairs and restorations, but is delayed whenever an HT customer fails to act promptly in complying with its obligation to isolate its equipment. Extended feeder outages place additional stress on feeders that remain in service within the network and may lead them to fail. This increases the risk of a network shutdown, which would affect all network customers. Six hours is a reasonable period of time for an HT customer to act because during these peak load periods the Company works to return primary feeders to service as promptly as possible but no later than twenty-four hours. The Company cannot allow more than six hours for an HT customer to isolate its equipment if it wants to restore service promptly.

Q. Why does the Company propose to collect contractor costs?

A. If the HT customer does not isolate its equipment within six hours, the Company will engage the services of a contractor to perform the isolation. The customer should bear the costs of complying with its obligation.

Q. Does this conclude your direct testimony?

A. Yes. It does.

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
CUSTOMER ENERGY SOLUTIONS PANEL

INTRODUCTION

Q. Would the members of the Customer Energy Solutions ("CES") Panel please state their names and business addresses?

A. Janette Espino, Margarett Jolly, Matt Ketschke, Vicki Kuo, Tom Magee, and Damian Sciano. Our business address is 4 Irving Place, New York, NY 10003.

Q. In what capacity are the panel members employed and what are their professional backgrounds and qualifications?

A. (**Espino**) I am Janette Espino, General Manager of Customer Information Systems. In my current position, I am responsible for replacing Consolidated Edison Company of New York, Inc.'s ("CECONY" or the "Company") and Orange and Rockland Utilities, Inc.'s ("O&R") Customer Service Systems ("CSS") with one new platform. I have held this position since October 2017. I joined Con Edison in 1988 and have held positions of increasing responsibility. Positions held prior to my current position include General Manager of Specialized Activities, Customer Operations; System Manager, Information Technology; Section Manager, Executive Action Group; Testing Lead, Human Resource PeopleSoft Implementation; Section Manager, Purchasing Services Technology and Strategic Initiatives; and Director, Procurement Operations – Supply Chain. I have a Bachelor of Science-Computer

Science from Manhattan College and a Master of Computer Science from Pace University.

(**Jolly**) I am Margarett Jolly, Director, Reforming the Energy Vision ("REV") Demonstration Projects. In my current position, I am responsible for the development and execution of the Company's REV Demonstration Projects and related projects. I have held this position since 2017. I have over 20 years of utility experience in a variety of positions of increasing responsibility, including power plant and control room engineer, Steam Business Unit; Policy Specialist, Energy Markets and Policy Group, Con Edison's Distributed Generation ("DG") Ombudsperson, and Director, Research & Development ("R&D"). I serve on the Board of the New York Battery and Energy Storage Technology consortium. I am a Registered Professional Engineer in New York State and hold a Bachelor of Science degree in Mechanical Engineering from Cooper Union.

(**Ketschke**) I am Matt Ketschke, Senior Vice President of CES. I am responsible for efforts to evolve the Company towards a customer-centric Distributed Energy Resource ("DER") enabled future through work in the following CES departments: Energy Efficiency ("EE") and Demand Management ("DM"), Advanced Metering Infrastructure ("AMI") Implementation Team, CSS Implementation Team, Distribution Planning, Utility of the Future, REV Demonstration Projects and Rate Engineering ("RE"). I have been in my current position since 2017. I have been employed by Con Edison for 23 years. I have held senior level positions in Electric Operations, Electric Construction, Electric Engineering, and Human Resources, including Vice President Manhattan Electric Operations, Human Resources Director, and General Manager of Electric Operations. I earned a Bachelor of Engineering degree in Mechanical Engineering and a Master of Science degree in Management Technology from Stevens Institute of Technology. Additionally, I earned a Master of Business Administration from Columbia University.

(**Kuo**) I am Vicki Kuo, Director, EE and DM ("EEDM"). I am responsible for the Company's EE, demand response ("DR"), DM, non-wires solutions ("NWS") and non-pipeline solutions ("NPS") programs. I have been in my current position since 2016. I have been employed by Con Edison for 20 years in a variety of positions within Electric Operations, Strategic Planning, IT, and with Con Edison Development. I also have 10 years of experience building new products and developing new markets outside of the utility industry in both North America and Europe. I hold a Bachelor of Science degree in Electrical

Engineering and a Master’s degree in Management from NYU-Polytechnic School of Engineering.

(**Magee**) I am Tom Magee, General Manager of the AMI Implementation Team. I am the business lead for the Company’s AMI Project. The AMI Project scope includes a full-scale rollout of AMI smart meters and supporting infrastructure for the Company’s electric and gas customers. I have been in this position since 2015. I have been employed by Con Edison for 33 years. I have held various positions including watch supervisor, Ravenswood Generating Station; associate engineer, Electrical Engineering; and engineer, Fossil Power Engineering. I have also served as Project Manager, Energy Management Plant Divestiture; Section Manager, Steam Distribution Engineering; Section Manager, East River Repowering Project, Technical Manager, East River Generating Station, and General Manager, Smart Grid Implementation Group. I hold a Bachelor of Science degree in Marine Engineering from the U.S. Merchant Marine Academy.

(**Sciano**) I am Damian Sciano, Director, Distribution Planning. I am responsible for the evolving integration of the Company’s Distributed System Implementation Plan (“DSIP”) and Distributed System Platform (“DSP”) designed to integrate DER, such as solar energy, into the traditional electric distribution system. I have been in my current position since 2015. I have nearly 30 years of utility experience working as a developer of cogeneration projects for Trigen Energy as well as working in power generation, strategic planning, electrical engineering, and, most recently, as Senior System Operator at Con Edison's Energy Control Center. I am a Registered Professional Engineer in New York State and hold a Doctorate degree in Electrical Engineering from NYU-Polytechnic School of Engineering and a Master of Business Administration in Finance from Baruch College as well as a Bachelor of Science degree in Mechanical Engineering from Cooper Union, and a Masters degree in Electrical Engineering from Manhattan College.

Q. Have panel members previously submitted testimony or testified before the New York State Public Service Commission ("Commission")?

A. Ms. Espino, Ms. Jolly, Mr. Ketschke, and Mr. Magee have submitted testimony or testified before the Commission in prior proceedings. Ms. Kuo and Mr. Sciano have not previously submitted testimony or testified before the Commission.

Purpose and Summary

Overview of CES Group

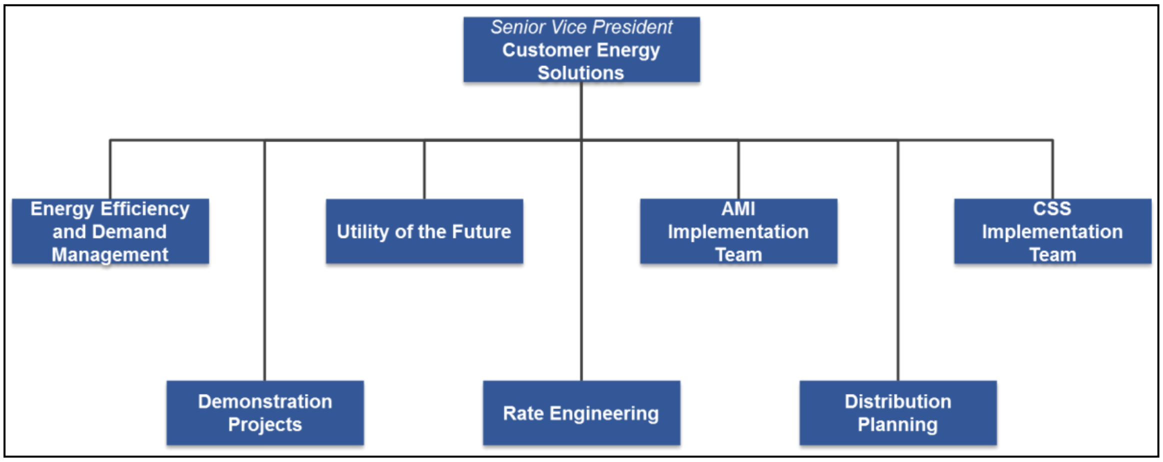
Q. Please explain the initiation, organization and responsibilities of the Company's CES group.

A. Con Edison recognizes that having an organization capable of quickly adapting to policy and technology advances and customer preferences is critical to facilitating the transition to a customer-oriented clean energy economy. Con Edison formed the CES organization in fall 2017. Initially, the Company formed this group to enable focused development and innovation across the functions directly affecting customers' clean energy experience. Since then, the group has evolved and is now responsible for the Company's EE, DM, REV, electric vehicles ("EV"), AMI, CSS, distribution planning, RE, and other projects. CES guides the Company's overall clean and distributed energy strategy, pursuant to which the Company has taken on a leadership role in providing a clean energy future for New Yorkers.

Q. Can you please explain how CES is organized?

A. Yes. CES's organization chart is:

Figure 1 – CES Organizational Chart



Organized in this manner, CES is leading the Company to evolve its energy business to become cleaner, adapt its business model to be more innovative, and transform the customer experience to provide best-in-class service. (Please note that although RE is part of this transition, it provides separate testimony to cover demand analyses, cost of service studies, revenue allocation, rate design, tariff changes and other RE items.)

The CES organization currently has 230 employees. Many of the departments that comprise CES were transferred into CES, moving their employees as well.

Q. Have there been any major changes in regulatory policy that, among other changes, CES was established to address?

A. Yes. Since late 2014, the Commission has been conducting a proceeding, REV, intended to transform the electric utility industry in New York. CES was formed to better respond to advancing policy goals, customer preferences, and technology developments. For example, REV's objectives include reducing greenhouse gas ("GHG") emissions, growing the clean energy economy, creating a robust market for DER, and expanding customer choice. In addition, with the encouragement of the Commission, Con Edison recently commenced its Smart Solutions proceeding to explore demand side and renewable gas alternatives to delivered services and contracting for new gas pipeline capacity.

Through REV and its related proceedings, the Commission and the State have set emission reduction and EE goals. These include generating 50 percent of New York's electricity from renewable energy sources and reducing GHG emissions State-wide by 40 percent by 2030,[1] and increasing EE savings to a level equivalent to three percent of utility sales by 2025.[2] Additionally, the Commission has set goals for emerging technology, like energy storage and EVs. For storage, a recent Commission Order targets 1.5 GW of State-wide storage to be

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[1] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, *Order Adopting a Clean Energy Standard*, issued August 1, 2016.
[2] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, New Efficiency New York ("NE:NY"), filed April 26, 2018.

installed by 2025 and 3.0 GW by 2030.[3] For EVs, the State has adopted Zero Emission Vehicle ("ZEV") regulations and is a signatory to the Multi-State ZEV Memorandum of Understanding which sets a New York goal of approximately 800,000 EVs by 2025.[4]

The investments requested in this testimony are aligned with the latest policy requirements in this dynamic regulatory environment.

Purpose

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

A. This Panel's testimony presents an overview of Con Edison's investments and initiatives for both the electric and gas systems to promote a cleaner, more sustainable energy future, enhance the customer experience, and build the capabilities necessary for integrating DER. These efforts include working towards a transformative and scalable DSP which enables the bi-directional flow of energy. Implementing these projects and programs will position the Company to meet customer expectations as well as make progress towards meeting the

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[3] Case 18-E-0130, In the Matter of Energy Storage Deployment Program, *Order Establishing Energy Storage Goal and Deployment Policy*, issued December 13, 2018.

[4] Zero Emission Vehicle Program, Memorandum of Understanding (executed on Oct. 24, 2013), *available at* http://www.nescaum.org/documents/zev-mou-9-governors-signed-20180503.pdf/

State’s clean energy policy goals. Each program and project for which the Company seeks funding is described in an accompanying exhibit that includes scope of work, cost, schedule, and justification, including discussion of alternatives, presented here as Exhibits __ (CES-1 through CES-9).

Q. What investments and programs are covered in the CES testimony?

A. The proposed investments and activities related to CES described in this testimony are listed below:

- EEDM – Increase the Company’s Electric and Gas EEDM initiatives for Commercial and Residential Customers.
- EVs – Expand access to public EV charging through an EV make-ready program and continue incentivizing off peak EV charging under SmartCharge New York.
- Energy Storage – Develop six energy storage facilities on Company locations and one turn-key make-ready site for third-party storage developers.
- DSP Implementation – Invest to further develop the DSP services related to DER integration, information sharing with customers and third parties, and market mechanisms.
- Targeted Initiatives to Defer Electric Infrastructure – Implement two NWS solutions to eliminate or defer

traditional infrastructure projects to meet forecasted electric demand.

- New CSS Implementation – Replace the existing CSS with a Commercial-off-the-Shelf ("COTS") system.
- AMI – Complete deployment of the AMI smart meters and gas modules, communications network, and back office IT systems.
- Innovation Initiative – Implement a corporate-wide innovation center of excellence and its activities.
- Demonstration Projects – Develop and test new business models that will help pave the way for a customer-centric, DER-enabled future.
- Earnings Adjustment Mechanisms ("EAMs") – Propose electric, gas, and AMI awareness EAMs.

We describe these programs and their status in the testimony that follows.

Q. Why is the Company undertaking these investments during the upcoming rate period?

A. The energy industry, including Con Edison, is undergoing a rapid transformation on several fronts. Technology advances and regulatory changes are accelerating the development and deployment of DER requiring new grid functionality, such as bi-directional power flows and the ability to host additional DER. At the same time, customer expectations are changing as instantaneous information and customization of available customer information becomes more widespread. Customers expect to better understand and manage their energy usage. Further, the utility business is evolving to facilitate State policies seeking to meet Commission and State goals for emissions reduction and EE. We chose the proposed investments to meet the near-term needs of our customers and our system while also positioning the Company to advance a customer-centric, DER-enabled, clean energy future.

Q. What period does your testimony cover?

A. This Panel presents the projects, programs, and initiatives planned for the 12-month period ending December 31, 2020 ("Rate Year" or "RY1"). Because the Company has stated that it is willing to enter into settlement discussions for a three-year rate plan, the Panel also addresses the capital additions and other programs and initiatives planned for the two years following the Rate Year. For the sake of convenience, we refer to the 12-month periods ending December 31, 2021, and December 31, 2022 as ("RY2") and ("RY3"), respectively.

Q. What are the capital costs associated with the initiatives described in this testimony?

A. Aggregate project capital requested for the investments described in this testimony is $1.365 billion over the three-year rate plan period, with $408 million in RY1.

Q. What is the Company’s CES Operations and Maintenance (“O&M”) expenditure for the historic test year (the period October 1, 2017 through September 30, 2018)?

A. The Company’s total CES O&M expenditure for the Historic test year is $29.1 million.

Q. What are the Company’s O&M program cost changes for CES in RY1, RY2, and RY3?

A. The Company is planning an increase of $55.5 million in RY1, a decrease of $5.0 million between RY1 and RY2, and an increase of $0.3 million between RY2 and RY3.

Q. Are there any previously approved expenditures?

A. Yes. The Commission previously approved forecasted AMI expenditures of $573 million in capital for the three-year rate period.

Q. Please provide an overview of the capital and O&M spending by activity.

A. A summary of the capital and O&M requirements for each activity is provided in the table below:

Table 1 - Total Capital and Regulatory Asset Requests ($000):

Investment	**2020**	**2021**	**2022**	**Total**
EEDM	$215,900	$257,800	$300,300	**$774,000**
EV Initiatives	$12,859	$14,478	$17,743	**$45,080**
Energy Storage	$14,000	$16,501	$60,000	**$90,501**
DSP	$35,200	$35,200	$35,200	**$105,600**
CSS	$129,619	$100,388	$119,100	**$349,107**
Total	**$407,578**	**$424,367**	**$532,343**	**$1,365,288**

Note that: (i) funds related to AMI, NWS, NPS, and Demonstration Projects are not included in this chart as they have been previously authorized by the Commission or pending before the Commission in a separate proceeding; and (ii) the Energy Efficiency Transition Implementation Plan[5] ("ETIP") portion of EE is included in base rates as a regulatory asset and reflected in the EEDM investment.

Q. What is a regulatory asset?

A. A regulatory asset is an accounting treatment arising in instances where a utility incurs a cost that is typically not treated as a capital expenditure. However, because treating such costs similar to capital investments advances policy objectives or provides customer benefits, for example, moderation of customer bill impacts through amortization of costs, regulatory Commissions, including

[5] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, *Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020*, issued March 15, 2018.

this Commission, have permitted treatment that allows for cost recovery over time. The regulatory asset appears on the utility's balance sheet and represents the costs that have been incurred by the utility but have not yet been recovered from customers.

Q. Which of the forecasted expenses listed in the "Total Capital and Regulatory Asset Requests" table above are considered as regulatory assets?

A. All EEDM costs and the SmartCharge portion of the EV initiatives. The SmartCharge portion is the total EV initiatives' cost minus $10 million (for the make ready program) each year in the rate period.

Q. Why are these investments treated as regulatory assets?

A. Regulatory asset treatment permits amortization of costs over time, moderating customer bill impacts. Such moderation allows the Company to make necessary investments towards clean energy resources and other initiatives to advance integration of DERs. Consequently, and as explained further below in this testimony, the Company is proposing continued regulatory asset treatment for these investments.

Q. What incremental O&M is requested by this Panel?

A. The chart below shows the O&M request.

Table 2 - Incremental Year over Year

Program Change O&M Requests ($000)

Investment	**2020**	**2021**	**2022**	**Total**
EEDM	$3,444	$1,370	$774	**$5,588**
Energy Storage	$12,868	$(11,689)	$233	**$1,412**
DSP	$2,090	$461	$339	**$2,890**
CSS	$7,283	$(1,348)	$3,563	**$9,498**
AMI	$27,597	$6,010	$(5,661)	**$27,946**
Innovation Initiative	$2,251	$225	$1,068	**$3,544**
Total	**$55,533**	**$(4,971)**	**$316**	**$50,878**

Note that funds related to incremental labor for Targeted DM is included in the EEDM line and exhibit, but discussed in the NWS section of this testimony.

Q. Does the Panel propose any incentives, regulatory asset treatments, or rate mechanisms?

A. Yes. The Company is making several proposals – continued treatment of EE as a regulatory asset, regulatory asset treatment of the SmartCharge portion of the EV initiatives, continuation of the existing regulatory framework for recovery of NWS projects not included in base rates, and continuing many of the existing EAMs.

First, Con Edison proposes to continue to recover EE costs as a regulatory asset. The Commission should continue regulatory asset treatment because it:

- mitigates immediate bill impacts by smoothing expenses over time when benefits are realized,
- matches costs to the benefit period, i.e., customers will receive the benefits during the period they are receiving service, and
- aligns EE investments with other utility business investments by treating such investments in a similar manner to traditional investments.

Second, the Company proposes all EV programs costs related to the SmartCharge program be treated as a regulatory asset.

Third, although the Company has not included costs for any new NWS projects in these filings, we anticipate proposing cost recovery for certain NWS projects in base rates in its preliminary update filing. To the extent the Company implements additional NWS projects during the term of the rate plan, the Company proposes to continue the existing cost recovery mechanism for NWS projects not already included in base rates.

Fourth, the Company proposes:

- electric EAMs for the three-year rate period building on the currently effective EAMs that positively incent the Company to deliver energy and peak demand savings, increase the amount of DERs that interconnect to the

Company's delivery system in order to reduce reliance on the grid, and increase the amount of DERs, particularly beneficial electrification technologies, in order to reduce GHG emissions,

- gas EAMs that positively incent the Company to deliver energy and peak demand savings and reduce GHG emissions,
- continuation of AMI Customer Engagement EAM, and
- discontinuation of the Energy Intensity and Interconnection EAMs.

The proposed EAM earnings opportunities are at 100 basis points each rate year for electric and 70 basis points each rate year for gas. The Company developed this proposed set of EAMs in advance of the December 2018 Commission orders in the New Efficiency: New York ("NE:NY") proceeding and the proceeding on energy storage goals and deployment. The Company may propose in its preliminary update additional EAMs to align with the NE:NY and Storage Orders.

Q. How is this testimony structured?

A. This testimony addresses the main categories of the CES Panel's responsibility. Programs and projects are discussed in testimony generally, and more fully in the corresponding exhibits for the projects. The testimony addresses recent Commission orders that affect the activities of this Panel. In addition, we have included white papers that provide more detailed information on each of the programs/projects in this testimony as exhibits.

Objectives

Q. What are the CES organization's overarching objectives with the investments and programs described in this testimony?

A. The investments proposed by this Panel support the following Company objectives:

- Integrating clean and distributed energy resources into the Con Edison system while empowering our customers to manage their energy usage,
- Optimizing our systems and business to provide excellence in the integration of DER, and
- Enhancing our customers' experience.

While the investments and programs described in this testimony and accompanying exhibits are primarily intended to meet one objective, many provide benefits across most of the objectives.

These objectives also align with and support our overall corporate objectives of enhancing the customer experience and further engaging our customers, advancing clean energy and operational excellence, and seeking benefits for our customers. The Electric and Gas Policy Panels further discuss these corporate objectives.

Integrating Clean and Distributed Energy Resources while Empowering Our Customers to Manage Their Energy Usage

Q. Describe how the Company is integrating clean and distributed energy resources and empowering customers to manage their energy usage.

A. Driven by State policy objectives and increasing customer interest, the Company is integrating a variety of clean and distributed energy resources into the grid, while reducing environmental impacts. These resources include the expansion of EE, EVs, and energy storage.

Q. Please discuss some successes to date in the expansion of EE, EVs, and energy storage.

A. The Company has increased program achievements and exceeded the maximum rate case EE targets in 2017 and expects to have done so again in 2018. In 2017, Company efforts saved 300 GWh and achieved over 60 MW of peak reduction as compared to the maximum stretch targets of 198 GWh and 59 MW. EE innovations included significant improvements to delivery of EE savings, through (i) accelerated implementation of projects and compression of lead times, *i.e.*, the time between identification of a prospective project and the beginning of project implementation, in commercial EE achievements, (ii) targeting upstream portions of the supply chain to align incentives across vertical supply chain market actors in promoting EE, and (iii) enhanced customer targeting and marketing.

For EVs, the Company has implemented a multi-faceted approach to promoting and preparing for increased EV adoption, including off-peak charging incentives and rate design, facilitating charging infrastructure deployment, and fleet initiatives.

Con Edison has also furthered the goal of integrating energy storage by procuring and installing a battery energy storage system rated at 2 MW and 12 MWh in the Brooklyn-Queens Demand Management ("BQDM") area and by initiating Demonstration Projects to better understand energy storage capabilities while testing new business and operational models.

Optimizing Our Systems and Business to Provide Excellence in the Integration of DER

Q. Is the Company working to integrate DER while continuing to prioritize grid reliability and safety?

A. Yes. The Company's efforts to build DSP capabilities will continue during this upcoming rate period by the development of systems, processes, and technologies to further integrate DER in alignment with the policy objectives noted above. Increasing monitoring and smart control capabilities and expanding distribution automation will make the distribution system more capable of managing bi-directional energy flow reliably, further enabling DER integration and providing operational flexibility. The Company's NWS and NPS focus on procuring DER to mitigate the need for traditional investments, while maintaining system reliability and enabling DER market development.

Enhancing Our Customers' Experience

Q. Describe the Company's approach to enhancing the customer experience.

A. In this evolving environment, customers expect access to data to manage their energy usage and alternatives to meet their energy needs. The Company's efforts to better serve our customers are discussed in this testimony as well as in other testimonies, including Electric Infrastructure and Operations Panel ("EIOP"), Gas Infrastructure, Operations and Supply Panel ("GIOSP") and Customer Operations Panel. As Con Edison's electric and gas infrastructure evolves, and more DERs and EE alternatives become available, the new CSS will enable the underlying transactions and more complex rate designs so that customers can take advantage of these new products and services.

Through Con Edison’s continued AMI implementation, AMI-enabled customers are already accessing their own usage data, enabling them to make energy-related decisions, through tools such as customized-energy-usage reports and high-bill alerts. Together, the new CSS and AMI will provide the infrastructure and data to enable greater customer choice. Further, customers will be able to more easily adopt DER and market actors will be able to provide them with useful products and services enabled through the Company’s investments in maintaining and building new DSP capabilities.

CES INVESTMENTS

Energy Efficiency and Demand Management

Q. Did the Company formulate a proposal for electric and gas EE initiatives as part of its development of these electric and gas rate filings?

A. Yes. The Company developed an electric and gas EE program that recognizes the State’s clean energy goals, and specifically the goals to increase EE achievement State-wide. As part of this development, we considered the NE:NY white paper (“White Paper”) jointly issued by Staff and the New York State Energy Research and Development Authority (“NYSERDA”) in Case 18-M-0084.

Q. Did the Commission act on the White Paper?

A. Yes. On December 13, 2018, the Commission issued its *Order Adopting Accelerated Energy Efficiency Targets* ("EE Order"). The EE Order adopts Con Edison-specific budgets and targets for calendar year 2020 (i.e., RY1 for these proceedings), and procedures for the development of utility EE programs for the period 2021 through 2025, which five-year period includes RY2 and RY3 in these rate filings.

Q. Does the Company's rate filing reflect the EE Order's Con Edison-specific budgets and targets?

A. No.

Q. Please explain why.

A. The Commission issued the EE Order while the Company was finalizing its proposed program and associated revenue requirement for its electric and gas rate filings. The Company did not have adequate time to complete its review and evaluation of its EE program in light of the timing of the EE Order prior to finalizing its revenue requirements.

Q. Does the rate filing reflect EE budgets and targets equal to or greater than the Con Edison-specific budgets and targets adopted in the EE Order?

A. Yes. The EE Order's Con Edison-specific budgets and targets, however, are premised on certain assumptions that differ materially from assumptions the Company used to develop its EE budgets. Accordingly, the Company may adjust its EE programs at the preliminary update stage of these proceedings. The Commission routinely accepts updates, if appropriate or necessary, when associated with developments outside of the utility's control that are close in time to the filing date.

Q. Is the Company also considering modifications to RY2 and/or RY3?

A. In light of the processes that the Commission has ordered be undertaken in 2019 for the five-year period (2021-2025), which includes these two years, the Company may update its proposal as discussed above. The Company may present additional information in its preliminary update in this regard.

Q. Does the Panel have an exhibit that discusses the costs associated with EEDM programs?

A. Yes. The Company has an exhibit entitled, "Energy Efficiency," which was prepared under the Panel's supervision and direction.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-1)

Q. What are the EE costs reflected in the Company's proposed revenue requirements for electric and gas?

A. We developed the electric and gas revenue requirements assuming aggregate forecasted EE program expenditures (electric and gas), including beneficial electrification technologies, such as efficient electric heating, of $215.9 million in RY1, $257.8 million in RY2 and $300.3 million in RY3.

The electric and gas revenue requirements reflect recovery of these expenditures in base rates as regulatory assets amortized over a ten-year period (e.g., $178.5 million and $37.4 million in RY1 for electric and gas, respectively).

The electric and gas revenue requirements also reflect recovery of incremental labor costs of approximately $3.4 million, $1.4 million, and $0.8 million in base rates as O&M expenses in RY1, RY2 and RY3, respectively. This is the result of the Company's plans to add 34 full-time employees to implement various functions in the EEDM Department.

Q. Why does this panel discuss the EE costs in aggregate for electric and gas?

A. The Company proposes to manage its electric and gas EE programs as a single combined portfolio for the benefit of electric and gas customers. For purposes of setting rates, the costs are allocated between electric and gas based on the costs of the proposed electric and gas programs in the proposed portfolio. The Company seeks flexibility to move actual expenditures between the electric and gas programs and proposes that full reconciliation of EE costs be continued, as discussed below.

Q. Are the goals and objectives of the State’s energy policies reflected in these rate filings?

A. Yes. The Company’s EE portfolio is designed to:

- Advance the State’s clean energy goals and help meet policy objectives through a reduction in emissions,
- Deliver meaningful benefits cost-effectively and with moderate bill impacts to our customers, and
- Integrate EE as a core part of the utility’s business.

The Company intends to achieve expansion of its EE portfolio through expanding existing, as well as adding new, programs and delivery channels, innovating to deliver additional savings more cost-effectively, using data analytics to target outreach and increase marketing effectiveness, and further developing data governance processes. These are discussed in greater detail in Exhibit __ (CES-1).

We will also discuss the EE regulatory framework needed to moderate customer bill impacts. This framework is particularly important as the State seeks to ramp up EE achievements and looks to utilities to make other investments that advance clean and distributed energy. The regulatory framework will also provide customers with a better opportunity to participate in programs and more meaningfully reduce their energy use and net bill impacts.

The Commission has recognized that EE is the most cost-effective means for achieving State environmental policy goals and that the utilities will have a key implementation role in helping achieve those goals. The Company will continue to optimize costs and improve the efficiency and effectiveness of program delivery.

Importantly, the proposed approach is helpful to low-to moderate-income ("LMI") customers specifically and allows more opportunity for their participation to offset program costs as well.

Q. What factors impact the unit cost of EE that the Company intends to pursue?

A. Despite efforts to optimize costs and the Company's success at driving down costs by more than 20 percent over two years, the Company notes that there will be countervailing upward pressure on costs as:

- the Company seeks to diversify beyond lighting (the predominant EE measure today) requiring the Company to work with customers to achieve greater savings from measures such as heating, ventilation, and air-conditioning ("HVAC") and building envelope,

- reported energy savings change due to baseline increases driven by building and manufacturing code improvements, decreasing reported savings for the same set of measures, even when the real savings realized through projects are actually higher, and
- lower-cost measures and programs reach saturation and the Company will need to implement EE at harder-to-reach customer locations with more expensive measures.

Q. How does the EE portfolio support the Company's overarching clean energy objectives as set forth in this testimony?

A. Con Edison's approach to meet EE growth targets supports the integration of clean energy. Our approach will also enable our customers to manage their energy usage while enhancing our customers' experience. The Company's proposed EE portfolio, with increasing targeted amounts of achievements over the three-year period, is designed to produce customer benefits, including environmental benefits.

Q. Please describe the Company's proposed portfolio of EE Programs.

A. The Company's portfolio is forward-looking but reflects and builds upon more than a decade of experience running cost-effective EE programs that deliver reduced energy usage and emissions. The Company's programs will enable customers to better manage their energy use, enhance their use of beneficial electrification technologies improve their comfort and well-being, and save on their utility bills.

At the broad level, the efficiency portfolio is divided into electric and gas offerings across customer segments. We reach our customers through a focus on four primary customer segments - commercial and industrial ("C&I"), small business, multifamily, and residential - designed to meet each customer group's needs.

The Company plans to grow the portfolio from current levels by:

- optimizing delivery for current offerings in order to generate more energy savings and demand reductions from current offerings, for example, by further streamlining the customer experience from the application stage to the point of full implementation of the EE measure using transparent information and simplifying and standardizing processes, and
- employing new strategies to reach deeper savings, expanding beyond lighting offers, exploring upstream interventions in the supply chain to fundamentally transform markets towards greater EE, and engaging harder to reach customers such as residential customers, including LMI customers.

In building the portfolio reflected in this rate filing, the Company envisioned growth across all customer segments. To achieve the expanded portfolio targets proposed in this testimony, including a trajectory for savings achievement to 1.5 percent of sales by 2022, the Company envisioned a GWh savings growth in C&I of over 180 percent, in small business of over 115 percent, in residential over 40 percent, and in multi-family of over 125 percent. The Company intends for the portfolio to evolve as it adjusts to the market response. Efficiency offerings and delivery channels are not static, nor are they uniform within a segment. Accordingly, the Company intends to manage and revise offerings and delivery channels applying continuous improvement and innovation as key priorities. While the portfolio is designed to provide solutions for all customers, in all customer segments, the Company will allocate 20 percent of incremental funding to LMI customers. In the Company’s territory, LMI customers generally live in public housing or are tenants in multi-family buildings and present uniquely difficult challenges to reach and serve.

In addition to the delivery channels described above, the Company will employ a host of strategies and operational improvements to better serve customers in a more innovative and market-oriented manner that is transparent and transformational for our customers, partners and other stakeholders in the EE marketplace. This includes giving our customers multiple options and opportunities to reduce their energy use based on their unique needs and continuing or expanding programs targeted to upstream portions of the supply chain that align interests in promoting more widespread installations of energy efficient equipment at our customer locations. Examples for residential customers include accessing rebates and incentives through market partners, shopping directly through the Company's Online Marketplace, managing energy and demand through smart thermostats and Wi-Fi-enabled air conditioners, and benefiting at the retail level from market-based partnerships between Con Edison and mid- and up-stream retailers and manufacturers.

The Con Edison Online Marketplace will transition in late 2019 from a REV Demonstration Project to a full integration within the EE portfolio. As this transition occurs, the Marketplace is expected to evolve to meet customers' needs through engagement channels of their preference.

Q. Please describe other programs that will be offered through the EE portfolio.

A. Other examples of programs that explore innovative delivery models and promote transformative offerings include (i) Instant Lighting, an upstream program that provides instant incentives to customers on eligible ENERGY STAR®-certified and Design Lights Consortium-listed lamps at the distributor point of sale; (ii) Smart Kids, that provides fifth-grade students in the service territory with classroom education on EE as well as a take-home kit of electric and gas efficiency measures; (iii) strategic energy partnerships, through which the Company is focused on identifying and engaging customers that are heavy-energy users (working to secure longer-term partnerships with customers in segment verticals such as hospitals, schools, and the banking sector are some of the areas where Con Edison may see significant potential for savings); (iv) Retail Lighting that provides instant rebates to customers at their point of purchase in big-box retailers, as well as other retailers, such as drug stores and dollar stores, providing accessibility to customers, including LMI; (v) Residential Upstream HVAC that focuses on incenting distributors or other entities in the supply chain upstream of the customer; and (vi) ENERGY STAR™ Retail Products Platform that leverages the purchasing power of multiple nation-wide utilities to work with retailers nationally to incent them to stock and sell efficient appliances.

The Company is also proposing a three-year beneficial electrification program, focused on increasing adoption of beneficial electrification technologies such as air-source and ground-source heat pumps that (i) provide customers with alternative options for heating, especially considering customers impacted by gas moratoriums, (ii) reduce environmental emissions that advance State, New York City, and other local or municipal decarbonization goals, including an 80 percent reduction in GHG emissions by 2050, and (iii) generally decrease peak energy usage and increase off-peak energy usage. The Company seeks to also expand electrification to customers that currently use a non-jurisdictional fuel, such as oil, gasoline, kerosene, or propane, to incentivize them to convert to an electrification technology. The Company may, however, update its beneficial electrification proposal after further evaluation of the EE Order and Commission decision on the proposed NPS portfolio.

NPS is a part of the Smart Solutions filing, Case 17-G-0606, Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customer Program, filed on September 29, 2017. The Company proposed four non-traditional initiatives to alleviate forecasted increases in customer demand for natural gas. These initiatives are a doubling of the Company's natural gas EE programs; developing a new natural gas DR pilot program; issuing a competitive market solicitation (the "Non-Pipeline RFP") to acquire resources as part of NPS that would seek to offset the Company's needs for pipeline capacity; and the Gas Innovation Program. In developing and implementing the beneficial electrification program, the Company plans to work with key stakeholders such as NYSERDA, New York City, and Westchester County, so Company efforts are complementary to other efforts related to beneficial electrification in its territory.

Q. What other demand-side programs does the Company offer to its customers?

A. In addition to the EE portfolio for both electric and gas customers described above, the Company offers or plans to offer customers and third parties (i) NWS opportunities that seek to aggregate customer-side solutions to enable deferral of or elimination of the need for traditional electric infrastructure described later in this testimony, (ii) DR opportunities through tariff-based programs that seek aggregation of commitments to reduce load during periods of high demand or periods of reliability needs, (iii) NPS opportunities that the Company has proposed to develop and implement upon

Commission approval to seek to aggregate customer-side and supply-side resources that are capable of providing peak-day gas consumption relief to reduce reliance on Delivered Services and potentially defer the need for incremental pipeline capacity when possible; and (iv) specific EV-related programs and investments described later in this testimony.

Q. Is the Company seeking to continue the EE Partnership Pilots with NYSERDA as authorized by the Commission in the ETIP proceeding?

A. Yes, the Company intends to continue collaboration with NYSERDA so more of the Company programs and offerings to customers account for and are generally complementary to those offered by NYSERDA. Such partnerships, which are limited to five percent of the total portfolio per partnership, allow for positive and enhanced cooperation by leveraging each organization’s strengths and resources to ultimately increase our customers’ EE adoption.

Q. Has there been material progress in program delivery and performance in the current rate period (2017-2019)?

A. Yes, the Company has made significant progress and achieved above the stretch goals established for 2017, and expects that the 2018 results will show the same.

Q. To what does the Company attribute this improvement?

A. The Company attributes these achievements to its enterprise focus on EE, which drove optimization of program performance and costs. This focus was driven at least in part by the regulatory framework that aligned customer and stakeholder interests with policy objectives. This framework is based on EAMs and amortization of new investments. Amortization of new investments has the additional important benefit of moderating bill impacts by allowing customers costs to be smoothed over a 10-year period, aligning costs with realized benefits.

Managing Electric and Gas Energy Efficiency as a Single Budget Portfolio

Q. How does the Company propose to manage the implementation and reconciliation of the budget for the portfolio of programs?

A. While the Company's program includes separate, annual electric and gas energy savings targets, the Company proposes to manage the portfolio of electric and gas EE programs as a single budget over the three-year period. The Company believes that managing its EE portfolio on a combined basis will benefit customers, for example, by providing flexibility:

- within the budget, which allows for the portfolio to respond to market conditions and customer needs, creating opportunities for focus to be shifted across programs to more cost-effective efforts that are driving results, and

- between the electric and gas programs, which allows the Company to align with the State's fuel-neutral approach to programs to be delivered by utilities.

The Company has previously discussed coordinating the electric and gas EE in prior electric rate cases.

Q. How does the Company propose to allocate the combined EE program costs between electric and gas customers?

A. The Company proposes to use the current allocation methodologies for EE costs, i.e., electric customers, excluding New York Power Authority ("NYPA")-supplied customers, are allocated the costs of the electric portion of the EE portfolio and firm gas customers are allocated the costs of the gas portion of the EE portfolio. These allocation methodologies were used to develop the revenue requirements.

Q. What is the relationship between the annual targets to the three-year program period?

A. The Company proposes to manage to the annual budgets and targets that form the basis of its final EE portfolio targets. The Company's annual budgets and targets that it developed prior to issuance of the EE Order are set forth later in this testimony.

To enable the Company the opportunity to maximize benefits to customers, the Company proposes that unspent funds in RY1 and/or RY2 be available to spend for customer benefit in RY2 and/or RY3.

That said, RY2 and RY3 are presented for illustrative purposes to facilitate settlement discussions. If there is no three-year rate plan established by Commission approval of a joint proposal, only the RY1 proposal would apply.

Q. Does the Company propose that the EE costs reflected in rates be fully reconciled to actual expenditures?

A. Yes we do, in accordance with historic practice and the Commission's confirmation in the EE Order (p. 67) that "[t]he governing principle for cost recovery will continue to be full recovery of prudently incurred costs."

In addition, consistent with our proposal to manage these expenditures over a three-year period, the Company proposes that reconciliation of amounts reflected in electric and gas rates be performed at the end of the three-year period, rather than annually, and be based upon comparing the total actual expenditures to the aggregate of three annual budgets.

Reconciliation would be subject to a total cap equal to the sum of the budgets for RY1, RY2 and RY3, where the amount by which actual expenditures are less than the cap are deferred for customer benefit. The Company is proposing such a unitary arrangement to provide the necessary flexibility to use authorized funds to manage the energy savings that the Commission expects the Company to achieve and that the Company expects will be reflected in the final targets established in this rate proceeding.

Regulatory Asset Framework ("RAF")

Q. How does the Company propose to recover costs for the portfolio of EE programs?

A. The Company proposes to continue the ratemaking framework established in the Company's current electric rate plan,[6] which provides for the recovery of EE costs over ten years using the overall pre-tax rate of return, with the extension to gas and reconciliation across the commodities over a three-year period, as discussed by the Accounting Panel.

Q. Why is the Company proposing continuation of this RAF?

A. Over the last rate period, the RAF has successfully assisted the Company in delivering on its EE targets and

[6] 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, *Order Approving Electric and Gas Rate Plans*, Appendix A – Joint Proposal ("current rate plan"), January 25, 2017.

providing benefits to our customers. Given the continued growth of the portfolio, the current RAF is in the best interests of our customers to mitigate the bill impact while achieving significant program and achievement expansion. The Commission stated in the EE Order that "amortization of EE program costs may be permitted where the overall context of the rate plan establishes a benefit to doing so, such as moderation of overall customer bill impacts." (p. 67) Amortization in this rate case would moderate bill impacts for electric and gas customers, allowing more opportunity to address policy priorities, as described in this case, and incent important technologies that support REV initiatives to integrate DER and improve the customer experience. For example, if the Company's EE program collects $103 million from customers in RY1 when expensed, the RY1 revenue requirements with amortization would only require recovery of approximately $13 million, reducing the annual customer bill impact. Moreover, while many customers stay in their premises for many years, others change location within and outside the service area; allocating the costs over time means that the right customers are paying for the benefits over the period the benefits, on average, are being realized.

Q. Is this adding costs to the overall program?

A. We have reviewed this on a net present value basis of the revenue requirement over the period, considering EE investments amortized over 10 years. When we use the Company's regulated rate of return, which is the same discount rate used for the Commission-approved Benefit Cost Analyses ("BCAs"), the result is slightly lower than if the revenue requirements of the EE investments were expensed in the first year. For example, the same EE investment described in the previous question would result in revenue requirements with a $102 million net present value when amortized instead of $103 million of net present value if expensed. In essence, the same cost.

Q. Are there other benefits that should be considered?

A. Yes. The Company's proposal includes the treatment of dollars approved under ETIP in the RAF rather than as a surcharge.

As noted already, matching costs to the benefits provided by EE programs is appropriate so customers bearing the costs of the EE program receive the benefits contemporaneously, rather than concentrating costs on customers at the time of expenditure. The life of the measures deployed in our EE portfolio, on average, is approximately 10-12 years and thus an amortization of 10 years appropriately matches costs to benefits. Further, when the costs and benefits established under the Commission-authorized BCA framework are considered, a 10-year amortization results in benefits exceeding costs every year. For example, an investment in a rate year that results in $103 million in EE related revenue requirement when expensed that same year, would result in a revenue requirement of approximately $13 million in the first year, increasing to and peaking at approximately $16 million in the second year, well below the average annual $37 million benefit the EE investment provides customers over the 10-year amortization period, when amortized over ten years.

Q. Please continue.

A. Further, American Council for an Energy Efficient Economy ("ACEEE") in its policy brief released on December 11, 2018 (https://aceee.org/topic-brief/pims-121118) states, "ROE mechanisms allow utilities that are rapidly ramping up EE investment to spread those costs over the entire period that customers benefit from the investment, often making it more equitable."

The policy brief also states that "another notable development is the recent adoption of incentive mechanisms that allow utilities to earn a rate-of-return on EE expenditures and to amortize EE expenses for cost recovery." The brief notes that Illinois, Maryland, New

Jersey, and Utah are examples of states pursuing such policies and states that the rationale for that type of approach is that it both moderates bill impacts when there are large changes in efficiency spending as well as makes EE investments, and the level of focus given to EE by the utility and its executives, more comparable to traditional rate-of-return treatment for supply-side investments.

In short, the cost recovery mechanism that is the most just and reasonable for customers is amortization over the average life of the EE investment.

Q. Are there unspent funds available from the Energy Efficiency Portfolio Standard ("EEPS") program?

A. Yes, there are and the Company recognizes that the EE Order provides for Con Edison to use some of these unspent amounts to fund its NE:NY Incremental Electric Budgets in 2020.

The revenue requirements in these filings were developed by the Company in advance of the EE Order. The Company will consider the Order in its preliminary update filing.

Q. What benefits does this regulatory framework provide in addition to mitigating customer bill impacts?

A. As discussed above, the Company believes that a regulatory framework that fosters long-term robust utility engagement in achieving EE goals is critical to advancing the State's clean energy objectives, including NE:NY EE goals, while also managing customer impacts. The White Paper estimates that the State must achieve energy savings equivalent to both three percent of investor-owned utility sales by 2025 and an average of two percent savings level or greater between 2019 and 2025. As a result, the Company must more than double its EE efforts and investments from current levels, which are currently under one percent of sales. Recovering these expenditures as regulatory assets through base rates, amortized using our overall pre-tax rate of return over a period of ten years, will not only moderate bill impacts but also establish parity with other utility capital investments and aligns interests of customers, policymakers, third party providers and utility investors.

Further, establishing the RAF framework for EE investments supplemented by appropriate EAMs supports the State's long-term commitment to EE, including the development of the business and human resource infrastructure and spurring private sector clean energy jobs critical to the success of clean energy policy objectives.

Q. Are there any other differences in cost from the proposed budget if the Company does not amortize the EE costs?

A. Yes, there is a 3% gross up on costs that are expensed.

EE Portfolio Budgets and Targets and Other Demand Reduction Initiatives

Q. What are the EE program funding levels associated with the EE programs reflected in the revenue requirements?

A. As noted above, the electric and gas revenue requirements reflect an aggregate of $215.9 million, $257.8 million, and $300.3 million in RY1, RY2 and RY3, respectively. Of these aggregate amounts, the electric revenue requirements reflect allocated shares equal to $178 million, $216 million and $254 million, and the gas revenue requirements reflect allocated shares equal to $37.2 million, $39.2 million and $41.8 million, for RY1, RY2 and RY3, respectively. As noted earlier in our testimony, the Company is also proposing beneficial electrification budgets that the Company may update after further evaluation of the EE Order and Commission decision on the proposed NPS portfolio. The respective proposed beneficial electrification budgets for RY1, RY2 and RY3 are $0.7 million, $2.6 million, and $4.5 million, respectively.

Q. Do these budgets capture expenditures made pursuant to the Company's Smart Solutions programs (Case 17-G-0606), in which the Company has proposed a number of non-traditional alternatives to meeting firm gas customer demand?

A. They do, in part.

Q. Please explain.

A. The aggregate electric and gas budget for RY1 includes the $20.2 million funding level for the Enhanced Natural Gas Efficiency Program approved by the Commission for 2020 in the Smart Solutions proceeding.

However, while these budgets include growth of gas EE savings above levels authorized in the Enhanced Gas Energy Efficiency program, they do not include the additional gas EE expenditures that may be approved by the Commission as part of the Company's portfolio of non-pipeline solutions ("NPS Portfolio"). The Company petitioned the Commission for approval of this program in September 2018, which is currently pending Commission action.

Q. How does the Company propose to recover NPS Portfolio and other Smart Solutions program costs?

A. Recovery of NPS Portfolio expenditures authorized by the Commission would be governed by the order issued in the Smart Solutions proceeding.

In addition, the Company is continuing to recover through the Monthly Rate Adjustment ("MRA") expenditures for customer incentives, metering, and administration of the gas DR pilot approved by the Commission in August 2018. Finally, the Company requested that the Commission approve a $10 million Gas Innovation Program proposal, which costs are not part of the EE budgets reflected in the revenue requirements. This program is focused on testing new business models leveraging clean heating technologies.

The Company may reflect changes to its current proposal in this filing, to the extent appropriate, in its update filing in response to a Commission order on Smart Solutions.

Q. What are the energy savings targets for the EE programs reflected in the revenue requirements?

A. The Company designed the electric program to achieve savings of 482 GWh, 562 GWh, and 640 GWh in RY1, RY2 and RY3, respectively, including beneficial electrification goals of 115 MWh, 340 MWh, and 550 MWh over those same years. The Company designed the gas program to achieve savings of 620,000 Dekatherm ("Dth"), 640,000 Dth, and 670,000 Dth in RY1, RY2 and RY3, respectively. Ramping electric EE savings from a level that is equivalent to approximately 1 percent of sales in 2019, the Company would reach an equivalence of 1.5 percent of sales in 2022 if the program met the targets.

Q. On what unit costs are the program budgets based?

A. The program budgets are based on the Company achieving an average unit cost of $0.37-$0.40 for each kWh saved through further optimization of program delivery and internal operations. This unit cost is lower than the Commission-approved levels of $0.43/kWh for ETIP and around the range of the blended ETIP and EE Order unit costs of $0.36/kWh-$0.37/kWh reflected in the Con Edison-specific budget and targets for achievements without and with LMI. It represents significant improvement in cost efficiency, particularly considering countervailing upward cost pressures discussed below. The Company projects $62.4/Dth gas EE unit cost efficiency.

Q. Are there other efforts that may impact gas EE growth?

A. Yes, the non-pipeline RFPs will advance gas EE and may reduce the direct EE program potential. The Company's unit costs for gas EE is higher than the currently authorized unit cost because of the need to develop new efficiency offerings to achieve significant growth in gas efficiency. The Company will continue to monitor this developing market.

Table 3 - EE Portfolio:

		2020		2021		2022	
Electric		**GWh**	**$M**	**GWh**	**$M**	**GWh**	**$M**
	Total	482	$178	562	$216	640	$254
	Unit Cost ($/kWh)	$0.37		$0.38		$0.40	
	% of Sales	1.1%		1.3%		1.5%	
Electri-fication		**MWh**	**$M**	**MWh**	**$M**	**MWh**	**$M**
	Total	115	$0.7	340	$2.6	550	$4.5
Gas		**Dth**	**$M**	**Dth**	**$M**	**Dth**	**$M**
	Total	620,000	$37.2	640,000	$39.2	670,000	$41.8
	Unit Cost ($/Dth)	$60.0		$61.3		$62.4	
	% of Savings	0.36%		0.37%		0.39%	

Q. Please explain how the Company determined the estimates for EE savings?

A. The Company made some key assumptions when determining the EE energy savings estimates. The Company, combining its EE program experience and market research with its most recent potential study,[7] evaluated the ramp up needed to align achievement with the State's ambitious policy goals, while minimizing customer bill impacts. In development of the estimated EE savings, the Company (i) looked at historic program achievement and ramp up; (ii) benchmarked current ramp up against other utilities around the country, looking at cost structure and

[7] Case 15-M-0252, 2017 Distributed Energy Resources (DER) Potential Study, December 18, 2017; and Case 15-M-0252, Con Edison DER Potential Study Supplemental Report: Natural Gas Add-on Analysis, November 22, 2017.

achievement for illustrative benefit even though the Company's territory represents a more complex, uncertain and expensive urban environment; and (iii) estimated the results of the above against the economic and annual achievable potential results in the potential study. The Company made other assumptions such as the calculation of savings in accordance with the 2018 Technical Resource Manual ("TRM").

Q. Please explain how the Company determined the budget for EE spending.

A. The Company established an overall budget for its EE portfolio using indicative unit costs, i.e., cost per unit of energy (kWh or Dth) saved or cost per unit of beneficial electricity consumed, that it can reasonably forecast. During implementation, EE unit costs will depend on a number of external variables that could have significant impact on program costs such as: (i) the Company seeking to diversify beyond lighting, the predominant EE driver today, requiring the Company to work with customers to achieve greater and deeper levels of savings from more complex measures such as HVAC and building envelope that have longer payback periods for customers and longer lead times to implement; (ii) amount of reported energy savings decline for the same set of measures, as baselines increase driven by code improvements such as the anticipated 2007 Energy Independence and Security Act federal efficiency standards for manufacturers lighting baseline shift in 2020; (iii) lower-cost measures and programs reaching saturation, for example, as anticipated for residential lighting measures, which would result in the Company implementing more expensive measures with harder-to-reach customers; (iv) additional desired outcomes, such as implementing longer-lived EE measures, for example, through maintenance of existing portfolio average levels of effective useful life; (v) overall level of flexibility provided to achieve reductions; and (vi) targets established and the target levels relative to the remaining potential of various measures in the Company's territory. Consequently, while recognizing Commission determinations in the EE Order, the Company believes that unit costs, as currently calculated, will increase as the proposed EE and beneficial electrification program portfolios evolve and ramp up.

Q. Please explain why the Company's proposed unit cost increases over the three-year rate period.

A. As the Company grows the portfolio at an accelerated pace to achieve unprecedented levels of EE, there will be upward pressure on unit costs. The Company anticipates unit costs to escalate over the three-year rate period even as the unit costs proposed represent significant cost efficiencies as discussed above. The Company forecasts that this will result from the uncertainties discussed above, i.e., the need to include program offers beyond lighting to HVAC, building shell, and other new technologies while reported savings decline due to the increase in baselines.

Q. Does the Company plan to make capital investments to advanced software applications to facilitate delivery of the EEDM portfolio?

A. Yes, the Company will continue to implement and expand advanced software applications to enhance EE and DM programs including the Demand Response Management System ("DRMS"), Demand Management Analytics Platform ("DMAP"), Demand Management Tracking System ("DMTS"), and for benchmarking of building energy performance. These investments are discussed further in the DSP section of this testimony. Similar to the EE portfolio, the Company plans to update the budgets for these programs as part of its preliminary update, as the Company identifies the scope of the applications and support needed to meet the analytical requirements directed through the EE Order.

Q. Does the Company propose to add any personnel to manage its expanded programs?

A. Yes, in order for the Company to achieve its proposed EE portfolio by 2022, an increase in labor resources across a number of functions will be critical. In total, we forecast that we will need to add thirty-four (34) incremental full-time employees, as described by job function below, 16 incremental Full Time Equivalents ("FTE") to be added in 2020 or earlier, 11 incremental FTEs to be added in 2021, and 7 incremental FTEs to be added in 2022.

As discussed in more detail in the attached white paper, we proposed the following 34 incremental employees:

i. 14 incremental employees to expand and grow successful current programs that have potential for expansion and design, build and execute on newer and more innovative programs including through new delivery channels across customer segments, and engineering to provide technical support and advice to customers

ii. 6 incremental employees to manage program data and analytics

iii. 7 incremental employees to focus on managing the different budgets, compliance, and manage process optimization and controls

iv. 6 incremental employees to develop additional capabilities in Evaluation, Measurement and Verification

v. 1 incremental employee to focus on marketing communication and develop the portfolio's marketing communication strategy

Q. Has the Company compared its department to other utility departments in terms of number of employees?

A. Yes. We benchmarked our program with peer utilities that are achieving similar levels of EE achievement as a percentage of utilities sales.

Q. Are certain employees in the EEDM Department compensated differently than other Con Edison employees?

A. Yes, with respect to the variable portion of their compensation for the eight employees on the sales team.

Q. Please explain.

A. We recently started compensating some EEDM Department employees engaged in sales and business development on a commission-based variable pay structure. These employees are excluded from the Management Variable Pay ("MVP") Program applicable to all other Con Edison management employees.

Q. Why are these employees subject to a different variable pay program?

A. Given the public policy goals to significantly increase EE, the Company is working to build a performance and results driven EEDM sales organization that will create a robust sales pipeline. In analysis for this compensation shift, the Company reviewed the sales representatives pay levels and selling activities, investigated sales team compensation structures in energy services companies and general industry, and are proposing a sales incentive plan that aligns with the Company's strategic and financial objectives, the responsibilities of the sales representatives role, and addresses the sales representatives' earning opportunity with a strong pay-for-performance orientation. Under the commission-based variable pay structure, sales people will be compensated based on performance and the variable compensation can range from zero to twice the MVP level that they would otherwise be eligible for.

Q. Is the Company recovering these payments in rates?

A. No. As stated above, these employees are not part of the MVP and this compensation is not being recovered in rates. This means that the cost of this compensation is excluded from the MVP reconciliation under the current rate plan.

Q. Does the Company's proposed revenue requirement reflect this commission-based variable pay?

A. No, it does not. As testified by the Compensation/Benefits Panel, these employees were excluded from the Company's calculation of MVP for the Rate Year and no separate amount was included for projected commissions payable to these employees because the Company believes that this program is too new to reasonably forecast the amount of commissions that may be earned.

Q. How does the Company propose to recover commissions paid to these employees during the rate plan established in this proceeding?

A. The Company proposes to treat these commissions as EE program expenses recoverable through the Monthly Adjustment Clause for electric and through the MRA for gas. The Electric and Gas Rate panels have included information about the recovery mechanism of the new variable compensation.

Q. Does the Company propose any other changes to the Company's Schedule for Electricity Service, P.S.C. No. 10 – Electricity ("Electric Tariff") and Schedule for Gas Service, P.S.C. No. 9 – Gas ("Gas Tariff")?

A. Yes, the Commission's Order Adopting Whole Building Energy Data Aggregation Standard,[8] Electric Tariff Leaf 128 and Gas Tariff Leaf 118.1, are updated to reflect the new standard established in the Order, subject to

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[8] Case 16-M-0411, In the Matter of Distributed System Implementation Plans and Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vison, *Order Adopting Whole Building Energy Data Aggregation Standard*, issued April 20, 2018.

additional Terms and Conditions on the Company’s website. The Company also proposes to update Electric Tariff leaf 355 related to the proposed conclusion of surcharge-funded EE programs as they are moved to base rates as ordered in the 2018 ETIP Order.[9] Finally, the Company proposes to eliminate Rider O – Curtailable Electric Service, which was added to the Electric Tariff in April 2003 as shown in Case 03-E-0112. No Customers have ever enrolled for service under Rider O and the Company has since implemented other DR programs such as Rider L - Direct Load Control Program and Rider T - Commercial Demand Response Programs with many participants in each of these programs.

Electric Vehicles

Q. Does Con Edison support State and local policy goals related to EVs?

A. Yes. The Company seeks to expand efforts related to EVs to facilitate expansion of the EV market in New York State consistent with State and local policy objectives for EVs, enabling progress towards the State’s 2050 GHG goal. The State’s EV policy goals are to enhance EV adoption through rebates, education, and incentives,

[9] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, *Order Authorizing Utility-Administrated Energy Efficiency Portfolio Budgets and Targets for 2019 – 2020*, issued March 15, 2018.

expand accessible charging stations to 10,000 by 2021, assist in meeting ZEV vehicle targets, and expand interstate and urban fast charging stations.

Q. Why is Con Edison proposing investments that increase options for customers seeking to adopt EVs?

A. The Company believes that transition from a fossil-fuel based transportation system to electrified transportation is an alternative approach that can meet customers' needs for transportation options. Increased EV options will support public policy goals by providing important environmental benefits. Transportation electrification will provide a meaningful pathway to reducing GHG emissions with the additional potential to provide customers with reduced fuel costs. Additionally, more EV options can enable more efficient use of the electric system if the times of charging, and discharging when applicable, are optimized.

Q. What has the Company already done to advance EVs?

A. The Company has taken several steps to increase EVs. The Company has implemented: (i) a SmartCharge NY program to incent off peak EV charging; and (ii) an EV category under its Business Incentive Rate ("BIR") to promote Direct Current Fast Charging ("DCFC"). The Company has also received approval for a REV Demonstration project for EV school bus charging. Finally, along with the other New York State utilities and several State agencies, including the NYPA, the Company is proposing an incentive to assist DCFC.

Q. Does the Company have a proposal to further advance EV?

A. Yes. The Company is proposing in this rate filing to (i) expand access to public EV charging through implementation of an EV make-ready program; and (ii) continuing the SmartCharge New York program to charge EVs during off-peak hours.

Q. Does the Panel have an exhibit that discusses these two EV programs?

A. Yes. The Company has an exhibit entitled, "Electric Vehicle Charging," which was prepared under the Panel's supervision and direction.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-2)

Q. What is make-ready infrastructure?

A. Make-ready infrastructure refers to the equipment associated with providing an electric service connection from Con Edison from the point of interconnection to the property line. Generally, customers with an existing electric service connection are responsible for costs to extend a new electric service to a new charging station. Such extensions can be costly, requiring extensive trenching and construction.

Q. Please explain the Company's proposal for make-ready infrastructure.

A. The Company is proposing a three-year program, at a cost of $10 million each year for a total of $30 million, to pay for interconnections and service line extensions costs for DCFC EV supply equipment that is installed on private property for public charging. The Company's efforts will result in development of delivery infrastructure enabling third parties to develop publicly accessible EV charging facilities on non-utility private properties that are not located in the public right-of-way.

Q. How would this program work?

A. Customers would file an application to qualify and demonstrate their intention to move forward with projects to build publicly-accessible charging stations (i.e., by installing their "property line box") and by meeting the terms of the BIR, which requires the EV-charging facilities be accessible to the public. The Company would process qualifying applications in a queue on a first-come, first-served basis. The Company would absorb the cost for the installation of the service facilities up to $10 million annually.

Q. How many stations would receive incentives under a $10 million per year program?

A. The median cost of a connection for an EV station with six 150 kW DCFC plugs in Con Edison’s service territory is $900,000. We expect to connect approximately 11 stations annually, adding approximately 10 MW of DCFC capacity.

Q. Why is this make-ready program necessary?

A. For publicly accessible EV charging stations, the Company’s analysis of the business case for third-party developers building DCFC stations indicates that the economic viability of such stations is closely tied to station utilization levels. The stations only become economically viable at utilization rates above approximately 25-30 percent. At this early stage of EV adoption in New York, vehicle counts, and consequently, demand for charging stations are relatively low. This results in a lower likelihood of charging stations reaching over 25 percent utilization, which discourages investment. However, without the buildout of adequate charging infrastructure, EV owners face the barrier of lack of adequate charging stations, which results in lower EV penetration rates. Accordingly, there needs to be sufficient publicly accessible charging infrastructure in place to enable increased adoption of EVs. The Company’s proposal lowers the capital costs associated with charging station development and facilitates an accelerated buildout of third-party-developed charging stations, while leveraging Company strengths.

Q. Does the program require the Company to modify its Electric Tariff?

A. Yes. The tariff rules related to the extension of electric facilities must be modified to reflect this program and the electric service connections at no cost. Please see the Electric Rate Panel testimony for a description of this tariff change.

Q. Turning to the other program, please explain the SmartCharge NY program.

A. As explained in Exhibit __ (CES-2), Con Edison's SmartCharge NY program currently offers incentives to eligible EV drivers for charging in Con Edison's service territory at off-peak times and provides a one-time financial incentive for installing and activating a free connected car device from FleetCarma that allows users (and the Company) to know where, when, and how much energy an EV consumes during charge events. Participants receive additional fixed monthly incentives for keeping the device plugged in and charging within the Con Edison service territory.

Q. Please explain how the SmartCharge NY program helps Con Edison develop EV offerings for its customers?

A. The SmartCharge NY program helps Con Edison understand charging behavior and EV driver and fleet operator response to incentives.

Q. Does the Company plan to continue SmartCharge NY?

A. At this time, yes. We will continue offering this program to customers. However, we will continue to review the results and determine if other off-peak charging incentives are available or provide greater customer response. For example, for buses, the FleetCarma device is not necessary as buses will have communication capabilities.

Q. What is the current enrollment level for SmartCharge NY?

A. There are currently over 1,500 EVs enrolled in the program, comprised of privately-owned and fleet vehicles.

Q. Has the Company made any changes to the SmartCharge NY program?

A. On September 12, 2018, the Commission approved the Company's expansion of the eligibility criteria for the SmartCharge NY program to include medium- and heavy-duty vehicles, including buses.[10] The charge rates for medium- and heavy-duty vehicles are also typically higher, with

[10] Case 16-E-0060, Proceeding as to the Motion as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service ("2016 Con Edison Electric Rate Proceeding"), *Order Expanding Electric Vehicle Charging Program Eligibility*, issued September 12, 2018.

some buses charging at 500 kW. The Company believes it is important to understand and manage these loads through incenting customers to shift as much charging as possible away from system peak times. Based on the projected increase of new vehicles in this category, the Company anticipates requiring additional funds to continue implementation of an EV program focused on influencing and understanding customers' EV charging patterns.

Q. Has the Company seen any enrollment associated with medium and heavy duty vehicles?

A. The Company is working with State agencies and private fleets to enroll the first medium- and heavy-duty vehicles into the program. We expect about twenty vehicles to enroll in 2019, and that enrollment could increase to almost 250 by 2022 as electric transit buses are placed into service by the Metropolitan Transit Authority ("MTA"). Consequently, the Company anticipates that the EV program will constitute a greater proportion of medium and heavy duty vehicles in the future.

Q. What is the Company proposing to do in this rate case for SmartCharge NY?

A. The Company is seeking increased funding for the program over the prior three-year funding level. We are looking to increase funding for the program by $9 million over the amount authorized in the current rate period to a total of $15 million over the upcoming three year period.

Q. How does the Company propose to recover these costs?

A. The Company proposes all EV programs costs related to the SmartCharge program be treated as a regulatory asset, which provides for the recovery of the EV regulatory asset over ten (10) years using the overall pre-tax rate of return. The Company's Accounting Panel discusses the cost recovery framework.

Energy Storage

Q. What is Energy Storage?

A. Section 74 of the New York State Public Service Law defines storage as "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy using mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time."

Q. Has the Commission addressed energy storage recently?

A. Yes. The Commission recently issued its *Order Establishing Energy Storage Goal and Deployment Policy*[11] ("Storage Order") that discussed storage. The Commission concluded that storage can provide benefits to customers,

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[11] Case 18-E-0130, In the Matter of Energy Storage Deployment Program, *Order Establishing Energy Storage Goal and Deployment Policy*, issued December 13, 2018.

including reductions in GHG emissions and other air pollutants and improvements to the efficiency and resiliency of the grid.

Q. Did the Commission establish an energy storage goal in its recent order?

A. Yes. The Commission set two storage goals. First, the Commission established a goal of the installation of 3,000 MW of storage in New York by 2030, with the deployment of 1,500 MW by 2025. Second, the Commission required the Company to issue a Request for Proposal in 2019 to procure the dispatch rights to 300 MW of bulk system connected storage to be sited in the Con Edison territory.

Q. What is the status of the energy storage market in New York State?

A. Although energy storage has the potential to play an important role in New York's clean energy future, the energy storage market is in the early stages of development. This market remains uncertain related to several issues -- technology maturity, wholesale market rules, permitting requirements, and economics. Additionally, the costs of batteries and other storage technologies are forecast to remain high relative to the system benefits and potential revenues they provide. These uncertainties are discussed in detail in DPS

Staff's New York Energy Storage Roadmap, filed in Case 18-E-0130.

Q. Is the Company pursuing storage in this case? If so, why?

A. Yes. Energy storage is a transformational technology that can provide numerous benefits to the electric system, and ultimately, to electric customers. Con Edison envisions a future state where storage provides support to the distribution system, enables the operation of intermittent renewable resources, and reduces GHG emissions and other local emissions.

Furthermore, as storage costs decline and use cases evolve, broader proliferation of storage will help customers and communities manage their usage to align with system capabilities, participate in DR, support integration of new applications, like EV charging, and respond to more cost-reflective rate designs, such as hourly pricing and demand-based rate structures.

Finally, the proposed investments will support the Commission's goals for energy storage deployment in part by supporting the development of the storage market in New York.

Q. Does the Company have any experience with installing energy storage systems?

A. Yes. While the energy storage market in Con Edison remains nascent, the Company has successfully procured and installed a battery rated at 2 MW and 12 MWh, the largest in our territory, on utility-owned land to support our BQDM effort.[12]

Q. Please describe the Company's proposed energy storage investments in this filing?

A. The Company is proposing a two-part strategy for energy storage. First, the Company intends to develop six energy storage facilities on Company locations. Second, the Company will develop one turn-key make-ready site for third-party storage developers.

Q. How much storage capacity will these two programs provide?

A. Together, the two project approaches will provide approximately 41.5 MW of load relief and up to 160 MWh of energy for discharge. In total, our six facilities will provide 31.5 MW and 120 MWh. The third-party-owned system will provide up to 10 MW and 40 MWh.

Q. Does this proposal support the State's energy storage deployment goals?

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[12] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program, issued January 22, 2015.

A. Yes. The Company's proposed projects will advance the deployment of storage in New York by building and testing scalable market capabilities, while also providing key learnings about the grid benefits. The proposed utility-sited projects provide a near-term path to developing a more robust storage market, testing storage for potential grid applications, and continuing to address permitting issues. The use of utility land can accelerate project development timeframes and reduce or eliminate some implementation costs – including soft costs like customer acquisition, siting, permitting, and interconnection. We note that the proposed projects will provide storage manufacturers and service providers with actual, shovel-ready opportunities.

Q. Has the Company prepared an exhibit that discusses its energy storage plan?

A. Yes. There is a white paper entitled "Utility Energy Storage."

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-3)

Q. Was this exhibit prepared under the Panel's direction and supervision?

A. Yes.

Q. Why is the Company proposing two different types of energy storage ownership models?

A. Con Edison expects that ultimately the New York energy storage marketplace will include a combination of utility-owned, customer-owned, and third-party owned energy storage, both in front of the meter ("FTM") and behind the meter ("BTM"). As a result, it is important to test different ownership models.

Q. Why is the utility proposing distribution system connected investments?

A. As the New York State Energy Storage Roadmap indicates, energy storage can provide unique values at different locations in our energy system. Smaller storage assets procured under existing and future NWS and Demonstration Projects will be installed at customer properties at lower voltages. On the other hand, the larger assets installed under the forthcoming bulk storage procurement will likely be interconnected at higher voltages. Even with these procurements, there is a gap for utility-scale systems on the distribution system at intermediate voltages. The investments proposed here address that gap so that a diverse portfolio of storage procurements is established along with the associated learnings around procurement, development, and operation of these assets, including for distribution level use cases at intermediate voltage classes.

Q. Why does Con Edison propose to own the six storage systems?

A. The REV Track One Order[13] permits utility ownership for storage integrated into the distribution system because the Commission recognized the usefulness of energy storage as a distribution system asset meeting key system needs. Utilities are best positioned to identify, develop, and procure solutions to distribution system needs. Storage can and should serve as an important option in the utility "toolbox."

Additionally, the six proposed sites are substation properties that house critical electrical infrastructure. Allowing third parties access to operations at the site will introduce potential personal safety and security concerns and risks.

While these six proposed storage facilities will be utility-owned, the Company will issue competitive solicitations allowing battery developers to submit proposals to design, implement, and commission the battery systems, similar to the process followed for the battery rated at 2 MW and 12 MWh in the BQDM area.

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[13] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Adopting Regulatory Policy Framework and Implementation Plan*, issued February 26, 2015.

Further, there exist opportunities for customer- and developer-owned assets through NWS, the forthcoming bulk storage procurement, and the Nevins Street make-ready site. Put in context, the proposed Company-owned storage systems with capacity and energy ratings of 31.5 MW and 120 MWh are roughly 10 percent of the 300 MW and 1,200 MWh of the forthcoming bulk storage procurement alone and just over 2 percent of the 2025 State-wide storage goal.

Q. Turning to the first storage program, please describe the six proposed energy storage facilities.

A. These locations, which are dispersed across three operating regions to address a diverse set of use cases, discussed below, will enable the Company to broaden its expertise for future deployments. The proposed locations and projected performance are listed below and not ranked in any specific order of deployment.

Table 4 – Proposed Storage Locations

Region	Location	Facility Type	Power (MW) / Energy (MWh)	Estimated Capital Cost ($M)	Estimated Start date for Remediation/ Construction
Brooklyn/ Queens	Richmond Hill	Unit Substation	6 / 12	10.4	2020
	Long Island City	Area Substation	3 / 12	9.9	2021
Staten I0sland	Fresh Kills	Area Substation	9 / 36	25.7	2021
	Fox Hills	Future Use	7.5 / 30	21.7	2020
Bronx/ Westchester	New Rochelle	Area Substation	2.4 / 12	8.6	2021
	Millwood	Substation	3. 6 / 18	14.1	2020
TOTAL			31.5 / 120	90.5*	

Note: Capital costs do not sum due to rounding

Q. How does the Company propose to deploy these assets?

A. In 2020, we will start the procurement process for a system at the Richmond Hill site in Queens. Con Edison has already received Board of Standards and Appeals approval for a battery installation at this site because this site was considered as an alternative for the BQDM 2 MW and 12 MWh battery system. We also began work on the permitting process with the Fire Department of New York and Department of Buildings at this location. Given the process that is underway, starting deployment at the Richmond Hill site is an efficient way to jumpstart the Company’s storage deployment.

In parallel, starting in 2020, we will begin the preparation of the other five sites, including any necessary remediation activities, with a goal of beginning construction on a second site in 2021 and the remaining sites in 2022. A more detailed deployment schedule cannot be provided at this time due to uncertainties in the remediation activities required and the local permitting process and requirements across the different city and municipal agencies, both of which can significantly impact project schedules.

Q. What are the in-service dates for these energy storage systems?

A. The energy storage devices at the six utility-owned sites are estimated to be in service by 2025 or earlier. The make-ready site is estimated to be in service by 2021.

Q. What is the proposed O&M expenditure during the rate period?

A. The O&M expenditure projected over the three rate years will total $15.5 million, including $11.5 million for remediation at the six sites and $4.0 million for operating and maintaining the systems.

Q. Does the Company have a proposed recovery method for the six energy storage locations?

A. Yes. The Company is seeking to recover all development and implementation costs of this grid support asset as a Company-owned asset.

Q. How were the six sites selected from a list of eligible sites?

A. The sites were selected with the goal of identifying available land in diverse geographical regions with an array of energy storage use cases where the systems may also provide system benefits. Larger-size sites were prioritized since they likely allow for lower unit cost of the overall storage installation through economies of scale, provide greater operational flexibility through various discharge modes (which can extend the life of the storage systems), and improve the cost effectiveness of battery installations to the benefit of our customers. Additionally, we selected locations that are within networks and load areas experiencing load growth and other current or potential needs storage may address, but which have not yet triggered an NWS solicitation. The Company will continue to adjust the criteria for installing energy storage based on its experience as it develops these proposed sites.

Q. Please explain the need to have diverse locations and use cases.

A. The diversity in location and use cases will allow for key learnings around factors affecting energy storage deployment and operations, such as construction considerations, managing relationships with the local communities, permitting requirements, and operations at different voltage classes and in regions with different load profiles.

Q. Please describe the diverse use cases the six storage systems will address.

A. The batteries will follow a variety of operational profiles depending on the local needs at the point of interconnection to address peak shifting, load ramping, and contingency response use cases. Battery systems in areas where local capacity is more limited will follow a peak shifting profile where the batteries charge overnight when prices and GHG emissions are relatively low, and then discharge during the day or evening during the local network peak. The systems installed in areas with growing solar penetration, such as those in Staten Island and Westchester, will address voltage management challenges associated with a duck-curve type load profile developing in these regions. This load profile contains a relatively steep evening ramp as solar generation wanes and local loads increase, creating the potential for voltage issues. Finally, in regions where a system contingency can cause voltage issues within a load area, the storage assets can be discharged to maintain reliability in lieu of the current operational measure in which diesel generators are deployed.

Q. Is there potential for modifications to the list of six deployment sites?

A. Yes. The Company will conduct a more detailed construction review before final site selection. The Company seeks the approval to pursue the proposed opportunities at the selected locations or at an alternate location if the Company, as it begins project implementation, determines an alternate location to be more suitable.

Q. If the Company receives any revenues for operations at these six storage facilities how will Con Edison manage them?

A. Any potential revenues received by the Company, such as wholesale market revenues, will be deferred to the next rate case, subject to any applicable Company incentives.

Q. Please explain the second proposed storage investment.

A. The Company proposes to build a turnkey energy storage docking facility at the Nevins Street property for third-party-owned energy storage. The Company will prepare the land, including any remediation and grading, extend distribution system feeders onto the land, and install interconnection hardware to accommodate up to 10 MW and 40 MWh of energy storage. The Nevins Street make ready investment is described Exhibit __ (EIOP-4).

Third-party storage developers will submit bids for access to the docking facility and interconnection, and winning developers will install, own, and operate their storage assets. This arrangement will provide a unique opportunity for the Company to collect revenues to offset docking station project costs while also allowing third-party developers the flexibility to leverage the storage systems for grid services, New York Independent System Operator ("NYISO") market services, or other applications. Additionally, DCFC EV chargers will be co-located on the site, allowing the Company to gain a better understanding of how energy storage can help mitigate the impact of EV charging on the grid. These EV chargers will be deployed and funded by a Demonstration Project and no funds for these chargers are requested here.

Q. How does the Company plan to recover the costs for this project?

A. The Company is seeking to recover all development and implementation costs of the turnkey energy storage project as a Company-owned asset. The EV charger costs will be recovered through the Demonstration Project as noted above. Before entering into a lease agreement with the third-party storage developers for access to the make-ready facility, we plan to file a petition under Section 70[14] which will include, among other items, a proposal to address revenues collected under the lease agreement.

Q. Why is the Company proposing FTM projects?

A. Investment and policy action to support FTM distribution system and bulk system deployment use cases will produce significantly higher overall benefits for all customers than untargeted BTM customer sited deployments. Both the distribution system and bulk system FTM use cases allow for the development of larger and more economic storage installations (on a per MW and per MWh basis, as recognized in the New York State Energy Storage Roadmap) that can be targeted to meet electrical system needs while also preparing our system for greater levels of intermittent renewable integration. Although customer-sited applications can provide grid benefits, particularly, when located in constrained areas and operated during grid need times, installations that are

[14] Public Service Law Section 70 requires a company to obtain Commission approval before disposing of its property; the granting of a lease is considered a disposition requiring Section 70 review and approval.

primarily operated to mitigate customer bills (for example, demand charges) offer fewer benefits to the system.

Q. Is the Company considering any customer sited BTM models?

A. Con Edison will continue to consider BTM storage through NWS and Demonstration Projects as well as support BTM storage interconnection requests. Additionally, the Company will continue to evaluate new storage opportunities, including BTM applications that can provide broad grid and customer benefits.

Distributed System Platform Implementation

Q. What is the DSP and what services does it provide?

A. New York's REV initiative is moving the electric industry forward to a sustainable energy future. This transformation includes increased market penetration for DER to focus on customer choice and participation and facilitates advances in technology, DER integration, and enables customer choice. The Company filed its second DSIP on July 31, 2018 in Case 16-M-0411 as a comprehensive roadmap to achieving its vision for the DSP. The Company's development of the DSP will allow it to offer the platform services necessary to evolve the distribution system. These services will enable the bi-directional flow of energy resulting from the growth of

DER and facilitate transactions to support market opportunities for DER.

Con Edison is building the DSP through investments in the people, processes, and systems that allow Con Edison to provide three core, interrelated platform services described below:

- **DER integration services** are the planning and operational enhancements that promote streamlined interconnection and efficient integration of DER, while maintaining safety and reliability.
- **Information sharing services** are information and communications systems that collect, manage, and share granular customer and system data, enabling customer choice and expanding third-party vendors' and aggregators' participation in markets for DER.
- **Market services** are utility programs, procurement, wholesale market coordination, and tariffs that create value for DER customers through market mechanisms.

Q. Please continue.

A. The projects included in this rate filing as DSP investments are incremental elements required to support the functionalities that will enable Con Edison to serve as the DSP Provider. Several of these investments (Modernizing protective relays, Volt VAR Optimization

("VVO"), and DER Management System ("DERMS")) are aligned with and enabled by Con Edison's Grid Innovation Roadmap, which is further described in the EIOP testimony.

Q. Do you have a document that explains the projects being proposed for the DSP?

A. Yes. We have developed a white paper entitled "Distributed System Platform."

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-4)

Q. Was this document prepared under the Panel's direction and supervision?

A. Yes, it was.

Q. Please describe steps the Company has already taken to develop its DSP and enable greater DER penetration.

A. Company investments have already supported significant progress in implementing the DSP. The full list of DSP achievements is included in Exhibit __ (CES-4), and an excerpt of notable accomplishments is included below:

- Installed advanced network protector relays that allow reverse power flow on network systems, increasing the amount of DER that can be hosted on a circuit.
- Installed VVO controllers and communicating modems at 150 4kV unit substations necessary for executing VVO capabilities in the 4kV grid.

- Implemented the Interconnection Online Application Portal ("IOAP") and developed hosting capacity maps to provide developers valuable information and streamline the interconnection process.

Q. Has market participation increased?

A. Yes. The Company's investments have resulted in greater integration of DER into the Company's planning and operations processes, such as forecasting, engineering, and area station planning to include NWS, and determining hosting capacity. These processes have enabled greater market penetration of DER than would have otherwise occurred. Since January 1, 2016:

- The amount of installed solar capacity connected to Con Edison's distribution system has doubled to approximately 190 MW Alternating Current.
- There are now over 20,000 rooftop solar installations in Con Edison's service territory, approximately double the amount in 2016.
- Customers can share their usage data with authorized DER developers through the Green Button Connect My Data, which will be enhanced as AMI is fully deployed.

Q. Please continue.

A. These achievements demonstrate Company progress from its Initial DSIP[15] and provide a solid foundation for continued development.

The net effect of all these efforts is DER totaling over 500 MW in capacity in the Company's service territory. This amount will help offset peak demand growth increases driven by population growth, economic development, and new technologies, such as EVs.

Q. Is the Company proposing changes to the Electric Tariff to promote DER and DER interconnection?

A. The Company is proposing a number of tariff changes to facilitate DER interconnection, as described below.

- General Rule ("GR") 8.2, Emergency Generating Facilities Used for Self Supply, has been amended to allow electric energy storage used as an emergency generating facility to be connected to the grid as long as it is not exporting. As this rule is currently written, an emergency generator cannot operate in parallel with the grid. With the increased use of energy storage as an emergency generator, this would preclude the charging of electric energy storage

[15] Case 16-M-0411, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Initial DSIP Con Edison, (filed June 30, 2016).

used as an emergency generator. Importantly, this change maintains the ability of customers with electric energy storage to apply for parallel service under GR 20 and/or Rider R service.

- GR 8.3, Generating Facilities Used under Special Circumstances for Export, currently states that a customer may not deliver to the Company's distribution system while the customer receives electric energy delivered by the Company. This section has been amended to specify that a customer may not deliver to the Company's distribution system while it is receiving electric energy delivered by the Company at the same point. This change allows customers with multiple service points to export from their DER at one of their service points while still importing energy at another.
- The Company proposes a number of changes to Form G[16] to clarify the application language and streamline the application process. Specifically, the Company created a separate section in the Targeted Exemption and Rider Q forms for applicants to certify their eligibility. The Company is requesting additional

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[16] Changes are proposed to Leaf Nos. 382.1, 383, 384, 384.1, 385, 385.0.1, 385.1, 386, 386.0.1

information regarding Contract Demand under GR 20 to track any revenue differences from Contract Demand under Rider Q Option A.

The Electric Rate Panel further discusses these tariff changes.

Q. What is the Company's proposed DSP investment in this rate filing?

A. The Company proposes to invest $35.2 million in capital in each of the three rate years. In addition to this capital request, the Company proposes an O&M investment of $7.5 million in total across a three year rate period. The O&M costs per year are $2.1 million in RY1, $2.6 million in RY2 and $2.9 million in RY3.

Q. What investments is the Company proposing in the filing and in this case?

A. The investments proposed for DSP development are intended to build upon and continue the Company's work in this area. The DSP investments are grouped and discussed using a framework in three categories, with several components under each overall category:

- DER Integration
- Market Services
- Information Sharing

Q. What are the proposed programs and expenditures?

A. The proposed DSP investments are shown in the table below:

Table 5 - DSP Capital Requests ($000)

Component	**Investment**	**2020**	**2021**	**2022**	**Total**
DER Integration	VVO	$14,300	$14,300	$14,300	**$42,900**
	Modernize Protective Relays	$12,600	$12,600	$12,600	**$37,800**
	IOAP	$1,300	$1,300	$1,300	**$3,900**
Market Services	DERMS	$2,800	$2,800	$2,800	**$8,400**
	DMTS	$1,600	$1,600	$1,600	**$4,800**
	DRMS	$1,300	$1,300	$1,300	**$3,900**
	DMAP	$1,300	$1,300	$1,300	**$3,900**
Information Sharing	Web Service Interface	$0	$0	$0	**$0**
	Total	**$35,200**	**$35,200**	**$35,200**	**$105,600**

Q. Are there any O&M costs associated with these capital investments?

A. Yes. Three of the programs require O&M expenditures:

- DMTS ($1.7 million in RY1, $2.0 million in RY2, $2.3 million in RY3)
- DMAP ($0.2 million in RY1, $0.3 million in RY2, $0.3 million in RY3)
- Web Service Interface ($0.2 million in each rate year)

Q. Before discussing the projects, please explain the relationship between the Company’s DSP investments and its Grid Innovation investments described in the EIOP testimony.

A. The Company's DSP investments are part of a holistic and comprehensive plan to modernize the grid. The Company's Grid Innovation Roadmap complements and enables DSP investments to develop capabilities and deliver benefits to customers in both the short term and the long term. Through the Grid Innovation initiative, the Company is building capabilities to facilitate a more dynamic integrated grid. Grid Innovation investments serve to develop a number of capabilities, beginning with foundational investments that both provide immediate benefits while also enabling future capabilities. Some Grid Innovation investments are foundational for capabilities developed through DSP initiatives, for instance, a Geographic Information System ("GIS"), described by EIOP, is necessary to implement a DERMS.

DER Integration

Q. Please elaborate on the DER Integration category.

A. DER integration refers to planning and operational enhancements that promote integration of additional DER. There are two key elements for DSP DER integration services - interconnection and operations. For interconnection, the goal is to safely, securely, and timely interconnect DG and energy storage to the distribution system.

Operationally, the goal is for safe and reliable operation of the distribution system as more DER, energy storage, EVs, and electric heating loads connect to the system.

Q. Please discuss the projects in the DER Integration category.

A. We discuss VVO and Modernizing Network Protector Relays in this testimony. IOAP/Hosting Capacity is explained in Exhibit __ (CES-4).

Q. Please describe the VVO project.

A. VVO is a set of voltage management capabilities, which includes both Conservation Voltage Optimization ("CVO") and reactive power management. The primary purpose of VVO is to maintain the proper voltage levels along distribution feeders under different loading conditions. Currently, there may be a higher level of voltage at the beginning of a feeder closest to the substation, and a lower level of voltage towards the end of the feeder. AMI data will provide voltage level visibility at the customer meter. This information will advise the Company where equipment, hardware, and communication upgrades will be required to optimally manage voltage under various loading conditions and greater DER penetration.

Q. Please continue.

A. Optimally managing system voltage levels increases system efficiency by regulating the voltage to adequately serve the points at the grid edge, while not oversupplying the points closer to the substations. VVO enhances control of voltage along distribution feeders, which, in turn, provides GHG reductions, customer energy usage savings, and allows for greater penetration of DER on the system, particularly in non-network areas where solar potential is greater and improved voltage control may increase hosting capacity.

Q. Does VVO assist with other technologies?

A. Yes. VVO functionality supports the penetration of solar photovoltaic ("PV") systems with smart inverters. The smart inverters are able to control the output of the PV system's active and reactive power. This can help balance active and reactive power, which protects customer and utility equipment, and improves grid efficiency by reducing line losses.

Q. How is VVO enabled?

A. This investment uses granular AMI data along with IT systems interfacing with the AMI platform. It also is enabled by system electrical equipment, hardware, and communications upgrades. Using this information helps determine if additional equipment is necessary to improve voltage levels.

Q. Please continue.

A. The full execution of VVO involves an evolution of capabilities in several phases that extend beyond the rate period. The first phase, and the focus of this rate period, comes from receiving the AMI data from the grid edge to set baselines across various load areas, and this will be done in parallel with equipment upgrades described below. Later phases involve more dynamic and distributed voltage control, and require additional voltage control equipment, real-time data analysis, and system integration.

Q. What VVO work has been completed to date?

A. Hardware and communication upgrades at 4kV Unit Substations have begun and all 224 of these substations will be completed by December 2019.

Q. What VVO work will take place during the rate period?

A. Work enabling VVO during the rate period involves:

- Installing additional VVO equipment at targeted area substations,
- Integrating this equipment to the back-end systems as more VVO-driven Supervisory Control and Data Acquisition ("SCADA") endpoints are created for operators to consume and visualize the VVO data, and

- Monitoring area substation meters for voltage and current levels at the area substation bus provides visibility to system operators so they can adjust voltage as required, keeping it within specifications.

Q. Why is visibility important?

A. Visibility is important because an understanding of the voltage at the grid edge is one of many inputs for optimizing voltage using VVO on the distribution system. In addition, as DER penetration increases, the Company will require dynamic capabilities to maintain optimal voltage and reactive power under various load conditions. To provide more granular voltage measurements necessary to enable VVO, the Company will target metering and SCADA equipment replacements at older (pre-1980) substations. This work is also required to verify the energy savings achieved through AMI-enabled VVO capabilities.

Q. What are the benefits of implementing VVO?

A. VVO benefits are closely related to the CVO benefits that will be achieved through the AMI implementation, as outlined in the AMI business plan.[17] The CVO benefits in AMI target a 1.5 percent aggregate energy savings,

[17] 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 Advanced Metering Infrastructure Business Plan, filed November 16, 2015.

however, in local pockets taking action on AMI data is not possible without the SCADA monitoring and metering equipment installed under this initiative.

Q. Please describe the Modernize Network Protector Relays project.

A. The Modernize Network Protective Relays project continues and scales up the installation of these relays, which started in 2017, to complete approximately 400 installations per year in 2018 and 2019. Simply put, and as more fully explained in Exhibit __ (CES-4), upgrading the network protector relays allows DER to safely backfeed into, *i.e.*, export, to the grid, and provides communications capability that is not available on existing network protector relays. Network protector relays on network transformers were originally designed for one purpose: to interrupt (commonly referred to as "clear") "backfeed," or stop the flow of power, from the associated low voltage network back onto the faulted portion of the grid. In a traditional electric distribution system, this uni-directional power flow design was a check so that backfeed from fault conditions would be cleared or stopped so as to avoid system or safety issues. However, when DER are providing power to the grid, they too can backfeed and open the network protector relay, *i.e.*, disconnect the DER from the grid.

To avoid these DER-related network protector relay operations, the DERs’ size was previously constrained so they could not export to the grid. The modernized, communicating network protector relays enable bi-directional power flow, afford the Company greater operational flexibility, and expand DER hosting capacity. As DER penetration increases, this capability becomes more important.

This project represents an opportunity to further use the AMI network in transformer vaults, which house the network protectors. The Company is currently testing the performance of AMI network communications for SCADA operations. Pending successful testing, through developing a robust SCADA system using AMI infrastructure, the Company gains an ability to implement advanced monitoring and remote control of its 27,000+ network protectors. This provides several fault identification and DER enablement benefits, discussed later.

Q. What is the scope of the Modernize Protective Relays project?

A. As mentioned above, this is a continuation and scale up of a multi-year program begun in 2017. To date, the Company has installed approximately 500 modernized network protector relays and 30 relays with SCADA capabilities, and projects the installation of an additional 400 by the end of 2019. During 2020-2022, the Company will complete approximately 600 network protector relay installations per year and an additional 200 relay upgrades per year with SCADA capabilities. In addition to the installations, enhancements to the back-end SCADA systems will be required to consume the data and provide visualization for engineers and operators. Because the total population of network protector relays is over 27,000, the Company prioritized installation in the locations where DER potential is highest, or where the load area is most constrained.

Q. Please describe the benefits associated with this project.

A. The benefits include increased system visibility, faster identification of feeder faults, reduced secondary faults, SCADA enablement, and soft transfer trip capability - which allows a trip signal to be sent to the respective network protectors on a feeder, and can reduce the number of times a feeder remains alive on backfeed ("ABF"). These benefits promote employee and public safety and well as enable resiliency.

Additionally, by installing these relays proactively in prioritized areas, this approach increases hosting capacity, facilitates lower cost interconnection, and enables DG customers to supply more energy to the system.

Market Services

Q. Please describe the Market Services category.

A. Market Services refers to functionality that enables greater access to market value through DER procurement, programs, and pricing. As described in the Company's 2018 DSIP filing, the Company has divided market services in four categories: procurement, market coordination, wholesale tariff, and settlement and billing. There are four projects that fulfill goals in one or more of these categories providing market services: DERMS, DMTS, DRMS, and DMAP. The DERMS and DMTS projects are described further below and the other two projects are discussed in Exhibit __ (CES-4).

Q. Please describe the DERMS project.

A. DERMS is a software solution designed to provide DER asset management, planning and forecasting, and monitoring and dispatch capabilities.

Q. Please describe DERMS efforts to date.

A. The Company has begun its implementation of DERMS. In 2017, the Company performed a benchmarking assessment of how peer utilities were thinking about DERMS implementations. The benchmarking effort, combined with a market assessment of vendor offerings, demonstrated that there was no available COTS offering suitable for the Company’s network design. The Company also undertook requirements gathering to identify DERMS use cases, and a current and future state assessment based on those requirements.

Q. Please describe the next steps for DERMS during the rate years.

A. Based on the fit gap assessment, DERMS functionalities were divided into four phases: (i) DER Asset Management, (ii) DER Planning and Forecasting, (iii) DER Monitoring and Dispatch, and (iv) DER Markets and Settlement. For the rate period, work is focusing on phases (i) and (ii), to integrate planning functions with DER data capabilities in a DERMS environment. The Company will also pilot reliability and market optimization/dispatch work that will commence between 2020 and 2022. This phase of DERMS will include investments in software as well as communications, monitoring, and control infrastructure that will be vital to the real-time operation of DERMS.

Q. Please describe the benefits of DERMS.

A. DERMS will enable a holistic view of the various types of DER on the system and provide an automated process for visualizing and understanding DER as it is considered in the Company’s planning process. DERMS will enable the

Company to understand the status and capabilities of DER on its system and will provide important data to the Company's Distribution Management System, and other key applications, such as GIS and DRMS. These capabilities will help the Company better manage an increasingly complex and bi-directional electric system.

The DERMS will also leverage many of the investments made between 2016 and 2018 in Hosting Capacity and IOAP projects as well as investment to be made through GIS, through registration of DER and mapping and visualizing that DER to real-world coordinates (described in the EIOP testimony, Grid Innovation section). This means that much of the valuable work already completed relative to the point registration and visualization of DER will be used for DERMS.

Q. Please describe the DMTS project.

A. DMTS currently tracks and records the performance of the Company's EEDM portfolio achievements. The DMTS serves as an important system of record and results in improved data governance related to reported achievements such as EE savings published in quarterly scorecards. Since it was put in production in 2014, the Company has increasingly relied on DMTS to track, record, and verify EE savings.

Q. Please describe the Company's plans for DMTS during the three year rate period.

A. The Company will expand DMTS capabilities, including enhancing Customer Relationship Manager functionality, developing and implementing an EE Measurement and Verification module, developing and expanding financial forecasting tools, and implementing new EEDM programs that are developed to reach EE targets. This work will also include maintaining DMTS as a repository and the system of record for reporting information related to EE and demand side programs, measures, and individual customer project data.

Q. Are there O&M costs associated with DMTS during the rate plan?

A. Yes. Four employees currently part of DSP capital funding authorized in the current rate plan will be moved to O&M as they will maintain and further develop the DMTS.

Information Sharing

Q. Please describe the Information Sharing category.

A. Information sharing refers to information technology enhancements that enable customer choice and participation of third-party vendors and aggregators in markets for DER. These investments either leverage or improve upon existing assets or are allocated for new systems that support required DSP functionality. The initial investments focus on building the necessary interfaces to engage customers, increase the volume and granularity of data, and enable greater DER penetration. There is one project in this category, Web Services Interface, described in further detail in Exhibit __ (CES-4).

Targeted Initiatives to Defer Electric Infrastructure

Q. How do targeted initiatives to defer electric infrastructure support the overarching CES objectives?

A. In addition to meeting locational load relief and reliability needs, the deployment of NWS can contribute to (i) reducing GHG and other emissions; (ii) enabling customers to leverage DERs to better manage their energy use; and (iii) providing valuable experience about the integration, implementation, and use of aggregations of DER, including use of advanced technologies, such as batteries and building management systems capable of delivering peak load reductions.

Q. Could you briefly describe what an NWS is and the benefits it provides?

A. An NWS is a cost-effective portfolio of non-traditional, typically customer-side solutions, that enable the elimination or deferral of a traditional asset that would be required to meet a reliability need. The Company implements NWS in an identified area of locational need where the NWS portfolio serves as an alternative to a traditional infrastructure solution. We develop NWS portfolios that are generally comprised of a variety of DER solutions that collectively satisfy the Company's ability to meet the customers' electric need in that area. In addition to deferring or eliminating the traditional solution, benefits can include decreased energy and capacity costs from the wholesale market, reductions in GHG emissions, marginal cost reductions to upstream transmission and distribution equipment as well as others described in the Benefit Cost Analysis Handbook ("BCAH").[18]

Q. Is the Company implementing NWS projects?

A. Yes. Con Edison remains committed to identifying and implementing cost-effective NWS projects. To date, in addition to the 41 MW of customer-sited solutions originally sought under the BQDM program, the Company is pursuing two new NWS projects representing 34 MW of required load relief, and is continually evaluating all suitable traditional projects for additional NWS opportunities.

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[18] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Con Edison Benefit Cost Analysis Handbook, issued July 31, 2018.

Q. Are there any NWS projects planned during the three rate years?

A. Yes. We have two NWS projects that the Company plans to implement to defer or eliminate traditional projects that would have been built within the rate plan years.

Q. Please briefly describe the BQDM program and its successes to date.

A. On December 12, 2014, the Commission issued its Order approving the Company's BQDM Program. Con Edison designed the BQDM Program to address a forecasted overload condition of the electric sub-transmission feeders serving the Brownsville No. 1 and 2 substations with a combination of traditional utility-side and non-traditional customer and utility side solutions.

Since then, the Company has been implementing the BQDM Program and achieving demand reductions while remaining under budget. The Company has achieved over 50 MW of peak hour non-traditional utility side and customer-side solutions.

We have achieved a majority of this load relief through installation of efficiency and DM measures at more than 6,900 small businesses, 1,770 multi-family buildings, 24,000 one-to-four family residences, and various commercial properties in the community.

Q. Is the Company proposing to alter cost recovery for BQDM?

A. No. The Company proposes to continue the existing BQDM cost recovery mechanism, which provides for recovery over ten years and a reconciliation subject to an overall program cap. BQDM implementation has been successful and the Company anticipates that the total cost of BQDM measures will be under the cap. As a result, the amount of requested BQDM recovery has decreased in this rate filings.

Q. Turning back to NWS, how does the Company identify NWS opportunities?

A. The Company performs the following as part of the distribution planning and NWS identification process:

i. The Company reviews load forecasts at least annually to identify areas on the electrical system with forecasted overloads where there is a projected need for load relief to maintain reliability.

ii. The Company performs an engineering analysis to identify and evaluate the traditional utility infrastructure solution.

iii. Separately, if the Company considers the need to be a suitable candidate for an NWS, the Company conducts a competitive solicitation for non-traditional solutions to determine if an NWS is feasible.

iv. If an NWS appears feasible for meeting the load relief need, the Company analyzes solicitation responses to determine if there is potential for a cost-beneficial NWS.

v. If the Company identifies a feasible, cost-beneficial NWS, it implements the portfolio and defers or eliminates the need for the traditional solution.

Q. How does the Company evaluate whether an NWS portfolio is cost-effective?

A. The Company evaluates an NWS portfolio using the Societal Cost Test ("SCT") defined in the BCAH. When the Company has reasonable certainty regarding NWS portfolio costs, it makes a BCA filing in accordance with its BCAH.

Q. Once cost-effectiveness of the portfolio is established, when does the Company begin implementation of an NWS?

A. The Company begins implementation after it has reasonable certainty that the portfolio passes the BCAH SCT. As the project progresses, the Company also updates implementation plans if a material increase or decrease of the amount of load-relief is warranted, or if there is a change in the length of the deferral period. As discussed below, the Company does not need Commission approval to implement a specific NWS project.

Q. How does the Company determine an NWS term?

A. The Company defines the beginning of an NWS to be the time when the Company has identified a viable cost-effective portfolio with reasonable certainty. The

Company defines the end of an NWS as the time when it has achieved the deferral or elimination of the traditional project that the original NWS portfolio had sought. If the Company determines that there are additional deferral opportunities for the same, or a new, reliability need in the same area where a prior NWS has ended, the Company will seek to develop a new NWS to enable that deferral.

Q. How does the Company classify an NWS as either a deferral or elimination of traditional infrastructure?

A. The Company classifies an NWS to be a deferral, and not elimination, if the traditional solution is still needed within the Company's 20-year plan. For those NWS that we forecast to defer the traditional infrastructure need beyond the Company's 20-year plan, the Company will use its best engineering judgment and, in consultation with Staff, either classify it as a deferral or elimination. If such an NWS is classified as a deferral, the Company will consider the traditional asset to be deferred to the 21st year, the first year beyond the Company's 20-year plan. Further, in the specific instance when a traditional project is needed for a certain number of years, i.e., the traditional project temporarily serves a reliability need and functions as a bridge to another traditional project further into the future, the Company will classify an NWS as elimination when that NWS enables the entire elimination of the need for the temporarily needed traditional project.

Q. Has the Company identified any NWS opportunities to implement in the near term that could potentially defer or eliminate otherwise necessary capital expenditures for traditional electric infrastructure?

A. Yes. The Company had identified two potential NWS opportunities that it had begun implementing as outlined in the table below. We will pursue the Water and Plymouth Street projects as one project as the load relief needs at both stations are required to eliminate common work at the supply station. As such, the portfolio will be pursued as one 32 MW portfolio. The Company has made the appropriate filings for these NWS and has moved ahead with them in accordance with the terms of its current rate plan.

Q. How is the Company proposing to recover the costs of these projects?

A. The Company is planning to recover the carrying costs for these projects in base rates. The Company has not included the capital costs of the traditional projects in this rate filing because the Company is planning to pursue these NWS projects as an alternative to these projects.

Q. Has the Company included the costs of these NWS projects in this rate filing?

A. No. The Company will include the costs of these projects in its preliminary update, after it has more certainty of the amount and timing of the payments for customer-side solutions. We are currently evaluating the RFP responses for development of a viable NWS portfolio this project. If, however, the Company determines that any of these NWS projects are not feasible, then the Company will include the cost of the traditional project in its preliminary update. Further, if the Company determines it is unable to fully implement the NWS during the rate plan period and instead needs to implement the traditional project, the Company proposes to adjust the electric net plant reconciliation, as discussed in the Accounting Panel testimony.

Q. Is the Company seeking approval for the costs of these NWS in this rate filing?

A. No. Under the Commission's NWS framework as approved in the Targeted Demand Side Management Order on December 17, 2015 in Case 15-E-0229, and as incorporated into the Company's current rate plan, the Commission does not approve individual NWS portfolios.

Q. Please provide a brief description of the Water Street and Plymouth Street NWS project.

A. The Water Street Substation, located in Brooklyn, supplies power to the Williamsburg and Prospect Park networks. The Plymouth Street Substation, located in Brooklyn, supplies power to the Borough Hall network. Per the Company's analysis, the substations will need a total of up to approximately 43 MW and 30 MW of load relief respectively, over the next 10 years.

To alleviate the projected deficiency using traditional infrastructure enhancements, a combination of two necessary traditional solutions were identified. The first traditional project would require installing cooling systems on the transformers at both substations as well their supply station, Farragut Substation. The second project would be to upgrade the supply feeders from Farragut to Plymouth. Since the constraint at the Farragut Substation would require load relief at both Water and Plymouth Substations, the Company will pursue these projects as one portfolio.

When the need for load relief was identified in 2016, the planned traditional projects described above were the best solution available that could be implemented within the required timeline. However, a more robust solution that will eliminate the constraint beyond the 20-year planning horizon, the Hudson Avenue Distribution Switching Station ("HADSS") was subsequently identified.

Q. Please describe that solution.

A. The traditional project comprises two new 138/27 kV transformers supplied by regulated 138 kV tie feeders from the Hudson Avenue East transmission station. The HADSS cannot be built in time to address the need in 2019, with the earliest in-service date possible by the summer of 2022. With a three-year NWS deferring the need for upgrades until 2022, the new plan is to eliminate the cooling and feeder upgrade projects entirely with a 32 MW portfolio, giving time to design and build the HADSS. The Company has currently developed a cost-effective portfolio of solutions to provide at least 32 MW of load relief that would defer the need for traditional upgrades from 2019 through 2021.

A white paper describing the HADSS is provided as Exhibit __ (EIOP-4) and will be evaluated for additional deferral with a separate NWS.

Q. Please provide a brief description of the Company's other potential NWS opportunities.

A. Additional details about other NWS projects Con Edison may pursue, if viable portfolios can be developed following market solicitations, are available in the most recent quarterly report filed by the Company in Case 16-E-0060. White papers for the traditional projects that these NWS would displace, can be found in Exhibit __ (EIOP-4). They include the following:

Table 6 – Other Potential NWS Opportunities

Project	Project Type	Required Load Relief (MW)	NWS Need-by-Date
W42 St. Load Transfer	Large	TBD	TBD
Newtown	Large	TBD	TBD
Hudson Avenue Distribution Switching Station	Large	TBD	TBD

Q. What is the Company's plan for implementing future NWS projects?

A. The Company is seeking to continue the current NWS framework into this rate period. The Company intends to continue the current practice of developing NWS implementation plans on an annual basis or more frequently when new NWS opportunities are determined to be viable. The Company will also develop and file BCAs as viable NWS are identified and continue to provide reports on a quarterly basis for NWS that are being implemented. As discussed in the Accounting Panel, the Company is proposing to continue the cost recovery mechanism approved for the current rate plan for these kinds of NWS.

Q. Does the Company propose to add any personnel to support current and potential future NWS projects?

A. Yes, two incremental employees to support all aspects of the DM programs such as NWS. Additionally, the Department is currently charging four of the FTEs working on Targeted DM to the BQDM Program and is moving them into O&M in order to uniformly categorize all labor expenses.

Q. How does the Company propose to recover the costs of additional NWS opportunities that it identifies?

A. The Company proposes to continue the current rate plan provision for the recovery of such costs. That provision has proven effective to date and should be continued as is.

New CSS Implementation

Q. Please explain the background of the Company's proposal to replace its current CSS.

A. The Company, Staff, and rate case parties discussed a new CSS system in the last two rate cases, Cases 13-E-0030 and 16-E-0060. In addition, the current Commission-approved rate plan requires the Company to begin to replace the system. Specifically, the Commission approved the rate plan's recommendation that "the Company will begin to implement its plan to replace its current" CSS in 2019.

Since then, the Company has been working towards implementing a new CSS system by 2023, through a process that to date has included pre-implementation planning. Con Edison is conducting these pre-implementation planning activities jointly with its regulated affiliate, O&R. This work aligns with NorthStar's 2016 Management Audit recommendation to explore the potential synergies, cost savings, and operational and customer benefits of jointly developing a new CSS. The O&R portion of CSS was addressed in the recent O&R electric and gas proposal. That Joint Proposal provides that the replacement of the O&R legacy CSS in conjunction with Con Edison has an estimated cost of $34 million, compared to an estimated cost of $66 million to complete the replacement project independent of Con Edison.

The result of this effort will consolidate the respective system environments of the Con Edison legacy CSS, O&R's legacy Customer Information Management System, as well as the Con Edison Oracle Customer Care and Billing ("CC&B") environment for complex electric billing, onto a single CSS platform.

Q. How does the new CSS implementation support State policy goals and Con Edison's objectives?

A. The new CSS will enhance our customers' experience and optimize our systems to better integrate DER by serving as a scalable and flexible IT platform and billing system of record that, in combination with AMI, will provide a foundation for billing alternatives designed to meet the needs of our customers. As customers choose to adopt DER or elect to participate in other EE programs, this system will enable billing for those options.

In addition, the new CSS will provide critical support for facilitating public policy objectives. While the Companies have previously made significant customizations to their legacy billing systems (e.g., Oracle CC&B off-system billing) to support State policies, such as Community Net Metering, Recharge New York, Mandatory Hourly Pricing, Reactive Power, and low-income program changes, the new CSS will make such changes easier and quicker.

Q. Has the Company developed a business plan for replacing CSS?

A. Yes, CECONY is including its CSS Business Plan as Exhibit __ (CES-5).

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-5)

Q. Was the exhibit titled "Customer Service System Business Plan" prepared under the Panel's direction and supervision?

A. Yes, it was.

Q. Does the CSS Business Plan provide an explanation of the Company's process for implementing a new CSS?

A. Yes. The CSS Business Plan explains Company's process for determining that a system was necessary, the new system's needs, which system the Company chose, the implementation plan for the new system and a cost benefit analysis for the new CSS.

Q. What are the expected benefits of the new CSS system?

A. As explained in the CSS Business Plan, the replacement of key business and billing processes with the proposed CSS solution is cost effective and will provide significant customer benefits. These benefits include enabling CECONY to implement new customer programs, creating new rate options, and providing customers with an improved, customer-centric service experience. The financial and non-financial benefits are further explained in the CSS Business Plan, Exhibit __ (CES-5).

Q. Are there non-financial customer benefits?

A. Yes. As explained in more detail in the CSS Business Plan, a new CSS will directly benefit our customers as it will lead to the development of enabling tools and services that can help them better understand and manage their energy usage, costs, and needs.

Q. Please describe non-financial customer benefits associated with the technology innovations in customer service and their relevance to CSS.

A. The new CSS will play an important enabling role in providing the necessary data to analyze customer energy profiles to provide targeted DER and EE offerings to customers.

Q. Did the Company prepare a formal Cost Benefit Analysis to support the new CSS project?

A. Yes. Con Edison completed a comprehensive assessment of the costs and benefits associated with a new CSS. The current cost/benefit analysis is included in Exhibit __ (CES-5) and incorporates a range of benefits to our customers.

In addition to the benefits discussed above and detailed in the business plan, the Companies forecast a total project cost of $505 million as shown in the Table 7 below.

Table 7 – CSS Cost Allocation

Cost allocation	O&R	CECONY	Total Cost ($M)
Capital	$34	$421	$455
O&M	$4	$46	$50
Total	**$38**	**$467**	**$505**

Key factors that are embedded into the CSS cost estimate include an assessment of the current state business processes, integration and technical architectures, labor resources, non-labor costs, such as hardware and software, and indirect costs.

The capital and O&M determination for the labor costs were driven by an analysis of the activities that would be performed by resource type and role, for each phase of the project, to determine whether the effort for that phase should be capitalized or expensed. Similarly, for the non-labor costs, the capital and O&M determination followed Plant Accounting rules and Generally Accepted Accounting Principles.

The CSS Business Plan provides further information on how the Company developed this cost estimate.

Q. What is the Company’s capital funding request for its CSS project during the rate period?

A. The table below shows the projected expenditures for Con Edison during the rate period.

Table 8 – Projected CSS Expenditures (2020-2022)

Three year summary (millions)				
Year	**2020**	**2021**	**2022**	**Total**
Capital	130	100	119	349
O&M	7	6	10	23

The Company expended approximately $12 million in 2018 and expects to expend $16 million in 2019 in capital.

Q. Please describe the Company's estimated operating expenses for the new CSS.

A. The following table provides information on the expected O&M work associated with the new CSS.

Table 9 – Expected O&M work for CSS

O&M Category	**O&M Description**
Labor	IT and Customer Operations support • Includes O&M labor associated with maintaining the CSS system • Temporary employees to assist in call center operations post go-live
Change Management	Implementation O&M: This includes costs for training development, training delivery, and communications, to design and develop training materials and methodology to prepare the organizations for the transition to the new CSS
Facilities	Facilities rental, maintenance and tax charges for project working space and associated communal areas

The CSS Business Plan describes the total O&M expenditure of approximately $23 million over the rate period.

Advanced Metering Infrastructure

Q. Please describe the components of AMI.

A. AMI consists of three major components: (i) smart meters and associated gas modules (gas modules are installed on gas meters to provide smart meter and communications functionalities), (ii) a communications network that enables two-way communication with the smart meters, and (iii) AMI back office IT systems to integrate with legacy systems and new AMI-related applications.

Q. Please explain the status of the Company's AMI implementation.

A. The Commission approved the Company's AMI program in the AMI Order.[19] The Company is deploying AMI across the service territory. AMI program deployment is on schedule and on budget with deployment expected to be complete in 2022. At a high level, the AMI status is:

- The AMI Operations Control Center ("AOCC"),that monitors both the AMI communications network and the electric and gas endpoints, has been established and operates around the clock.

[19] 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.

- The communications network installation is on schedule to be completed across our service territory prior to mass meter/module deployment.
- A number of the AMI back-office software systems ("AMI Systems") are in service.
- As of year end 2018, the Company has installed nearly 800,000 AMI meters across the service territory.
- The Company has implemented a robust Customer Education Plan dedicated to increasing customer acceptance of AMI, facilitating implementation, and engaging customers to maximize the benefits of AMI.

Q. Has the Company updated the Commission on both the status of AMI implementation and the metrics previously approved for AMI?

A. Yes. The Company filed two metrics reports with the Commission in April and October 2018, including explaining the progress of AMI and updating metrics status for AMI Meter Deployment, Customer Engagement, Billing, Outage Management, and System Operation and Environmental Benefits.

Q. What does AMI do for the Company and customers?

A. AMI enhances our customers' experience by providing them with detailed information about their energy usage and tools that empower them to manage their energy use. AMI eliminates manual meter reading and the need for customers to provide access to read meters. As noted throughout this testimony, AMI enables the Company to better understand and operate the distribution system more efficiently. The visibility into the grid provided by AMI data enables further integration of DER as well as other benefits, including efficient outage management and restoration efforts.

Q. Please explain how AMI has helped in restoration efforts.

A. As an example, during Winter Storms Reilly and Quinn (March 2018), the Company used the AMI system then in place to perform pings and remotely read meters on impacted AMI meters to verify outage status and deploy crews where needed, instead of sending a crew to determine whether an area was impacted by the outage. In fact, since October 2017, the Company has been able to avoid over 800 truck rolls based on information received from AMI.

Q. Are the projected AMI costs in line with the prior forecasts?

A. Yes, the projected AMI costs are in line with prior forecasts.

Q. What are the forecasted AMI expenditures for the rate plan?

A. The AMI Program forecasted expenditures during the rate period are $573 million in capital and $145 million in O&M. Below is a summary of the total project capital expenditures and O&M projected in this rate period:

Table 10 – AMI Capital and O&M (2020-2022)

AMI Requirements ($M)	**2020**	**2021**	**2022**
AMI Project Capital	$322.00	$231.00	$20.00
AMI Project O&M	$46.13	$52.14	$46.18

Q. What is the status of the Customer Engagement activities?

A. The Company has a robust Customer Education Plan that is dedicated to increasing customer acceptance of AMI, facilitating implementation, and engaging customers to maximize the benefits of AMI. Detailed information on the other Customer Engagement activities, including the Company's Innovative Pricing Pilot, are provided below.

Q. Please provide an update on the AMI program's capital investment spending and provide a summary of funds included in this filing.

A. The Company's AMI program continues into this rate plan. Among other related AMI investments, the Company is planning to spend previously approved expenditures of an estimated $573 million between 2020 – 2022, shown in Table 10.

Q. Please describe the O&M costs that will be incurred to complete territory-wide AMI deployment.

A. The AMI Program O&M expenditures are separated into two overarching categories:

- AMI project
- Customer Engagement

We have an exhibit entitled, "Advanced Metering Infrastructure" prepared under the Panel's direction and supervision, which describes these costs in detail.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-6)

Q. Please describe the AMI project expenditures.

A. AMI implementation required that the Company put new metering and computing infrastructure in place. As such, implementation and ongoing maintenance expenses are incurred to maintain the new infrastructure and systems that support AMI. These systems include, among others, Meter Asset Management System, Meter Data Management System, Head End System, Enterprise Data Analytics Platform, and the communications network.

During RY1-RY3, the Company has additional O&M program costs for AMI related infrastructure and systems that include:

- software system maintenance and hosting fees
- communication costs
- personnel to support both the internal AMI Systems and the deployed smart meters

- AOCC O&M costs

Q. Please discuss the customer engagement costs related to AMI.

A. The Company plans to continue its AMI customer engagement activities described in its Customer Engagement Plan filed with the Commission in July 2016 and the subsequent filed status reports. Customer Engagement activities include:

- work related to AMI customer education,
- identifying innovative rate structures that can enhance customer benefits resulting from AMI in a cost-effective manner, and
- evaluating potential third party applications to leverage the AMI network.

Q. Please describe what the Company intends to do for AMI customer education.

A. The Company has a broad education plan before, during and after AMI implementation. The plan includes educating: (1) elected officials, community resources and business leaders and (2) customers about AMI as well as using media channels to advertise AMI.

Prior to AMI deployment in each region, the Company will:

- engage with local elected officials, community resources, and business leaders through email and presentations to provide information about AMI and the benefits of smart meters, and

- advertise in various formats (e.g., social media) to create regional public awareness of the project.

Customer-focused activities will be scheduled prior, during, and post-installation including:

- customer surveys and focus groups
- pre-installation direct mail notifications
- mailers with energy reports and alerts
- door hangers

The Company's website and call center provide other resources to customers with more information, including information for residential customers regarding the option to opt-out of receiving a smart meter. As customer insights are gained, customer messaging and channels will be adjusted to fit customer preferences and needs.

Informational materials, promotional items, and presentations have been developed and will be provided to the community to raise customer awareness and serve as a resource to customers.

Regional energy forums will be used to reach current and potential third-party vendors in areas where smart meter deployment is in progress. Community activities will continue after deployment as a means of continuing to engage our customers.

The Company will continue to provide information on customer engagement activities in its semi-annual AMI Metrics reports.

Q. Does the Company have any new rate pilot programs as a result of AMI?

A. Yes. As a part of the AMI Order, the Commission required the Company to test new and innovative rate structures leveraging the functionality of AMI smart meters, including developing a pilot program to test new rate designs, such as demand-metered delivery rates, hourly supply pricing, peak rebate pricing, or other time and location-sensitive designs. On July 6, 2018, the Company filed a proposed Innovative Pricing Pilot for residential and small commercial customers.[20] The Commission approved the Innovative Pricing Pilot on December 13, 2018,[21] pending compliance filings.

The pilot is in the implementation phase and the Company expects to start enrolling customers to participate in the pilot in 2019.

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[20] Case 18-E-0397 - Tariff filing by Consolidated Edison Company of New York, Inc. to Make Revisions to its Electric Tariff Schedule, P.S.C. No. 10, to Add New Riders Z (Residential) and AA (Small Commercial) Innovative Pricing Pilot to Implement Rate Structures for Residential and Small Commercial Customers, filed July 6, 2018.

[21] Case 18-E-0397 - *Order Approving Tariff Amendments with Modifications*, issued December 13, 2018.

In the rate years, the Company intends to implement other pricing pilots, such as the Company's Smart Home Rate REV Demonstration Project.

Q. What are the expected AMI O&M expenditures for both AMI project and customer engagement activities?

A. Total O&M costs anticipated to support the AMI Program and Customer Engagement activities are estimated to be $145 million from 2020 – 2022. The table below summarizes the O&M costs, and additional details for the O&M costs can be found in Exhibit __ (CES-6).

Table 11 - AMI Program O&M Costs (2020-2022)

AMI O&M Requirements	**$M**	**Request**	**Request**	**Request**
Year	**$M**	**2020**	**2021**	**2022**
AMI Project O&M	AMI Project O&M	$36.13	$42.14	$41.18
Customer Engagement	Customer Education	$5.80	$5.50	$2.70
Customer Engagement	Rate Pilots	$3.00	$3.30	$1.40
Customer Engagement	New Revenue Opportunities	$1.20	$1.20	$1.20
Total Costs	Total Costs	$46.13	$52.14	$46.48
Incremental Costs	From Test Year $18.53	$27.60	$6.01	$(5.66)

Q. Is there a reconciliation mechanism associated with the AMI Customer Engagement efforts under the current rate plan?

A. Yes. We reconcile actual customer engagement costs to the level allowed in rates over the three year term of the rate plan.

Q. Does the Company intend to continue this reconciliation?

A. Yes. The customer engagement effort is still underway and it is appropriate to continue this mechanism.

Q. Are there O&M expenditure savings discussed in other testimonies associated with the AMI Program?

A. Yes. The Company anticipates O&M cost reductions in both Customer Operations and Electric Operations. These savings are discussed in Customer Operations and EIOP testimonies and in the Exhibits titled O&M White Paper - AMI Customer Operations, Exhibit __ (CO-11) and O&M White Paper – AMI Electric Operations, Exhibit __ (EIOP-07).

Con Edison's Innovation Initiative

Q. Please describe the Company's Innovation Initiative.

A. The Company is establishing a corporate-wide Innovation Initiative to strengthen our existing capability to identify and facilitate the development of transformative innovation projects. The initiative complements and builds upon the Company's existing innovation efforts, REV Demonstration Projects and Research and Development ("R&D"). Under this initiative, the Company will develop and scale innovative ideas that are technically mature enough to not require further R&D investigation but whose path to customer and commercial success remains uncertain. We are requesting funding to establish an innovation center of excellence ("Innovation Hub") with associated O&M ("Innovation Common Fund").

Q. How will this work?

A. A small team of Innovation Hub employees will lead the effort to identify innovative ideas with the potential for growth, and provide support and oversight of the initiatives targeted. Innovative ideas that will need assistance from the Innovation Hub are those which require cross-departmental collaboration, do not have a natural "home" in any single Con Edison department, and whose outcome are uncertain. The Innovation Common Fund is the funding mechanism to provide resources for "owners" of these initiatives, subject matter experts and any required third-party support teams (e.g., IT, contract services), and to facilitate the development and testing of the ideas prior to scaling.

Q. Please explain why these types of projects may be different from other innovative projects that may be funded through R&D or by Demonstration Projects.

A. Con Edison's R&D team tests novel technological solutions in early-stage research and product development, with a focus on technology that has the potential to provide core operational and safety value. The results of R&D

projects are typically prototypes that do not go into commercial, productive use, but rather provide the underlying specifications for purchase orders of new equipment to be built by third-party manufacturers for procurement by various Company operating departments. REV Demonstration Projects test new technologies and innovative business models which meet the approved regulatory definition.

Q. Please provide more detail concerning Innovation Hub projects.

A. The Innovation Hub will evaluate projects that either: (1) have successfully completed an R&D effort and show potential for wider business model development and customer-focused innovation but do not warrant development into a Demonstration Project, or (2) do not have a natural home in any single business operating group. In addition, the Innovation Hub will look for ideas and applications of existing products coming from non-R&D sources that do not require further investigation from R&D. Finally, the Innovation Hub provides initiatives with the support and resources required to maximize the chances of the product creating the necessary customer and business value.

Q. Is there a document that further explains the Innovation Initiative?

A. Yes. There is a white paper entitled "Innovation Initiative."

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-7)

Q. Was this exhibit prepared under the Panel's direction and supervision?

A. Yes.

Q. Are you requesting funding for the Innovation Initiative?

A. Yes. The Innovation Initiative program will require O&M funding to institute the elements described above for RY1 through RY3. In total, the Company estimates that the expenses for this initiative will be $2.3 million in RY1 1, $2.5 million in RY2 and $3.5 million in RY3.

Demonstration Projects

Q. Please describe how the Company's Demonstration Projects are playing an important role in allowing the Company to test new technologies, prove conceptual business models, and inform DSP development.

A. Demonstration Projects adapt and explore innovative business models. These projects are a key means of advancing State policy goals including increased DER penetration, reduction of GHG emissions, increased EE, and enhanced customer engagement. Demonstration Projects allow the Company to test new business models that will help pave the way for a customer-centric, DER-enabled future.

Q. What is the Company authorized to spend on REV Demonstration Projects and what has it spent to date?

A. The REV Track One Order authorized the Company to spend an amount to "not exceed 0.5 percent of its delivery service revenue requirement."[22] Con Edison's total authorized amount was $135 million. As of December 31, 2018, the Company has spent $31.0 million and plans to spend an additional $43.8 million during 2019.

Q. What is the forecasted expenditure for Demonstration Projects through the rate period?

A. The Company projects to spend $34.6 million during the upcoming three year period on the existing and planned Demonstration Projects. These costs are currently expected to be $20.3 million, $9.4 million, and $4.9 million for 2020, 2021, and 2022, respectively. Though not developed at this time, if the Company plans new or expanded Demonstration projects, the Company would address the need for additional funding under the provisions included in the REV Track One Order (pp. 116-117).

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[22] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Adopting a Regulatory Policy Framework and Implementation Plan*, issued February 26, 2015.

Q. Does the Company currently have a reconciliation mechanism for the REV Demonstration costs?

A. Yes. The Company will continue to defer annually the revenue requirement associated with program expenditures above or below the expected expenditures noted above. Given the nature of these projects and expenditures, the Company believes the existing reconciliation mechanism should continue.

Earnings Adjustment Mechanisms

Q. Please describe the background for the Panel's EAM proposal in this proceeding.

A. We developed the Company's EAMs proposal to align with the Commission's *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework* in Case 14-M-0101, and the State's clean and distributed energy resource policy goals. The Company developed this proposed set of EAMs in advance of the December 2018 Commission NE:NY and energy storage orders, discussed earlier.

Q. Based on the EE Order and the Storage Order, will there be any proposals regarding EAMs in the preliminary update?

A. We do not plan to make changes to the EAMS proposed here but in its preliminary update, the Company may propose the two new earnings mechanisms discussed in those orders:

- a cost-reduction shared savings mechanism based on lifetime Btu achievement under the NE:NY Order
- an EAM as provided for in the Storage Order.

In addition to the cost-reduction-based shared savings incentive mechanism for lifetime Btu savings, the Company, however, plans to allocate some basis points from the EAMs it proposed in this testimony to any EAM developed as a result of the Storage Order that may be proposed in the preliminary update.

Q. Is the Panel sponsoring any EAM exhibits?

A. Yes. This Panel is sponsoring two exhibits that were prepared by or under the supervision of the Panel:

1. Exhibit __ (CES-8), entitled "EAM Formulas and Target Sources" which contains the formulas and input assumptions; and
2. Exhibit __ (CES-9), entitled "EAM Targets" which contains our calculation of the annual EAM baselines and targets.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-8) AND EXHIBIT __ (CES-9)

Q. Please describe the EAMs that exist under the Company's current rate plan and how the Company has performed to date.

A. The Company's current rate plan consists of seven electric EAMs:

- Electric EE
- System Peak Reduction
- DER Utilization
- Energy Intensity Reduction
- GHG Emissions Reduction
- AMI Customer Awareness
- Interconnection

In 2017, the Company achieved the maximum EAM for Electric EE and System Peak Reduction, and did not achieve the minimum levels for the DER Utilization, Energy Intensity, and Interconnection EAMs. Also in 2017, the Company did not yet have sufficient AMI deployment to consider AMI Customer Awareness EAM achievement, and the GHG Emissions Reduction EAM is new for 2019.

Q. Are the results available for the Company's 2018 EAM performance?

A. Not yet. The Company will report on its 2018 EAM achievements in March 2019 except that it will report on the AMI customer awareness EAM in April 2019 as part of the Company's semi-annual AMI Metrics Report.

Q. Please describe how the current EAMs and the Company's performance under those EAMs have informed the Company's proposal in this rate filing.

A. Overall, the Company supports continuing the EAM construct, as it has demonstrated to be successful as an appropriate mechanism to spur utility action and drive achievement of outcomes in alignment with State policy. The Company's current EAMs and the Company's performance under those EAMs have informed the proposal in this rate filing as follows:

- As reflected in the Company's 2017 results, the EE and System Peak Reduction EAMs are well-designed, straightforward metrics under which the Company's actions and influence are appropriately linked to EAM achievement.
- The DER Utilization, GHG Emissions Reduction, and AMI Customer Awareness EAMs tie key State environmental and customer engagement outcomes with a reasonable level of Company influence toward EAM achievement.
- The Energy Intensity EAM is not designed to allow market participants and the Company to meaningfully influence the desired outcome and we do not propose to continue it.
- The intent of the Interconnection EAM may be better achieved through different means, and now DPS Staff

has recommended that the Interconnection EAM be eliminated.[23] (We are not proposing to continue the Company's existing Interconnection EAM in this rate filing and instead urge that bases points identified thereunder be allocated to other EAMs as proposed below).

Q. Please describe how you developed the Company's EAM proposal.

A. The Company's proposed EAMs build on progress to date under the Company's 2017-2019 EAMs structure and on the experience the Company has gained from engagement with stakeholders through collaboratives for both electric and gas.

The Company's proposed EAMs appropriately balance multiple objectives important to the State and stakeholders:

- supporting advancement of important State and municipal policy objectives, such as (i) growth of EE and DERs, including beneficial electrification technologies, such as heat pumps, and advanced technologies, including storage, (ii) lowering system

[23] Case 14-M-0429, In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision, Interconnection Earnings Adjustment Mechanisms Staff Proposal, issued October 24, 2018, p.6.

peak to achieve State-wide delivery system efficiencies, and (iii) reducing GHG emissions,

- driving utility behavior with measurable outcomes by appropriately accounting for the Company's ability to both facilitate positive outcomes as well as directly influence these outcomes through the Company's portfolio of programs, and
- signaling to utilities and their third-party vendors the State's intent to drive real and measurable change annually and over the longer-term.

Q. Please summarize the Company's proposed EAMs.

A. The Company proposes to implement the following Electric EAMs:

- The Electric Energy Efficiency EAM ("E3 EAM") measures the energy savings achieved through increased efficiency of electricity use by our customers. The Company proposes the E3 EAM to be based on the total incremental, annual MWh reductions achieved through the Company's electric EE programs.
- The Electric Peak Reduction EAM ("EPR EAM") measures customers' reduction of system peak period electricity usage through both adoption of EE as well as DER, such as battery storage and clean cooling solutions.

- The DER Utilization EAM ("DER EAM") measures the amount of incremental, annual MWh the Company's customers do not need to rely on the grid for, through generating locally or through reductions by participation in the Company's DR programs.
- The Electric GHG Emissions Reduction EAM ("EGHG EAM") measures the amount of incremental lifetime GHG emissions reductions resulting from increasing adoption of beneficial electrification technologies, based on the technologies in the Company's existing GHG Emissions Reduction EAM.

The Company proposes to implement the following Gas EAMs:

- The Gas Energy Efficiency EAM ("GE2 EAM") measures the incremental annual energy savings achieved through increased efficiency or avoidance of natural gas use by our customers. The Company proposes to base the GE2 EAM on the total Dth reduction achieved by the Company and its customers through its portfolio of EE and four Smart Solutions programs.
- The Gas Peak Reduction EAM ("GPR EAM") measures customers' reduction of peak day gas usage. The Company proposes to base the GPR EAM on incremental, annual peak day gas usage reduction or avoidance by

our gas customers achieved through the Company's programs.

- The Natural Gas GHG Emissions Reduction EAM ("GGHG EAM") measures the amount of incremental lifetime GHG emissions reductions resulting from increasing adoption of technologies that reduce, replace, or avoid technologies that use natural gas, based on some of the technologies in the Company's existing GHG Emissions Reduction EAM.

The Company is not proposing any changes to the existing authorized AMI Customer Awareness EAM that measures customer awareness of AMI technology, features, and benefits.

Q. Please describe the Company's overall proposal regarding EAM earnings opportunities.

A. The Company proposes positive earnings adjustments, calculated as return on equity basis points, for each of the EAMs. Our proposed EAM earnings opportunities are at 100 basis points annually for the electric business. We also propose 70 basis points annually for the gas business. The allocation of these earnings opportunities is shown in Tables 12 and 13 below. As shown, the EAMs would be effective for RY1 through RY3.

Table 12 - Electric EAM Basis Points

		2020	2021	2022
Electric Energy Efficiency (E3 EAM)	Min	7.0	7.0	7.0
	Mid	21.0	21.0	21.0
	Max	35.0	35.0	35.0
Electric Peak Reduction (EPR EAM)	Min	5.0	5.0	5.0
	Mid	15.0	15.0	15.0
	Max	25.0	25.0	25.0
DER Utilization (DER EAM)	Min	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
Electric Greenhouse Gas Emissions Reduction (EGHG EAM)	Min	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
TOTALS	Min	20.0	20.0	20.0
	Mid	60.0	60.0	60.0
	Max	100.0	100.0	100.0

Table 13: Natural Gas EAM Basis Points

		2020	2021	2022
Natural Gas Energy Efficiency (GE2 EAM)	Min	7.0	7.0	7.0
	Mid	21.0	21.0	21.0
	Max	35.0	35.0	35.0
Natural Gas Peak Reduction (GPR EAM)	Min	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
Natural Gas Greenhouse Gas Emissions Reduction (GGHG EAM)	Min	3.0	3.0	3.0
	Mid	9.0	9.0	9.0
	Max	15.0	15.0	15.0
TOTALS	Min	14.0	14.0	14.0
	Mid	42.0	42.0	42.0
	Max	70.0	70.0	70.0

Q. What EAM targets is the Company proposing in this testimony?

- The Company proposes that the mid-point targets for E3 EAM, EPR EAM, GE2 EAM, and GPR EAM be equal to or directly derived from the Company's proposed targets, or updated targets following any changes made by the Company in its preliminary update as noted earlier in this testimony for its EE programs and consistent with the Company's existing electric EAMs in the 2017-2019 rate period. The Company is proposing a minimum level at 75 percent of the mid-point target and a maximum level at 125 percent of the mid-point target for these four EAMs.

- For the DER EAM, EGHG EAM, and GGHG EAM, the Company proposes to file in its preliminary update baseline levels for 2020 that are to be derived from the formulas and forecast sources in Exhibit ___ (CES-8), and that the minimum targets be set at the baseline level, mid-point targets be set 10 percent above the baseline, and the maximum targets be set at 20 percent above the baseline. We also propose to file baseline, mid-point, and maximum target levels for these three EAMs annually by August 31, 2020 and August 31, 2021 for RY2 and RY3, respectively.

Q. Please continue.

A. The EAMs as described above would provide the Company with a meaningful incentive to undertake additional efforts to drive achievement consistent with State policy objectives that will also benefit our customers and stakeholders.

Q. Please describe how the Company will measure the E3 EAM.

A. The Company will measure the E3 EAM by calculating EE savings from the Company's EE programs.

Q. How would the Company calculate the midpoint target for this EAM?

A. The Company will use the EE targets developed in this rate proceeding as the mid-point target for this EAM.

Q. Please describe how the Company will measure the EPR EAM.

A. The Company will measure the EPR EAM through electric peak-coincident MW reductions at the customer level from EE technologies included in the Company's portfolio of programs and beneficial electrification technologies. The Company's EE programs' contribution to peak demand reduction will be calculated using the NYISO coincident system peak for each EE measure from the New York TRM and engineering analyses where the TRM does not provide peak coincidence values.

Q. How will the Company calculate the midpoint target for this EAM?

A. The Company will calculate the midpoint target for this EAM by calculating the expected peak coincidence of the Company's portfolio of EE and beneficial electrification programs authorized in this proceeding.

Q. Please describe how the Company will measure the proposed DER EAM.

A. For the DER EAM, the Company will track installations and calculate annualized MWh from air- and ground-source heat pumps, battery storage, battery and plugin hybrid light-duty EVs, Combined Heat and Power ("CHP"), electric DR, fuel cells, electric buses, ice energy storage, solar PV, and distributed wind energy. This tracking and measurement methodology will build on the Company's tracking methods for its 2019 DER Utilization EAM. We will measure DERs in terms of their rated capacity and related capacity factors, except for DR for which we will use the number of DR events and actual performance. To standardize across technologies, all measurements will be in annualized MWh using the formulae described in Exhibit ___(CES-8). For each DER type, Con Edison will determine MWh produced, consumed, discharged, or reduced from incremental resources. MWh are treated as positive values with the sum of produced, consumed, and reduced (in the case of DR and heat pump efficiency), energy determining achievement against a target; that is, one MWh produced is equivalent to one MWh consumed (or one MWh reduced in the case of DR and heat pump efficiency) for the purpose of the DER EAM.

Q. How will the Company calculate the baseline for this EAM?

A. The Company will calculate the baseline for this EAM as developed through stakeholder consensus in the Company's 2018-19 EAM collaboratives, i.e., by using a combination of (i) the MW of customer projects in the Standardized Interconnection Requirements ("SIR") inventory adjusted for historical cancellation rates, delay rates, and other historical trends by technology; (ii) for technologies not required to enter the SIR process (e.g., EVs, heat pumps, DR, electric buses, and ice energy storage), the Company will forecast expected DER adoption levels that would be reasonably expected to be reached absent Company efforts beyond initiatives identified in this testimony with the sources of forecast and formulas to convert forecasted technologies to annualized MWh identified in Exhibit __ (CES-8).

Q. Please describe how the Company will measure the EGHG EAM.

A. The Company will measure contributions to the EGHG EAM by tracking installations and calculating lifetime metric tons of carbon dioxide equivalent ("CO_2e" includes CO_2, CH_4, N_2O) emissions reduced from the following measures: battery storage, electric buses, electric DR, ice energy storage, medium-duty light-duty battery and plugin hybrid EVs, solar PV, the cooling efficiencies from air- and ground-source heat pumps, distributed wind energy, and voluntary renewable energy certificates ("VRECs"). To standardize measurement across technologies, all measurements will be in lifetime avoided metric tons CO_2e using the formulae described in Exhibit __ (CES-8). Metric tons CO_2e are treated as positive values with the sum of avoided kg CO_2e emissions, converted after initial calculation to metric tons CO_2e emissions, determining achievement. The avoided emissions measurements use electricity emissions factors of Grid kg CO_2e per MWh and/or Peak kg CO_2e per MWh, and other technology-specific factors, to determine lifetime avoided metric tons CO_2e. For the purposes of the EGHG EAM, the Grid kg CO_2e value is the New York City electricity emissions factor from the most recently published New York City GHG Inventory. The Peak kg CO_2e per MWh value is sourced from the Environmental Protection Agency ("EPA") Emissions & Generation Resource Integrated Database ("eGRID") for the Northeast Power Coordinating Council ("NPCC") NYC/Westchester sub region.

Q. How will the Company calculate the baseline for this EAM?

A. The Company will calculate the baseline for this EAM as developed through stakeholder consensus in the Company's 2019 EAM collaborative, i.e., by using a combination of (i) the MW of customer projects in the SIR inventory adjusted for historical cancellation rates, delay rates, and other historical trends by technology; (ii) for technologies not required to enter the SIR process (e.g., EVs, heat pumps, DR, electric buses, and ice energy storage), the Company will forecast expected DER adoption levels that would be reasonably expected to be reached absent Company efforts beyond initiatives identified in the CES panel testimony with the sources of forecast and formulas to convert forecasted technologies to lifetime avoided CO_2e emissions identified in Exhibit __ (CES-8).

Q. What data sources will the Company use for DER, EGHG, and GGHG EAM baseline development?

A. The Company will use the following for DER, EGHG, and GGHG EAM baseline development for: (i) battery storage, CHP, fuel cells, solar PV, and distributed wind energy, the Company will use historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends by technology; (ii) battery and plugin hybrid EVs, the Company will use historical registration trends from the Department of Motor Vehicles; (iii) electric buses, the Company will receive data from the MTA and Westchester County; (iv) ice energy storage, the Company will utilize its own program data and customer project data; (v) air- and ground-source heat pumps, the Company will use its own program data; (vi) DR, the Company will use its own program data; and

(vii) VRECs, the Company will utilize its own program data and the New York Generation Attribute Tracking System.

Q. How are incremental resources defined for the Company's EAMs?

A. For each technology under the DER EAM, EGHG EAM, and GGHG EAM, incremental resources, for the purposes of determining achievement under these EAMs, are defined as all DERs belonging to the respective technology that becomes electrically connected to the Con Edison delivery system during the rate year.

Q. Please describe how the Company will measure the GE2 EAM.

A. The Company will measure contributions to the GE2 EAM by calculating energy savings achieved through increased efficiency or avoidance of natural gas use by our customers. Customers throughout the Company's gas service territory are eligible to participate in the Company's portfolio of gas EE and Smart Solutions programs.

Q. How will the Company calculate the midpoint target for this EAM?

A. The Company will use the EE targets developed in this rate proceeding as the mid-point target for this EAM, while considering any additional EE efforts approved as part of Smart Solutions' NPS portfolio.

Q. Please describe how the Company will measure the GPR EAM.

A. The Company will measure contributions to the GPR EAM by measuring customers' reduction or avoidance of peak day gas usage through both adoption of EE as well as DER installed as part of the programs authorized in this proceeding while also considering Smart Solutions initiatives.

Q. How will the Company calculate the midpoint target for this EAM?

A. The Company will calculate the midpoint target for this EAM through a combination of gas peak day reduction values from its Smart Solutions programs, gas EE program experience, and market research with its most recent gas EE potential study.

Q. Please describe how the Company will measure the GGHG EAM.

A. The Company will measure contributions to the GGHG EAM by tracking installations and calculate lifetime metric tons of CO_2e emissions reduced from air-source and ground-source heat pump heating loads, and heat pump water heaters that replace natural gas. To standardize measurement across technologies, all measurements will be in lifetime avoided metric tons CO_2e using the formulae described in Exhibit __ (CES-8). Metric tons CO_2e are treated as positive values with the sum of avoided kg

CO_2e emissions, converted after initial calculation to metric tons CO_2e emissions, determining achievement. The avoided emissions measurements may use electricity emissions factors of Grid kg CO_2e per MWh and/or Peak kg CO_2e per MWh, and other technology-specific factors, to determine lifetime avoided metric tons CO_2e. For the purposes of the GGHG EAM, the Grid kg CO_2e value is the New York City electricity emissions factor from the most recently published New York City GHG Inventory. The Peak kg CO_2e per MWh value is sourced from the EPA Emissions & eGRID for the NPCC NYC/Westchester sub region.

Q. How will the Company calculate the baseline for this EAM?

A. The Company will calculate the baseline for this EAM consistent with the stakeholder consensus developed through the Company's 2019 EAM collaborative, i.e., through a combination of (i) forecasting expected DER adoption levels that would be reasonably expected to be reached absent Company efforts beyond initiatives identified in the CES panel testimony with (ii) the formulas to convert forecasted technologies to lifetime avoided CO_2e emissions identified in Exhibit __ (CES-8).

Q. Please describe how the AMI EAM is measured.

A. As described in the Company's current rate plan, the Company measures its performance based on pre- and post-deployment surveys of customers in each of the six deployment regions (i.e., Staten Island, Westchester, Brooklyn, Manhattan, the Bronx, and Queens). Specifically, the Company conducts an initial survey three months prior to the deployment of AMI in each region to establish a baseline of customer AMI awareness, and then uses this baseline to establish with DPS Staff a regional post-deployment target for customer AMI awareness. At the end of AMI deployment in each region the Company conducts a post-deployment survey that measures customer AMI awareness using the same questions as the baseline survey. If the results of the post-deployment survey meet or exceed the established target, the Company receives a positive earnings adjustment of $250,000 per region.

Q. With respect to the measurement of AMI awareness, how many regions have established a baseline for AMI awareness?

A. The Company has established pre-deployment baselines for all regions except Queens, as provided in the semi-annual AMI Metrics Report. As of this filing, the Company has also established post-deployment awareness targets with DPS Staff for all of our regions except the Bronx and Queens: Staten Island (75 percent), Westchester (80 percent), Brooklyn (80 percent), and Manhattan (80 percent). The Company expects to finalize a target for the Bronx with Staff in the first quarter of 2019. The Queens pre-deployment survey is scheduled to be conducted in March 2019, after which the Company will agree upon a regional target with DPS Staff.

Q. Will the Company complete deployment in any regions during the current rate plan that would potentially be eligible for earnings adjustments during the proposed rate plan under this EAM?

A. Yes. The Company expects deployment in Westchester to be completed in December 2019. The Company will conduct a post-deployment survey in Westchester in or around January 2020 and expects to report the results in its April 30, 2020 AMI Metrics Report.

Q. Does the Company propose to continue the AMI Customer Awareness EAM for the 2020-2022 period for its remaining regions?

A. Yes. The Company proposes to continue the AMI Customer Awareness EAM for the 2020-2022 period, subject to the same methodology, regional incentive amounts, terms, and conditions as applied in the 2017-2019 rate period. We expect that the EAM will cover the following regions during the potential rate plan period: Bronx, Brooklyn, Manhattan, and Queens.

Q. How does the Company propose to report and collect EAM achievements?

A. The Company proposes to continue to report and collect EAM achievements consistent with the current rate plan provisions.

Q. Does the Company propose any changes to the Tariff?

A. Yes, the Company proposes to update Electric Tariff Leaf 26.1 and 343.1 related to the proposed electric EAMs. The Company also proposes to update Gas Tariff Leaf 183.5 related to the proposed gas EAMs.

Q. Does this conclude the Panel's initial testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
ELECTRIC & GAS

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
ELECTRIC & GAS

INTRODUCTION

Q. Would the members of the Municipal Infrastructure Support Panel please state your names and business addresses?

A. (**Boyle**) Robert Boyle and my address is 1610 Matthews Avenue, Bronx, NY 10462.

(**Kong**) Theresa Kong and my address is 1610 Matthews Avenue, Bronx, NY 10462.

(**Minucci**) John Minucci and my address is 4 Irving Place, New York, NY 10003.

Q. What are your current positions at Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company")?

A. (**Boyle**) I am employed by Con Edison as the Vice President of Construction.

(**Kong**) I am employed by Con Edison as the General Manager in Construction's Public Improvement Department.

(**Minucci**) I am employed by Con Edison as a Construction Manager in Construction's Public Improvement Department.

Q. Please describe your educational backgrounds.

A. (**Boyle**) I graduated from Manhattan College in 1986 with a Bachelor of Science degree in Civil Engineering. I received an MBA in Finance from Manhattan College in 1989.

(**Kong**) I graduated from Steven's Institute of Technology in 2003 with a Bachelor of Engineering Degree in Industrial

Engineering. I graduated from Columbia University in 2013 with a Master’s of Science degree in Construction Management.

(**Minucci**) I graduated from St. John’s University in New York City with a Bachelor’s degree in Accounting in 2001 and a Master’s degree in Accounting in 2002.

Q. Please describe your work experiences.

A. (**Boyle**) I have been employed by Con Edison since 1986 when I joined the Company as a management intern. Since then, I have held various management positions of increasing responsibility, including Section Manager of Contract Administration and Inspection, General Manager of Public Improvement and Engineering, General Manager of Substation Operations Planning, General Manager of Substation and Transmission Construction, General Manager of Steam Distribution, General Manager of Gas Operations. In December 2015, I assumed my present position as the Vice President of Construction.

(**Kong**) I joined Con Edison in 2003 as a management intern in the Company’s Growth Opportunities for Leadership Development (“GOLD”) program. Since then I have held positions of increasing responsibility in Public

Improvement. Starting In 2005, I held the role of Chief Construction Inspector and then Project Specialist in Public Improvement. In 2013, I assumed the role as the Section Manager of Public Improvement Engineering in Regional Engineering ("Public Improvement Engineering") and in 2017 I assumed my present position as General Manager of Public Improvement.

(**Minucci**) I joined Con Edison in 2002 as a management intern in the Company's GOLD program. Since then I have held positions of increasing responsibility all within Public Improvement. Starting in 2004 as an Analyst, Senior Analyst, Chief Construction Inspector, Project Specialist and in 2015 I assumed my present position as Construction Manager in Public Improvement.

Q. Do you belong to any professional organizations?

A. (**Boyle**) I am a member of the American Society of Civil Engineers.

(**Kong**) No.

(**Minucci**) No.

Q. Please generally describe your current responsibilities.

A. (**Boyle**) My current responsibilities as Vice President of Construction are to oversee the installation of electric and gas facilities in the streets and capital improvements to our generating, substation and other facilities. Additionally, I have responsibility to maintain the integrity of our electric, gas and steam systems during municipal construction projects.

(**Kong**) My current responsibilities as General Manager of Public Improvement are to oversee all work in Public Improvement and maintain the integrity of Con Edison's electric, gas and steam systems during the course of municipal construction projects. This requires planning, coordinating, engineering and negotiating with municipalities and their contractors to facilitate the completion of municipal projects.

(**Minucci**) My current responsibilities as Construction Manager of Public Improvement are to oversee the operational support for all municipal projects that impact Con Edison in the service territory. This requires planning, coordinating, operational support and negotiating with contractors to facilitate the administration of projects.

Q. Have you previously testified before the New York State Public Service Commission ("Commission")?

A. (**Boyle**) Yes, I have provided testimony to the Commission in the Company's electric, gas and steam rate filings (03-G-1671, 03-S-1672, 04-E-0572, 16-E-0060, and 16-G-0061) with regards to Municipal Infrastructure programs and steam rate filing 13-S-0032 with regards to Steam Operations.

(Kong) No.

(**Minucci**) No.

Q. What is the purpose of your testimony?

A. Our testimony provides the Company's forecast for interference cost during the rate year, and we also provide forecasts for rate years two and three to provide a basis for settlement negotiations if the parties decide to seek a three-year rate plan settlement. In providing this forecast, we demonstrate the material costs the Company incurs to comply with its obligations to perform interference work. We will describe the nature of interference and the challenges faced in forecasting costs because this work is largely driven by factors outside of the Company's control. Accordingly, while we provide a forecast based on the best available information, because the Company's interference expenditures are significant and largely driven by the infrastructure work performed by the

City, State and other municipalities, the Company proposes a full, bi-lateral reconciliation for these costs. Finally, we will describe how the Company, within the limited ability it has to control interference work, has implemented an array of cost-mitigation measures.

Q. Please summarize the areas your testimony addresses.

A. Our testimony addresses:

(1) The definition and significance of “interference” as it relates to Con Edison’s system;

(2) Interference Forecasting Methodologies;

(3) Projected Operation and Maintenance (“O&M”) interference costs associated with the Company’s electric and gas facilities for the 12 months ending December 31, 2020 (“Rate Year” or “RY1”), and for two additional 12-month periods ending December 31, 2021 and December 31, 2022 (which we will refer to as RY2 and RY3, respectively, for ease of reference);

(4) Projected Capital interference costs associated with the Company’s electric and gas facilities for calendar years 2020 to 2022 (*i.e.*, RY1 through RY3);

(5) Mitigation measures the Company undertakes to reduce its interference costs; and

(6) A proposal for reconciliation of interference capital and O&M expenses.

DEFINITION AND SIGNIFICANCE OF INTERFERENCE

Q. Please explain the term “interference” as it pertains to the Company.

A. Con Edison has an extensive system of gas mains, gas services, electric cables, conduits, structures and poles, in addition to electric services and appurtenances of various sizes and operating voltages, within the streets of its gas and electric service territories, respectively. These service territories include Manhattan, Bronx, Queens, Brooklyn, Staten Island and Westchester County. These facilities share the space under the streets with privately-owned facilities such as telephone and cable TV, and municipal owned facilities such as water, sewer, transit and traffic facilities. In addition, electric overhead facilities share space above the streets with private and municipal facilities such as telephone, cable TV, fire alarm, street lighting and traffic signals. When a municipality plans to perform work, either underground or overhead, and is unable to complete the proposed plan absent our relocating or supporting Company facilities that are “in the way,” the term “interference” is used.

Q. Why is the Company required to perform interference work associated with municipal projects and some state projects?

A. On advice of counsel, it is our understanding that courts have held that Con Edison’s right to lay and maintain its facilities pursuant to a franchise granted by a municipality is subject to the municipality’s right to require Con Edison to remove or relocate its facilities at the Company’s expense whenever public health, safety, or convenience requires. If the Company fails to comply with such a request by the municipality, the Company may be liable for damages caused by its failure. The City of New York has enhanced its right to require utilities to perform interference work by enacting New York City Administrative Code sections 19-143 (Excavations for Public Works), 24-521 (Excavations for Public Works), and 19-150 (Civil Penalties) that, along with court decisions interpreting these franchise provisions, impose financial penalties up to $5,000 on the Company on a per day, per location basis, if the Company does not timely relocate or protect its facilities located at the site of public works projects undertaken for the benefit, health or safety of the residents of the City. New York State also has provisions for public utilities in New York Highway Law Article 52, and Part 131 of NYSDOT Rules and Regulations - NYCRR Title 17 (Accommodation of Utilities within State Highway Right-Of-Way) that specify the facility owners are required to maintain their facilities.

Q. Is there more than one kind of interference?

A. Yes. Interference can be “direct” or “indirect.” A direct interference is that in which 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 that in which 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 by compensating the contactor for utility work performed and any incremental changes to the construction means and methods that may be incurred. This includes, for example, a change to the proposed trench sheeting and shoring system to accommodate Company facilities.

Q. Please describe the cost responsibility for Company interference related to work by or for private entities as distinguished from work performed by or on behalf of municipal entities.

A. If a private developer performs work in the vicinity of the Company’s facilities, and the Company determines that any component of its electric or gas systems needs to be supported, protected, adjusted or relocated to accommodate the work, then the private entity is required to reimburse the Company for costs the Company incurs.

If, however, the City of 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.

There are some exceptions to this general rule. For example, certain governmental authorities, such as the New York City Transit Authority and Port Authority of New York

& New Jersey, may reimburse the Company for interference costs.

Q. Apart from the installation of municipal facilities, are there any other types of governmental activities that affect the Company’s interference expenses?

A. Yes. For example, when a City street is repaved or the pavement around Con Edison’s facilities is modified, the Company may need to raise or lower its structures (*e.g.*, castings of manholes). The costs that the Company incurs to raise or lower these castings or modify these structures are also considered to be an interference expense.

State projects also may have an impact on Company facilities. For example, when a New York State bridge is repaired, replaced or modified and the existing Company infrastructure is required to be supported, relocated or replaced.

Q. What types of municipal construction activities typically result in interference with Company facilities?

A. 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, as mentioned above, the repaving of roadways.

Q. How often does the Company have to support, protect and/or relocate its facilities due to interferences?

A. On any given day, there are hundreds of municipal projects being planned, engineered, or constructed within the Company’s service area. These projects are initiated by various New York City organizations such as the Department of Design and Construction (“DDC”), Department of Transportation (“DOT”), Department of Environmental Protection (“DEP”), Department of Parks, Bureau of Bridges, and the Economic Development Corporation (“EDC”), in addition to various Westchester County municipalities. The projects may be planned or they may be the result of an emergency, such as responding to a water main break. In either case, any resulting municipal activities will typically impact Con Edison facilities located in that area and, therefore, may present interference issues.

Q. Does the Company coordinate with municipalities in order to mitigate interference costs?

A. Yes. The Company coordinates with municipalities to mitigate interference costs both during the design and the construction phases of municipal projects.

Q. Please explain further how the Company coordinates with municipalities.

A. During the municipal design phase, the Public Improvement Engineering section of the Company's Regional Engineering Department works closely with City and municipal agencies to minimize the impact on Company facilities. The Company may request design changes and accommodations that minimize or eliminate Company interferences. For example, if an electric facility is identified to be either in direct or indirect interference with the proposed location of a water main and if a municipal design change is viable, the Company and the municipality would work together to implement an alternate design for the municipal facility. This will reduce or eliminate the interference. The Company would then pay the municipality for the incremental cost of their design changes with the goal of achieving an overall project synergy among all stakeholders and reducing the project's duration and/or cost to the Company.

Similarly, the Public Improvement department continues to work closely with City and municipal agencies during the project construction phase to further minimize any impact on Company facilities. For example, if during construction a gas facility not previously identified is found to be in direct or indirect interference with the proposed municipal plan, the Company and the municipality work together and where viable, the municipality would approve and implement an alternate plan or a field modification to eliminate or mitigate the interference.

Q. Is it possible to avoid or mitigate all interference conditions through City and municipal design changes and construction-phase accommodations?

A. No, it is not. Despite best coordinated efforts, due to the heavy congestion of various underground facilities within the streets, relocating or supporting Company facilities is generally unavoidable.

Q. Is the City the primary municipality that drives the level of the Company’s interference expenditures?

A. Yes. The City’s Capital Infrastructure Improvement Program is the primary driver of the Company’s interference expenditures, both for capital and O&M. Other municipalities in Westchester County and certain New York State projects also results in interference costs, but generally on a smaller scale.

MUNICIPAL INFRASTRUCTURE EXPENDITURES - RESOURCE DATA

Q. Does the City develop a forecast for its infrastructure expenditures?

A. Yes. The City of New York Office of Management and Budget (“OMB”) publishes its four-year Capital Commitment Plan (“Commitment Plan”) three times a year, usually in May, September and February. This plan describes anticipated infrastructure projects to which the City expects to commit funding in the current fiscal year and each of the three upcoming fiscal years for the different categories of reconstruction work. The City’s fiscal year runs from July 1st to June 30th.

Q. Is the Commitment Plan the primary resource document used by the Company to identify City projects for the purpose of forecasting interference expenditures?

A. Yes, the Capital Commitment Plan is the primary resource document because it includes the most current and the best available information relating to the forecasted City expenditures that impact the Company’s interference costs.

Q. Where is the Capital Commitment Plan published?

A. The OMB publishes the report on the official website of the City of New York. The OMB's web address is: https://www1.nyc.gov/site/omb/publications/publications.page

Q. Are there any particular categories of City infrastructure work listed in the Commitment Plan that typically involve interference work?

A. Yes. The categories of City infrastructure work that typically result in interference work are Highways, Highway Bridges, Water Main 1, Water Main 6 and Sewers.

Q. Explain the funding sources for the projects comprising the Commitment Plan.

A. Projects under the Commitment Plan may be funded by the City ("City Cost") or by other sources ("Non-City Cost" or "NC Cost"). The Commitment Plan identifies both City Cost and Non-City Cost funding sources.

Q. Do the projects funded by Non-City sources reduce the Company's interference expenditures?

A. No. The impact is the same for City and Non-City funding sources. The aggregate of the two sources is the driver of the Company's expenditures.

Q. What is the forecasted City OMB Budget for City fiscal years 2020, 2021 and 2022 as it relates to the categories of City infrastructure work described above (*i.e.*, Highways, Highway Bridges, Water Main 1, Water Main 6 and Sewers)?

A. The OMB Capital Commitment Plan published in October 2018 forecasts $2.8 billion for 2020, $3.5 billion for 2021 and $3.6 billion for 2022 for these categories of City infrastructure work.

Q. Does the Company also review the City's actual spending on infrastructure?

A. Yes, the Company reviews the OMB's "Monthly Transaction Analysis" reporting for the infrastructure categories, Highways, Highway Bridges, Sewers & Water Mains, to review and track City and Non-City expenditures.

Q. Was Exhibit ___ (MISP-1), entitled "NYC OMB EXPENDITURES 2014-2018" prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-1) shows actual OMB expenditures for City fiscal years 2014 to 2018 for these interference-type categories, as well as the City’s current commitment forecast for 2019 to 2022.

Q. Why does the Company review the City’s actual expenditures?

A. The Company compares its actual O&M expenditures to the City’s infrastructure expenditures in order to validate the historical correlation between these expenditures. This correlation is discussed in more detail later in our testimony.

Q. Are there other resources of information used by the Company to identify projects other than the City’s Commitment Plan that impact interference costs?

A. Yes, the Company actively communicates with other key municipalities/agencies, such as various Westchester municipalities, NYSDOT, NYCDOT, EDC, NYC Parks Department, DEP and DDC to obtain additional project information and other details that impact the Company’s interference expenditures.

Q. What additional details are provided by these other resources?

A. For example, in Westchester, there are over forty independent municipalities who provide project specific information that the Company uses to develop its forecast for interference expenditures.

Q. Are there particular categories of infrastructure work listed by these resources that typically involve interference work?

A. Yes. Similar to New York City, the categories of infrastructure work that typically involve interference work are highways, highway bridges, parks, water mains, and sewers.

FORECASTING METHODOLOGY

Q. Did the Company modify the methodology used in its last rate filings (Cases 16-E-0060 & 16-G-0061) to forecast interference costs for the Rate Year in this filing?

A. Yes, the Company has expanded upon the existing methodology and incorporated additional analyses.

O&M Forecasting Methodology

Q. Please list the different analyses the Company used to develop its approach for forecasting O&M expenditures relating to municipal interference work.

A. The Company's O&M forecast was calculated using the following four methods of analyses:

1. Project-By-Project Analysis,

2. NYC Budget Calculation,
3. Exponential Growth Analysis, and
4. Regression Analysis.

Q. Please explain the Project-by-Project method.

A. The Company's O&M Project-by-Project forecast is comprised of costs associated with: (1) recurring annual programs ("Annuals"); (2) municipal projects with defined scopes ("Defined"); and (3) design phase municipal projects with undefined locations or scopes ("Design Phase").

Q. Please explain these Project-by-Project categories of expenditures and the different methodologies employed to forecast expenditures in these categories.

A. The first category includes annual programs that consist of recurring work. Examples of these programs are the excavation of test pits to locate facilities and the adjustment or replacement of manhole castings. The forecast of annual programs is based on the prior year's (*i.e.*, 2017) annual cost. This method of forecasting is used for this type of work because these items are fairly predictable and repeat annually.

Q. How is this approach different from the Company's past approach?

A. This approach is different because it uses a single year's costs rather than a three-year average. Due to the progressive cost escalations experienced in recent fiscal years, the use of a three-year average would have set a target lower than the reasonably anticipated costs. The annual programs after RY1 were then escalated three percent annually to account for anticipated year-over-year growth.

Q. Please continue with your description of the second category of Project-by-Project costs.

A. The second category includes projects with defined scopes, which include projects in construction, out for bid or awarded by the municipality. These projects are evaluated based on infrastructure design plans. The Company then develops a project specific scope of work and cost estimate using established unit work items and pricing.

Q. What is the third category of Project-by-Project costs?

A. The third category includes municipal projects in the design phase. The Company's cost estimates for this category of projects are developed taking into consideration a variety of factors and using two separate methods. The first method for developing a cost estimate is for projects with a defined location and undefined scope. For these projects, the Company evaluates the potential impact based on a variety of factors: the type of Company facilities existing within the project area, the location (*i.e.,* borough and specific geographic work area), the type of interferences anticipated (*i.e.*, support, protect, alter), the type of the municipal project (*i.e.*, water mains, sewers, drainage, curbs, sidewalk, roadway) and the cost estimate of the municipal project. These factors are then evaluated based on historical experience to develop the Company's "impact cost estimates" for these types of projects.

The second method is for developing a Company "impact cost estimate" for projects with undefined locations and defined scopes, (*e.g.*, Pedestrian ramp installations, catch basin replacements). For these projects, the Company extrapolates expenditure trends from available completed projects of a similar type.

Q. Please explain the NYC Budget Calculation analysis.

A. Using NYC OMB publications, the Company analyzes the Monthly Transaction Analysis for prior expenditures and the Capital Commitment Plan to identify future forecasts. In short, the Company extracts the categories of Highway,

Highway Bridge, Sewers, Water Mains 1, and Water Mains 6 to identify the correlation between City forecasts and City actual expenditures.

Q. Please explain the Exponential Growth analysis for forecasting.

A. The Exponential Growth analysis forecasts both City liquidations (*i.e.*, actual City expenditures) and Company expenditures. Using NYC OMB Monthly Transaction Analysis reports from prior fiscal years, the Company calculated the ten, seven and five-year growth rates of actual City liquidations. The Company used these growth rates to forecast future City liquidations.

Q. What were the growth rates for the ten, seven and five-year calculations?

A. As shown in the table below, the Company calculated the growth rates as follows:

Year Range	Span of City FY	Growth Rate
10 Year	2008-2018	7.26%
7 Year	2011-2018	7.90%
5 Year	2013-2018	10.27%

Q. What growth rate did the Company use to forecast City expenditures and why?

A. The Company used a seven-year growth rate to forecast City liquidations. The seven-year growth rate was selected because it accounts for both short and long term economic variables.

Q. How did the Company apply the forecasted City expenditures as it relates to Company expenditures?

A. To forecast City expenditures using a seven-year growth rate, the Company took the average of Company expenditures divided by City liquidations over the same seven-year period and applied that factor to the forecasted City liquidations from years 2020 to 2022.

Q. Please explain the Regression Analysis used for forecasting.

A. The Regression Analysis assumes that Company expenditures are dependent on City liquidations. The model runs a regression from forecasted City liquidations which in turn are used to forecast Company expenditures.

Q. How does the Company forecast future City liquidations?

A. The City liquidation forecast for years 2020 to 2022 is based on the analysis as explained in the Exponential Growth Rate method.

Q. Please explain the results of the Regression Analysis?

A. Assuming a perfect correlation between the City and the Company there would be a 1.0 correlation coefficient. A perfect one-to-one relationship would mean that the two variables move in the same direction. In fact, the Company derived a correlation between Company expenditures and City liquidations to be .90.

Q. Did the Company rely on one single analysis to develop its O&M forecast?

A. No. The Company used all four methods described above to develop its forecast, which also reflects aspirational cost mitigating efforts and initiatives, discussed later, that are within the range of the models.

Q. Please show how the results of the various analyses are used to calculate your Rate Year forecast.

A. Exhibit MISP-2 shows the four O&M methodologies and the total O&M forecast for fiscal years 2019 to 2023.

Q. Was Exhibit ___ (MISP-2), entitled “O&M Methodologies” prepared under your supervision?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-2) shows the four O&M methods and the O&M forecast on a line chart to demonstrate the conclusions.

Capital Forecast Methodology

Q. How did you develop the Company’s capital forecast?

A. The Company’s capital forecast is derived from three of the four methods used in the O&M forecast: Project-By-Project, Exponential Growth Analysis and Regression Analysis. The Company developed the cost estimates for the capital projects using the same methodologies as described earlier in the document.

Q. Please explain the challenges associated with relying solely on a Project-by-Project analysis to develop a forecast.

A. In recent years this methodology has resulted in forecasts that turned out to be lower than the actual costs incurred.

Q. Please explain.

A. From 2014 through 2018, the Company frequently incurred costs higher than forecast under the Project-by-Project methodology. For example, the Electric Capital forecast for 2017 was $91.2 million. Actual costs incurred were $127.9 million.

Q. Was Exhibit ___ (MISP-3), entitled “Forecasts versus Capital Expenditures” prepared under your supervision?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-3) shows the Company’s prior capital forecasts compared to actual costs from 2014 to 2018. As illustrated in this exhibit, material changes in municipal infrastructure forecasts may impact the Company’s expenditures.

Q. How does the Company propose to mitigate these potential forecast variances from the Project-by-Project forecast analysis?

A. The Company seeks to improve on the Project-by-Project analyses by adding two additional methods to develop better financial estimates than would otherwise result from solely relying on a Project-by-Project approach. As discussed later, material changes in recent years have left the Company under-estimating costs relating to municipal projects when relying solely on the Project-by-Project approach.

Q. Why is the NYC Budget Calculation method that is used in the O&M forecast not used for the capital forecast?

A. Historically, the Company has applied this methodology to O&M forecasting only. There is no internal history to validate using this method for capital forecasting.

Q. Have there been any modifications in the gas capital program that have reduced MISP forecasts?

A. Yes, modifications were made to the Encroachments Program within the Company's gas capital budget that have reduced this Panel's forecasts. The Encroachment Program costs will be discussed by the Gas Infrastructure, Operations and Supply Panel ("GIOSP").

Additional Challenges

Q. What influence, if any, does the Company exercise over the scope and/or timing of the work performed by the City and other municipalities?

A. While the Company employs measures to mitigate the costs related to municipal interference work (as discussed in detail in the Mitigation section below), the Company has no control over project and contractor selection, bidding methodologies, availability of municipal contractor resources, start dates or the duration of City/municipal projects. Moreover, we do not control a municipal contractor's construction means and methods and we cannot forecast the resulting incremental cost impact.

Q. Are the projects identified by the City, State and other municipalities in their plans the only projects they execute in the target year?

A. No, projects are regularly added or delayed by the City and other municipalities as compared to their proposed municipal plans.

Q. Why is it reasonable to assume that the City and other municipalities will generally execute the projects reflected in the Company's forecast for the Rate Year?

A. The majority of the Company's forecast for RY1 is based on projects already in construction/design and recurring work.

Q. What do the City's actual expenditures, as set forth in Exhibit ___ (MISP-1), demonstrate with regard to the City's spending trends?

A. Exhibit ___ (MISP-1) demonstrates that the City's actual expenditures have been steadily increasing.

Q. Has the Company identified any trends in tracking the City's Capital Commitment plan forecasts that further supports anticipated increased spending?

A. Yes, in City FY-2014 to 2018, the City progressively increases its forecasts as it approaches the actual City fiscal year. For example, the City's October 2014 projection for fiscal year 2018 was $884 million. In September 2015, the target for fiscal year 2018 was $1.6 billion. In May 2017, two months before the 2018 City fiscal start, the projection had nearly tripled to $2.8 billion.

Q. Was Exhibit ___ (MISP-4), entitled “NYC-Historical Review of Capital Commitment Plan” prepared under your supervision?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-4) shows the OMB’s commitment plans for FYs 2014 through 2019 extracted from prior Capital Commitment Plans starting in September 2010 through October 2018.

Q. Let’s turn our attention to commitments versus actual municipal expenditures. Was Exhibit ___ (MISP-5), entitled “NYC Initial Commitment versus NYC Actual Expenditures” prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit compare?

A. Exhibit ___ (MISP-5) compares the initial municipal commitment to actual municipal expenditures.

Q. What does this exhibit show?

A. This exhibit illustrates that a comparison of the City's initial commitments for fiscal years 2014 to 2018 (published in the Commitment Plans) versus the City expenditures for this same period, has resulted in average actual expenditures that are approximately 71.6% above initial forecasts.

Q. Does the Company assume that this relationship between projected and actual expenditures will change in the coming years?

A. Yes, but the exact scope of the change will remain uncertain. Based on some of the major initiatives currently planned by the City, as described elsewhere in our testimony, the Company expects actual expenditures to be above current levels for the foreseeable future.

Q. In past proceedings, Staff has proposed basing the forecast for O&M and capital interference expenditures on a five-year average of recent actual Company costs. Is a forecast based upon a five-year average of recent actual costs a reasonable basis for setting rates?

A. No, it is not.

Q. Please explain why using an average of recent actual costs is not reasonable.

A. From 2014 to 2018, Company costs have been increasing materially because municipal spending has been increasing materially. The five-year (2014-2018) average is $104.9 million for electric O&M and $95.6 million for electric capital. In contrast, the forecasts for the Rate Year are $129.6 million in electric O&M and $193 million in electric capital, with no reasonable expectation that actual spending would, under any circumstance, be anywhere near the five-year average. Accordingly, using an average approach would not be reflective of current municipal infrastructure spending and would result in interference being significantly underfunded.

Q. Aside from the use of an average formula, have actual expenditures resulted in underfunding for past periods?

A. Yes. Under the adopted electric and gas rate plans, capital expenditure targets have consistently been less than incurred costs. As demonstrated in MISP-3, in Electric and Gas, the actual costs incurred over this period were significantly higher than the targets set as shown in the tables below:

Electric Capital	2014	2015	2016	2017	2018
Target	$69.3	$63.7	$60.6	$91.2	$103.5
Actual	$77.0	$78.6	$92.6	$127.9	$101.8

Note: Dollars in Millions and rounded

Gas Capital	2014	2015	2016	2017	2018
Target	$76.0	$72.8	$61.0	$82.4	$82.1
Actual	$73.6	$85.3	$115.4	$123.1	$120.9

Note: Dollars in Millions and rounded

Q. Please explain further the challenges of exclusively using the historic average methodology and why using an historic average is unreasonable?

A. It is not reasonable to ignore the cost estimates and timing of planned municipal projects when forecasting future expenditures.

The Company is required to respond to City/municipality timetables for the projects that the City and other municipalities design and choose to execute and is subject to penalties for failure to respond.

Accordingly, for all of the foregoing reasons, using a simple average of recent Company expenditures is not a reasonable basis for forecasting expenditures for a future period in an environment where costs have been increasing and are expected to remain above the historic average.

Q. What is the percentage of actual City expenditures compared to actual Company O&M expenditures?

A. From 2011 to 2018, the Company's actual expenditures have ranged between 9.7% and 13.7% of the City's actual expenditures. Exhibit ___ (MISP-6) illustrates the correlation between escalating City expenditures and similarly increasing Company O&M expenditures.

Q. Was Exhibit ___ (MISP-6), entitled "NYC EXPENDITURES VERSUS CON EDISON EXPENDITURES" prepared under your supervision or direction?

A. Yes, it was.

Q. Has the correlation been closer to the middle of the historical range, 9.7% and 13.7%, in recent years?

A. Yes, in 2015 to 2018 the average was 11.5%. Although the Company has had higher expenditures year-over-year there has been a decrease in the ratio of City expenditures to Company O&M.

Q. What decrease has the Company seen?

A. The ratio of City expenditure to Company O&M expenditure has decreased progressively in recent years;

Year	Ratio
2015	12.3%
2016	11.8%
2017	11.3%
2018	10.5%

Q. Does the Company expect to continue this downward trend?

A. This will depend on several different factors. As mentioned elsewhere in this document, costs associated with interference work are directly impacted by the type of projects selected by the municipality, the location of the projects and the Company facilities identified to be in interference. For example, in Staten Island, the Company only has an electric system that is comprised of an overhead system and underground system that shares the street with other subsurface facilities with limited congestion. By contrast, in Manhattan, the Company has an extensive electric and gas underground system that shares heavily congested streets with other subsurface facilities. Therefore, there is a direct relationship between the location and types of projects selected by the municipality and the resulting facility impact to interference costs. In addition to heavily congested subsurface infrastructure in Manhattan, there are other work conditions such as: restrictive work-hours, extensive maintenance and protection of traffic requirements, and high volume of vehicular and pedestrian traffic that are also factors impacting interference costs that are not conditions indicative to Staten Island.

Q. Upon what basis is the Company forecasting that the City’s capital expenditures will continue at the current high levels?

A. Based on current City project plans, various publications and confirmations by municipal agencies, the Company anticipates the City’s capital expenditures to be above the current levels over the next several years.

Q. Are there other emerging programs that could affect interference costs during the rate years, which cannot be fully evaluated at this time?

A. Yes. The most significant example is that the City continues to be in active design on a coastal resiliency program to reinforce the southern perimeter coast line of

Manhattan from East 23rd Street to the Battery to West 23rd Street. The City states that it plans the first phase of the coastal resiliency program for construction starting in 2020 in the area along the East River from East 23rd Street to Montgomery Street to the south. The program goal is to provide flood protection by installing a coastal barrier to protect the surrounding neighborhood from future storm surges, while simultaneously providing new community space, recreational and economic opportunities.

Q. Are there published resources from the City regarding this project?

A. Yes, please see the NYC.gov web site for The East Side Coastal Resiliency Project at:
https://www1.nyc.gov/site/escr/index.page

Q. Has the Company been communicating with the City regarding this project?

A. Yes. The Company has been in joint discussions with City representatives and their design consultant to complete the design plans. The Company has provided information as to the location of its existing transmission and distribution facilities incorporating Company infrastructure support and protection requirements into the City project.

Q. What is the current design status of this project?

A. The City announced on September 28th 2018, that it is pursuing an alternative design for part of the East Side Coastal Resiliency project. See https://www1.nyc.gov/office-of-the-mayor/news/493-18/fact-sheet-de-blasio-administration-faster-updated-plan-east-side-coastal

Q. Has the Company included this in its five-year forecast?

A. Yes, the Company has included this project in its five-year forecast with a preliminary forecast totaling approximately $250 million in capital electric transmission and distribution work combined based on the original design.

Q. What is the Company’s revised cost estimate for this project?

A. The Company is in the design phase with the City and therefore has not finalized the cost estimate for this project.

Q. Are the other interference costs that are currently included in the Company’s financial projections also subject to material changes?

A. Yes. The Company’s forecasts are based on the best information available at the time the forecasts are developed. However, there are many variables that may affect the Company's expenditures that cannot be reasonably forecasted.

Some examples are:

- Unanticipated large-scale emergency sewer or water main breaks beyond what is already included in the current financial projections.
- Critical infrastructure projects, such as the Van Wyck project, pose a risk to the Company because the design-build project model is fluid and the final design that is ultimately selected could have a significant cost impact on the Company.
- Should additional State or City design-build projects emerge during the rate period the Company will not have these projects included in current forecasts.
- Fast-track projects by City agencies, expansion of shared costs between the Company and the municipality (*e.g.*, City Engineering costs, Traffic Enforcement Agents, Pedestrian Managers), are other conditions that the Company cannot reasonably forecast at this time.

INTERFERENCE – O&M

Q. Please describe O&M interference costs.

A. As described earlier in our testimony, the Company’s O&M interference costs are the maintenance expenditures incurred when the Company is required to support, protect or maintain facilities due to interference with proposed City or other municipal facilities. O&M interference costs are most often associated with indirect interference and there can be some associated with direct interferences.

Q. Please provide the Company’s recent actual O&M interference costs for electric and gas (excluding Company labor) by calendar year and for the 12 months ended September 30, 2018 (“Historic Year”).

A. The total O&M cost in 2014 to 2017 and the Historic Year (“H.Y.”) were as follows:

O&M	2014	2015	2016	2017	2018	H.Y.
Electric	$99.9	$84.1	$92.3	$126.1	$122.2	$128.7
Gas	$27.6	$28.6	$31.1	$26.9	$27.2	$28.5

Notes: Excludes Company Labor, Dollars in Millions and rounded.

Q. Why has interference O&M spending increased between 2014 and 2018?

A. As noted above, the City’s actual infrastructure expenditures in the project categories that typically generate interference work for the Company have increased during the period 2014 to 2018. As demonstrated by the historic data set forth in Company Exhibit ___ (MISP-6), the level of Company O&M costs are directly related to the level of City capital infrastructure costs, and have therefore increased accordingly.

Q. What are the Company’s O&M cost projections for interference in the Rate Year (excluding Company labor)?

A. The Company is forecasting $129.6 million in electric O&M and $27.1 million in gas O&M expenditures in the Rate Year.

Q. Has the Company forecasted O&M interference expenses for periods beyond the Rate Year?

A. Yes. The Company has forecasted O&M interference expenses for two annual periods beyond the Rate Year. The Company is forecasting O&M expenditures (excluding Company labor) of $140.0 million in electric O&M and $28.1 million in gas O&M expenditures for RY2. For RY3, the Company has forecasted O&M expenditures (excluding Company labor) of $146.2 million in electric O&M and $28.9 million in gas O&M expenditures.

Q. Was Exhibit ___ (MISP-7), entitled “ACTUAL AND FORECASTED O&M EXPENDITURES” prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-7) shows actual electric and gas O&M expenditures for 2014 to 2018, as well as the historical year O&M expenditures. This exhibit also shows forecasted O&M expenditures for 2019 to 2023.

INTERFERENCE - CAPITAL

Q. Please describe the capital costs associated with interference.

A. As described earlier in our testimony, the Company’s capital interference costs are expenditures incurred when the Company is required to relocate its facilities to a new location due to interference with proposed municipal facilities. Capital interference costs are most often associated with direct interference.

Q. What were the total capital interference costs incurred between calendar years 2014 and 2018?

A. The total capital costs incurred from 2014 to 2018 were as follows:

Capital	2014	2015	2016	2017	2018
Electric	$77.0	$78.6	$92.6	$127.9	$101.8
Gas	$73.6	$85.3	$115.4	$123.1	$120.9

Note: Dollars in Millions rounded

Q. What is the forecast for capital expenditures related to interference going forward?

A. The Company is forecasting from 2019 to 2023 the following expenditures:

Capital	2019	2020	2021	2022	2023
Electric	$131.0	$193.0	$201.0	$210.0	$225.0
Gas	$126.0	$101.3	$109.3	$116.8	$127.0

Note: Dollars in Millions and rounded

Q. Was Exhibit ___ (MISP-8), entitled “ACTUAL AND FORECASTED CAPITAL EXPENDITURES” prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-8) shows actual capital expenditures for 2014 to 2018 for Electric and Gas. This exhibit also shows forecasted capital expenditures for 2019 to 2023 for Electric and Gas.

MITIGATION

Q. What measures has the Company undertaken to mitigate interference costs?

A. In addressing interference costs, the Company is required to adhere to state and municipal statutes, codes, regulations and other established protocols. Given the nature of interference work and that this work (and related expenditures) is driven by factors outside of the Company's control, our opportunities for mitigation measures are limited. As part of the Company's initiative to promote a cost conscious culture, while improving external relationships with the numerous municipal agencies, the Public Improvement department has implemented the following initiatives to mitigate interference costs:

<u>Strengthening Regional Engineering</u>:

Engineering is the first opportunity for cost mitigation when interfacing with various municipal agencies during the initial design and planning phases of a project. Engineering takes the opportunity to study the agencies' scopes of work and perform an in-depth analysis to determine the type, nature, and extent of the interferences. During the planning phase of agency projects, Engineering may suggest, request and/or discuss with the municipal agency possible scope changes to minimize interferences and request design accommodations, as discussed earlier in our testimony. The engineering group also provides consulting support to the field that assists to mitigate the impact of unanticipated, as-found subsurface field conditions during construction. Additionally, when the municipality determines the street will be excavated, Con Edison uses this opportunity to consolidate existing infrastructure and reduce maintenance costs while still providing the same level of service capacity. For example, when multiple service boxes or manholes exist on a block, the Company’s engineering group may redesign, consolidate and reduce the number of structures, thereby lessening future maintenance costs. Moreover, consolidating structures provides for additional space in the streets for future use by the Company, the City and other utilities.

<u>Coordinate interference work with other Company capital projects for synergies and cost savings</u>:

The Company incorporates interference work with other Company capital project work to the greatest extent practicable that the municipal schedule allows. Our effort to coordinate the interference work with other Company capital projects is accomplished during the municipal engineering design phase or during the construction phase of the municipal projects.

When the Interference group receives notice from the City that a new municipal project is planned, it issues a notification of the project scope and locations to the Company's Electric, Gas and Steam Engineering groups. During the municipal project design phase, internal Company meetings are scheduled between the Public Improvement Engineering section and other Company engineering groups that review the potential to include Company capital project work, (such as new business, system upgrades, gas main replacement program, and/or other system reliability work) with the proposed municipal project work. This effort results in minimizing adverse impacts to the community by reducing street opening redundancies and minimize delays to municipal projects.

<u>Maximize Number of Section U Projects</u>:

The protocol for Section U is established jointly by the City and the major utilities operating in the City. The

Section U protocol provides the Company with certain limited leverage to negotiate a fair market price with the City agency contractors for the Company's portion of interference work. Under the Section U protocol, the contractor of record for the Section U project negotiates in an attempt to reach an agreement with the utilities prior to the start of the project. If an agreement cannot be reached, the matter is submitted for arbitration to the American Arbitration Association and the result is final and binding.

Projects are not automatically classified as Section U until approved by the DDC. Through efforts undertaken by the Company's engineering department while meeting City requirements, the Company has been able to maximize the number of interference projects categorized under Section U. Benefits include early coordination and participation between the City and the utilities in the development of the overall project scope, resulting in municipal design changes and accommodations to minimize utility interferences.

Joint Bid Protocol:

For work performed under the Joint Bid protocol, the Company’s interference work is included in the City bid documents and is bid along with the City work. The City and the various utilities jointly coordinate their work from the outset of the project and both City and utility work is managed under singular project oversight, which generally results in improved project scheduling and more efficient construction management providing for an overall enhanced customer experience. The program has evolved from Lower Manhattan in 2004 to Citywide today.

Negotiating Team:

The Company uses a negotiating team concept when entering into agreements. The team consists of the estimator, the project engineer, the borough manager and the borough project specialist. The negotiating team has been extremely successful since its inception by facilitating pricing uniformity for work items throughout the boroughs thereby reducing prices for commonly used items that resulted from estimating time studies. Additionally, time studies support challenges from contractors in arbitration if the pricing offered by the company is perceived to be inconsistent with fair market value.

Unit Price Agreements

The Company has also used multi-year and multi-borough contractor agreements for macro work units to establish consistent pricing across its service area. This effort may also reduce Company administrative costs that would normally be associated with multiple negotiations for different projects with the same vendor.

Evaluate field conditions to create new macro work units:

Since the mid-1990s, Con Edison has been working with the communication utilities Time Warner (Time Warner is currently doing business as, Spectrum, a brand of Charter Communications Inc.) and Empire City Subway (“ECS”), which owns and maintains underground facilities for Verizon. The Company has worked with Time Warner and Empire City Subway to develop a list of common work units as a means of standardizing municipal field work. These standardized units are referred to as Con Edison, ECS and Time Warner (“C.E.T.”) specification items. The list has expanded over time and presently includes more than 250 items that cover common utility work tasks.

Maximize Lump Sum Agreements:

The Company promotes lump sum agreements, which are single price agreements that encompass all labor, material and equipment to complete the defined work. This creates financial incentive for efficient construction management by the contractor instead of negotiating for extra work on a piecemeal basis. The agreements also reduce the Company's risk by minimizing adverse impact on Company facilities and potential costs associated with project schedule delays. These project agreements also aid the Company in forecasting future budget years, but cannot remove the overall uncertainty.

Opportunities to reduce project costs by performing advanced relocation:

When feasible, the Company utilizes advanced relocation of Company facilities to avoid interferences with City facilities. The Company utilizes predominately in the outer boroughs where it is more feasible than in Manhattan's congested streets. Recently and where operational flexibility has been afforded, the Company has been more aggressive in attempting to perform advance work in Manhattan to minimize the impact on the City schedule, the community, and reduce the financial exposure from having to negotiate pricing with the City’s contractor. The Company uses the Company’s existing contractors to perform the work in advance at a lower overall cost when compared to the costs of using the municipal City contractors to perform interference work. The advance work will result in less interferences, which in turn will minimize overall interference costs and potential delays.

RECONCILIATION

Q. Does the Company’s current electric and gas plans provide for reconciliation of capital and O&M expenditures related to interference?

A. For O&M expenses, the plans provide for full downward reconciliation of actual expenses below the targeted level of expenses and reconciliation of amounts (other than Company labor) for up to 30 percent above the target level of expenses, shared on an 80/20 basis between customers and the Company, respectively, with three exceptions as set forth in the rate plan.

For electric capital expenditures, Municipal Infrastructure Support costs are not subject to separate reconciliation.

They are part of electric net plant, which is subject to downward-only reconciliation.

For gas capital expenditures, Municipal Infrastructure Support costs are subject to full downward reconciliation as part of gas operations net plant with a limited upward reconciliation for certain interference capital costs.

Q. Is the Company proposing any modifications to these mechanisms as they apply to either capital or O&M expenditures?

A. Yes. The Company is proposing a full reconciliation of Municipal Infrastructure Support capital expenditures and O&M expenses, in the manner proposed by the Company's Accounting Panel.

Q. Why should the Commission adopt full reconciliation of Municipal Infrastructure Support capital expenditures and O&M expenses?

A. As we have explained in this testimony, interference costs are beyond the Company's direct control, are not subject to reasonable estimation, are driven by the infrastructure work performed by the City, State and other municipalities, and constitutes work the Company is required to perform pursuant to a schedule established by the municipality that often requires a significant diversion of Company resources and significant incremental costs. Moreover, there are a number of major City infrastructure initiatives under consideration that are not yet included in the Company's forecast, but which could potentially have significant cost impacts.

Accordingly, the Company believes that rates should reflect a reasonable estimate of these expenses and then be subject to full reconciliation, as further explained by the Company's Accounting Panel.

Q. Should there be a concern that the Company will not seek to minimize its interference costs if there is full reconciliation of these expenses?

A. There should be no concern. The Company has demonstrated a long-standing and consistent approach to mitigating these costs, to the extent practicable, and continued coordination between the City and the Company during the design phase, which is a critical component of the continued success in controlling rising costs. The Company has consistently followed this approach, including during periods when a bilateral reconciliation mechanism for interference expenses was in place (*e.g.*, as adopted in the

Commission’s April 2009 rate order in Case 08-E-0539). Moreover, these cost mitigation efforts are ingrained in the Company’s efforts to implement cost management improvements.

Q. Do you have any concluding remarks?

A. Yes. For all of the foregoing reasons, the Commission should adopt the Company’s forecasted O&M and capital expenditure levels for the Rate Year and the proposed reconciliation mechanisms for capital and O&M interference expenses.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

CUSTOMER OPERATIONS PANEL

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

CUSTOMER OPERATIONS PANEL

I. INTRODUCTION

Q. Would the members of the Customer Operations Panel please state their names and business addresses?

A. Marilyn Caselli, Christopher Grant, Hollis Krieger, Michael Murphy, Christine Osuji, and Matthew Sexton. The business address of Ms. Caselli, Ms. Krieger, Mr. Murphy, and Mr. Sexton, is 4 Irving Place, New York, NY 10003; the business address of Ms. Osuji is 30 Flatbush Avenue, Brooklyn, NY 11217; and the business address of Mr. Grant is 1601 Bronxdale Avenue, Bronx, NY 10462.

Q. By whom are the Panel members employed?

A. We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company").

Q. In what capacity are the panel members employed and what are their professional backgrounds and qualifications?

A. **(Caselli)** I am the Senior Vice President of Customer Operations. I have overall responsibility for the Company's customer service programs, including customer outreach, meter reading, billing, and answering customer inquiries. I also oversee the administration of the Company’s retail choice program that supports the competitive energy marketplace. I began my employment with Con Edison in 1974. From 1974 to 1989, I held positions of increasing responsibility within the

Company, rising to the position of General Manager, Customer Operations for Queens. In l992, I took the position of General Manager, Customer Operations for Brooklyn and then, in 1996, I took the position of General Manager, Gas Operations for Queens. In October 1997, I took the position of Vice President, Customer Services for Staten Island and, in May 2005, I was promoted to my current role of Senior Vice President, Customer Operations. I hold a Bachelor of Science degree in Business Administration from the State University of New York.

(Grant) I am the General Manager of Field Operations in Customer Operations. I am responsible for meter reading and field collections throughout the service territory. I am also responsible for theft-of-service investigations and the Field Operations Performance Management Group. I have been employed by Con Edison for almost 21 years and have held a variety of management positions within Customer Operations, in addition to a position in the Steam Business Unit. In 2014, I was promoted to General Manager, Field Operations. I earned a Bachelor of Science degree in Business Management from Cornell University.

(Krieger) I am the Department Manager for Customer Outreach and Education. I am responsible for the Company's outreach and education program, including outreach to customers, community groups, and officials. I have held this position since January 2015. I joined Con Edison in 1980 and have held positions of increasing responsibility. The Customer Operations positions held prior to my current position include: Section Manager in Regulatory and Performance Analysis, Section Manager in Retail Choice, and Senior Specialist in various Customer Operations departments. I have a Bachelor of Arts in English from Queens College, City University of New York and a Masters of Arts in Creative Writing from Queens College, City University of New York. I also attended the Program for Manager Development at the Fuqua School of Business, Duke University.

(Murphy) I am General Manager of Strategic Applications. My current responsibilities include oversight of various operating components: the Final Bills collection group, Public Assistance processing group, and the replevin processing group. My organization also provides subject matter expertise and operational support in the areas of system design and implementation, metering and billing systems, credit/collections, and oversees analysis and improvements in the area of Customer Experience, including our Digital Customer Experience ("DCX") program. I have been employed by Con Edison for over 18 years and have held a variety of positions within Customer Operations, in addition to an assignment as Section Manager Stores Operations in Supply Chain. My prior positions in Customer Operations include Department Manager Digital Customer Experience, Department Manager Operations and Applications Support, Section Manager Retail Choice Operations, Senior Specialist Corporate Customer Group, and Supervisor Specialized Activities. I earned a Bachelor of Science degree in Business Administration from the University at Albany. I also earned a Masters of Business Administration from Fordham University in Management of Information Systems.

(Osuji) I am General Manager of the Customer Assistance group in Customer Operations. My group includes the Company's Customer Experience Centers (formerly known as the Call Center), back office functions including billing, credit operations, and customer investigations, as well as the Company's Walk-in Centers. I joined Con Edison in 2000 as a specialist in Human Resources. I have held positions of increasing responsibility in Human

Resources Employee and Labor Relations, Leadership and Career Development, and Customer Operations. I earned a Bachelor of Science degree in Business Administration from State University at Buffalo.

(Sexton) I am the General Manager of Specialized Activities in Customer Operations. Specialized Activities includes the Corporate Customer Group, Retail Choice Operations, Executive Action Group, and Meter Action/Unmetered Services Group. I have held this position since December 2017. I joined Con Edison in 2004 as a Supervisor in Customer Operations, and have held a variety of positions within Customer Operations, in addition to an assignment as Section Manager for the NorthStar Management Audit in Business Finance. My prior positions in Customer Operations include: Department Manager Digital Customer Experience, Section Manager Accounting/Personal Service, Section Manager Process Excellence, Section Manager Off-Hours Call Center, and Senior Specialist Off Hours Call Center. I have a Bachelor of Business Administration degree in Financial Accounting from Baruch College and a Master of Business Administration in Human Resource Management from Baruch College.

Q. Have you previously submitted testimony or testified before the New York State Public Service Commission the "Commission")?

A. Ms. Caselli, Mr. Grant, Ms. Krieger, Mr. Murphy and Ms. Osuji have submitted testimony in previous cases. Mr. Sexton has not submitted testimony before the Commission.

II. <u>SUMMARY OF TESTIMONY</u>

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

A. This Panel's testimony presents an overview of planned programs for Customer Operations that are necessary, in conjunction with other Company programs addressed by other witnesses/panels, to achieve the following core objectives: 1) strategically transform operations to provide customers with a 'Next Generation Customer Experience,' 2) address ongoing operational priorities, including elimination of customer-funded credit and debit card transaction fees, increased resiliency of our customer care infrastructure, expanded use of electronic delivery ("e-delivery") for written correspondence, and leveraging Automated Metering Infrastructure ("AMI") data to achieve greater success in the revenue protection area, and 3) meet our Operations and Maintenance ("O&M") savings targets identified as part of the Company's Business Cost Optimization ("BCO") initiative. The Panel will also discuss continuation of the Company's Off-System Billing program and Electric and Gas Low Income programs, plans for Customer Outreach and Education, and a proposal to eliminate reconnection fees for some customers to reflect new operating procedures enabled by AMI technology.

Q. Please expand on the core objectives you outlined above and how they are addressed in this rate filing.

A. First and foremost, Customer Operations is committed to enhancing the customer experience. Customer Operations will achieve this through its Next Generation ("Next Gen") Customer Experience ("CX") initiative by meeting rising customer expectations, facilitating New York's clean energy policy goals and programs, and driving operational efficiencies. The Company is working to provide industry-leading CX by listening to our customers, continuing to close the technology gap between utilities and other industries (*e.g.*, telecommunications and banking), and implementing a comprehensive CX strategy to increase customer satisfaction and drive cost efficiency.

The Company will continue addressing ongoing operational priorities that will enable us to provide quality customer service. In this testimony, we discuss planned programs to address the sustainability of our infrastructure, the use revenue protection analytics, expanded electronic communications with customers, and elimination of credit and debit card transaction fees for residential and small business customers.

We are working to meet our O&M savings targets identified as part of the Company's BCO initiative by improving operational efficiencies and managing costs. Through the Next Gen CX initiative, the Company will invest in programs that will expand self-service resources and tools designed to meet customer needs and expectations, which we expect will lead to cost savings due to reduced calls to our Customer Experience Centers.

Finally, many of the programs described below support the Company's efforts to implement the Commission's Reforming the Energy Vision ("REV") goals. The Company aims to continue to be a trusted energy advisor and facilitate REV goals by building trust with customers though excellent service and providing customers with choice, control, and convenience in the tools and products provided as part of its Next Gen CX initiative.

Q. What period does your testimony cover?

A. The Panel will present the programs planned for the 12 month period ending December 31, 2020 (“Rate Year” or “RY1”). While, as discussed by the Company’s Accounting Panel, the Company is not proposing a multi-year rate plan in this rate case, the Company is interested in pursuing, through settlement discussions with Staff and interested parties, a multi-year rate plan. To facilitate settlement discussions, we also address capital plant additions and other programs and initiatives for the two years following the Rate Year. We will refer to the 12 month periods ending December 31, 2021 and December 31, 2022 as “RY2” and “RY3,” respectively.

Q. What is the aggregate projected spending for Customer Operations activities described in this testimony?

A. In total, the Company projects expenditures of $26.69 million in RY1, $22.975 million in RY2, and $20.8 million in RY3 on customer-service related capital programs described in this testimony. The Company projects the programs discussed by this Panel will require additional incremental O&M expenditures of $7.419 million in RY1, $2.516 million in RY2, and $1.088 in RY3. We note that these expenditures do not include the O&M costs to achieve BCO savings, which are netted out of the Customer

Operations’ total BCO savings targets as discussed in the Accounting Panel. Customer Operations also anticipates O&M savings across the three Rate Years resulting from the Company’s ongoing AMI program. AMI-driven savings for Customer Operations are described below and in EXHIBIT__(CO-11).

Q. Are some of your programs applicable to both electric and gas services?

A. Yes. We note that the programs described in our testimony address the needs of both electric and gas customers and, therefore, the associated costs are allocated as common programs. The Accounting Panel describes and applies the allocation of these costs between electric and gas service.

Q. Does your testimony address any other topics?

A. Yes. Our testimony also addresses continuation of the Company’s Customer Service Performance Mechanism (“CSPM”) and the Residential Service Terminations and Uncollectible Bills performance mechanism established in the Company’s 2016 rate proceeding.

Q. Does your testimony propose any new incentives or mechanisms?

A. No. The Clean Energy Solutions Panel discusses continuation of the AMI Customer Awareness Earnings Adjustment Mechanism.

III. NEXT GENERATION CUSTOMER EXPERIENCE INITIATIVE

Q. Please summarize the Company’s Next Gen CX initiative.

A. The Next Gen CX initiative is a portfolio of investments that will allow the Company to continue to meet customer’s rising expectations, facilitate policy goals, and drive operational efficiencies. To achieve these objectives, the Company plans to make investments in proven technologies that will allow for the development of new customer services during this rate plan and lay the foundation for the future. We developed the Next Gen CX investments described below with a leading customer experience consultant that works across several industries, including banking, telecommunications, and retail. We incorporated current cross-industry customer expectations and technology investment trends.

The three major categories of investments included in the Company’s Next Gen CX initiative are Business Intelligence, Omni-Channel Optimization, and Back Office Automation and Agents Tools, described below:

- Business Intelligence – invest in a Data and Analytics program that uses advanced data and analytics to drive new customer and business insights;

- Omni-Channel Optimization – enable a seamless multi-channel self-service experience for customers with investments in DCX, Journey Mapping, Virtual Assistants, and Bill Redesign; and
- Back Office Automation and Agent Tools – develop intelligent tools designed to improve processes and operational efficiency, and concentrate on value-add customer focused activities.

Q. Please elaborate on the practical or real-world benefits that customers will see from the Next Gen CX investments.

A. Next Gen CX has two overarching benefits for customers. First, customers will see more streamlined, prompt, and accurate customer service in the customer’s channel of choice (e.g., web, phone, text, chat). This includes, for example, new enhanced self-service tools for managing payments and faster resolution of inquiries when interacting with the Company. Overall, customers will see more choice, control, and convenience when managing their energy and interacting with the Company. Second, customers will benefit from cost savings realized through operational efficiencies such as resolution of issues on lower-cost self-service channels, and automation of back office work.

Q. When will the Company be making these investments?

A. These investments are planned during the Rate Years 1-3. However, each investment will be foundational and we will use an iterative approach. This allows for continued value-based investment beyond the rate years to address rising customer expectations and the required services associated with new programs supporting the State's clean energy goals.

Q. How does this initiative intersect with other programs that the Company is proposing in this rate filing?

A. This initiative intersects with a number of programs and projects including AMI, the new Customer Service System ("CSS"), the Information Technology ("IT") Technology Enabler known as Data Analytics, and our Energy Efficiency and Demand Management ("EEDM") programs. Each of these initiatives impact customer facing processes, and therefore proper coordination will be essential. We have considered them in each initiative's development. In addition, this initiative supports the BCO initiative through cost savings, as explained in the BCO Savings section of this testimony.

Q. How will the Next Gen CX initiative advance the State’s clean energy and REV goals?

A. The Next Gen CX initiative supports advancement of the State’s clean energy and REV goals through the development of an overall flexible technology platform that can be cost effectively modified to support emerging program needs. For example, the Data and Analytics program will deepen the Company’s understanding of customer needs and behavior and will inform how different REV programs influence and impact different customer groups, enabling a deeper analysis for the expected success of each REV program. The DCX program will facilitate greater customer engagement and provide convenient, seamless experiences for customers to sign up and participate in demand-side management (including EEDM), distributed energy resources, new time-variant rates and other advanced energy technologies and programs. The DCX program is already supporting the State’s policy goals through the development of a new Home Energy Analysis tool that enables customers to better understand their energy usage and suggest actions to achieve savings. The Journey Mapping program will help deliver consistent, positive experiences, creating the potential for increased engagement in EEDM and other clean energy programs. Finally, the Bill Redesign program will provide customers with a paper bill that is available electronically and easy to read, provides graphics for a quick understanding of their energy usage, and has a flexible format that allows for customized product suggestions and program offerings directly on the bill, further encouraging customer adoption of innovative solutions that make sense for their home or business.

Q. Has the Company already begun to incur costs associated with the Next Gen CX initiative?

A. Yes – the Company conducted benchmarking and research to develop the business cases outlined below, and established a Customer Experience Center of Excellence ("CX COE") to oversee and coordinate implementation of the Next Gen CX initiative across the enterprise. Further information on this preliminary work is included in the program descriptions that follow.

A. BUSINESS INTELLIGENCE

1. DATA AND ANALYTICS

Q. Please summarize this Panel's Data and Analytics program.

A. The Data and Analytics program, a foundational component of the Business Intelligence category of investment for the Next Gen CX, will provide the Company with customer insights through the development and use of advanced data analytical tools that will help improve the customer experience and reduce operating costs. With this program, the Company seeks to gain a deeper understanding of our customers and unlock the business intelligence that is an enabler for the entire Next Gen CX initiative.

The Company already has a significant amount of data about its customers that resides in numerous internal systems and databases, including but not limited to, energy consumption, payment history, rate/program enrollment (e.g., EEDM programs, time of use (“TOU”) rates, low income discounts), and the type and channel of historical interactions with the Company (including detailed interactive voice response (“IVR”), chat and web logs). The Data and Analytics program will connect these disparate data sources, and enable Con Edison to sort through the resulting data to identify patterns, trends, and correlations.

Q. What are the overall goals and objectives for the Data and Analytics program?

A. The Data and Analytics program seeks to:

- Develop a deep understanding of customer’s needs through analysis of customer segmentation, program adoption, and interaction pain points;

- Recommend programs and services to customers through propensity analytics of customer behavior, resulting in actionable recommendations;
- Create actionable insights for employees such as cross channel usage analytics, operational analytics, and natural language analytics; and
- Enhance quality assurance through insights based on analysis of customer inquiry resolution at initial contact, operational efficiency and compliance analytics, and employee or customer fraud reviews.

Additional details and the work that will be done to achieve these goals are provided in EXHIBIT__(CO-1).

Q. Please describe the status of the Company’s efforts related to the Data and Analytics program.

A. Con Edison conducted a study to define the business requirements, technical design, and architecture of the Data and Analytics platforms and tools. The Company also launched a pilot project in 2018 using data profiling and advanced analytics to identify outliers or anomalous behavior related to employee processing of customer related transaction such as customer refunds and transfers of funds between accounts.

Q. What benefits will the Data and Analytics program provide for customers?

A. The Data and Analytics program will analyze customer data to identify patterns, trends, and correlations, which will enable the Company to better identify customer pain points and future needs. Using these insights, the Company can anticipate and preemptively address customer pain points and future needs, resulting in more positive customer interactions. As the program matures, Con Edison expects to provide customers with more tailored recommendations on how to meet their energy usage and cost savings goals. Additionally, Con Edison will use customer interaction insights to provide front-line employees and customers with personalized real-time customer-specific assistance.

Q. Why is it important that these investments are made at this time?

A. Insights from the Data and Analytics program are essential to the successful execution of the Next Gen CX initiative. This program will be able to answer critical questions for other investment programs including, but not limited to:

- How customers interact with Con Edison across multiple channels and transaction types (Journey Mapping)

- Communication delivery preferences and engagement analysis for electronic delivery (Bill Redesign)
- Next best action identification engines and natural language analytics (Agent Tools)

Q. What is the projected capital cost of this project?

A. The capital costs for the Data and Analytics program is estimated to be $5 million for each Rate Year 1-3.

Capital funding requested for this program will cover the costs to incorporate data into platforms. The Company will be able to use these platforms to develop data models, and integrate these models with customer-facing and employee-facing systems to perform functions such as the creation of executive-level dashboards.

Q. Are there any cost savings projected from this program?

A. Yes. The Data and Analytics program will contribute to achieving Customer Operations' BCO Savings targets. Additional details regarding these savings are provided in the BCO section of this testimony and presented in Exhibit AP-3, Schedule 16.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Data and Analytics program?

A. Yes. We have prepared two exhibits, entitled "DATA AND ANALYTICS" EXHIBIT__(CO-1) and "DATA AND ANALYTICS USE CASES" EXHIBIT__(CO-2).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-1) and EXHIBIT___(CO-2).

B. OMNI-CHANNEL OPTIMIZATION

1. DIGITAL CUSTOMER EXPERIENCE

Q. Please summarize the Company's DCX program.

A. The DCX program is a core program for Omni-Channel Optimization, one of the three major categories of investments included in the Company's Next Gen CX initiative, as explained above. The DCX program was established in 2016 to improve the digital experience for customers through a redesign that covered the www.conedison.com and www.coned.com external websites, with a new mobile-enabled design, My Account portal, and mobile apps (IOS and Android). Quarterly reports filed by the Company in Cases 16-E-0060 and 16-G-0061 provide additional implementation details.

Q. Have these digital investments been well-received by customers?

A. Yes. As a result of customers' engagement with the new My Account features and positive customer experience, the Company's Net Promoter Score ("NPS" – a common metric for websites that is also referred to as an online user’s ‘likelihood to return’ with a range from -100 to 100) has increased from –28.6 to +26.7. The average NPS score overall for utility websites is listed by Esource, an independent market research and consulting company, as -3.

Customers have also responded well to the Company’s new mobile applications for Apple and Android devices launched in 2018, with ratings of 4.8 and 4.6 (out of 5), respectively. Additionally, Esource ranked the new applications as the second best utility mobile applications, behind Florida Power & Light.

Q. Has the DCX program resulted in increased customer use of self-service tools and other benefits as outlined in the DCX business plan?

A. Yes. The DCX program has already begun is already successfully delivering improved customer satisfaction, customer engagement, and reduced costs because customers have their problems resolved without the need for a phone call. Since the launch of the new My Account experience in July 2017, the Company has seen monthly average users (i.e., the number of Con Edison and Orange & Rockland Utilities, Inc. users who log in at least once in a month) dramatically increase from approximately 99,000 to 376,000.

The Company has also seen positive trends in online/digital transactional activity that support the conclusion that increased customer engagement on digital platforms is, in fact, resolving issues without calls. An example of this is the positive performance of the recently-released Start/Stop/Transfer functionality, which has enabled over 250,000 completed transactions online since its launch in July 2017.

Q. Does the Company propose to continue investing in the DCX program through 2022?

A. Yes. Customers’ expectations of digital customer service will continue to rise based on interactions with companies outside of the energy industry. Examples of these rising expectations include customer-focused simplicity, mobile access, and real-time tracking and notifications. Over time, customers’ rising expectations will iteratively escalate base-level service expectations, making what was once extraordinary, ordinary. In recognition of this rapidly evolving digital landscape, the Company has made continued investment in DCX a foundational component of its Company Omni-Channel Optimization strategy, which, in turn, will help us achieve our goals of delivering a Next Gen CX. We, therefore, propose to extend the DCX program through 2022 to refine and build upon the digital platforms that we have developed to date.

Q. Does the Company intend to maintain the same guiding principles and project management approach for the DCX program if these digital investments continue through 2022?

A. Yes. The Company intends to maintain the same guiding principles for the DCX program during Rate Years 1-3, which are available in EXHIBIT__(CO-3).

The Company will also continue to use a customer-centric, “Agile” project management approach (i.e., an iterative and incremental method of managing the design and build of digital platform) that adapts project scopes to changing priorities based on customer feedback and analytics. The Company will continue to update Staff and stakeholders on the evolution of the DCX program by filing quarterly reports with the Commission as it has since 2017.

Q. Please describe the proposed scope and objectives of the DCX program for the 2020-2022 time-period.

A. The Company will continue to optimize and expand its digital platforms in order to offer additional online self-service tools, enhance mobile app functionality, provide customers with more personalization and control, consolidate additional existing digital channels into the DCX program scope (e.g., text and email), and expand customer payment options, among other things. Please refer to EXHIBIT__(CO-3) for a comprehensive description of each of the DCX program's key focus areas during Rate Years 1-3.

Q. What is the Company's forecasted capital cost to continue this program?

A. The Company proposes to spend $13 million in capital per year for Rate Years 1-3, for a total of $39 million.

Q. Is the Company planning to increase the amount of O&M associated with the DCX program?

A. Yes. The Company requests an increase of $79,000 for RY1 and additional increases of $152,000 and $159,000 respectively for RY2 and RY3. As the DCX program will contribute to achieving Customer Operations' BCO Savings targets, fifty percent of the incremental O&M costs associated with this program are treated as costs to achieve those targets. As such, the O&M costs shown have been adjusted to reflect this treatment.

The DCX program has introduced new IT infrastructure to support the experience on the Company's various digital platforms. As such, associated implementation and ongoing O&M funds are needed to maintain the new systems brought online. Non-labor expenses for this program include software-related fees charged by vendor support and ongoing costs for related technology solutions deployed by the DCX program. Labor expenses will fund additional full time equivalent ("FTE") resources to provide day-to-day maintenance and management of the new digital architecture, manage the customer experience, and create and introduce new creative content. Additional information on these expenses are included in EXHIBIT__(CO-3) and EXHIBIT__(CO-4).

Q. Are there any cost savings projected from this program?

A. Yes. The DCX investments described in EXHIBIT__(CO-3) are part of the BCO savings described later in this Panel's testimony.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the DCX program?

A. Yes. We have prepared two exhibits, entitled "DIGITAL CUSTOMER EXPERIENCE" EXHIBIT__(CO-3) and "DIGITAL CUSTOMER EXPERIENCE WORKSHEET" EXHIBIT__(CO-4).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-3) and EXHIBIT__(CO-4).

2. JOURNEY MAPPING

Q. Please summarize the Company’s Journey Mapping program.

A. Journey mapping, another component of the Company’s Next Gen CX Omni-Channel Optimization investment category, is a process improvement method that explores the full sum of a customer’s experience when interacting with a company, not just discrete interactions or transactions. Unlike other process improvement techniques, journey mapping focuses on the customer and is grounded in what is commonly referred to as Voice of the Customer (“VOC”) data, which is an amalgam of customer research, benchmarking data, and operational data.

Con Edison’s Journey Mapping program will undertake seven core customer journeys during Rate Years 1-3: Sign up for Service and Onboarding, Outage Communications, Billing and Payment Assistance, Billing and Payment Process, Energy Efficiency and Management, Emergency Services, and Account Changes.

Q. What are the overall goals and objectives for the Journey Mapping program?

A. The goals and objectives of the Journey Mapping program are:

- Meet the current and future expectations of Con Edison’s diverse customer base.
- Define and redesign customer interactions for experiences associated with each of the journeys.
- Improve customer satisfaction through identification and prioritization of pain points in each journey.
- Drive customer loyalty by delivering consistent and satisfying experiences across all channels.
- Build trust in Con Edison by redesigning journeys based on customer feedback, customer research, and external benchmarking.

Q. Please describe the status of the Company’s efforts related to Journey Mapping.

A. To date, Con Edison has started journey mapping efforts for two of the seven core journeys. The first effort began in January 2018 for the ‘Sign Up for Service and Onboarding’ journey. This journey seeks to improve the overall experience for customers requesting service regardless of whether they use a self-service channel or speak to a Customer Service Representative (“CSR”). This includes streamlining the process to make it more simple, and providing clear and timely notifications of the status of the customer’s request to initiate service.

The second effort began in March 2018 for Outage Communications, and focuses on delivering clear and more frequent Estimated Time of Restoration ("ETR") communications on customer's most preferred communication channels, and providing additional outage resources to customer facing employees.

Q. Has the Company already learned valuable information from the journey mapping done to date?

A. Yes. The Outage Communications journey mapping team conducted a survey of customers that experienced an outage in the past year. The findings indicated that a majority of customers want to communicate with Con Edison more frequently, via text message. As a result, the Outage Communications journey mapping team has created a series of new messages and revised wording to improve clarity and empathy of existing messages. In addition, the journey mapping team is working on a project to enable over one million customers to have the ability report an outage via text message. By expanding the text notification program, the Company expects to improve customer satisfaction and reduce the volume of emergency-related calls during a major outage event.

Q. Briefly explain the work involved in Journey Mapping.

A. The work involved for the Journey Mapping program can be categorized into five main process steps, which are detailed in EXHIBIT__(CO-6). Journey mapping follows a lifecycle of continuous improvement, which means that the journey mapping teams do not move linearly from step to step. This flexibility is necessary because customers and external influences are always changing.

Q. What is the projected capital cost of this project?

A. The estimated capital costs for the program are $1.19 million in RY1, $975,000 in RY2, and $600,000 in RY3. The estimated total capital cost of this program for the 2020-2022 period is $2.765 million. The capital funding requested for this program will fund capital improvement projects identified by each of the journey mapping teams, such as new processes and technology investments in new systems.

Q. Are there any cost savings projected from this program?

A. Yes. The Journey Mapping program will contribute to achieving Customer Operations' BCO Savings targets. Additional details regarding these savings are provided in the BCO section of this testimony and presented in Exhibit AP-3, Schedule 16.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed capital investment in the Journey Mapping program?

A. Yes. We have prepared two exhibits, entitled "JOURNEY MAPPING" EXHIBIT__(CO-5) and "JOURNEY MAPPING PROCESS OVERVIEW AND BENEFITS" EXHIBIT__(CO-6).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-5) and EXHIBIT__(CO-6).

3. VIRTUAL ASSISTANTS

Q. Please summarize the Company's Virtual Assistants program.

A. The Virtual Assistants program, another component of Omni-Channel Optimization, will deploy a conversational virtual assistant, or bot, to provide unique, interactive, and personal assistance to customers across the chat, IVR, web/mobile web, mobile app, social media, and text platforms. Virtual assistants will provide customers with a new form of frontline support that automates many simple interactions, such as Start/Stop/Transfer service, payment, and payment assistance, currently performed by a CSR on the phone or through the existing live chat tool. With this program, the Company will expand the channels of interactions that are already available to customers across a variety of industries.

Q. How will virtual assistants provide frontline support to customers?

A. Virtual assistants will use artificial intelligence (“AI”) to learn Company processes and interact with customers to answer customer inquiries. The bots are also programmed to detect customer frustration, respond appropriately, and initiate seamless transfers to live agents when necessary.

The Company will invest in a virtual assistant AI program that will integrate with all of the systems that manage customer data or serve as an interface for customer interactions. Once we integrate the virtual assistant AI program with these systems, the bots will be able to suggest Next Best Actions or communicate directly to CSRs or customers on behalf of the Company.

Q. What are the overall goals and objectives for the Virtual Assistants program?

A. The overall goals of the Virtual Assistants program are to improve the customer experience and achieve operational efficiencies that result in cost savings. Virtual assistants will provide an interactive and personal way for customers to obtain answers and assistance across multiple channels, 24 hours a day, 7 days a week, and 365 days a year without having to wait for a CSR to become available. Virtual assistants will also augment human capabilities and proactively solve a range of customer inquiries at every touchpoint, at any hour of the day or night, which will reduce the likelihood of a digitally-oriented customer needing to speak or chat with a CSR.

Q. Please describe the status of the Company’s efforts related to Virtual Assistants.

A. Con Edison conducted a study to define the use cases, technical architecture, and suggested software for the Virtual Assistants program. Additional details are in EXHIBIT__(CO-7).

Q. Are there any cost savings projected resulting from this program?

A. Yes, the Virtual Assistant program will help the Company achieve its BCO savings targets associated with self-service optimization, which is described in the BCO section of this testimony and presented in Exhibit AP-3, Schedule 16.

Q. What is the projected capital cost of this program?

A. The estimated capital costs for the program are $2 million each rate year. The estimated total capital cost of this program for the 2020-2022 period is $6 million. The capital funding requested for this program will cover the purchase and installation of a virtual assistant AI program, and integrating that program with systems that manage customer data and act as an interface with customer interactions.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Virtual Assistants program?

A. Yes. We have prepared one exhibit, entitled "VIRTUAL ASSISTANTS" EXHIBIT__(CO-7).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-7).

4. BILL REDESIGN

Q. Please describe the Company's Bill Redesign program.

A. We established in 2017 the Bill Redesign program, the final component of Omni-Channel Optimization, to implement changes to the customer bill and increase electronic delivery ("eDelivery") adoption. The Bill Redesign program will update and modernize the paper bill to highlight key customer information, such as bill amount and payment due, and align the paper bill with the Company's digital platform for consistent presentment of bill-related information. Aligning the bill with our digital platform is becoming increasingly important as more than 46% of customers are currently receiving their bill electronically. The program will also use insights drawn from the Journey Mapping and Data and Analytics programs proposed in this panel to encourage eDelivery adoption.

Q. Please elaborate on how the Journey Mapping and Data and Analytics programs support the Bill Redesign program.

A. The Company will begin a Billing and Payments journey mapping exercise in 2019, which will review the customer experience for customers on eDelivery, explore barriers to adoption, and identify solution or tools to encourage eDelivery adoption. The proposed Data and Analytics program proposed will also play a role in developing propensity models to identify customers with a high likelihood to enroll in eDelivery, which will be used to develop targeted messaging to encourage eDelivery adoption among select customer groups.

Q. What customer research has the Company completed or reviewed to support the need for the Bill Redesign program?

A. As part of Phase 1 of the Bill Redesign program, the Company conducted extensive research and benchmarking within the utility and telecom industries (e.g., Accenture, Info Trends, Chartwell, CS Week) to identify bill design best practices. Findings from the research are available in EXHIBIT__(CO-8).

The Company also conducted online customer surveys using the Con Edison Advisory Community to gather feedback on billing and bill prototypes. The Company performed a survey in 2017 for feedback on the bill and its contents, and one in 2018 for feedback on a bill prototype with our initial modifications that was developed based on the 2017 survey results and broader industry research discussed above. The Company will continue to seek this type of iterative customer feedback throughout the Bill Redesign program with additional customer surveys and focus groups.

Q. Please describe the status of the Company’s efforts related to Bill Redesign.

A. Phase 1 of the program focused on researching bill design trends, analyzing customer feedback about the current bill and identifying bill enhancements that were easy to implement. This included migrating from a bill printed on paper with background images to plain white paper, introducing color, and highlighting certain key information with boxes. The Company also procured add-on modules for its software platform that generates customer bills, to increase operational flexibility to modify the bill design.

The Company also began Phase 2 of the Bill Redesign program in January 2019. In Phase 2, the Company is applying the insights gained from the Phase 1 research to develop new bill design prototypes, testing the new design with the Advisory Community surveys and customer focus groups, and coordinating with internal and external stakeholders to gain additional feedback and affirm compliance with regulatory requirements.

Q. What is the projected capital cost of this project?

A. The estimated total capital cost associated with the Bill Redesign program is $1 million in RY 1.

Q. What is the estimated level of incremental O&M costs associated with the Bill Redesign program?

A. The incremental O&M request for the Bill Redesign program is $200,000 in RY1, and $8,000 for RY2.

These O&M costs include staff time to manage the project, expenses to support customer surveys and focus groups for feedback on bill changes, customer communications to encourage eDelivery adoption, contractors to maintain the software, and training for CSRs on changes made as part of the Bill Redesign program.

The Bill Redesign program will also contribute to achieving Customer Operations’ BCO Savings targets. By migrating from pre-printed paper forms to a plain, white paper form, the Company will save in back office costs and materials. The efforts to increase customer eDelivery adoption can help the Company reduce costs associated with postage from paper bill mailings.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company’s proposed investment in the Bill Redesign program?

A. Yes. We have prepared two exhibits, entitled “BILL REDESIGN” EXHIBIT__(CO-8) and “BILL REDESIGN WORKSHEET” EXHIBIT__(CO-9).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-8) and EXHIBIT__(CO-9).

C. BACK OFFICE AUTOMATION AND AGENT TOOLS

Q. Please describe the Company’s Back Office Automation and Agent Tools program.

A. The Back Office Automation and Agent Tools program is one of the major categories of investments included in the Company’s Next Gen CX. With this program, the Company seeks to improve the customer experience by streamlining processes and providing enhanced CSR tools. The program encompasses a collection of investments that include:

- Robotic Process Automation (“RPA”) - automate repetitive back office tasks
- Exception Management Tool - improve and streamline the resolution process for discrepancies identified by the system or raised by customers requiring additional internal review
- CSR Tools – implement enhancements to tools CSRs use when responding to customer inquiries and invest in a single system knowledge management tool that can be used by all employees for quick access to information, procedures, and policies relating to customer queries.

Q. Why is it important for the Company to make these improvements now?

A. Currently, the Company uses a number of manual processes to resolve back office work that is time intensive, creates risk associated with employee error, and is operationally inefficient. With RPA, the Company will be able to automate back office processes more quickly and accurately, and be confident that the results will be consistent. Improvements in RPA have also now made it feasible to automate processes that incorporate multiple business rules and encompass actions across several software programs.

The Company also maintains exception management system tools that are outdated and no longer supported by the vendor. Not only is the system outdated, but also has limited functionality, which requires manual assignment and tracking of work. Upgrading to a new exception management reporting tool will result in improved overall management of exceptions including prioritizing and assigning work to employees.

Finally, with REV and the expansion of clean energy programs and the AMI pilot program(s), the Company needs to invest in CSR tools that enable CSRs to respond effectively to customer inquiries. Enhancements to the desktop tool will provide CSRs with a quick reference to critical customer information as well as past interactions. Development of a knowledge management tool will enable the integration of information in an organized and easy to access format, allowing for faster creation and management of new information, such as new clean energy programs associated with EEDM and distributed generation.

Additionally, the operationally efficiencies gained from this program will help the Company meet its BCO savings goals, as described below. For details on the BCO savings achieved through Back Office Automation and

Agent Tools, please refer to the BCO section of this testimony and Exhibit AP-3, Schedule 16.

Q. What is the projected capital cost of this program?

A. The estimated total capital costs associated with the Back Office Automation and Agent Tools program are $2 million in RYs 1 and 2, and $200,000 in RY3. The total capital cost for the program over the 2020-2022 period is $4.2 million.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Back Office Automation and Agent Tools program?

A. Yes. We have prepared one exhibit, entitled "BACK OFFICE AUTOMATION AND AGENT TOOLS" EXHIBIT__(CO-10).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-10).

IV. BUSINESS COST OPTIMIZATION SAVINGS

Q. Are you familiar with the Company's BCO program as discussed in the direct testimony of the Company's Policy Panels?

A. Yes, we are. The Company has implemented the BCO program to enhance its cost optimization efforts. Following a comprehensive review of business processes, the Company's various business teams, including the Customer Operations organization, identified specific cost savings initiatives.

Q. Please discuss the types of O&M costs that the Customer Operations organization will incur.

A. Company labor accounts for approximately 90 percent of the Customer Operations organization’s O&M expenses. Company labor within Customer Operations consists primarily of CSRs who handle customer inquiries across multiple channels, as well as those CSRs who process back office transactions in support of these inquiries and other customer needs. For the purposes of the BCO program, reduced labor costs provides the greatest opportunity for cost reduction within the Customer Operations organization. However, the Company also identified savings opportunities in its postage and uncollectible bill costs, and has factored these additional savings into the Company’s revenue requirement calculation.

Q. Please describe the main cost reduction opportunities that Customer Operations identified as part of the BCO program.

A. Customer Operations separated the broader goal of cost optimization into three cost savings initiatives that present opportunities to reduce O&M costs: Self-Service

Optimization, Workforce Management, and Back Office Automation.

The Self-Service Optimization initiative serves to identify opportunities to allow customers to self-serve through channels, rather than using a CSR, and to reduce the need for customers to call the Company. Within this initiative, projects typically fall into one of two categories. The first category is an effort to direct customers to our digital platforms. Through technology enhancements, internal training, and customer awareness, we intend to broaden the services available through our digital platforms (as well as the convenience and accessibility of such services), thereby encouraging customers to self-serve on these platforms. The second category is an effort to improve the likelihood that customers will be able to meet their transaction objectives using the Company’s IVR system, thereby avoiding the need to speak with a CSR. Projects in this category are designed to identify and eliminate points in our IVR system that may lead to customer frustration or transaction failures. Customer Operations has formed several teams tasked with identifying specific projects that would support both efforts, including a full-time Self-Service Optimization team.

The Workforce Management cost savings initiative focuses on providing CSRs with the proper training and tools to respond to customer inquiries and meet customer expectations effectively and efficiently. This effort involves identifying and using data analytics, call volume forecasting and scheduling efficiencies to decrease the staffing required to handle customer inquiry demand. In parallel, CSR enablement projects in the form of skillset refinement and tool delivery will enhance the quality and efficiency of customer service so as to reduce the need for future calls, as well as the duration of each call. The Company also may realize further improvements in efficiency in the form of greater productivity per CSR. The initiatives in this category will result in labor expense savings through reduced overtime and staffing at the Company’s Customer Experience Centers.

Q. Please continue.

A. In addition to front-line CSRs, Customer Operations also employs a substantial back office workforce of approximately 150 FTEs. Our Back Office Automation initiatives will streamline and automate back office processes, consolidate work functions and eliminate manual tasks, thereby reducing labor and other expenses.

Key to achieving the savings identified for this category will be investment in RPA and a new exception management tool to facilitate workflows and enable back office areas to become more efficient. RPA will provide advanced process robotics that can handle specific billing errors or exceptions without requiring human intervention. A new exception management tool will allow the Company to process those back office exceptions that cannot be automated using RPA tools. This tool will allow supervisors to efficiently identify, prioritize, and route exception work to employees, and manage pending work with dashboards that provide a complete picture of work streams.

In addition to the BCO savings categories identified above, Customer Operations will achieve additional savings in postage and uncollectible bill charge-offs. We plan to achieve these savings through investments in Bill Redesign and continued work to limit uncollectible bills.

Q. Did you quantify the expected savings from these initiatives for Rate Years 1, 2 and 3?

A. Yes, the forecasted savings from the Self-Service Optimization, Back Office Automation and Workforce Management initiatives are presented in Exhibit AP-3, Schedule 16.

Q. Please explain how you arrived at these savings projections.

A. As noted above, we expect to realize Customer Operations' BCO cost savings primarily through lower staffing requirements. Within each of the three cost saving initiatives, Customer Operations assessed baseline projections of CSR count over the three Rate Years, as well as historical customer inquiry volume as compared with the projected inquiry volume once the aforementioned process and technology improvements are implemented. The Company then calculated the BCO savings amount based on the delta between the baseline CSR count (from end of year 2017) and future number of CSRs required to field the projected inquiry volume.

Q. Do your BCO costs savings account for any O&M costs that must be incurred to achieve your savings? If so, please explain.

A. Yes. As described in the Accounting Panel testimony, the BCO savings included in these rate filings are net values that reflect the total expected savings minus any O&M costs to achieve. As noted throughout this testimony, the O&M costs to achieve are not reflected in the program requests outlined in Customer Operations' white papers.

Q. Do any of the capital programs proposed in the Customer Operations Panel testimony support these BCO savings? If so, please explain.

A. Yes. The following table lays out the programs that support our BCO cost savings initiatives.

Customer Operations Capital Program	**BCO Cost Savings Initiative(s) Supported**
Digital Customer Experience (DCX)	Self-Service Optimization
Journey Mapping	Self-Service Optimization
Data & Analytics	Self-Service Optimization Workforce Management
Virtual Assistants	Self-Service Optimization
Back Office Automation and Agent Tools	Back Office Automation Workforce Management

Q. In addition to the direct BCO savings discussed above, are there other savings that the Company may realize within the Customer Operations function?

A. Yes. The Company has identified “influenced savings” associated with the Customer Operations function. “Influenced savings” refer to savings driven by initiatives implemented by Utility Shared Services, but that are allocated to another organization. For more detail on such savings, please see the direct testimony of the Shared Services Panel.

Q. What challenges does Customer Operations face in implementing its BCO-driven initiatives and realizing its cost savings?

A. External factors that drive customer inquiry volume are a constant challenge for Customer Experience Center staffing. For example, customer reaction to smart meter deployment and unexpected trends in weather all represent headwinds that may affect Customer Operations’ ability to achieve projected results from the BCO cost savings initiatives. In addition, as the Company implements more complex rates and distributed energy resource solutions, and opens new channels of customer interaction, our customers’ expectations will grow and evolve as well.

While the Company has endeavored to estimate the reduction in customer inquiry volume stemming from each of our cost savings initiatives, forecasts by their nature include certain assumptions that will vary from actual experience. The degree of variation will have a corresponding impact on the resulting savings. A piloted program may produce a smaller return than predicted because of the factors above. This poses risks to realizing our projected savings. Customer Operations’ primary means of managing such risks is through data-intensive baselining of our current state, paired with ongoing analysis of the results of our myriad initiatives, with the expectation that we will identify methods to close any gaps between expected and actual results on an ongoing basis.

V. ADVANCED METERING INFRASTRUCTURE SAVINGS

Q. Does the Company anticipate continued savings to O&M expenditures associated with the AMI smart meter initiative?

A. Yes. The Company expects continued O&M cost reductions from AMI deployment. O&M cost reductions are driven by labor savings in the following areas in Customer Operations: Meter Operations, Field Services, the Customer Experience Center, Billing, and Replevin.

Anticipated O&M labor cost reductions take into consideration the following:

- Meter Operations: Reduction in meter reader FTE staffing
- Field Services: Reduction in FTE staffing - includes turn-on / turn-off ("T&T") staff, Special Forces staff (includes Replevin), Collections staff, and supervisory staff
- Customer Experience Center: Reduction in call volume translated into FTE staffing - includes reduction in account investigation listings ("AILs"), meter

reading and estimated read calls, T&T calls, and high bill complaint calls

- Billing: Reduction in call volume and work associated with billing AILs, and avoided PSC complaint costs, translated into FTE staffing

Q. What other O&M cost reductions are anticipated in the Customer Operations organization because of AMI?

A. The Company also expects the AMI program to result in non-labor reductions in O&M costs associated with Replevin through reductions in administrative fees associated with Replevin.

The incremental O&M cost savings associated with Customer Operations as a result of AMI deployment are summarized in the table below.

('000s)	RY1 2020	RY2 2021	RY3 2022
Labor	$(19,316)	$(12,120)	$(7,315)
Non-Labor	$(183)	$(75)	$(35)
Total	$(19,499)	$(12,195)	$(7,350)

Q. Are the AMI Savings identified included in the BCO savings described in this testimony?

A. No. The AMI-related O&M savings identified in this testimony are separate and distinct from the BCO savings described in this testimony and in the Accounting Panel testimony.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's AMI Savings for Customer Operations?

A. Yes. We have prepared two exhibits, entitled "ADVANCED METERING INFRASTRUCTURE SAVINGS" EXHIBIT__(CO-11) and "ADVANCED METERING INFRASTRUCTURE SAVINGS WORKSHEET" EXHIBIT__(CO-12).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-11) and EXHIBIT__(CO-12).

VI. CREDIT AND DEBIT CARD FEES

Q. Please describe the Company's current policy regarding payments made using prepaid, credit, and debit cards (collectively "CC/DC").

A. Currently, customers can pay their Con Edison bills using CC/DC on the phone or through the Company's website or mobile app. Residential and small commercial customers pay a $3.35 transaction fee each time they pay using the CC/DC option. This fee is assessed and collected by the Company's CC/DC payment processing vendor and has no impact on the Company's revenues. Large commercial customers that choose to pay via CC/DC are subject to a transaction fee equal to 2.6 percent of the payment amount; the fee for large commercial customers is also assessed and collected by the vendor and does not impact

Company revenues. The Company does not currently accept recurring CC/DC payments because customers must actively accept the vendor’s transaction fee at the time of each transaction.

Q. Does the Company propose to change its policy regarding CC/DC payments?

A. Yes. The Company proposes to include in base rates the estimated cost of residential and small commercial customers making CC/DC payments. This will eliminate the per-transaction cost to our customers, and the Company will become responsible for the aggregate costs of processing CC/DC payments. This is referred to as a “no-fee model.” The Company proposes to recover the costs under the no-fee model in base rates.

Q. Please explain why the Company is making this proposal.

A. Credit and debit cards have become one of the most common payment methods for a variety of reasons, including convenience to customers. According to a 2016 Federal Reserve Payments Study, card payments (including credit, debit, and pre-paid cards) accounted for 72 percent of the total number of non-cash payments in the United States in 2015, up from 39 percent in 2000. EXHIBIT__(COP-1) demonstrates this economy-wide trend.

Customers expect the Company to provide billing and payment options on par with the options available to customers for their other day-to-day transactions, such as paying a wireless bill or a medical bill. Indeed, through its quarterly customer experience surveys, the Company has consistently received feedback from customers that they would like the ability to make CC/DC payments without a fee, or the ability to schedule recurring payments. This proposal will, therefore, bring the Company in line with what customers have come to expect, and will improve customer satisfaction.

Once this program is implemented, residential and small commercial customers will have the opportunity to pay their bills using all of our accepted methods without a fee. This will enhance the customer experience and allow customers to choose the payment option that best meets their needs.

The Company also expects that the number of customers using CC/DC payment options will increase with this program, and will lead to operational benefits including a reduction in returned payments and faster same-day payments. Additionally, a 2014 study by Fiserv, a CC/DC payment-processing vendor, showed that across 105 utilities, transitioning to a no-fee model led to increased use of self-service payment options, specifically more web payments and recurring payments.

The Company also believes transitioning to a no-fee model will benefit customers who receive public assistance benefits via pre-paid debit cards. Under the current model, such customers can pay their utility bill with their pre-paid debit card, but must use a portion of the benefits to cover the vendor fee for CC/DC payments, resulting in an added economic disadvantage. Adopting a no-fee model will eliminate the need for a portion of public assistance benefits to pay this administrative fee.

Q. Has the Commission approved utility proposals to shift to the no-fee model?

A. Yes. The Commission has approved similar models at New York State Electric and Gas Corporation, Rochester Gas and Electric Corporation, and Central Hudson Gas and Electric Corporation. Similarly, Orange and Rockland Utilities, Inc.’s pending Joint Proposal in its most recent base rate case provides for transition to the no-fee model. Con Edison’s proposal in this testimony is consistent with the proposals made by other utilities and approved by the Commission and there are no particular circumstances in Con Edison’s service territory that warrant different treatment.

Q. Has the Company sought more competitive CC/DC transaction fees from vendors?

A. Yes. The Company recently completed a Request for Proposals seeking competitive CC/DC transaction fee rates from payment processing vendors and selected a vendor for the proposed no-fee model.

Q. What are the per-transaction costs under the no-fee model?

A. Upon Commission approval of the no-fee model, the Company’s cost per transaction for these customers will be $2.10 beginning in RY1, which translates to a reduction of 37% over the current fee of $3.35 paid by customers per transaction. The cost of large commercial CC/DC payments would remain unchanged at 2.6 percent of the payment amount.

Q. Does the Company anticipate seeing an increase in payments made via CC/DC under a no-fee model?

A. Yes. Based on benchmarking data provided by the vendor, the Company expects to see a 47% increase in CC/DC payments with the no-fee model in RY1, and incremental increases of 31% and 10% in RY2 and RY3, respectively.

Q. What are the Company’s estimated total annual O&M costs that would result from a transition to the no-fee model?

A. The Company estimates that the total annual O&M costs associated with this new program would be $6.3 million in RY1, $8.2 million in RY2, and $9.0 million in RY3.

Q. How does the Company propose to recover these incremental costs?

A. The Company proposes that any costs incurred by the Company associated with this payment option be considered among the general costs of doing business similar to fees paid for other payment methods (such as direct debit) and be included in the Company’s revenue requirement.

Q. Have you prepared, or had prepared under your supervision, an exhibit that details the Credit and Debit Card Fee proposal?

A. Yes. We have prepared three exhibits, entitled “CREDIT AND DEBIT CARD FEE ELIMINATION” EXHIBIT__(CO-13), “2016 FEDERAL RESERVE PAYMENTS STUDY” EXHIBIT__(CO-14), and “CREDIT AND DEBIT CARD FEE ELIMINATION WORKSHEET” EXHIBIT__(CO-15).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-13), EXHIBIT__(CO-14), and EXHIBIT__(CO-15).

VII. CUSTOMER EXPERIENCE CENTER DISASTER HARDENING

Q. Please summarize the Company's Customer Experience Center Disaster Recovery program.

A. The Company proposes to harden its Internet Protocol ("IP") telephony system to maintain operational reliability when multiple events occur, such as cyber attacks or physical disasters, which might affect the Company's network infrastructure. Currently, the IP telephony system is supported by two physically separated server farms, and if one of the server farms supporting the IP telephony system experiences an outage, all call traffic is automatically processed via the alternate location. However, the IP telephony system is not designed to endure two simultaneous events ("double contingency events") that might damage or compromise operation of both server farms at the same time.

In total, the IP telephony system processes nearly 100 million minutes of voice traffic annually, and millions of customer interact with the system each year. While double contingency events are unlikely, they would severely impede the Company's ability to effectively assist customers with system related emergencies, such as power outages or gas leaks, and receive customer service inquiries.

In light of the growing threat of cyber security attacks, which could shut down multiple server farms at once, the current IP telephony system’s single contingency configure is a risk that requires additional hardening to protect against double contingency events that would prevent the Company from learning about or responding to situations that threaten public safety and result in substantially lower volumes of customer-reported outages that aid in damage assessment and restoration planning.

Q. Please explain how the Company will harden the IP telephony system against double contingency events.

A. The Company will perform a comprehensive analysis of potential solutions in 2019 – including a combination of off-premises telephony design options – and will select a technology solution based on project feasibility, cost, time to implement, and integration compatibility with existing systems. The off-premises disaster recovery solution (e.g., cloud-based or software as a service) will be hosted by a qualified vendor and will integrate with the Company’s customer information systems.

Q. What is the overall goal of the program?

A. The goal of the Customer Experience Center Disaster Recovery program is to harden the IP telephony system to maintain operational reliability in the event of simultaneous incidents that might damage or compromise operations of both server farms at the same time.

By hardening the IP telephony system, the Company will be able to maintain reliable access to the Call Center and IVR self-service during double contingency events, providing continuous system availability to service customers, and, provide uninterrupted flow of critical outage and public safety-related information.

Q. Why is it important that these improvements are made at this time?

A. The Company is taking a proactive stance to maintain reliable operation of its mission-critical IP telephony system. In the worst-case scenario of a double contingency event, the impact on customers would be particularly far-reaching and prevent the Company from learning about or responding to situations that threaten public safety.

Also, cyber attacks on utilities have become more prevalent in recent years, raising significant concerns among corporations and governments alike because of the impact such attacks could have on the power grid as well as utility customer service infrastructure. The

Information Technology Panel provides additional details on cybersecurity risks.

Q. What is the projected capital cost of this project?

A. The estimated total capital costs associated with the Customer Experience Center Disaster Recovery program is $1.5 million for Rate Year 1.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Customer Experience Center Disaster Recovery program?

A. Yes. We have prepared one exhibit, entitled "CUSTOMER EXPERIENCE CENTER DISASTER RECOVERY" EXHIBIT__(CO-16).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-16).

VIII. OFF-SYSTEM BILLING

Q. Please explain what is meant by "off-system" billing and why the Company uses such processes.

A. The Company uses a number of billing processes to perform complex billing that occur outside of CIS, the front-end mainframe application for the existing CSS. These complex billing processes, which include new or modified rate structures and calculations, cannot be handled by CIS and instead are performed in the Company's satellite Customer Care and Billing ("CC&B") application to automate certain rates and programs, such as the Value of Distributed Energy Resources (“VDER”) tariffs.

As the Commission continues to approve and refine complex rate designs and expand REV clean energy programs that rely on new billing approaches, the Company must adapt to new billing requirements. If the Company were to rely on manual billing processes for complex rates, the experience of participating customers would diminish and increase the risk of billing errors and delays in the application of bill credits and/or charges.

Q. Please describe the status of the Company’s efforts related to off-system billing.

A. The Company continues to automate billing processes such as Standby Offset billing automation, Standby Reliability credit calculations, Distributed Generation Gas Load Factor Validation, Standby Multi-party Offset billing and Rider Q billing. Additionally, as a result of the Commission’s *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources and Related Matters* (issued March 9, 2017) in Case 15-E-0751, which among other things established the value stack paradigm for compensating distributed generation sources and directed the utilities to file VDER tariffs, the Company made upgrades to CC&B to automate the calculation of complex value stack credits and the application of those credits to customer bills.

Q. Why is it important that these improvements are made at this time?

A. The Company anticipates that the Commission will continue to approve new programs and rate designs under REV and other clean energy proceedings in conjunction with broader AMI deployment. The Commission has expressed its intent to make additional improvements to the VDER program, such as addressing rate design issues, in its September 14, 2017 *Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters*. In that Order, the Commission clearly stated that it had only taken the “first steps in the necessary evolution of compensation for Distributed Energy Resources (DER)…” While specific upgrades have not yet been defined, continued investment in off-system billing processes is necessary for the Company to deliver timely, accurate bills to customers participating in innovative new rates and programs. Delaying investments to update systems and automate processes will not only lead to poor customer experiences because of late or incorrect bills, but also stifle customer adoption of REV programs because of poor customer experiences. Continued work on billing automation will afford the Company greater flexibility to develop and modify billing processes to comply with future regulatory and /or legislative mandates and enable the Company to be responsive to evolving customer needs and interests.

Q. Will continued investment in off-system billing result in any stranded costs with the New CSS?

A. No. Continued investment in off-system billing automation will not result in any stranded costs as both programs use the CC&B platform. Customer Operations is working closely with the CSS team. Based on the technology used, the existing CC&B system will seamlessly integrate with the New CSS, allowing for a smooth transition for customers billed under complex rates and programs.

Q. What is the proposed capital cost for this project?

A. The Company proposes to make $1 million capital investment for RY1 to implement additional modifications and upgrades to its off-system billing processes to accommodate anticipated changes.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in off-system billing automation?

A. Yes. We have prepared one exhibit, entitled "OFF-SYSTEM BILLING" EXHIBIT__(CO-17).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-17).

IX. REVENUE PROTECTION ANALYTICS

Q. Please explain the Revenue Protection Analytics program.

A. The Revenue Protection Analytics program will use data from multiple data sources to analyze customer accounts for indications of potential theft of services or other irregular metering conditions. These data sources include our CSS, AMI Head-End System ("HES"), Meter Data Management System ("MDMS"), and the Revenue Protection Operations Optimizer system on the Company's Enterprise Data Analytics Platform ("EDAP").

Q. Please describe the role of the Revenue Protection Unit ("RPU") in Customer Operations.

A. The RPU's primary function is to investigate instances of possible theft of the Company's gas and electric services. RPU conducts these investigations by visiting customer premises and conducting inspections on the Company's metering equipment. Upon discovery of theft or other irregular metering conditions such as malfunctioning meters, RPU will work with Customer Operations' Unmetered and Metered Services group to correct the condition and backbill customers in accordance with Commission regulations.

Q. How does RPU determine which customer(s) to investigate?

A. RPU receives leads for investigation from a variety of sources, including, but not limited to, reports from Company employees conducting other job functions, customers, local law enforcement, the Department of Buildings, and CSS-generated leads for account investigations.

Q. What will the Revenue Protection Analytics software do?

A. The Revenue Protection Analytics software will leverage the software used by the Company's EDAP to generate leads for investigation based on analyzing data from a variety of sources. The Revenue Protection module will use machine learning to evaluate prior thefts or other irregular metering conditions to identify and flag accounts that have similar consumption patterns. It will also prioritize investigations based on the success and failure of investigations on an ongoing basis. The software module can incorporate data from a variety of sources, including AMI data, outage data, work management, or any other data accessible to the analytics platform.

Q. Why is this program necessary for RPU?

A. The Company expects that the Revenue Protection Analytics program will offset the loss of investigative leads that will result from the AMI implementation, as described below. One of the primary sources of leads for investigation is from the Customer Field Representatives ("CFRs"), our meter reading employees. Beginning in 2018, the Company began reducing CFR staffing due to the deployment of AMI meters. As AMI meter deployment progresses, the Company will further reduce the number of CFRs it employs. As a result, RPU will receive fewer leads from these resources. Reports from CFRs are among the highest in terms of successfully finding theft or other irregular metering conditions, because CFRs can visually confirm these conditions in the field. RPU will need to find an alternative means to determine which locations to investigate if it is to continue in its efforts to find theft of services.

Q. How much will this program cost?

A. This program will cost approximately $201,000 in RY1, and $509,000 each for RY2 and RY3. In addition to software, the program will require the addition of two FTEs. These two FTEs will be responsible for analyzing data, working with field forces to verify and report on investigation findings, and working with the software vendor to refine the machine learning models as needed.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Revenue Protection Analytics program?

A. Yes. We have prepared two exhibits, entitled "REVENUE PROTECTION ANALYTICS" EXHIBIT__(CO-18) and "REVENUE PROTECTION ANALYTICS WORKSHEET" EXHIBIT__(CO-19).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-18) and EXHIBIT__(CO-19).

X. ELECTRONIC CORRESPONDENCE EXPANSION

Q. Please summarize the Company's proposal regarding electronic correspondence with customers.

A. The Company proposes to evolve its delivery practices for regulatory-required correspondence to match its existing practices for bills, customer education and other discretionary outreach. Specifically, the Company proposes to establish a pilot e-delivery/electronic document program applicable to all documents for customers who have indicated their preference to receive their bill electronically ("ebill"). With this pilot, the Company would deliver all communications, including those required by Commission directive, electronically in lieu of providing a paper copy via mail. The Company will monitor the success of this pilot and, based on the findings, expand the pilot to provide electronic documents for non-ebill customers that have provided the Company an email address.

Q. What led to the current state of correspondence delivery where some items are delivered electronically and others are mailed in hard copy format?

A. The Company has successfully moved a number of pieces of correspondence to electronic format over the past five years. This includes customer bills and bill inserts, non-regulatory required correspondence, and general customer education notices (e.g., information on energy efficiency programs, storm preparation tips, and gas safety messages). However, historically, the Company has continued to send certain forms of correspondence required by the Home Energy Fair Practices Act ("HEFPA"), such as credit-related disconnect notice, via regular mail.

Q. Does the Company believe that this differential treatment for certain kinds of correspondence has a meaningful impact on customer experience?

A. Yes, the Company believes its current practices are inefficient and diminish the customer experience for a number of reasons. Sending documents through both channels (email and U.S. mail) is duplicative and costly. As a result, the Company currently sends these mailings to U.S. mail. Where a customer has elected to enroll in ebill, they expect to receive communications through the email address provided (in many cases customers have elected to receive all of their bills and correspondence from all of the companies they do business with electronically, such as banking, retail and telecom, to this same email address) and the practice of then sending regulatory mandated correspondence via U.S. mail may make these customers less likely to respond timely (or respond at all) to important notices.

Additionally, delivering documents differently across different types of correspondence for the same customer is confusing for customers that prefer to receive all of their correspondence via digital channels. For instance, they might receive the email first, make immediate payment resolve a credit action, and then subsequently receive the same notice via U.S. mail. The customer could then be confused that their payment made after receipt of the initial email did not satisfy the issue. As described in the Next Gen CX section above, the Company wants to meet its digitally-oriented customers where they are, and encourage use of lower-cost self-service options. Continuing to send regulatory-mandated correspondence via mail is counter-productive to this goal and prevents the Company from achieving deeper savings on postage costs.

Q. Why does the Company feel that this is the right time for proposing this change?

A. The Company is proposing this change now for a number of reasons. First, the number of customers requesting to receive documents electronically has grown over the last five years from 8% in 2013 to 47% in 2018. This growth reflects the changing expectations of customers with respect to being able to choose the delivery method of all correspondence.

Also, as a result of these changing expectations, the Company has enhanced its e-delivery processes over the last few years to improve the experience. Specifically, today the Company has the ability to send any customer correspondence to a customer’s email address through a pin-protected pdf document. This means that the customer receives a secure copy of the exact same document in terms of content and look and feel that would otherwise be sent via U.S. mail. Finally, the Company received approval of an Electronic Deferred Payment Agreement Signature program that acknowledges the opportunity to improve engagement with customers by delivering important documents electronically.

Q. Please describe the actions that the Company proposes to take to assure proper consumer protections associated with the proposed change.

A. The Company proposes to track whether the customer has opened an email containing regulatory-mandated correspondence within three days of receipt. If the Company cannot confirm that the customer opened the email, a duplicate correspondence would be sent via U.S. mail. This process is identical to the process approved by the Public Service Commission as part of the Company’s Electronic Deferred Payment Agreement filing.

Q. Has the Company conducted a risk assessment associated with this new pilot?

A. Yes. This pilot has the potential to pose the following risks: risk of human error in obtaining electronic mail addresses, risk of intrusion by an unauthorized third party; risk of repudiation; and risk of fraud. The Company is planning to implement the same risk mitigation measures for this pilot as it is for its Electronic Deferred Payment Agreement program.

XI. CUSTOMER OUTREACH AND EDUCATION

Q. Please explain the role of Customer Outreach.

A. The Company established Customer Outreach to develop and provide outreach and education activities and programs and materials to educate the Company's customers regarding their rights, responsibilities and options as utility customers. Over the years, its mission has expanded to include educating customers on safety, billing and payment options, programs and services available to help customers manage their energy costs, special services for elderly, blind and disabled customers, and options available for interacting with the Company. Customer Outreach activities include interacting with customers at community events and meetings where Outreach Advocates distribute literature and present information to customers and community organizations on various topics.

In addition, the Company develops outreach and education plans for new Company initiatives, including the AMI deployment project, the Company's AMI Innovative Pricing Pilot and Shared Solar pilot described in the Customer Energy Solutions Panel testimony. The annual report filed by the Company in Case 16-E-0060 provides more detailed information on the Company's Outreach and Education Plan.

Q. Is the Company planning to increase the amount spent on outreach initiatives?

A. Yes. An increase of $666,000 is needed for Rate Year 1. Additional increases of $103,000 and $107,000 respectively are needed in Rate Year 2 and Rate Year 3.

Q. How will this funding be used?

A. Funding will pay for the following activities:

1. Development of personalized online (website), offline (email), and mobile engagement (mobile app) campaigns that provide customer specific and actionable information to targeted audiences;
2. Expansion of email campaigns, including those associated with key customer journeys and Company work notifications;
3. Increased spending on customer research;
4. Expanded training for Company employees in CX and other topics, including REV initiatives and diversity and inclusion competency; and
5. Increased costs for postage and materials involved in direct mail campaigns and educational awareness materials.

Q. Have you prepared or supervised the preparation of an exhibit describing the Company’s planned expenses for general outreach and education programs?

A. Yes. We have prepared two exhibits. These are entitled "CUSTOMER OUTREACH AND EDUCATION," EXHIBIT___(CO-20), and "OUTREACH AND EDUCATION WORKSHEET," EXHIBIT___(CO-21).

MARK FOR IDENTIFICATION AS EXHIBIT___(CO-20)and EXHIBIT___(CO-21).

XII. <u>ELECTRIC AND GAS LOW INCOME PROGRAMS</u>

Q. What is the purpose of the Panel's testimony related to the Electric and Gas Low Income Programs?

A. This testimony discusses the continuation of the Company's Low Income Programs, in accordance with the Commission's Orders issued in its Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers in Case 14-M-0565 ("Low Income Proceeding"). In particular, the Commission's May 2016 *Order Adopting Low Income Program Modifications and Directing Utility Filings* ("May 2016 Order") established a standard framework for all New York State utilities' low income programs. The Commission established a method to set the low income discount to achieve an average target energy burden (i.e., the percentage of a household's income that is spent on energy) of six percent of monthly household income – or three percent for customers taking electric or gas service only. The Commission also established a tiered discount system, with four levels of discounts for customers based on level of need. The framework also established a funding limit so that the total budget for each utility cannot exceed two percent of total electric and/or gas revenues for sales to end-use customers. Additionally, utilities are now required to enroll eligible low income customers in budget billing (referred to as a "Level Payment Plans" by the Company) on an opt-out basis. The Commission also established certain rules for utilities that choose to offer reconnection fee waivers to customers participating in low income discount programs, and set forth a new standardized quarterly reporting format for all utilities. In accordance with the May 2016 Order, the Company submitted an Implementation Plan outlining its proposal to conform its Electric and Gas Low Income Programs with the new framework as part of the 2017-2019 rate plan.

Q. Was the Company's Implementation Plan approved by the Commission?

A. Yes, the Commission approved the Implementation Plan and the Electric and Gas Low Income Programs were revised as part of the 2016 Joint Proposal adopted by the Commission. Since 2017, the low income programs are in line with the Commission's new framework for low income programs. Importantly, this includes an annual adjustment to discounts levels, if necessary, in accordance with the Commission's *Order Approving Implementation Plans with Modifications* (issued February 17, 2017). On December 1, 2017 and November 30, 2018, the Company filed Annual Low Income Program Update Reports in the Low Income Proceeding and the 2016 Rate Proceeding informing parties of updated discount amounts.

Q. Please describe the current Electric Low Income Program.

A. Effective January 1, 2019, the Company offers discounts to eligible low income electric customers as shown in the following table. Discounts were calculated pursuant to the formulas established by the Commission in the Low Income Proceeding.

Electric Low Income Discounts Effective 1/1/2019

Income Level	**Electric Non-Heat**	**Electric Heating**
Tier 1	$10	10
Tier 2	$10	10
Tier 3	$27	$27
Tier 4	$12	$12

Customers participating in the Electric Low Income Program are also eligible to receive a waiver of the reconnection fee if their electric service is terminated for non-payment – limited to one waiver per rate year as outlined in the Company's 2016 Rate Plan – and are automatically enrolled in the Company's Level Payment Plan ("LPP") on an opt-out basis.

Q. How do customers qualify for the Company's Electric Low Income Program?

A. Customers are eligible for electric bill discounts if they participate in one or more qualifying public assistance programs. Qualifying programs include the Home Energy Assistance Program ("HEAP"), Medicaid, Safety Net Assistance, Supplemental Nutrition Assistance Program ("SNAP"), Supplemental Security Income ("SSI") and the Temporary Assistance to Needy Persons/Families ("TANP") program. Customers are also eligible for the Low Income Programs if they are enrolled in a Direct Vendor or Utility Guarantee Program ("DV/UG Program"). All customers that the Company learns are participating in these qualifying programs are enrolled in the Electric Low Income Program, without limit.

Q. How does the Company assign eligible customers to each tier in the Electric Low Income Program?

A. The Company's tier-based system has the following eligibility criteria:

- Tier 1 – Customers who are participating in one or more qualifying public assistance programs – including Medicaid, Safety Net

Assistance, SNAP, SSI, and TANP – and/or have received a HEAP benefit in the preceding 12 months.

- Tier 2 – Customers who have received one HEAP "add-on"[1] benefit.
- Tier 3 – Customers who have received two HEAP "add-on" benefits.
- Tier 4 – Customers who are receiving utility bill payment assistance as part of the DV/UG programs. Note that when Tier 4 customers are no longer receiving bill payment assistance, their eligibility for the Company's Electric Low Income Program will be re-evaluated and, if warranted, assigned to a different tier.

Q. Is the Company proposing to continue the Electric Low Income Program?

A. Yes. The Company proposes to continue the Electric Low Income Program with the same terms.

Q. Is the Company proposing any updates to the Electric Low Income Program target cost or budgets for the Rate Year?

[1] An "add-on benefit", as defined in the Commission's Low Income Program Order, is an incremental payment that is provided to HEAP recipients if their household income is at or below 130% of the federal poverty level, or if their household contains a vulnerable individual (i.e., household member who is age 60 or older, under age 6, or permanently disabled). A customer can receive two add-on benefits if both of these conditions apply to their household.

A. Yes. The Company is proposing to update the targeted annual aggregate amounts for electric low income discounts and reconnection fee waivers, respectively, that are included in base rates. Specifically, the Company proposes a target amount of $52,782,102 for electric low income discounts for the Rate Year, and a target amount of $527,821 for electric reconnection fee waivers for the Rate Year.

Q. Why does the Company need to update the targeted amount for electric low income discounts?

A. Customer participation in the Electric Low Income Program is projected to decrease relative to the participation levels assumed in the 2017-2019 rate plan; additionally, the electric discount levels have increased slightly for Tiers 3 and 4, as indicated in the Company's November 30, 2018 Annual Low Income Program Update Report. The Company is proposing to update the discount target amounts to reflect both of these changes. Please refer to EXHIBIT__(CO-22) for supplemental information.

Q. Why is the Company updating the targeted amount for reconnection fee waivers?

A. The May 2016 Order specified that utilities offering reconnection fee waivers as part of a low income program must limit spending on such waivers to 1% of the budget.[2] Since the Company is proposing to revise its target discount amounts as described above, it is also proposing to decrease the reconnection fee waiver target amount. It should be noted that for the first two years of the 2017-2019 rate plan, the Company granted waivers equivalent to 64% and 49% of its annual target amount ($547,000). As such, we do not expect this reduction to have a material impact on our Low Income Program participants.

Q. Does the Company propose to continue funding up to $50,000 per year of administrative costs for the New York City Human Resources Agency and Westchester Department of Social Services?

A. Yes.

Q. Does the Company propose any form of reconciliation if actual participation in the Electric Low Income Program is higher or lower than the Company's forecast, or if the annual updates to discount levels result in increased or decreased spending on electric bill discounts?

A. Yes. Consistent with the 2017-2019 electric rate plan, all over and under-recoveries associated with the electric low income discounts and the waiver of

[2] May 2016 Order, p. 38.

reconnection fees will be reconciled through the Revenue Decoupling Mechanism ("RDM") from all customers subject to the RDM for the Electric Low Income Program. The Company proposes to continue this reconciliation without modification.

Q. Please describe the Company's Gas Low Income Program.

A. Effective January 1, 2019, the Company offers discounts to eligible low income gas customers as shown in the following table. Discounts were calculated pursuant to the formulas established by the Commission in the Low Income Proceeding.

Gas Low Income Discounts Effective 1/1/2019

Income Level	**Gas Non-Heat**	**Gas Heating**
Tier 1	$3	$50
Tier 2	$3	$50
Tier 3	$3	$56
Tier 4	$3	$50

Customers participating in the Gas Low Income Program are also eligible to receive a waiver of the reconnection fee if their gas service is terminated for non-payment – limited to one waiver per rate year as outlined in the 2016 Joint Proposal – and are automatically enrolled in the Company's LPP on an opt-out basis.

Q. How do customers qualify for the Company's Gas Low Income Program?

A. The eligibility requirements for participation in the Gas Low Income Program are the same as those outlined above for the Electric Low Income Program. All customers that the Company learns are participating in the qualifying programs listed above and taking gas service are enrolled in the Gas Low Income Program, without limit.

Q. How does the Company assign eligible customers to each tier in the Gas Low Income Program?

A. The Company's tier-based system for gas discounts has the same eligibility requirements as those outlined above for electric discounts.

Q. Is the Company proposing to continue the Gas Low Income Program?

A. Yes. The Company proposes to continue the Gas Low Income Program with the same terms.

Q. Is the Company proposing any updates to the targets or budgets for the Gas Low Income Program?

A. Yes. The Company is proposing to update the target budget amount for gas low income discounts that are included in base rates. Specifically, the Company proposes a target budget amount of $15,935,526 for gas low income discounts for the Rate Year. The Company proposes to keep the target budget amount for gas reconnection fee waivers flat relative to the 2017-2019 rate plan (i.e., up to $75,000 per rate year).

Q. Why is the Company updating the targeted amount for gas low income discounts?

A. Customer participation in the Gas Low Income Program is projected to increase relative to the participation levels assumed in the 2017-2019 rate plan; additionally, the gas discount levels have increased slightly, as shown in the Company's November 30, 2018 Annual Low Income Program Update Report. The Company is proposing to update the discount target amounts to reflect these changes. Please refer to EXHIBIT__(CO-23) for supplemental information.

Q. Does the Company propose any form of reconciliation if actual participation in the Gas Low Income Program is higher or lower than the Company's forecast, or if the annual updates to discount levels result in increased or decreased spending on gas bill discounts?

A. Yes. Consistent with the 2017-2019 electric rate plan, all over and under-recoveries associated with the gas low income discounts and the waiver of reconnection fees will be reconciled through the Monthly Rate Adjustment ("MRA") from all customers subject to the MRA for the Gas

Low Income Program. The Company proposes to continue this reconciliation without modification.

Q. What are the forecasted combined costs of the Electric and Gas Low Income Programs for the Rate Year, including both bill discounts and reconnection fee waivers?

A. The forecasted costs of the Electric and Gas Low Income Programs for the Rate Year are outlined below.

Projected Cost of Electric and Gas Low Income Programs ($ millions)

Period	Electric	Gas
January 1 – December 31, 2020	$53,329,102	$16,010,526

Q. Is it possible that the actual costs of the Electric and Gas Low Income Programs may change in subsequent years if the Commission approves a multi-year rate plan in this proceeding?

A. Yes. Based on past experience and the Commission's required annual review and potential reset of low income discounts in each tier, actual participation in the Company's Low Income Programs will vary over the course of a multi-year rate plan. However, the target amounts for both bill discounts and reconnection fee waivers outlined above will not be modified in RY 2 or RY3 of a multi-year rate plan. It should be noted that this method of recovering program costs in a second and third rate year is consistent with how the Company's Low Income Programs were funded during the 2017-2019 rate period.

Q. Does the Company plan to continue its existing enrollment reconciliation and reporting requirements from the 2016 Joint Proposal?

A. Yes.

Q. Have you prepared or supervised the preparation of an exhibit describing the Company's Low Income Program?

A. Yes. We have prepared two exhibits. These are entitled "LOW INCOME PROGRAM-ELECTRIC" EXHIBIT__(CO-22), and "LOW INCOME PROGRAM-GAS" EXHIBIT__(CO-23).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-22)and EXHIBIT__(CO-X3).

XIII. ELECTRIC RECONNECTION FEES

Q. Please explain the Company's proposal with respect to reconnection fees for electric customers with AMI meters.

A. As proposed on page 44 of the November 2015 AMI Business Plan, the Company is in the process of installing electric AMI meters that are capable of connecting and disconnecting from the distribution system via a remote wireless signal. (For the remainder of this testimony we refer to this functionality as "RCD-capable.") The vast majority of electric AMI meters installed through 2022 will be RCD-capable, with the exception being some commercial customers and customers that opt-out of receiving electric AMI meters.

There are a number of benefits to RCD-capable metering, including (but not limited to) faster service initiation and restoration after disconnections. RCD functionality also helps to reduce costs because in many cases it will obviate the need for an in-person visit to restore service following a disconnection for non-payment or tampering-related reasons.

As outlined in General Rule 15.2 of the Company’s Schedule for Electricity Service (“Tariff”), the Company currently charges a fee of $26-28 to reconnect service at the meter. This fee helps to defray the cost of sending a field representative out to the customer premises for reconnection purposes. Given that RCD-capable metering will significantly reduce the number of reconnection-related work orders, the Company proposes to eliminate the aforementioned reconnection fees for electric customers with RCD-capable meters whose service was shut off for non-payment or tampering-related reasons, if the customer’s service is able to be restored remotely. Reconnection fees will still apply for customers whose service restoration requires an in-person visit from Company personnel – including customers whose service is cut in the street as well as customers whose service cannot be restored remotely despite the presence of an RCD-capable meter.

It should be noted that the Company does not currently plan to install RCD-capable gas meters, so the above proposal is only applicable to electric customers. The Electric Rate Engineering Panel testimony describes the associated Tariff changes.

Q. What impact will this proposal have on the Company's revenue during the Rate Year?

A. The Company projects that other operating revenue will be reduced by $224,000 in the Rate Year as a result of this proposal.

Q. Please explain how you developed this projection.

A. The Company reviewed data from October 1, 2017 – September 30, 2018 and determined that it collected $672,000 in fees for electric service reconnections at the meter (not including instances where low income customers received fee waivers and therefore the $26/$28 charges were reversed).

Given the uncertainty as to how many remote reconnections there will be in any given year, the Company reduced the $672,000 by 33 percent to estimate the loss of revenue associated with these charges.

Q. Does this proposal impact the reconnection fee waiver component of the Company's Electric Low Income program?

A. This proposal does not directly impact the reconnection fee waiver benefit for electric low income customers. It is true that if one assumes that a disconnected low income electric customer has an RCD-capable AMI meter and their service is successfully restored via remote signal, then this proposal would eliminate the need for that customer to receive a reconnection fee waiver. However, due to the timing of the Company's AMI meter deployment there will still be low income electric customers that are assessed reconnection fee waivers during Rate Years 1-3. The Company believes it is important to continue providing these customers relief from reconnection fees. As such, any customer participating in the Electric Low Income Program that is charged a reconnection fee during the rate plan will still be granted a fee waiver according to the terms outlined in the Electric and Gas Low Income Programs section of this Panel's testimony.

Q. Is this proposal reflected in any other testimony or exhibits included in this rate filing?

A. Yes. This proposal is reflected in the Accounting Panel testimony, Exhibit E-3, Schedule 5.

XIV. CUSTOMER SERVICE PERFORMANCE MECHANISM

Q. Do you have any proposals with respect to the Customer Service Performance Mechanism ("CSPM")?

A. The current rate plan provides for the CSPM to continue unless and until changed by the Commission. For purposes of this proceeding, the Company is not proposing to eliminate the CSPM.

Q. Is the Company proposing any changes to the CSPM?

A. No. Assuming continuation of a CSPM during the Rate Year, the Company is not proposing to modify the terms of the current CSPM.

Q. Has the Company incurred any revenue adjustments under the current CSPM?

A. No. The Company has not incurred any revenue adjustments in the last two rate years.

Q. Other than surveys required by the CSPM, is the Company conducting any other surveys?

A. Yes. Pursuant to the Commission's Order Authorizing Implementation of a Pilot Statewide Customer Satisfaction Survey, in 2019 the Company began a one-year transaction-based customer satisfaction survey. The Company will file quarterly reports with the results of this survey and will reconvene with Staff and the other electric and gas utilities after one year.

Q. Is this transaction-based survey part of the CSPM?

A. No, the pilot survey is not part of the CSPM and, although the Company will report its results, there are no metrics associated with this survey.

XV. **RESIDENTIAL SERVICE TERMINATIONS & UNCOLLECTIBLE BILLS**

Q. Please describe the Company’s current performance metric related to residential service terminations and uncollectible bills (“UB metric”).

A. The 2016 Joint Proposal established a UB metric for the 2017-2019 time period where the Company would earn a positive revenue adjustment for achieving certain targets for residential service terminations and bad debt write-offs. Any positive revenue adjustment earned will be allocated between electric and gas based on the common cost allocation for Customer Accounting Expenses (84%/16%).

Q. Did the Company meet the metric in 2017 and 2018?

A. Yes, in both years, the Company achieved performance levels below the targets listed under part (a) in the above excerpt (i.e., Terminations < or = 62,000 and Bad debt write-offs < or = $45.7M), thereby earning a two-year total of $12 million in incentives ($6 million for each year). Specifically, in 2017 the Company had 50,135 residential terminations and recorded a total of $37.8

million in residential UB. In calendar year 2018, the Company had 38,147 residential service terminations and residential UB of $37.9 million.

Q. What factors contributed to the Company’s successful performance in 2017 and 2018?

A. There are a variety of factors that contributed to the ability of the Company to achieve the targets established for this metric. Some of those factors are within the Company’s control, and others are not. For example, the Company is committed to working with customers early on in the arrears process in a variety of ways to help reduce the likelihood that they are terminated for non-payment. A few examples help to illustrate this point:

- Be flexible on deferred payment agreement (“DPA”) terms and we give them multiple chances before we pursue credit action.
- Offer customers a variety of convenient ways to enter into a DPA, including on the phone with a CSR, in the IVR, at any of our Walk-in Centers, or online using the My Account portal. In 2018 we also began proactively offering customers most likely to call because they were eligible to be turned off for non-payment DPAs via e-mail. Results thus far have been positive.

- The Company goes above and beyond the terminations-related requirements of the Home Energy Fair Practices Act (HEFPA) by providing customers extra notices regarding the status of their account.
- If a customer's account is ultimately fielded for service termination, the Company accepts all forms of payment at the customer's premises and attempts to enter into a DPA with the customer prior to locking the meter.

In addition to the above efforts to work with customers, in 2018, the Company implemented a risk-based routing approach in fielding service terminations. Specifically, we began to field accounts for termination with a higher likelihood of writing off to UB. The new strategy has shown positive results thus far.

Also, it should be noted that the overall economy continued to improve over the 2017-2018 time period, which generally leads to fewer customers in arrears, lower volume of service terminations, and lower final bill balances.

Q. Does the Company propose to continue this performance mechanism in the coming Rate Year?

A. Yes. The Company recognizes that the Commission has established a UB Metric for all utilities. Therefore, despite the uncertainty associated with the ability to achieve these targets because it is, in part, dependent on factors outside the Company’s control, the Company is not proposing to eliminate the UB Metric.

Q. Does this conclude your testimony?

A. Yes.