CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
GAS CASE TESTIMONIES
VOLUME 1

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DIRECT TESTIMONY OF

POLICY PANEL - GAS

TABLE OF CONTENTS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DIRECT TESTIMONY OF

POLICY PANEL - GAS

I. INTRODUCTION

Q. Would the members of the Gas Policy Panel ("Panel") please state your names and business addresses?

A. Marc Huestis, Marilyn Caselli, Matthew Ketschke, and Stuart Nachmias. Our business address is 4 Irving Place, New York, NY 10003.

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

A. We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company").

(HUESTIS) I am Senior Vice President, Gas Operations.

(CASELLI) I am Senior Vice President, Customer Operations.

(KETSCHKE) I am Senior Vice President, Customer Energy Solutions.

(NACHMIAS) I am Vice President, Energy Policy and Regulatory Affairs.

Q. Please explain your work experience, current general responsibilities and educational backgrounds.

A. (HUESTIS) I joined Con Edison in 1982 as a Management Intern. I have held various positions of increasing responsibility in Nuclear Power Generation, Steam Operations, Substation Operations, Construction, Electric Operations, and Gas Operations. I was promoted to Vice President Construction in October 2008, a position I held through December 2013. In

January 2014, I was assigned to Manhattan Electric Operations as Vice President. In January 2015, I was promoted to Sr. Vice President, Gas Operations, assuming responsibility for all aspects of Gas Operations on February 1, 2015. In my current position as senior vice president for Gas Operations, I am responsible for the overall Con Edison Gas Operations, Engineering, and Compliance and Quality Assurance groups. I hold a bachelor's degree in Mechanical Engineering from Stevens Institute of Technology and a master's degree in Mechanical Engineering from Manhattan College. I have also completed Power Technology Institute's ("PTI") Power Technology Transmission Course.

(CASELLI) 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 was elected to 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 have overall responsibility for the Company's customer service programs which include: 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 and the operations of the Telecom Applications Management (TeAM) group that provides access to Con Edison facilities and infrastructure for telecommunications purposes and manages the relationships between Con Edison and the telecommunications companies. I hold a Bachelor of Science degree in Business Administration from the State University of New York.

(KETSCHKE) I have been employed by Con Edison since 1995. 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. In 2017, I assumed my current role as Senior Vice President of Customer Energy Solutions. I am responsible for Con Edison’s integration of Distributed Energy Resources (“DER”) into system design and operations, Con Edison’s REV demonstration projects, and Con Edison’s Energy Efficiency (“EE”) and Demand Management (“DM”) programs. 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.

(NACHMIAS) I have worked for Con Edison since l988. I began in the Company's management intern program, and worked in capital budgeting, customer sales and revenue forecasting and corporate planning. I worked to develop the state's plan for deregulation, including establishing the New York ISO. I also worked at Con Edison Solutions from 1997 to 2000, initially in the wholesale power group and later as marketing manager for large business customers. After leaving the Company from 2000-2001, I rejoined Con Edison in the Energy Markets Policy Group, focused on competitive wholesale electric and gas markets. I have had increasing responsibilities in this area, as well as a one-year job rotation in customer operations, where I worked on customer complaints to executives and the Commission. As Vice President, Energy Policy and Regulatory Affairs, I am currently responsible for development of energy policy and the management of state and federal regulatory matters. I was also President of the New York Transco, an electric transmission development company whose members include all of New York's investor-owned utilities, from November 2014 until December 2018. I graduated from the State

University of New York at Binghamton with a bachelor's degree in Economics and Psychology and also earned a Master of Business Administration degree with a concentration in Finance from Baruch College. I also earned an Advanced Certificate in Energy Management from the New York Institute of Technology, and completed a Power Technologies Inc. ("PTI") Distribution Engineering program.

Q. Have you previously testified in Commission proceedings?

A. Yes. We have all testified in Commission proceedings.

II. OVERVIEW

Q. What are the core principles that guide the Company's development of projects and programs to meet the needs of its gas customers?

A. Our core principles are safety, operational excellence and enhancing the customer experience. In furtherance of these principles, we continue to focus on advancing our energy future – where safe, reliable, resilient and clean energy will allow our customers and our region to continue to grow and prosper. We will continue to work hand-in-hand with our customers and stakeholders to draw upon the best ideas in the marketplace, implement cost-effective and environmentally sound solutions, and provide customers new ways to better manage their energy use.

Our customers are at the core of everything we do. Our first priority every day is safety – for our customers, as well as our employees and the public.

We are seeing customers' expectations continue to grow as they seek more control over their energy use, more convenience in working with us, and more advice about their energy options.

To meet these expectations, we continue to pursue excellence in all of our operations, optimizing our work processes, enhancing productivity, and reducing costs for customers.

We are leveraging technology in new ways, including our smart meter network, to enhance our service, reliability, and resilience, and to detect and respond to natural gas leaks.

Q. What is the purpose of the Panel's testimony in this gas rate proceeding?

A. We will

- present an overview of the Company's strategy in applying its three core principles of safety, operational excellence and enhancing the customer experience to the gas and gas-related projects and programs that comprise the Company's gas business plans for the next three years;
- highlight the major projects and programs that comprise the Company's plans to maintain, enhance, upgrade, extend and innovate the infrastructure that is essential to the

Company’s ability to provide safe and reliable service to our customers;

- discuss various initiatives the Company is pursuing to enhance the customer experience and further engage customers;
- describe Company efforts to implement clean energy goals by increasing energy efficiency, reducing peak day demand and seeking cost-effective alternatives to new gas infrastructure;
- discuss the Company’s overall approach to managing expenditures cost effectively and cost efficiently;
- express the Panel’s support for incentive ratemaking proposals sponsored by various Company witnesses;
- present the status of the Company’s response to several Commission management and operations audits; and
- present the status of the Company’s Climate Change Vulnerability Study.

Q. Which Company witness panels present these initiatives, projects and programs?

A. The Gas Infrastructure, Operations and Supply Panel ("GIOSP"), Customer Energy Solutions ("CES") Panel, Customer Operations Panel, Shared Services Panel, Municipal Infrastructure Support

Panel, and Information Technology ("IT") Panel present the essential details of these projects, programs and initiatives.

Q. What period of time do these presentations cover?

A. These presentations cover multi-year periods, including calendar year 2020, which is the Rate Year (or “RY1”) for this gas rate filing, and calendar years 2021 and 2022, referred to as “RY2” and “RY3”, respectively.

Q. How does the Company propose to fund these projects and programs?

A. To effectuate these projects and programs, the Company seeks in this rate filing a revenue increase of $210 million in RY1. As discussed by the Accounting Panel, the Company also presents illustrative revenue requirement increases for RY2 and RY3 in order to facilitate the Company, Staff and other interested parties developing a multi-year rate plan to present to the Commission for approval.

III. GAS OPERATIONS STRATEGY

Q. Please describe the nature of Con Edison’s gas service.

A. Con Edison operates in one of the largest, most dynamic metropolitan areas in the world. We serve over 1.1 million gas customers (including accounts representing many additional consumers), from single-family homes, to high-occupancy high-rise office buildings, apartments, hospitals, schools and colleges. These consumers depend on Con Edison for safe, reliable gas service to meet essential needs.

Q. Are there unique challenges to providing gas service within the Company’s service territory?

A. Yes. Providing gas service in the New York City (“NYC”) portion of our service territory presents unique challenges. The Company’s many miles of gas transmission and distribution facilities share space with many other types of utilities that make up NYC’s infrastructure – subways, water and steam mains, and underground electric, cable and fiber optic lines. Accordingly, Company work on its gas facilities is both impacted and dictated by critical facilities owned, operated and maintained by or for other constituents, thereby providing less flexibility and requiring greater coordination in all aspects of the Company's gas operations. These operations include continually monitoring, repairing, replacing and upgrading our gas system to maintain and enhance our provision of safe and reliable service to our customers, as well as maintain a safe environment for our employees and the general public.

Q. Are there additional challenges associated with serving new gas customers?

A. Yes. During recent years, there has been a significant increase in demand for natural gas service, largely driven by conversion of buildings using heavier heating oils (#6 and #4 oil) as well as home heating oil (#2).

While the Company has met this demand to date, the Company currently faces challenges in acquiring the additional firm gas supplies needed to meet the continuing growth in gas winter peak demand. As discussed later in this testimony, the Company is exploring alternative means to satisfy this gas demand through non-pipe alternatives, similar in many respects to the non-wires alternatives that the Company pursues with respect to its electric service, including advancing energy efficiency and demand response programs for existing gas customers and working to advance new clean alternative heating options for new customers. Pending the successful implementation of these and other initiatives, the Company has instituted a temporary moratorium for new gas service in most of Westchester County, as discussed later in our testimony.

Q. Please describe the strategies the Company uses to continuously enhance safety, reduce risk and improve operational efficiency.

A. To improve its performance, the Company takes a comprehensive approach to risk mitigation. Our strategy includes enhanced prevention, detection and response.

We utilize the American Petroleum Institute's Recommended Practice (API RP 1173) "Pipeline Safety Management System," which establishes the essential elements of a holistic gas pipeline safety management system for pipeline operators. This standard promotes implementation of a Plan-Do-Check-Act cycle, to provide continuous improvement and feedback loops for our existing practices, procedures and management systems. This standard is cascaded into our Transmission and Distribution Integrity Management Programs ("DIMP" and "TIMP").

Our Pipeline Safety Management personnel identify industry best practices and incorporate them into our TIMP and DIMP. These programs help us identify and mitigate risks to our system. We use the information to guide the enhancement of our programs and the creation of new programs.

The Company then targets investments for the gas distribution and transmission systems to provide for greater reliability, reduced impacts of coastal flooding and reduced risk of events that can result in property damage or impact public safety.

Q. Please describe the categories of gas investments designed to address safety, risk reduction, reliability and operational efficiency that largely come out of the DIMP and TIMP programs.

A. The categories of gas investments include the following areas of gas operations:

- Distribution projects and programs to reduce risk and enhance safety, which are primarily identified through our DIMP;
- Transmission projects and programs to reduce risk and maintain reliability of our transmission facilities, which are primarily identified through our TIMP;
- Customer Connections projects and programs;
- Technical Operations projects and programs that focus on contingencies in the event of an incident that may impact our external supply sources, in particular, upgrades to the Company’s LNG Plant; and
- IT projects and programs to reduce administrative and operational risk and achieve improved efficiencies and management of operations, programs and projects.

Q. What is the purpose of the DIMP?

A. The purpose of the DIMP is to enhance public and employee safety by identifying and prioritizing gas distribution pipeline integrity risks and implementing mitigating measures to address them. These risks include distribution system leaks, excavation damages, and human error (which the Company continually seeks to minimize).

Q. Please highlight some of the planned projects and programs that are designed to maintain and enhance system safety, reliability and resilience for customers, while reducing environmental impacts.

A. The Integrity Management program examines risk on our system through data analytics, subject matter expert input, root cause analysis, lessons learned from industry events, effective change management, open communication and standardization, which in turn lead to the improvement of existing programs or the creation of new programs to reduce risk and, as a result, enhance safety. Key initiatives include:

- replacing all 12-inch and smaller cast iron, wrought iron, and unprotected steel by 2036;
- enhancing and leveraging new leak detection technologies; and
- responding to and repairing leaks in a timely manner.

Under the Distribution Improvement Program, the Company replaces sub-standard and undersized mains on both a proactive and emergent basis.

Under the Large Diameter Gas Main Program, the Company replaces or rehabilitates large diameter gas mains where the loss of service, in many cases, could lead to customer outages during the winter heating season.

Under the Service Replacement Program, the Company coordinates replacement of services with replacement of gas mains in order for Company work to be less disruptive to customers.

Under the Isolation Valve Program, the Company installs isolation valves to be used in the event of an imminent or actual uncontrolled release of natural gas or need to isolate an area for safety; the program is focused on infrastructure near critical facilities such as hospitals and schools, in NYC and Westchester County.

Q. Do these programs also provide environmental benefits?

A. Yes. Many of these facility replacement programs have and will reduce Greenhouse Gas ("GHG") emissions.

Q. Is the Company also enhancing its leak detection initiatives?

A. Yes. Detection of gas leaks through state-of-the-art technology is critical to our comprehensive approach to risk management and commitment to public safety. In furtherance of this objective, the Company is

- investing in natural gas detectors to be installed near building service points of entry that are designed to send an alarm to our Gas Emergency Response Center ("GERC") when natural gas is detected, leveraging the communications infrastructure being installed for our smart meters; GERC personnel will then contact the fire department and dispatch an emergency response crew; and
- continuing to evaluate cavity ring down spectroscopy ("CRDS") leak detection technology, a state-of-the-art mobile methane leak detection technology

Through enhanced leak detection, we can identify, respond and remediate leaks more rapidly, reducing risk, keeping the public safe, and protecting the environment by reducing emissions of methane, a greenhouse gas.

Q. Please describe the Gas Reliability Improvement Program.

A. This program has several components, including continuing to reduce the risk of an over pressurization event; upsizing mains and regulator stations to avoid large-scale outages during peak demand periods; and rehabilitating regulator stations by replacing unserviceable equipment and verifying that regulators are adequately sized to provide the capacity to meet existing and added load in the event of the loss of other system components.

Q. What are the major projects and programs planned for the Company's gas transmission facilities?

A. The Company has various gas transmission projects and programs that are focused on maintaining or enhancing system safety and reliability, including:

- installing remotely operating valves ("ROVs") to provide for rapid isolation of a compromised section of the transmission facilities;
- replacing sections of transmission main containing leaks or defects that cannot be made safe using a maintenance repair technique;
- upgrading the Newtown Creek Metering Station, including adding equipment to enable the Company to control the flow rate to National Grid and thereby protect Con Edison customers from abnormal operating conditions;
- installing Con Edison-owned over-pressure protection ("OPP") equipment at Transco (Manhattan) and Tennessee (Rye) gate stations, which is designed to provide for the safe operation of our gas transmission facilities in the event that Transco- or Tennessee-owned OPP devices at these gate stations fail and the maximum allowable operating

pressure (“MAOP”) of the pipeline cannot otherwise be controlled; and

- replacing existing gas mains to reduce risk and provide contingency for the loss of the Tennessee gate station at White Plains.

Q. Does the Company have a new approach to growth-related projects, that is, customer connections to the gas system?

A. Yes. Historically, the Company addressed gas growth through several programs including Traditional New Business, NYC Area Growth Program, #2 oil-to-gas (“OTG”) conversions in NYC, Westchester gas conversions, and Westchester Area Growth. Going forward, the Company has consolidated these programs into one program called the “Customer Connections Program.”

Q. What are the reasons for the new consolidated program?

A. The NYC Area Growth Program, which was established to address NYC-mandated conversions from #6 and #4 fuel oils, is essentially complete. In accordance with the program’s guidelines, by the end of 2019 all eligible customers will have been offered the opportunity to participate in an Area Growth Zone, no new zones will be added, and we have ceased our marketing efforts associated with this program. The Company does need to complete inspections and construction associated with work requests that were previously submitted by customers that requested participation in this program. Also, the Company has discontinued the Westchester Area Growth program, which was initiated in White Plains and Port Chester where there is a high concentration of multi-family and commercial oil heating customers to target conversion to natural gas. Discontinuation was due to a combination of gas supply constraints and the Company receiving minimal interest for conversions in these areas.

Q. Is there still customer demand for conversions to natural gas in the Company's service territory?

A. Yes. Under the Customer Connections program, the Company will continue to proactively work with customers to manage their energy needs and costs, and support new construction and customers seeking gas service if gas supply is not constrained. Unfortunately, as discussed later in our testimony, there are gas supply constraints that have compelled the Company to announce a temporary moratorium on connecting new gas customers in most of Westchester County.

Q. Have these changes in growth-related programs impacted the rate filing?

A. Yes. The rate filing reflects a small forecasted reduction from historical service and main installation levels.

Forecasted sales revenues are also lower than they would be if the Company was continuing to pursue an aggressive new gas customer program.

Q. Please discuss the Company's planned modernization of its liquefied natural gas ("LNG") plant.

A. The LNG plant has historically played a critical role in the Company's gas supply planning and reliability of gas service. The LNG plant serves as a cost-effective alternative to more expensive firm peaking supplies and to potentially mitigate short term price volatility. It is also the only source of in-City natural gas from which Con Edison gas customers can be supplied in the event of an interstate pipeline interruption or other emergency condition affecting the Company's external gas supply. In addition, in light of the severe constraints the Company currently faces in securing additional gas pipeline capacity to its service territory, the LNG plant’s supply and reliability benefits are increasingly important. In order to continue safe and reliable plant operations, and enhance the contribution of the LNG plant in gas supply planning, the Company plans to replace and/or upgrade several of the plant's systems.

Q. What are some of the major upgrades planned for the LNG Plant?

A. A new nitrogen refrigeration closed loop system will replace original, obsolete equipment and provide the cryogenic chilling required to liquefy natural gas and fill the LNG tank in six months. The new system will also have an efficient turbine that will produce less air emission per million cubic feet of LNG produced.

We plan to install a new vaporizer to replace Vaporizer No. 1, which is near the end of its useful life. This will complete the replacement of the Plant's five vaporizers.

These upgrades in combination with other upgrades to critical plant components, such as instrumentation and electric distribution equipment, will significantly improve overall plant reliability, liquefaction capability and flexibility, which will allow us to rely on the maximum LNG plant capability in our gas supply planning.

Q. Does the Company have any projects associated with its tunnel facilities?

A. Yes. There are eight utility tunnels on the Company’s system, which house critical gas, electric and steam facilities, as well as fuel oil lines and telecommunications systems, and serve as critical pathways for service lines, for the most part, under bodies of water. Structures and components in the tunnels, such as elevators, structural concrete, ladders and landings, ventilation fans, and electric and communication systems, are subject to corrosion and deterioration due to ground water intrusion and exposure to extreme moisture, salt, humidity, and heat. Accordingly, these structures and components require continuous maintenance, refurbishment, replacement or upgrade in order to maintain or enhance system reliability and resiliency, employee safety, and to enable continued access to critical infrastructure.

Q. How has the Company demonstrated its commitment to enhancing clean energy and environmental performance?

A. The Company has converted more than 7,600 large buildings from oil to cleaner natural gas, which has contributed to New York City reporting that it has achieved its cleanest air in 50 years. Fine particulate matter reduction has been a focus of the Company since 2011, when we created and staffed a team to support NYC's “Clean Heat” regulations. We have reduced 534 tons of fine particulate matter (2.5 microns) from the air – the equivalent of 1.7 million cars off the road. We have been a member of the EPA’s Natural Gas STAR Program since its inception in 1993. The Natural Gas STAR Program is a flexible, voluntary partnership that encourages natural gas companies to adopt proven, cost-effective technologies and practices to improve operational efficiency and reduce methane emissions. Nearly all distribution sector methane emissions are due to leaks, and the Company is focused on eliminating leaks, of course addressing hazardous leaks first, and continues to make leak information available to the public on its website. The Company also participates in industry reporting and benchmarking efforts.

Q. Are the Company’s planned investments likely to further reduce methane emissions?

A. Yes. As noted earlier in our testimony, the Main Replacement Program will not only improve safety by reducing the risk of potential gas leaks, but will also reduce methane emissions by greatly reducing the likelihood of leaks. Our work with new natural gas detection technologies to better identify and quantify gas leaks will also allow us to respond more quickly when leaks occur, which while primarily a safety benefit, will also help reduce methane emissions.

Q. Are there any planned projects from an Information Technology (“IT”) perspective?

A. Yes, from both a gas operations perspective and an overall Company perspective.

Q. Please explain

A. The Company’s IT organization continues to focus on projects and programs designed to address needs of all the Company’s systems, and customers, including

- implementing a new Customer Service System, which we discuss later in our testimony, and an Enterprise Geographic Information System;
- reducing and modernizing the Company’s portfolio of more than 500 IT-supported applications and migrating to a core set of business systems in order to simplify processes and reduce infrastructure costs and licensing fees;
- modernizing and consolidating Company data centers and leveraging cloud technologies;
- maintaining confidentiality and privacy of data and personally-identifiable information; and
- investing in and leveraging new technologies designed to improve business processes, reduce costs, and protect against new and evolving cyber security threats.

A number of these IT projects and programs are focused on cyber security, which is a top risk. Since a successful cyber security attack could result in operating failures of control systems, damage to transmission and distribution assets, or the loss of sensitive data, the Company allocates extensive resources to mitigating the risk of a successful cyber-attack and thereby avoid safety and/or reliability consequences to our customers, our employees and the general public.

Q. Please discuss the major gas IT initiatives described in this filing.

A. The major initiatives designed to support core gas business functions include asset work management, and several IT projects that the Company initiated during the current gas rate plan, replacing the Integrated Gas Supply ("IGS") system and updating the Transportation Customer Information System ("TCIS"). The Company initiated these projects to update the technology, streamline processes, accommodate new functional requirements to support changing market conditions, accommodate new retail access program initiatives, and adhere to the corporate strategy to consolidate applications. We expect TCIS to be completed in RY1 and IGS in RY2.

Q. Has the Company included business plans for its IT investments?

A. The Company has included business plans for our largest IT investments - the Customer Service System, which is sponsored by the Customer Energy Solutions Panel, and the Enterprise Geographic Information System, which is sponsored by the Electric Infrastructure and Operations Panel in the Company’s electric rate filing, with support from the GIOSP. The other

IT investments are accompanied by white papers that discuss expected savings, including financial benefits and reduced and avoided costs, where appropriate. The white papers also explain why the Company chose the solution it is proposing to implement.

IV. ENHANCING CUSTOMER EXPERIENCE AND ENGAGEMENT

Q. Is the Company pursuing new initiatives to enhance the customer experience and further engage customers?

A. Yes. The Company is engaging in a series of new efforts, including the formation and implementation of the Company's new Customer Energy Solutions organization, the Next Generation Customer Experience Initiative, a new Customer Service System ("CSS") and its smart meter program.

Q. What is driving these Company initiatives?

A. The energy industry is undergoing a rapid transformation. Over the next decade, New York's electricity and gas systems will become significantly cleaner and more efficient, flexible, reliable, and resilient. The drivers underlying this transformation include (i) new technologies that change energy needs; (ii) evolving customer expectations regarding choice, control and convenience with respect to their energy use; and (iii) policy goals advancing customer choice, sustainability, and changing the energy supply mix.

The utility business, both electric and gas, will need to evolve and change to facilitate State policies directing 50% renewables and 40% reduction in GHG emissions by 2030, energy efficiency equivalent to three percent of electric sales by 2025, and increased adoption of heat pumps to increase beneficial electrification, among other State objectives.

Q. What actions has Con Edison taken to recognize and more effectively address this evolution?

A. First, in order to maximize the potential success of investments and initiatives designed to both meet these State objectives as well as enhance the customer experience, Con Edison recognized that having an organization capable of innovatively and proactively accommodating these shifts is critical to facilitating this transformation. Accordingly, in 2017, the Company established the Customer Energy Solutions organization in order to enable innovation across Company functions directly influencing the customer experience, including in energy efficiency and demand management programs, the smart meter program, development of the new CSS, and ratemaking, as well as Company functions involved in implementing various Reforming the Energy Vision (“REV”) initiatives.

The CES organization, in conjunction with Customer Operations, Gas Operations and other Company departments are collectively working to

- enhance the customer experience through the integration of clean energy resources;
- enable our customers to better manage their energy usage, thereby reducing environmental impacts and energy burdens;
- enhance the safety, reliability and excellence in the management of our energy systems; and
- foster innovation throughout Con Edison to drive towards a more DER-enabled, customer-focused system;

while continuing to meet the Company’s fundamental responsibility to provide our customers with safe and reliable service.

Q. What is the Next Generation Customer Experience (“Next Gen CX”) initiative?

A. The Next Gen CX Initiative is a set of strategic business objectives and associated programs designed to enable Con Edison to continue to be a trusted energy provider by offering increased customer choice, control and convenience through personalized services across a variety of engagement channels.

Q. What are the strategic business objectives?

A. The strategic business objectives are creating an industry-leading customer experience, operational efficiency and an empowered workforce, which we plan to achieve by creating personalized and straightforward experiences that are valuable to our customers; improving our processes, reducing cost and improving service to customers; and providing employees with better tools to meet customer expectations.

Q. Please describe the nature of the investments the Company plans to make to implement these objectives.

A. The investments fall within the following three areas:

- Omni-Channel Optimization, which focuses on a seamless self-service experience leading to greater customer satisfaction and lower cost to serve by utilizing modern, personalized and intelligent tools for our customers.
- Business Intelligence, which will use advanced data/analytics to drive new customer and business insights and leverage real-time analytics to enable strategic business decisions and introduce customer-specific recommendations to increase customer satisfaction.
- Back Office Automation and Agent Tools, which will develop intelligent tools designed to help our employees work efficiently and focus on value-add customer focused

activities, and improve our core processes that support technology and public safety.

Q. What are some of the enabling investments associated with Omni-Channel Optimization?

A. Omni-Channel Optimization seeks to deliver modern, personalized, and intelligent self-service tools to our customers via a seamless multi-channel experience. This effort will streamline customers' experience with the Company over multiple touch points and platforms, including web, mobile, text, email, chat, paper billing, and phone calls. Specific investments include Journey Mapping, which studies the entire arc of a customer's interaction (*e.g.*, moving) instead of a single touch point (*e.g.*, a phone call to the Company); building on and expanding the scope of the Company's Digital Customer Experience ("DCX") initiative; modernizing our paper bills to better align with the experience customers receive on our website; and a state-of-the-art Virtual Assistant that will provide immediate service, enhancing customer satisfaction while managing costs.

Q. Please describe the nature of the enabling investments associated with Business Intelligence tools.

A. Business Intelligence investments are focused on advanced analytics, which are designed to centralize key customer data to more deeply understand customer behavior, attitude and preferences leading to more advanced and personalized experiences; and tools, which utilize interaction insights from advanced analytics to provide employees and customers with self-service options with real-time customer-specific services and offerings.

Q. Please describe enabling investments associated with Process Efficiency improvements.

A. The Company is focused on developing back office automation tools designed to:

- automate back office processes and tasks using robotic process automation, in order to reduce operating costs and provide faster customer service;
- better manage exceptions that require employee review, resulting in improved transaction efficiency and customer service;
- provide enhanced tools to empower customer-interacting employees to provide better service in order to improve customer satisfaction; and
- provide a single system for Con Edison employees to quickly access and understand process, procedure and policy content.

Q. What other initiatives is the Company pursuing to enhance the customer experience?

A. The Company is pursuing significant IT system investments to replace its legacy customer service system with a new, modern system ("CSS") and to deploy smart meters across the service territory.

Q. Please explain why the Company is developing a new CSS.

A. Con Edison's Customer Service System performs all of the Company's meter-to-cash processes, including billing, payment processing, and collections. The system holds all confidential customer information, meter, and premise-level data. As such, it is critical to the core functioning of the Company. The current system is a mainframe-based system that went into service in 1972 and is reaching the end of its useful life. Maintaining the system is becoming increasingly difficult as the programming language has become all but obsolete, leading to high ongoing maintenance costs and reduced flexibility to implement new rates and programs.

The Company's 2016 gas and electric rate plans directed that the Company should begin implementing the CSS replacement. As noted earlier in our testimony, the Company has developed a business plan for this effort. The Company's current plan will conduct the detailed design and build of the new program during RY1, RY2, and RY3, with a projected launch in 2023.

Q. Please discuss the status of the Company’s smart meter program.

A. The Company is in the midst of deploying smart meters across the service territory. Smart meters help customers with access to more information, and facilitate control, choice, and convenience. The communications infrastructure being deployed as part of the implementation, and the data available from the smart meters, will enable the Company to better understand and more reliably operate its energy delivery systems as well as enable future added capabilities. The Company is on target (and budget) to complete the program by 2022, which includes the installation of approximately 3.6 million smart electric meters, and approximately 1.2 million smart gas meters that are being modified or replaced altogether.

Q. Are there other Company initiatives designed to enhance the customer experience and further engage customers?

A. Yes. The Company is proposing to establish a new credit and debit card bill payment program, investing in customer experience center disaster hardening, establishing off-system billing, enhancing revenue protection analytics, expanding electronic correspondence, as well as enhancing the Company's long-standing customer outreach and education and low income programs.

V. CLEAN ENERGY SOLUTIONS, INCLUDING TEMPORARY GAS MORATORIUM

Q. What is the Company's overall approach to clean energy solutions?

A. The Company supports State and local clean energy policy goals and is committed to helping achieve those goals by integrating clean energy resources and helping our customers, especially low and moderate income ("LMI") customers, better manage their energy usage.

The Company is advancing its Smart Solutions program. There are several elements including expanding gas energy efficiency ("EE"), starting a gas demand response program, pursuing non-pipeline alternatives, and testing innovative business models to deploy clean heating technologies. We discuss the Smart Solutions program later in our testimony.

Q. Please describe the Company's gas energy efficiency program reflected in this rate filing.

A. The Company is proposing to implement a combined electric and gas energy efficiency portfolio that would add new programs and new delivery channels; innovate to deliver more savings more cost-effectively; use data analytics to target outreach and increase marketing effectiveness; and further develop data governance processes to report results with a high degree of confidence. The Company may modify this program at the preliminary update stage of this proceeding.

Q. Please explain why the Company may modify this program.

A. As discussed by the Customer Energy Solutions Panel, on December 13, 2018, the Commission issued its Order Adopting Accelerated Energy Efficiency Targets in Case 18-M-0084 ("EE Order"). The EE Order adopts Con Edison-specific budgets and targets for calendar year 2020 (i.e., Rate Year 1 for these proceedings), and certain processes for the development of energy efficiency programs by all utilities for the period 2021 through 2025 (which five-year period includes the illustrative Rate Year 2 (2021) and Rate Year 3 (2022) presented by the Company in these rate filings).

The Commission issued the EE Order at or about the time that the Company was finalizing its revenue requirements for the rate filings. The Company did not have adequate time to complete its review and evaluation of its EE program in light of the EE Order prior to finalizing its revenue requirements.

Q. Why is the Company proposing to manage its electric and gas energy efficiency programs as a single portfolio?

A. The integration of electric and gas programs is consistent with the Commission's call for annual site energy savings targets on a BTU basis that account for both electricity and natural gas (as well as other delivered fuels consumed by the residential, commercial, and industrial sectors), and will provide the Company flexibility to manage program expenditures in a manner designed to most effectively achieve the annual site energy savings targets.

For purposes of ratemaking, cost recovery and reconciliation, the Company proposes to continue to allocate the projected costs of electric energy efficiency programs to electric customers, excluding NYPA-supplied customers, and to allocate the projected costs of gas energy efficiency programs to firm gas customers; to recover costs through base rates and amortize costs over a 10-year period; and reconcile the costs included in the electric and gas revenue requirements at the end of the three-year period 2020 through 2022, subject to an overall cap on recovery of costs equal to the sum of the aggregate budgets established for electric and gas for all three years of this period.

Q. Is the Company undertaking any other clean energy solutions for its gas customers?

A. Yes. The Company is pursuing its Smart Solutions for Natural Gas Customers program ("Smart Solutions"), which the Company first presented to the Commission in a petition filed in September 2017.

Q. Please describe the major elements of this program as described in further detail in the testimony of the Customer Energy Solutions Panel.

A. Four initiatives comprise the Smart Solutions program:

- Increasing the Company's natural gas energy efficiency programs (the "Enhanced Natural Gas Efficiency Program");
- Developing a natural gas demand response pilot program;
- Issuing a competitive market solicitation (the "Non-Pipeline RFP") to acquire resources as part of non-pipeline solutions ("NPS") to offset the Company's needs for pipeline capacity, reduce use of third-party-controlled pipeline capacity, and make greater progress in reaching environmental goals; and
- Testing whether business model innovation can increase customer access to renewable thermal resources ("Gas Innovation Program").

Q. What is the status of these four initiatives?

A. The status of the four initiatives is as follows:

- Enhanced Natural Gas Efficiency Program: On July 12, 2018, the Commission approved the Company's request to expand its gas energy efficiency program with an increase in authorized funding. The Company proposes in these rate filings to manage a combined portfolio of electric and gas energy efficiency programs that include the programs and associated funding for the Enhanced Natural Gas Energy Efficiency Program.
- Natural Gas Demand Response Pilot: On August 9, 2018, the Commission approved the Company's proposed gas demand response pilot, authorizing the Company to spend up to $5 million over three years to fund the costs of customer incentives, metering, and administration of the pilot.
- Non-Pipeline RFP: On September 28, 2018, the Company submitted a petition to the Commission requesting $305 million to fund a portfolio of non-pipeline resources (the "NPS Portfolio") that we selected from third party proposals submitted in response to a request for proposals initiated by the Company in December 2017. As of the date of this rate filing, the Commission had not acted on this petition.
- Gas Innovation Program: On June 18, 2018, the Company issued a solicitation to the marketplace for proposals

designed to encourage business innovation to increase customer access to renewable thermal resources. The Company evaluated proposals submitted in response to this market solicitation and selected three proposals that are the subject of a submission to the Commission that occurred on December 20, 2018.

Funding for the Non-Pipeline RFP and Gas Innovation programs is not requested in this rate filing. Funding will be determined by Commission orders issued on these two programs.

Q. For portions of both the EE and Smart Solutions programs, the Company has sought to amortize project costs as regulatory assets. Please explain why such treatment is in the best interest of customers.

A. As more fully explained by the CES Panel, such a framework mitigates immediate bill impacts for customers by smoothing expenses over the period when benefits will be realized and also collects those costs from the customers taking service over that period of time.

Q. Are there other benefits to amortizing the costs over 10 years?

A. The Company supports a regulatory framework that treats energy efficiency, demand response, and other non-pipeline solutions on a parity with traditional investments (i.e., as regulatory assets recoverable over longer terms, which better match the recovery period with the program benefits and include a return on such investments). The combination of EAMs and regulatory asset treatment of non-pipeline solutions to drive preferred policy outcomes can result in both superior performance and meaningful cost efficiency.

Q. Has the Company recently implemented a temporary moratorium on new gas sales?

A. Yes. On January 17, 2019, Con Edison notified the Secretary of the New York State Public Service Commission as well as active parties in Cases 16-G-0061 and 17-G-0606 that it was establishing a temporary moratorium on connecting new gas customers in most of Westchester County. Customers may apply for service until March 15, 2019.

Q. Why did the Company initiate this moratorium?

A. This temporary moratorium is necessary because there are gas supply constraints in this part of our service territory that limit our ability to meet customer demand on the coldest winter days. While we have and will continue to pursue alternatives as laid out in our Smart Solutions program, we do not currently forecast that these programs will be sufficient to offset customer demand on the coldest winter days and thereby avoid the temporary moratorium.

Q. What is the extent and nature of this moratorium?

A. The moratorium will apply to new firm gas customers in the affected areas of Westchester County that will increase winter peak demand, including heating, hot water, laundry, and cooking loads. Existing customers are not affected. During the temporary moratorium, the Company will continue to accept applications from new customers that do not contribute to peak day demands, such as applications for interruptible service or gas service for emergency generators.

Q. Under what circumstances does the Company anticipate being able to lift this temporary moratorium?

A. The moratorium will remain in effect until peak demand in those areas is sufficiently reduced through energy efficiency, gas demand response or alternative energy programs or new gas pipeline infrastructure than can meet the State’s requirements and provide supply capacity to the affected areas.

Q. What actions is the Company taking to provide customers affected by the temporary moratorium with non-gas options for space heating and water heating?

A. The Company currently provides incentives that can reduce equipment costs for qualifying customers choosing to install electrically-powered air source heat pumps and heat pump water heaters, and is working with NYSERDA to make customers aware of additional incentives provided by NYSERDA to reduce the equipment costs of cold-climate air source heat pumps and geothermal heat pumps. The Company's gas conversion group will staff a toll-free number that affected customers can call to learn about Company and NYSERDA programs, and the Company will educate customers about their options and assist them in participating in Con Edison and NYSERDA renewable heating incentive programs

To the extent Commission action in the Smart Solutions petition results in additional programs, the Company will be able to provide customers with more options through these programs.

VI. MANAGING EXPENDITURES COST EFFECTIVELY AND COST EFFICIENTLY

Q. Please describe the Company's planning and budgeting process.

A. The Company seeks to manage its future costs by considering solutions to reliably meet needs while increasing overall efficiency. Annual budgets and shorter-term plans must be linked to the long-range plan through the development of annual business plans. Risk management is also integrated into the budget process. Annual business plans include an update and discussion of resources committed to mitigate risks. All of this information feeds the Company's Capital

Optimization process that evaluates projects and programs and drives optimized expenditure decisions.

Q. Is the Company experiencing increased costs associated with its capital programs?

A. Yes. The GIOSP explains the primary drivers of increased costs, which include new roadway restoration requirements imposed in NYC and various municipalities in Westchester County, and higher material costs associated with the higher quantities of larger diameter plastic and steel we are installing to improve system reliability. The GIOSP also explains the actions the Company is taking to manage these costs.

Q. The Accounting Panel and the Municipal Infrastructure Support Panel propose that the current gas net plant reconciliation mechanism be modified to eliminate the $10 million cap on upward reconciliation associated with municipal infrastructure support (also known as interference) expenditures. They also propose full bilateral reconciliation of interference O&M expenses.

Q. Do you agree with these proposals?

A. Yes, we do. As explained by these Panels, interference capital and O&M expenditures are driven by factors largely outside of the Company’s control and cannot be reasonably forecasted.

Q. Is the Company proposing the continuation of any other reconciliation mechanisms that are specific to gas service?

A. Yes. The Company's current rate plan provides for the deferral of O&M expenses associated with the Company's implementation of the Commission's new definition of gas service lines and implementation of federal regulations implemented pursuant to the Pipeline Safety Act of 2011. As the GIOSP and Accounting Panel explain, the Pipeline Safety Act deferral mechanism will continue and the gas service line deferral mechanism will convert to a reconciliation mechanism; although the revenue requirement reflects estimated costs to address the new service line definition, Company expenses to implement these initiatives cannot be reasonably forecasted.

Q. Is the Company planning to use any particular tools to implement its gas programs in a cost-effective manner?

A. Yes. The Gas Central System is our gas work and asset management system under development. It will be a single repository for work and asset related data that we will first deploy in 2019 to facilitate improved regulatory compliance, operational efficiencies, and financial insights; coordinate all construction, operations, and maintenance activities; and enable field personnel to interface with the system on a mobile platform (for example, receive, acknowledge and perform action on incoming work requests).

Some of the anticipated benefits from this program are:

- an integrated view of financial and operational data for better trending and analysis;
- more effective risk mitigation strategies and movement to a more proactive approach to integrity management; and
- increased transparency and visibility into materials management, job costing, resource availability, operational productivity, and operational efficiencies.

The Company is also mindful of the impact on our customers and the communities we serve when performing system improvements and reinforcements. By better coordinating construction, operating and maintenance programs, work is performed in a more efficient and timely manner. For example, the GIOSP explains actions we take to limit the number of times we return to excavate a particular area and enhanced communications with public officials, community boards and city agencies in advance of commencing work.

Q. What is the Company's Business Cost Optimization program?

A. Business Cost Optimization, or BCO, is the name of the Company's recent initiative to optimize its operating and capital costs, with a particular focus on reducing its O&M costs.

Q. Was the Company seeking to optimize these costs prior to commencing the BCO program?

A. Absolutely. As detailed by Company witnesses in prior Con Edison rate filings, the Company routinely undertakes many cost-savings efforts designed to reduce the overall cost of providing service to customers. Moreover, as explained in these testimonies, these initiatives include efforts to reduce or minimize costs that are, for the most part, outside of the Company's reasonable control, such as property taxes and municipal infrastructure support costs.

Q. What makes the BCO program different from these cost-saving efforts?

A. Prior to the BCO program, cost-savings efforts have, for the most part, been developed on a department-by-department basis. For example, during the Company's annual budget process, each Company organization is tasked with identifying cost-savings initiatives when it develops its individual budget. In contrast, our new BCO initiative is a structured and comprehensive approach to identifying and implementing cost reduction opportunities on a Company-wide basis that considers the operating and capital expenditures at both Con Edison and Orange & Rockland Utilities, Inc. (“O&R”). In an effort to maximize cost-saving opportunities, the Company retained the services of an experienced consultant, who specializes in cost reduction programs, to assist in setting up the framework for the assessment and to provide input on best practices.

Q. Please describe the nature and status of the BCO program.

A. The initial stage of the program, conducted during the fourth quarter of 2017, was a diagnostic stage. During this stage, the Company worked with the consultant to conduct an in-depth review of the Company's spend patterns by cost category, resource type and function. We used cost trend data and internal and external benchmarking to isolate areas to focus on and identify potential cost savings opportunities. As a result of these efforts, the Company identified potential cost saving initiatives for Con Edison and O&R, which were then prioritized based on several factors, including feasibility, cost to achieve and estimated savings. Over the coming months and years, many of these initiatives will progress into implementation.

Q. Does the Company present in the gas rate filing BCO initiatives that the Company plans to pursue?

A. Yes. Various Company operating panels, including GIOSP, Customer Operations Panel, and Customer Energy Solutions Panel, among others, discuss in their testimonies the cost-saving initiatives that they plan to pursue as a result of their participation in the BCO process.

Q. What are some of the challenges the Company faces in implementing BCO initiatives?

A. Each level of the program faces challenges and risks. During ideation and design, there must be certain assumptions made based on our current environment. As an initiative is further developed, those assumptions might change.

Q. Have projected savings associated with these initiatives been taken into account as part of the Company's budget processes for the three–year period 2020 through 2022?

A. Yes. Con Edison has incorporated the projected savings opportunities in the budgets developed for these years. This reflects the Company's commitment to identify, flesh out and implement these initiatives, or to find new initiatives in order to meet the overall reduction opportunities.

Q. Are the full amount of these projected savings reflected in the revenue requirements for RY1, RY2 and RY3?

A. Approximately seventy percent of these projected savings are credited to the revenue requirements for the three rate years.

Accordingly, assuming the establishment of a three-year rate plan in this proceeding, gas customers will receive the benefit of 70% of these projected savings whether or not the Company achieves them. Moreover, on a going-forward basis following the end of the multi-year rate plan, customers will receive the full benefit of any efficiencies actually achieved by the Company.

Q. Why is the Company not crediting the full amount of the projected savings to the revenue requirements?

A. As explained by the Accounting Panel in its testimony, the proposed credits to the revenue requirements are approximately three times the size of the one percent productivity adjustment traditionally incorporated into the revenue requirement. Here, however, the projected savings result from Company initiatives that go well beyond traditional utility efforts to manage costs and it will be very challenging for the Company to achieve these savings. The Company therefore proposes to give customers the benefit of 70% of these projected savings up front, and that the Company retain, for the term of this agreement, actual savings (which may be more or less than the projected savings), as an incentive to achieve the full projected amount, which will benefit customers in subsequent years.

VII. INCENTIVE RATEMAKING

Q. Does the Company's gas rate filing include incentive ratemaking proposals?

A. Yes it does. The Company is proposing that the Commission continue and/or institute several forms of incentive ratemaking as part of a new rate plan for Con Edison gas service.

Q. What is the basis for these incentive ratemaking proposals?

A. As we have explained in this testimony, the Company is planning to implement a myriad of projects and programs designed to meet increasing and changing customer expectations; to respond to technological and other changes affecting the natural gas industry; to achieve higher levels of operational and administrative efficiencies; and to meet various challenges specific to the Company's service territory.

As part of its policy-making proceedings, in particular, the REV and related proceedings, and in establishing new rate plans in major rate case proceedings, the Commission has adopted incentive mechanisms for utility initiatives that are designed to encourage utility companies to pursue non-traditional means, or enhance and extend traditional means, for meeting or exceeding changing customer expectations, while maintaining and/or enhancing the safety, reliability and efficiency of utility service.

We believe this incentive ratemaking policy should be continued and applied to the implementation of the projects and programs that the Company has developed and/or is developing to complement and supplement its core activities designed to provide safe and adequate utility service at just and reasonable rates.

Q. What are the forms of incentive ratemaking that the Company is proposing?

A. Generally, the forms of incentive ratemaking that the Company is seeking in this proceeding are:

- positive incentives associated with achieving or exceeding various gas safety performance metrics, as discussed by the GIOSP;
- positive incentives associated with the residential service termination and uncollectible bills metric, as discussed by the Customer Operations Panel; and
- Earnings Adjustment Mechanisms (“EAMs”), as discussed by the CES Panel.

Each Panel presents the reason(s) for the proposed incentive and the details of the proposed mechanism(s).

Q. Is the Company proposing to discontinue any positive incentive mechanisms that are currently in place?

A. Yes. Consistent with the changes to the Company’s growth-related programs in light of challenges in meeting increased peak day demand and State policies aimed at reducing reliance on fossil fuels, as explained by the GIOSP in their testimony, the Company proposes to change the revenue decoupling mechanism from a Revenue Per Customer mechanism to a Revenue Per Class mechanism. This eliminates an incentive for the Company to add new firm gas customers.

The proposed Revenue Per Class mechanism, which is presented by the Company’s Gas Rate Panel in their direct testimony, is similar to the revenue decoupling mechanism in effect for the Company’s electric customers.

Q. Do you have any concluding remarks regarding the Company’s incentive proposals?

A. Yes. We believe the proposed incentives and regulatory asset treatment discussed earlier in our testimony align customer, investor and other stakeholder interests while meeting State energy policy goals and better positions the Company to continue to be an industry leader in providing customers with safe, innovative and competitive gas energy solutions today and for future generations.

VIII. MANAGEMENT AUDIT UPDATE

Q. Please discuss the most recent Commission-initiated management and operations audit of the Company.

A. In December 2014, in Case 14-M-0001, the Commission commenced a comprehensive management and operations audit of Con Edison and O&R pursuant to Public Service Law §66(19). The Commission selected NorthStar Consulting Group ("NorthStar") to perform the audit. NorthStar released its Final Report on May 20, 2016. The Final Report contained 36 separate Recommendations for Con Edison.

Q. Is the Company implementing the Final Report's Recommendations?

A. Yes. The Con Edison Implementation Plan, which the Commission approved on October 13, 2016, contains a milestone schedule for the completion of each of the 36 Recommendations. In its latest update to the Implementation Plan, which the Company filed with the Commission on October 15, 2018, the Company explains that it has completed 33 of the 36 Recommendations and Staff has accepted and closed 30 of the 36 Recommendations. As to the remaining three Recommendations, the update explains that the remaining three recommendations are "in progress."

Q. What is the current status of the remaining three “in-progress” Recommendations?

A. The Company has completed two of the three Recommendations that were “in-progress” as of the October 15, 2018 update. In addition, Staff has accepted and closed two additional Recommendations. In total, the Company has completed 35 of 36 Recommendations and Staff has accepted and closed 32 of 36 Recommendations. As to the one remaining recommendation that remains “in-progress,” which relates to the implementation of Gas Operations’ work management process improvements, the Company remains on track with its plan; the target dates for completion milestones are in 2019 and 2020 and the Company is working towards completing the recommendation by these dates.

Q. Have there been any other Commission-initiated operations or management audits of the Company during the past several years?

A. Yes. The Commission initiated two state-wide operations and management audits in 2013.

Q. Please explain the status of these audits.

A. In August 2013, the Commission initiated Case 13-M-0314 to examine the accuracy of electric interruption, gas safety, and customer service data that is regularly reported to the Commission (“Utility Data Audit”). The Commission selected

Overland Consulting to perform the audit. In April 2015, Overland Consulting issued a report recommending various actions to be undertaken by the State's electric and gas utilities. By letter from Staff's Director of the Office of Accounting, Audits and Finance dated March 1, 2018, Staff confirmed the completion of its implementation oversight of Con Edison's audit recommendations in Case 13-M-0314, stating that Con Edison has implemented all recommendations, based on Staff's review of the Company's July 17, 2017 Implementation Plan.

Q. Please describe the status of the second state-wide audit.

A. In Case 13-M-0449, the Commission selected the Liberty Consulting Group ("Liberty") to examine internal staffing levels and the use of contractors at major New York State utilities. Liberty's final report for that audit included 24 recommendations for Con Edison. The Company filed an implementation plan on March 24, 2017, which the Commission approved on December 15, 2017.

In its latest update to the Implementation Plan, which was filed with the Commission on December 17, 2018, the Company explains that it has completed all 24 recommendations. A number of these recommendations are pending Staff review and closeout.

IX. CLIMATE CHANGE VULNERABILITY STUDY STATUS REPORT

Q. Please provide an update on the Company's Climate Change Vulnerability Study.

A. As a continuation of the Superstorm Sandy Storm Hardening Collaborative, we are working to complete a comprehensive Climate Change Vulnerability Study. As provided for in the current rate plan, Con Edison is required to complete this study by December 31 2019.

We retained a consultant, and we contracted with Columbia University's Lamont-Dougherty Earth Observatory for the climate science. The Working Group has met five times in total, twice in 2017 and three times in 2018. We will continue to convene the Working Group until we complete the Study, in order to share information and ideas with stakeholders.

In 2017, we developed the study work plan, established the climate variable set that will be used in the study, and held workshops with Company SMEs to identify appropriate subsets of the variables and identify high impact assets and processes that should be included.

As stated in the study's work plan, the Company will pursue three goals we reviewed with the Working Group:

- Develop a shared understanding of new climate science and anticipated weather conditions.
- Assess the impact of climate change on Con Edison’s infrastructure and complete a quantitative risk analysis that considers key uncertainties.
- Propose revisions to system and equipment design standards, if applicable, and create a risk mitigation plan.

In 2018, we completed study tasks related to Temperature, Humidity, Temperature Variable, and Load.

In 2019, we will complete study tasks relating to Sea Level Rise, Precipitation, Major Events, and Multiple Events. We will then review with the working group our resiliency options, including any potential recommendations, and issue the report.

Q. Are there any projects or programs in this rate filing that are a result of the work done to date?

A. Our findings from the study tasks completed thus far did not yield concerns of short-term significance that warranted the development of projects or programs for this rate filing. Nevertheless, as we work through the remaining study tasks and other assessments, we will consider whether any findings we obtain are significant enough to warrant including in our update filing an additional project(s) and/or program(s).

Q. How do you plan to use the findings from the study?

A. The study will develop a suite of adaption options to address the vulnerabilities identified. We will consider potential synergies among the different adaption options to establish the best overall strategy. The Company then plans to evaluate and then implement changes to its planning processes, system and equipment design standards and operating procedures consistent with the adaptation strategy. As part of this effort, the Company will periodically review the potential impacts from climate change, including updating climate projections. Barring any significant issues that require immediate action, we feel we can most effectively and efficiently make use of the information provided by this study after it is complete.

Q. Does this conclude the Panel’s testimony?

A. Yes.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DIRECT TESTIMONY – ACCOUNTING PANEL

TABLE OF CONTENTS

I. INTRODUCTION

Q. Would the members of the Accounting Panel please state their names and business address?

A. Robert Muccilo, Scott Sanders, Edlyn Misquita, Wenqi Wang and Kyle Ryan. Our business address is Consolidated Edison Company of New York, Inc. ("Con Edison," the "Company" or "CECONY"), 4 Irving Place, New York, NY 10003.

Q. What are your current positions and general responsibilities with Con Edison?

A. (**Muccilo**) I am the Vice President and Controller. In this position I am the Company's chief accounting officer with the overall responsibility for the development and maintenance of the Company's financial accounting records.

(**Sanders**) I am the Vice President Financial Planning and Analysis.

(**Misquita**) I am the Assistant Controller responsible for the Regulatory Accounting & Policy, Accounts Payable, Payroll and Account Reconciliation sections.

(**Wang**) I hold the position of Department Manager of Regulatory Accounting and Revenue Requirements.

(**Ryan**) I am the Department Manager of Regulatory Policy.

Q. Please explain your educational background and work experience.

A. (**Muccilo**) In 1978, I graduated from Jersey City State College with a Bachelor's Degree in Accounting. I graduated from Fairleigh Dickinson University in May 1983 with a Master's Degree in Corporate Finance. I began my employment at Con Edison in June 1978 and, from that time until 1998, I worked in the General

Accounts and Accounting Research and Procedures ("ARP") sections of Corporate Accounting in increasing levels of responsibility up to and including Manager of ARP. In 1999, I was promoted to Assistant Controller, responsible for General Accounts and ARP. In 2002, I assumed the responsibilities for Financial Forecasting and Budgets and Electric Revenue and Volume Forecasting sections of Corporate Accounting, and in 2003 continuing through 2006, I assumed the additional responsibility of Regulatory Accounting and Regulatory Filings sections of Corporate Accounting. As part of a career developmental opportunity, in 2006 I assumed the position of General Manager, Stores Operations where I was responsible for operating and managing the central warehouse and distribution facility for electric, gas and steam materials. In April 2008, I returned to Corporate Accounting to assume a special assignment as Assistant Controller and team leader for the Finance Transformation Project. The team was responsible for implementing process, people, and system changes designed to minimize financial reporting risk. I have also served on and led several corporate teams, including the establishment of the Consolidated Edison, Inc. holding company corporate structure and the Orange and Rockland ("O&R") Merger Transition Team. I became Vice President and Controller in 2009.

(**Sanders**) I hold a B.S. in Nuclear and Chemical Engineering from the University of California, Berkeley (1986), and an MBA from the University of Chicago (1996). I joined Con Edison in January 2010 as Vice President and Treasurer. I assumed my current position as Vice President Financial Planning and Analysis in 2016. I previously co-founded New Infrastructure Advisors in 2009, a boutique financial advisory firm. Prior to New Infrastructure Advisors, I was employed at Bank of America where I was a Managing Director in the Power and Utilities group covering U.S. utilities. I previously covered U.S. utilities during my tenure at Citigroup and New Harbor Incorporated. My work with utilities also included work as a consultant to U.S. utilities at Deloitte Consulting. I began my career with the California Public Utilities Commission, working as a staff engineer on electric, gas, water and telecommunications rate matters and then as an advisor to Commissioner Patricia Eckert on electric and gas matters. During my twelve years in the financial services industry, as a senior investment banking professional, I regularly valued, or directed the valuation of utilities and utility assets employing discounted cash flow valuations that applied capital asset pricing model-derived market costs of equity.

(**Misquita**) I received a Bachelor's degree in Accounting and Audit from University of Bombay, India in 1992 and am a CPA. I joined Con Edison in 2001 in the Corporate Accounting department. In my current role as Assistant Controller, I have oversight of regulatory and accounting operations. My previous assignments include assistant controller of Financial Accounting and Reporting, business lead for the implementation of Oracle Finance and Supply Chain systems, assistant to the CEO, and department manager of Accounting Research and

Procedures. Before joining Con Edison, I worked for seven years in the audit practice at Ernst & Young, India.

(**Wang**) In June 1999, I received a Bachelor of Science Degree in Accounting from the University at Albany, State University of New York. I began my employment with Con Edison in July 1999 as a Management Intern. I worked in the Corporate Accounting Department from July 2000 until April 2014, primarily in the General Accounts section starting as a Staff Accountant, then Supervisor and ultimately reaching the Department Manager level. In May 2014, I assumed my current position as Department Manager of Regulatory Accounting and Revenue Requirements.

(**Ryan**) I graduated from the University of Wisconsin-Madison in 2006 after earning a Bachelor of Business Administration in Accounting and a Masters of Accountancy. I began my employment with Con Edison in 2012 as a Senior Accountant in the Accounting Research and Procedures section and was promoted to Department Manager of the section in 2014. I assumed my current position as Department Manager of Regulatory Filings in June 2017. Prior to joining Con Edison, I worked for Ernst & Young in Minneapolis, Minnesota from 2006 to 2012, ultimately reaching the position of Audit Manager. I am a licensed CPA in New York and Minnesota.

Q. Have any members of the Accounting Panel previously testified before the New York State Public Service Commission ("PSC" or the "Commission")?

A. Yes. All members of the Accounting Panel have previously submitted testimony, some numerous times, before the Commission on behalf of CECONY and/or O&R in previous electric, gas and/or steam proceedings.

II. PURPOSE OF TESTIMONY

Q. Please summarize your testimony.

A. The Accounting Panel testimony covers the following topics:

- An overview of the costs driving the need for electric and gas rate relief for the twelve months ending December 31, 2020 (the “Rate Year” or “RY1”),
- An overview of the Company’s efforts to mitigate the cost of providing electric and gas service, including through its Business Cost Optimization (“BCO”) Program and its proposal for a BCO shared savings incentive
- Historic financial statements and statistical data required by the Commission;
- The development of the Rate Year electric and gas revenue requirements;
- The effect of the proposed electric increase as allocated between the Monthly Adjustment Clause (“MAC”) and delivery service rates;
- The proposed overall rate of return and capital structure for the Rate Year;
- Sources and uses of funds and interest coverage ratios;
- The Company’s proposals related to certain deferral accounting and reconciliation mechanisms; and
- The Company’s forecasted financial information for the two annual

periods beyond the Rate Year to provide a basis for settlement discussions regarding multi-year electric and gas rate plans.

III. ORGANIZATION OF TESTIMONY

Q. Please describe your testimony and how it is organized.

A. The Accounting Panel testimony covers the below-listed topics and exhibits. All of these exhibits were prepared under our supervision and direction, but rely on input from other Company witnesses. Certain projections will be updated based on the latest information available during the course of these proceedings.

Exhibit Title and Description	Exh. No.	E, G*
Historic Financial and Statistical Data	AP-1	E, G
Rate Base	AP-2	E, G
Operating Income/Revenue Requirement	AP-3	E, G
Estimated Net Plant and Capital Expenditures	AP-4	E, G
Capital Structure/Cost of Capital	AP-5	E, G
Allocation of Electric Rate Increase	AP-6	E
Finance and Other White Papers	AP-7	E, G

* The numbering convention for exhibits indicates whether the exhibits address electric or gas (E, G) service as follows: AP-E1, AP-E2, etc. for electric exhibits and AP-G1, AP-G2, etc. for gas exhibits. For ease of presentation, the exhibits are often referenced without the commodity designation. Please note that AP-6 is only applicable to electric service.

The Company is not proposing a multi-year rate plan for electric or gas in its filing. However, in addition to providing projections for the Rate Year, in order to facilitate the negotiation of multi-year electric and gas rate plans, the Company has included forecasted financial information for two annual periods beyond the

Rate Year, *i.e.*, the twelve-month periods ending December 31, 2021 and December 31, 2022 (which we and other Company witnesses will refer to as "RY2" and "RY3," respectively, for ease of reference).

IV. THE NEED FOR RATE RELIEF

A. Costs Driving and Mitigating the Need for Rate Relief

Q. When and in what cases were existing electric and gas rates set?

A. The Company's existing electric rates were set by the Commission in Case 16-E-0060 under a three-year rate plan that began January 1, 2017 and extends through December 31, 2019.

The Company's existing gas rates were set by the Commission in Case 16-G-0061 under a three-year rate plan that began January 1, 2017 and extends through December 31, 2019.

Q. What amount of rate relief is the Company requesting in this proceeding?

A. For the Rate Year, the Company is requesting $485 million of electric rate relief and $210 million of gas rate relief.

Q. Please explain why the Company is requesting an increase in its rates for electric and gas service at this time.

A. The primary drivers for the requested electric service rate increase, as explained in greater detail below, are growth in rate base, higher financing costs, higher property taxes, higher operating expenses, amortization of net deferred credits/ costs, and lower sales forecasts. These are mitigated by decreases in income taxes and anticipated savings as a result of the Company's BCO Program. As explained in greater detail below, the primary drivers for the requested gas service rate increase are growth in rate base, higher financing costs, higher property taxes, and higher operating expenses. These are likewise mitigated by decreases in income taxes and anticipated savings as a result of the Company's BCO Program. These various drivers are summarized in Table 1. Additional detail is set forth in the AP-3 exhibits.

Table 1 ($millions)		
Driver	**Electric**	**Gas**
New infrastructure investment / Net plant additions	271	147
Higher ROE / Financing	175	56
Property and other taxes	168	63
Sales revenue change	124	(15)
Amortization of net deferred credits/costs	242	64
Operations and maintenance expenses	43	41
Depreciation changes	23	9
Other operating revenue	16	6
Income taxes and other items	(577)	(161)
Total	**$485**	**$210**

All amounts are revenue requirement levels and represent changes relative to RY3 of the Company's current rate plans

1. Net Plant Additions

Q. Please discuss the impact of net plant additions on the Company's rate base.

A. The Company has a continuing statutory obligation to maintain safe and reliable electric and gas systems. As discussed by the Company's Electric Infrastructure and Operations Panel ("EIOP"), the Company's Gas Infrastructure, Operations and Supply Panel ("GIOSP") and other Company witnesses, the projected level of spending reflects the investments determined to be necessary to install and replace infrastructure and manage risk, meet current customer needs, plan for future customer needs and enable the transition to a dynamic customer oriented clean energy system. The Company makes capital spending decisions following its extensive and rigorous analysis, including an optimization assessment that is guided by our long- and short-term planning processes and takes into account State and local policy objectives. As the witnesses explain, the Company's strategy is to invest in infrastructure enhancements only when less expensive alternative solutions are not available to sustain existing reliability levels, provide for localized delivery capacity needs, provide for employee and public safety, and enable the clean energy transition.

The ongoing need for capital investment contributes to the increase in the carrying cost on rate base relative to current RY3 rate levels of approximately $271 million for electric and $147 million for gas, which includes additional depreciation expense of $107 million for electric and $54 million for gas on the higher plant investment at the Company's currently-authorized depreciation rates.

2. Financing, Depreciation and Property Taxes

Q. Please discuss the increase in financing costs for both electric and gas services as shown in Table 1.

A. The overall effect of the change in financing costs amounts to $175 million for electric and $56 million for gas. The primary factor contributing to this increase is the proposed return on equity ("ROE") of 9.75 percent (as compared to the current ROE of 9.0 percent). Other factors include increasing the equity ratio from 48.00 percent to 50.00 percent, an increase in the cost of debt from 4.74 percent to 4.86 percent, and an increase in the customer deposit rate from 0.85 percent to 2.45 percent.

Q. Why is the Company proposing an ROE of 9.75 percent in this rate filing?

A. As discussed in her direct testimony, Company witness Villadsen calculated a 10.00 percent ROE as being appropriate for the Company. The Company is filing with the lower 9.75 percent ROE in order to facilitate the resolution of the issues in these proceedings.

Q. Please explain the increases in depreciation expense for electric and gas.

A. The increases in depreciation expense are due primarily to updating for projected plant balances through the Rate Year and to a request for increased amortization levels of the accumulated depreciation reserve deficiency for electric and gas. The Company's Depreciation Panel presents a study of the appropriateness of the depreciation rates currently authorized for use and makes certain findings. However, in order to facilitate the resolution of the issues in these proceedings, the Company is not proposing a change in depreciation rates in these cases. Had the Company reflected the rates found warranted in the Depreciation Studies and requested amortization of the reserve deficiency at levels supported by the Depreciation Studies, the rate relief request would have been approximately $113 million higher for electric and $33 million higher for gas. By not proposing to change depreciation rates in this case, the Company should not be viewed as waiving its rights to seek recovery of the full reserve deficiencies or to increase depreciation rates in future rate filings. Moreover, should the Commission decide to shorten the amortization periods proposed by the Company (for the reserve deficiencies or for the recovery of any other costs, which the Company proposed to mitigate bill impacts to customers), and determine that more of such costs should be recovered in the Rate Year, the revenue requirements should be increased to reflect any such changes in recovery periods.

Q. Please discuss the increases related to property and other taxes for electric and gas services as shown in Table 1 above.

A. The total increase in taxes, other than income tax, is $168 million for electric and $63 million for gas. The $168 million increase for electric is comprised of an increase in property tax of $171 million, offset by a decrease in payroll and other taxes of $3 million. The $63 million increase for gas includes an increase in property tax of $64 million, offset by a decrease in payroll taxes of $1 million. The increases in property taxes above the current rate allowances are attributable to higher projected property taxes in New York City ("NYC"), the County of Westchester and other upstate localities, as addressed in the testimony of the Company's Property Tax Panel.

3. Operation and Maintenance ("O&M") Expenses

Q. Please explain the increases in electric and gas O&M expenses that contribute to the need for rate relief.

A. Increases in O&M expenses result from a variety of normalizations of Historic Year (*i.e.*, October 1, 2017 through September 30, 2018) costs and program changes described later in this testimony and in the testimony of various Company witnesses. Please note that the O&M drivers include deferred expenses that are being amortized, including Site Investigation and Remediation ("SIR"), Energy Efficiency ("EE"), Brooklyn Queens Demand Management Demand Response Program ("BQDM") and Reforming the Energy Vision ("REV") demonstration projects. In addition, the Company escalated Historic Year expenses using labor and non-labor escalation factors to arrive at Rate Year amounts, as described later in this testimony.

For electric, the $43 million overall increase in O&M expense includes, in addition to general inflation and wage awards, funding of a number of operational enhancements, including maintenance of the Advanced Metering Infrastructure ("AMI") systems and communications infrastructure and additional information technology ("IT") support for Oracle systems, the Digital Customer Experience ("DCX"), cyber security, and enterprise data analytics. Increases also include recovery of EE program costs and the Company's energy storage proposal. There are also increases related to employee benefits and interference. These increases are partially offset by certain reductions, most notably savings driven by the Company's BCO Program, AMI implementation and decreases in customer uncollectibles and SIR expenditures.

For gas, the $41 million overall increase in O&M expense is mostly driven by a significant increase in the number of gas inspections that must be performed. This change for gas inspections is primarily due to a change in the Commission's definition of a "gas service line" and is further described in the GIOSP testimony. AMI, labor, employee benefits and IT support are other major contributors to the increase in gas O&M costs. These increases are partially offset by certain reductions, most notably savings driven by the BCO Program, AMI implementation and decreases in customer uncollectibles and SIR expenditures.

4. Income Taxes

Q. Please discuss the $574 million decrease to the electric revenue requirement and the $161 million decrease to the gas revenue requirement related to income taxes.

A. The large decreases in the revenue requirements are primarily related to the reduction in the corporate tax rate from 35% to 21%, resulting from the Tax Cuts and Jobs Act of 2017 ("TCJA"). This change greatly reduced both current and deferred income taxes. Offsetting these reductions are the expiration of the amortization of the reduction in the State corporate tax rate from 7.1 percent to 6.5 percent included in current rates.

5. Amortization of Net Deferred Credits / Costs

Q. Please explain the references in Table 1 to the amortization of net deferred credits and costs.

A. The Company has recorded deferred costs and deferred credits under its current rate plans and has made projections of further deferrals between the end of the

Historic Year and the start of the Rate Year. The specific items are discussed in detail in later sections of this testimony

Q. What effect does the amortization of these net deferred credits have on the Company's request for rate relief?

A. The effect for electric and gas is summarized below:

Table 2 ($ millions)		
Amortization of Net Credits	**Electric**	**Gas**
Expiring net credits	152	45
New net debits	90	19
Effect on revenue requirement	**242**	**64**

Electric: Excluding the deferred items relating to SIR, EE, BQDM and REV demonstration projects, which as discussed above are included in O&M, and the deferral of the TCJA related benefits, which as discussed above are shown as an income tax driver, the Company has deferred $149 million of net customer debits through September 30, 2018 and is projecting this balance to increase to $436 million by December 31, 2019. The Company is proposing to collect the net debits from electric customers over five years rather than three years, as is being done in current rates, in order to moderate rate impacts in this case. The effect of amortizing these customer debits increases the Company's necessary rate relief by $90 million. The biggest drivers of this $90 million increase are $50 million for recovery of MTA costs and $32 million for property taxes. The net effect on the electric revenue requirement of removing the expiring customer debits and credits is a $152 million increase to the amount of necessary rate relief. Thus, the total increase to the electric revenue requirement related to the amortization of deferred customer debits and credits is $242 million.

Gas: Excluding the deferred items relating to SIR and EE, which as discussed above are included in O&M, the deferral of the TCJA related benefits, which as discussed above are shown as an income tax driver, and the Meadowlands Heater project, which is discussed separately in this section, the Company has deferred $49 million of net customer credits through September 30, 2018 and is projecting this balance to be a net deferred debit of $77 million by December 31, 2019. The Company is proposing to collect this customer debit from gas customers over five years rather than three years as is being done in current rates in order to moderate rate impacts in this case. The effect of amortizing the net $77 million customer debit over five years increases the necessary rate relief by $16 million. The Commission previously approved the amortization of the Meadowlands Heater project over 15 years. The Company proposes to collect the remaining balance of $38 million over the remaining twelve years of the amortization period, or $3 million per year. Thus, the net effect on the gas revenue requirement of new customer debits and credits is a $19 million increase to the amount of necessary rate relief. The biggest drivers of this $19 million increase are $8 million for property taxes and $6 million for gas service line inspections and repairs. The net effect on the gas revenue requirement of removing the expiring customer debits and credits from the current gas rate plan is a $45 million increase to the amount of necessary rate relief. Thus, the total increase to the gas revenue requirement related to the amortization of deferred customer debits and credits is $64 million.

6. Sales Revenue and Other Operating Revenues

Q. Please explain the sales revenue effect on the revenue requirement shown in Table 1 above.

A. With regard to electric, the Company is projecting lower sales volumes due to forecasted energy use reductions, as discussed in the Electric Forecasting Panel's testimony. The Company is projecting the need for $124 million of additional revenue attributable to the projected reduction in electric usage, as compared to the level assumed in current rates.

With regard to gas sales revenues, the Company is projecting slightly higher sales due to an increase in forecasted natural gas usage, as discussed in the Gas Forecasting Panel testimony, which incorporates the forecasted impacts from the Company's temporary gas moratorium in Westchester. The Company is projecting the reduced need for $15 million of additional revenue attributable to the projected increase in gas usage, as compared to the level assumed in current rates.

Q. Please address the impact of changes to Other Operating Revenues on the electric and gas revenue requirements.

A. Decreases to Other Operating Revenues from the amounts reflected in current rates serve to increase the revenue requirements by $16 million for electric and $6 million for gas, respectively. For electric, the decrease is primarily driven by an $8 million decrease in projected purchase of receivables ("POR") discounts. For gas, the decrease is primarily driven by lower rental revenues due to the changes in the accounting for the New York Facilities agreement, discussed below.

B. Business Cost Optimization

Q. What is Business Cost Optimization?

A. Business cost optimization, referred to as "BCO," is a Company-wide program that seeks to improve processes, functions, and tasks to reduce costs while upholding our core strategic imperatives of safety, operational excellence and customer experience.

The program has three main objectives: (1) identify ways to improve or re-engineer our work that results in reduced O&M costs; (2) develop a plan for and implement cost savings initiatives; and (3) build a long-term and sustainable process for achieving ongoing cost savings.

Q. Why is the Company undertaking BCO?

A. The BCO is one measure the Company is employing to advance our business to the benefit of our customers as we manage the changing industry landscape. New York utilities face an increased focus on customer costs and, in the case of electric, flat sales. At the same time, technology, data and analytics are giving our employees the ability to gain new insights and unlock value. These advances are transforming the way we do business –giving us the ability to enhance the safety of our systems, improve our customers' experience, and work towards operational excellence while reducing costs.

Q. How is BCO different from managing costs as you have in the past?

A. In the same way we are transforming our business, we are transforming the way we manage costs. Con Edison has always sought to manage costs. With BCO, we are building a broader and deeper capability to take advantage of new digital technologies, and to apply consistent frameworks, techniques and approaches across our Company to improve our ability to manage costs. We are challenging organizations to think differently about improving the work we do, and by doing so, reduce costs. Our BCO Program is a step-change difference from "business as usual" for the Company in how we are looking at costs. First, it is utility-wide, and centrally managed. To drive the cost transformation, we have committed significant human resources toward the effort with our existing staff, establishing at least a dozen teams that represent all major organizations within the Company. In addition, we have established a centralized program office ("BCO Program Management Office") to coordinate the teams, manage an oversight process to measure progress, track results and provide direct and facilitated support where required on initiatives. Second, we designed the BCO Program to our specific operations. That is, while the program is guided by high-level benchmarking (both utility and non-utility), it was primarily designed by critically evaluating and improving our current processes. These are internally generated solutions, although we draw on best practices from across industries.

Q. Please describe the BCO Program to date.

A. At the end of 2017, the Company undertook a diagnostic review with a consultant at its own cost to identify improvements in the way we work and the associated costs savings. The diagnostic review was a broad, high-level process to evaluate the spending patterns of the Company's business organizations by cost category, resource type and function. In this "diagnostic phase," the Company used cost trend data and internal and external benchmarking to identify areas on which to focus for cost savings initiatives.

In 2018, the Company began to design and implement initiatives. Each initiative is managed by a team consisting of a business lead, other business unit members and a Finance department liaison. Each team is sponsored by a Vice President or Director. As discussed above, a central BCO Program Management Office team in the Finance organization tracks each initiative and provides support. Centrally managing the BCO Program increases visibility and accountability and allows for more transformative, cross functional changes in the Company compared to singularly-focused savings initiatives within a single organization.

As of the fourth quarter of 2018, the BCO Program Office included over 70 initiatives across the Company's various departments. For a summary of the major initiatives and a description of how the Company developed their associated cost savings, please see the direct testimony of the EIOP, GIOSP, IT, Shared Services, and Customer Operation Panels.

The BCO effort is still in the early stages. Therefore, we expect to maintain the current level of resources and management structure in place for BCO for some time. Only after we are confident we have made sustainable changes to our processes will we consider decentralizing the effort and making it normal business practice.

Q. What are the Company's BCO savings projections for RY1, RY2, and RY3?

A. The Company projects it can achieve approximately $59 million in savings in RY1, an additional $34 million in savings in RY2 and an additional $13 million in RY3 savings for electric and $3 million in savings in RY1, an additional $12 million in savings in RY2 and an additional $4 million in savings in RY3 for gas, net of the O&M and capital costs to achieve.

Q. How does the Company reflect BCO savings in this rate filing?

A. BCO savings for 2020, 2021, and 2022 are reflected in the Company's electric and gas program changes. Exhibits AP-E3 and G3 detail the cost-savings associated with the initiatives reflected in the program changes. Schedule 16 of the AP-3 exhibits identifies the organizations in which the savings are reflected and the panels wherein the savings are discussed. The Company also applied an adjustment for fringe benefit savings to any labor-related BCO program changes. The BCO O&M savings presented in these exhibits are net of O&M costs to achieve and net of the sharing mechanism proposed below.

Q. What costs does the Company include in its BCO costs to achieve?

A. BCO costs to achieve include both O&M and capital costs required to implement BCO initiatives. As stated above, the BCO O&M savings in Schedule 16 of the AP-3 exhibits are reflected net of the O&M costs to achieve. The capital costs to achieve are included in the company's overall capital expenditures and net plant model. Costs associated with the Company's BCO consultant are funded solely by shareholders and are not included in our costs to achieve.

Q. Is the Company including a one percent labor productivity adjustment its O&M projections in addition to the BCO savings?

A. No. We are including savings that are much greater than the traditional one percent labor productivity adjustment. The BCO savings in this rate filing will be approximately three times the savings level traditionally included. In developing its labor escalation rates in past base rate cases, the Company has included a one percent productivity adjustment as a proxy for future potential efficiencies. In the instant proceedings, as we have indicated, the Company has performed a thorough study and is implementing a comprehensive, centralized cost-savings program that has quantified cost savings. Instead of waiting to realize concrete savings from that program to credit customers, the Company is incorporating all anticipated savings into its proposal in this filing.

Q. You indicated that the Company is assuming additional business risk by incorporating BCO savings in its Program Changes. What is the source of that business risk?

A. As discussed below, and addressed by other Panels, there are challenges to meeting the projected cost savings. By passing on the savings to customers despite those challenges, the Company assumes additional business risk. Our rate case proposal is designed to shield customers from the impacts of that risk by passing on the majority of anticipated savings regardless of whether those savings are actually achieved.

The primary uncertainty in achieving cost savings relates to labor costs. As seen in Exhibits AP-E3 and G3, Schedule 16, 44 percent and 26 percent of the net RY1 BCO O&M cost savings for electric and gas, respectively, are tied to changes in how the Company organizes and deploys labor. The timing of when the associated savings will be realized is uncertain. There are several steps to implement any initiative, each of which could take longer or shorter than initially projected. For instance, where the Company is implementing a new technology, the software needs to be integrated with the Company's systems, protocols will have to be established by the groups who directly use or draw information from it, and employees will need to be trained on how to use its various functionalities. In addition, employees who are being re-assigned to other work need to be trained and transitioned prior to assuming their new positions. Any changes in the implementation timeline of this and other initiatives may affect the timing of cost savings and what is achievable in RY1-RY3.

For additional detail on the challenges associated with various initiatives, please see the direct testimony of the EIOP, GIOSP, IT, Shared Services, and Customer Operation Panels.

Q. Is the Company proposing a BCO savings sharing mechanism?

A. Yes. The Company is the first utility in this State to implement on its own accord a utility cost savings programs of this magnitude. The Company's proposed incentive is justified because: (1) it provides the Company with the incentive to continually refresh the pipeline of potential initiatives as we identify further opportunities; and (2) it addresses some of the business risk associated with not achieving the aggressive level of savings reflected in the rate filing.

Q. What is the Company's proposed BCO savings sharing mechanism?

A. In order to determine the BCO savings sharing, the Company computed the net savings, i.e., gross savings reduced by O&M costs to achieve and a carrying charge on capital costs to achieve. The Company first proposes to pass back to customers an amount equivalent to the typical one percent labor productivity adjustment. The Company then proposes to share the remaining net savings 70 percent to customers and 30 percent to the Company. By passing back to customers an amount equal to the one percent labor productivity adjustment, the Company preserves the full impact of the traditional adjustment for customers. The Company has built the savings sharing into its proposed O&M program changes. The cumulative annual BCO savings by rate year is as follows:

BCO Cumulative Savings **($ millions)**	**RY1**	**RY2**	**RY3**
Gross BCO Savings	$110	$165	$186
Less: O&M Costs to Achieve	(37)	(44)	(47)
Subtotal: Net O&M Savings	73	121	139
Less: Carrying Charge on Capital Costs to Achieve	(11)	(13)	(14)
Net Savings Subject to Sharing	$62	$108	$125
Customer Share			
Amount equivalent to 1% productivity	16	24	33
70% of remaining net savings	33	59	66
Total Customer Share	**$49**	**$83**	**$99**
Company Share – 30% of remaining net savings	**$13**	**$25**	**$26**

Q. Why does the Company propose 30% as the shareholder incentive?

A. The Company proposes 30% because that is the Commission authorized sharing percentage for the implementation of non-wires solutions ("NWS"). We believe that the Commission's justification for a 30% shareholder incentive applies to the Company's implementation of the BCO initiative. The Commission stated in its order adopting the NWS 30% incentive:

> incentive opportunities should be financially meaningful and structured such that they encourage enterprise-wide attention at the utility and spur strategic, portfolio-level approaches beyond narrow programs. Further, incentive opportunities should be commensurate with the level of financial risk borne by utility shareholders. The 30% sharing adopted here represents a financially meaningful incentive opportunity that should encourage Con Edison to pursue the innovative portfolio-level approach to implementing NWA projects, while producing significant net benefits to customers and reflecting the financial risk required of Con Edison shareholders.

Case 15-E-0229, Order Approving Shareholder Incentives, at 3 (January 25, 2017). Here, too, the 30% incentive will encourage "enterprise-wide attention" and "spur strategic, portfolio-level approaches beyond narrow programs."

Moreover, there is shareholder risk associated with the proposal, as we are "baking in" the BCO savings and there will be no after the fact true-up. In other words, customers are assured of the 70% share of BCO savings and the risk of not achieving the aggressive targets falls solely on the Company. As such, the Company's proposed 30% incentive is fair to customers and investors and should be adopted as proposed.

Q. Under the Company's proposal, after the end of the rate period covered by this proceeding, will 100% of the achieved annual BCO savings accrue to customers?

A. Yes.

V. HISTORIC FINANCIAL AND STATISTICAL DATA (Exhibits AP-1)

Q. Are you familiar with the Company's accounting books and records?

A. Yes.

Q. Are the accounts of the Company kept in accordance with the Uniform System of Accounts prescribed by the Commission?

A. Yes.

Q. Does this filing include historical financial and statistical data as required by the Commission for major rate filings?

A. Yes. The required information is included in the AP-1 exhibits.

Exhibits AP-1, Schedules 1-10, consist of an index and supporting schedules (*i.e.*, ten for electric and nine for gas) containing financial data and the results of operations for the particular utility service. The balance sheets are shown as of December 31 for the years 2014 through 2017, and as of September 30, 2018, the end of the Historic Year. Details of the income statement accounts are shown for the calendar years 2015 through 2017, and the Historic Year. Exhibits AP-1, Schedules 1-10 are:

- Schedule 1 – Balance Sheets;
- Schedule 2 – Income Statements;
- Schedule 3 – Unappropriated Retained Earnings;
- Schedule 4 – Utility Operating Income;
- Schedule 5 – Operating Revenues;
- Schedule 6 – Statement of Commodity Supplied and Revenue Billed
- Schedule 7 – Other Operating Revenues;
- Schedule 8 – Operation and Maintenance Expenses;
- Schedule 9 – Taxes Other Than Income Taxes; and
- Schedule 10 – Power Production Expenses (electric only).

All of the financial information in Exhibits AP-1, Schedules 1-10, are from the books and records of the Company, except statistical information in cents per kWh and dekatherm, which were computed based on the data contained in the exhibits.

VI. HISTORIC FEDERAL AND STATE INCOME TAXES (Exhibits AP-1, Schedule 11)

Q. Have you included a presentation of federal and state income taxes for the Historic Year in your exhibits?

A. Yes. The first part of Exhibits AP-1, Schedule 11, sets forth the calculation of federal income tax for electric and gas operations, including accruals, deferrals and amortizations of deferrals for the Historic Year. The second part of those exhibits show the calculation of New York State ("NYS") income tax for electric and gas operations for the same twelve-month period.

VII. HISTORIC BOOK COST OF UTILITY PLANT (Exhibits AP-1, Schedule 12)

Q. Have you included a presentation of the historic book cost of utility plant in your exhibits?

A. Yes. Exhibits AP-1, Schedule 12, contain historic balances of the book cost of utility plant, by utility plant account, and the balances of construction work in progress ("CWIP") for electric and gas as of the end of the Historic Year and as of the end of the preceding four calendar years taken directly from the books and records of the Company. The utility plant accounts are maintained in balance with the continuing property records, which show the original cost of the existing property classified in accordance with established continuing property record units.

VIII. HISTORIC ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT (Exhibits AP-1, Schedule 13)

Q. Have you included a presentation of the historic balances of the accumulated provision for depreciation of utility plant in your exhibits?

A. Yes. Exhibits AP-1, Schedule 13, contain historic balances of the accumulated provision for depreciation as of the end of the Historic Year and as of the end of the preceding four calendar years. The amounts shown in Exhibits AP-1, Schedule 13, were taken from the books and records of the Company. We will address projected changes to the accumulated provision for depreciation below in this testimony.

IX. RATE BASE (Exhibits AP-2)

Q. Turning to rate base, do your exhibits include an itemization of the components of electric and gas rate base?

A. Yes, that information for the Historic Year and the Rate Year is presented in Exhibits AP-2.

Q. Please describe your presentation of rate base in Exhibits AP-2.

A. The presentation approach is the same for the electric and gas rate base exhibits. There are a total of six pages in Exhibits AP-2. Page 1 summarizes the overall rate base calculation for the Historic Year and Rate Year. Page 2 shows the details of the forecasted net plant and non-interest bearing CWIP calculation, as shown on page 1, lines 1 to 11 for electric (lines 1 to 10 for gas). Page 3 provides the details of the working capital, unamortized premium & discount and customer advance construction figures, as shown on page 1, lines 12, 13 and 15 for electric (lines 11, 12, and 14 for gas). Page 4 provides the details of the projected deferred balances from reconciliation mechanisms contained in the current rate plan as shown on page 1, line 16 for electric (line 15 for gas). Page 5 shows the details of accumulated deferred federal and state tax balances, as shown on page 1, lines 17 to 20 for electric (lines 16 to 19 for gas). Page 6 provides a detailed calculation of the Earning Base Capitalization Adjustment amount, as shown on page 1, line 22 for electric (line 21 for gas).

Q. Are there any remaining rate base items on page 1 of Exhibits AP-2 that are not detailed on pages 2 - 6 of Exhibits AP-2?

A. Yes. Unamortized Preferred Stock Expense on line 14 for electric (line 13 for gas), Pension/OPEB Reduction on line 23 (line 22 for gas), and Former Employee/Contractor Proceeding Rate Base Reduction on line 24 (line 23 for gas), are the remaining rate base items that are shown on page 1 of Exhibits AP-2. Unamortized Preferred Stock Expense reflects the unamortized preferred stock expense as additions to rate base. The Commission directed this rate base treatment in its Order on Rehearing in Case 27353.

For the Pension/OPEB Reduction, without waiving its right to modify its position in future rate proceedings, the Company made an adjustment for prepaid pensions based on a decision in Case 07-E-0523.

Regarding the Former Employee/Contractor Proceeding Rate Base Reduction, the Company made this adjustment due to an April 2016 Commission Order regarding the Former Employees/Contractor proceeding in Cases 09-M-0114 and 09-M-0243. Pursuant to the Joint Proposal and subsequent order in these cases, the Company agreed to, among other things, forgo earning any return after January 1, 2017 on certain capital expenditures and to limit the return on certain other capital expenditures after January 1, 2017 to the Company's embedded cost of long-term debt.

A. Net Plant Rate Base (Exhibits AP-2, page 2)

Q. What rate base items related to net plant investment are included on page 2 of Exhibits AP-2?

A. Page 2 of Exhibits AP-2 includes projected net plant and the portion of CWIP not subject to Allowance for Funds Used During Construction ("AFUDC"). Net plant includes utility plant in service, the allocated portion of common utility plant, plant held for future use, Oracle agreement payment liability and the accumulated provision for depreciation at current depreciation rates, including proposed recovery of reserve deficiencies. Rate Year plant and accumulated depreciation forecasts are based on capital budget models and a thirteen-point average methodology. A description on how the Company developed the forecasted amounts of these items for the Rate Year is included in Section XIII of this testimony.

B. Detailed Development of Working Capital, Unamortized Premium & Discount, and Customer Advance Construction (Exhibits AP-2, page 3)

Q. Please explain the rate base component labeled "Working Capital" on page 1 of Exhibits AP-2.

A. The detailed elements of working capital rate base are shown on page 3 of Exhibits AP-2. Working capital rate base contains three categories: Materials and Supplies, Prepayments, and Cash Working Capital.

1. Materials and Supplies

Q. How did you determine the average balance of Materials and Supplies rate base for the Rate Year shown on page 3 of Exhibits AP-2?

A. As in many past Company rate cases, the Rate Year forecast of Materials and Supplies inventory generally represents the Historic Year amount escalated using the general escalation factor.

An exception with respect to gas, however, but also consistent with the practice in many past Company gas rate cases, is that we excluded from rate base the inventory balances of both gas stored underground and Liquefied Natural Gas in storage. As discussed later, we have also eliminated from sales revenues the effects of gas in storage (as well as other items) to reflect only pure base revenues on which the revenue requirement should be based. This elimination would match our adjustment to revenues.

2. Prepayments

Q. What is included in the "Prepayments" category of working capital rate base on page 3 of Exhibits AP-2?

A. The prepayment component of working capital rate base includes local property tax, computer maintenance and software support, insurance, Commission assessment, NYS GRT, rents and other items.

Q. Please explain how you developed the Rate Year rate base amount for the Prepayment items.

A. All prepayments except for the prepaid property taxes were projected at the Historic Year level and escalated by general inflation. Prepaid property taxes are forecasted to increase at the same rate as property taxes. In their direct testimony, the Property Tax Panel discusses the Company's property tax forecasts.

3. Cash Working Capital

Q. Please explain the allowance for the cash working capital component of working capital rate base on page 3 of Exhibits AP-2.

A. We determined the cash working capital component of working capital rate base following well-established Commission practice including application of the 1/8 FERC Working Capital Formula. As such, we performed separate calculations of the rate base amount for electric and gas. For each, we started with projected total O&M expenses from Schedule 6 of Exhibits AP-3. Continuing with the established approach, we eliminated certain expenses from the O&M expense amounts to arrive at the level of O&M expenses that would be subject to the 1/8 FERC Working Capital Formula.

For electric, we eliminated purchased power and fuel expenses, amortization of energy efficiency programs and energy efficiency surcharges, amortization of MGP/Superfund Site, interdepartmental rents, East River Repowering Project ("ERRP") Rent and uncollectible accounts expense.

For gas, we eliminated purchased gas expenses, interdepartmental rents, amortization of MGP/Superfund Site, energy efficiency surcharges, and uncollectible accounts expense for that purpose.

The amounts for gas are the final cash working capital amounts, but there is an additional element of the cash working capital allowance for electric related to the fuel and purchased power expenses previously eliminated from the calculation. The cash working capital allowance related to fuel and purchased power is calculated based on a time lag between fuel costs included in customer bills and when payments are collected from customers, as customarily applied by the Commission. This additional element of the cash working capital allowance adds $86.6 million to the cash working capital rate base for electric as shown on page 3 of Exhibit AP-E2.

4. Unamortized Premium & Discount and Customer Advance for Construction

Q. Please explain the unamortized premium/discount and expense and customer advance for construction on page 3 of Exhibits AP-2.

A. The unamortized premium/discount and expense reflects the unamortized balance of debt discounts, premiums and expenses, as additions to rate base. Customer advance for construction represents the amount billed to customers and others for the construction necessary to provide utility service to their premises (rather than for general system service) and represent a reduction to rate base. The Historic Year levels of these items were carried forward to the Rate Year.

C. Net Deferrals/Credits from Reconciliation Mechanism (Exhibits AP-2, page 4)

Q. Are deferral balances net of deferred income taxes?

A. Yes.

Q. Please explain each item on Exhibit AP-2, page 4.

A. For detail on lines 1-52 of Exhibit AP-E2, page 4, and lines 1-39 of Exhibit AP-G2, page 4, please refer to Section XVII (Reconciliations & Deferred Accounting) of this testimony.

Line 49 (G), Underground Gas Storage – Noncurrent, represents the Company's investment in the non-current portion of cushion gas stored underground. The Historic Year levels of underground gas storage were carried forward to the Rate Year.

Line 64 (E)/Line 48 (G), Unbilled Revenues, represents the unbilled revenue deferral that was established to allow the Company to recover a portion of the deferred World Trade Center ("WTC") related costs. The electric amount included in rate base, $91 million, was approved by the Commission as part of Case 08-E-0539. The amount included in gas rate base, $44 million, was approved by the Commission in Case 06-G-1332.

Line 65 (E), Deferred Fuel - Net of Tax, is the average balance of deferred fuel, net of taxes. Deferred fuel is comprised of deferred Market Supply Charge ("MSC")/MAC costs.

D. Detailed Development of Accumulated Deferred Income Taxes (Exhibits AP-2, page 5)

Q. How did the Company develop Accumulated Deferred Federal Income Taxes on page 5 of Exhibits AP-2?

A. The Company developed Accumulated Deferred Federal Income Taxes for plant-related items using data from its capital budget and tax depreciation models. The Company calculates the rate base impact for federal deferred income taxes by using a proration methodology that is required by the Internal Revenue Service for any revenue requirement calculation that employs a future test period. The Company developed non-plant related deferred taxes by escalating the historic balances.

Q. How did the Company develop the Accumulated Deferred State Income Taxes on page 5 of Exhibits AP-2?

A. The Company developed Accumulated Deferred State Income Taxes using data from the Company's capital budget and tax depreciation models. The forecasted rate year balance is based on 50% of beginning and 50% of ending forecasted balance.

Q. Please explain the line items pertaining to federal and state deferred income taxes.

A. Below are detailed descriptions of the line items common to federal and state deferred income taxes. For figures for each line item, please see page 5 of Exhibits AP-2.

Statutory Tax Deduction, represents the deferred income taxes resulting from the normalization of federal/state tax depreciation. The Company developed the average balance of accumulated deferred taxes for the Rate Year by starting with the actual balance at the end of the Historic Year and increasing it each month through the Rate Year if forecasted deferred income taxes generated by tax depreciation normalization exceeded the amortization of such amounts previously deferred.

Change in Accounting Section 263A, represents deferred income taxes for capitalized overheads deducted on the Company's tax returns under Section 263A of the IRS Code.

Repair Allowance, represents deferred income taxes for repair allowance deductions claimed in lieu of tax depreciation on new plant.

Cost of Removal, reflects deferred income taxes associated with the timing differences between financial accounting and accounting for income tax purposes related to removal costs.

Materials and Supplies Deduction, represents deferred income taxes for non-incidental materials and supplies costs claimed in lieu of the tax depreciation that would be otherwise claimed on new plant.

Vested Vacation (non-plant portion), reflects the amount of accumulated deferred federal/state income taxes on the vested vacation pay deduction.

Prepaid Insurance Expense, reflects the amount of accumulated deferred federal/state income taxes on prepaid insurance expenses.

Unbilled Revenues, represents the deferred balance of taxes paid on unbilled revenues. The Commission, in its Statement of Policy on Accounting and Ratemaking Procedures to Implement Requirements of the Tax Reform Act of 1986 ("TRA-86"), issued July 8, 1989 in Case 29465, directed utilities to normalize the effect of unbilled revenues in taxable income. This line also reflects the effects of the unbilled revenue change previously mentioned in this section.

Call Premiums, is the deferred federal/state income tax effect resulting from the payment of call premiums when redeeming long-term debt issues prior to their maturity dates. The call premiums paid are a current deduction for federal/state income tax purposes, but amortized over the remaining lives of the redeemed issues, in accordance with Commission policy.

E. Rate Base Over/Under Capital Adjustment (Exhibits AP-2, page 6)

Q. Please explain the rate base over/under capitalization adjustment ("EB/Cap Adjustment") on Exhibits AP-2, page 6.

A. The rate base over/under capitalization adjustment on Exhibits AP-2, page 6, reflects the required adjustment to rate base to make earnings base equal to capitalization. The Commission has required this EB/Cap Adjustment in past proceedings to synchronize rate base plus interest bearing items (together, "Earnings Base") with the total capitalization employed in utility service. Line 53 on Exhibits AP-2, page 6, shows the EB/Cap adjustment amount to each electric and gas rate base. The Company calculates the EB/Cap adjustment amount by taking the total capitalization amount on line 51, less the rate base balance on line 29.

X. REVENUES AND OPERATING EXPENSE DATA (Exhibits AP-3)

Q. Have you included a presentation of the Historic Year and projected Rate Year revenues and expenses in your exhibits?

A. Yes. Historic Year levels and Rate Year levels of revenues and expenses are presented in Exhibits AP-3.

Each of Exhibits AP-3 contains extensive detail regarding elements or components of revenue and expense on which the Company's rate request is based. The first page of Exhibits AP-3 is an index of the 17 schedules included in the exhibits.

- Schedule 1 presents the major cost drivers of the proposed revenue requirement increase.
- Schedule 2 presents the summary of the proposed revenue requirement increase.
- Schedule 3 presents the total revenues at current rates used to develop the revenue requirement.
- Schedule 4 presents projected amortizations of deferred debits and credits.
- Schedule 5 presents projected other operating revenues.
- Schedule 6 shows projected O&M expenditures.
- Schedule 7.1 presents depreciation at current rates with no additional recovery of the reserve deficiency and Schedule 7.2 presents depreciation at current rates after increasing the annual recovery of the reserve deficiency.
- Schedule 8 presents projected taxes other than income taxes.
- Schedules 9 and 10 present projected state and federal income taxes.

- Schedule 11 projects Rate Year interest expense for purposes of reflecting the interest deduction included in Schedules 9 and 10. The schedule applies the weighted cost of debt from the Company's capitalization schedules to forecasted rate base inclusive of interest bearing CWIP in order to derive the projected interest deduction.
- Schedule 12 presents projected fund requirements and sources.
- Schedule 13 presents interest coverage ratios.
- Schedule 14 shows how the general escalation factor was derived.
- Schedule 15 presents underlying calculations supporting the labor escalator.
- Schedule 16 summarizes normalizations, program changes, and other Rate Year adjustments.
- Schedule 17 lists cost elements and other items that the Company expects to update during these proceedings, and the sponsoring witnesses. In addition, any adjustments identified during discovery will be updated as well.

A. **Sales Delivery and Net Revenue Margins (Exhibits AP-3, Schedule 3)**

Q. How did the Company develop the sales revenues and associated fuel, purchased power and purchased gas costs, as applicable, for the Rate Year shown on Schedule 3 of Exhibits AP-3?

A. The Company's Electric and Gas Forecasting Panels provided the sales revenue forecast for each commodity shown in Exhibits AP-3, Schedule 3. The methodology used to derive sales revenue forecasts is addressed in the direct testimony of those Company witnesses.

The Company developed fuel and purchased power costs as follows:

- Electric fuel and purchased power costs were developed by Company witness Kimball. We adjusted the electric fuel costs to an accounting basis to reflect the deferred accounting for these costs prescribed by the Commission as implemented through the MAC and the MSC.
- Purchased gas costs were developed by the GIOSP. We adjusted the purchased gas costs to an accounting basis to reflect the deferred accounting for these costs prescribed by the Commission as implemented through the Gas Cost Factor ("GCF") and the Monthly Rate Adjustment ("MRA").

Q. Did the Company make modifications to the revenues to reflect current projected levels of low-income discounts?

A. The Company made an adjustment to Electric Sales Revenues of $1.9 million to reduce the total amount of low-income discounts reflected in the electric revenue requirement from $54.7 million to $52.8 million. Similarly, the Company made an adjustment to Gas Sales Revenues of $5.0 million to increase the total amount of low-income discounts reflected in the gas revenue requirement from $10.9 million to $15.9 million. The updated low-income discount levels are consistent with the testimony of the Customer Operations Panel.

B. Amortization of Regulatory Deferrals (Exhibits AP-3, Schedule 4)

Q. Please explain the amortizations of regulatory deferrals as shown on Exhibits AP-3, Schedule 4.

A. These adjustments reflect the Company's proposals for crediting or charging customers for a variety of deferred credits or deferred charges. The Company projects the balance of deferred charges at the beginning of the Rate Year by obtaining the deferral balances as of September 30, 2018 and projecting any additional deferrals and amortizations from October 2018 to December 2019. In the preliminary update, the Company will update this exhibit with the December 31, 2018 deferral balances and revise its 2019 projections of deferrals and amortizations as appropriate.

Q. Do these proposals and adjustments result in a net credit to or net charge to customers in the Rate Year?

A. For electric, the result is a net credit to customers of $19,502,000 in the Rate Year. For gas, the result is a net credit to customers of $11,549,000 in the Rate Year.

Q. What amortization period is the Company proposing for these deferred credits and deferred charges?

A. For most items, the Company proposes an amortization period of five years starting at the beginning of the Rate Year (*i.e.*, January 1, 2020). With regard to electric, the Company proposes the following exceptions to a five-year amortization period: for adjustments related to deferrals for REV Demonstration, BQDM, EE, Electric Vehicle, and System Peak Reduction programs, the Company reflects a ten-year recovery period consistent with the REV Demo Order and the BQDM Order. The BQDM and REV Demonstration programs were further adjusted to eight-year and nine-year recovery periods, respectively, to reflect the average remaining recovery period for the deferred charges. In addition, consistent with the Commission's Order in Case 17-M-0815, the Company is proposing amortization of deferred credits related to the 2018 benefits of federal tax reform over three years for electric and two years for gas (as gas has begun returning credits to customers in 2019). Finally, for gas, the Company is recovering costs of the Meadowlands Heaters Projects from customers over the remaining twelve years of the fifteen-year amortization period approved by the Commission in Case 16-G-0061.

Q. Are the deferred credit and deferred charge balances the Company is proposing to amortize, projected balances as of the start of the Rate Year?

A. Yes, the amounts shown on Schedule 4 of Exhibits AP-3 are based on projected deferred balances as of the start of the Rate Year.

Q. Are there any significant additional deferred credits or deferred charges that the Company anticipates may materialize over the course of this proceeding?

A. Yes; in particular, the Company is preparing to sell vacant property on North First Street in Brooklyn. The sites were previously used for oil storage until 1997. The Company has identified a buyer and anticipates that the net gain on the sale before income taxes would be approximately $139 million. The Company plans to submit a Section 70 filing in February 2019 to provide additional details of the transaction, to determine any allocations between services as appropriate, and to propose an equitable sharing of the proceeds from the sale.

Q. Please identify and explain the deferred credit and deferred charge items included in the amortization of regulatory deferrals on Schedule 4 of Exhibits AP-3.

A. Below are detailed descriptions of each item and a designation to which commodity(ies) it applies (E- Electric, G-Gas).

1. Electric and Common Items

Line 1, AMI Customer Engagement: (E, G) Reflects a refund over five years of AMI Customer Engagement under-spending during the current rate plans.

Line 2, Carrying Charges (Net Plant Reconciliation): (E, G) Reflects a recovery from electric customers and refunds to gas customers over five years of carrying charges on net plant reconciliations during the current rate plans.

Line 3, Carrying Cost – SIR Deferred Balances: (E, G) Reflects refunds to electric customers and gas customers over five years of carrying charges accrued on the variation between the forecasted balance of deferred SIR costs reflected in rate base under the Company's current rate plans and the actual deferred balances.

Line 4, Customer Cash Flow Benefits- Bonus Depreciation: (E, G) Reflects a recovery for electric and refunds to gas customers over five years related to reconciliations of bonus depreciation.

Line 5, Deferred Workers Compensation Recoveries: (E, G)

Reflects the recovery over a five-year period of residual deferred workers compensation costs accrued during the previous rate plans. From 2014-2016, the Company reconciled between expenses incurred and expenses reflected in rates due to changes to the fees assessed by the NYS Workers Compensation Board.

Line 6, Energy Efficiency: (E, G) Reflects the recovery from electric customers and gas customers over a ten-year period for Energy Efficiency Project expenditures. Note that in the current filing, the expenditures being recovered through base rates over ten years for both electric and gas includes the Company's annual ETIP funding, which in the Company's current rate plan is being recovered through surcharges. These numbers do not reflect modifications to the Company's EE program in response to the Commission's December order adopting accelerated EE targets in Case 18-M-0084. The Company's Customer Energy Solutions Panel discusses this order and may update its program and funding proposals in the Company's preliminary update. This item is presented within the O&M section of the revenue requirement.

Line 7, Federal Tax Reform Transition Period: (E, G) Reflects the refund to electric customers and gas customers for tax savings accrued between the effective date of the TCJA (*i.e.*, January 1, 2018) and the time that accrued savings begin to be passed back to customers, in accordance with the Commission's order in Case 17-M-0815. For electric customers, the net benefits realized in calendar year 2018 are to be passed back over three years beginning

January 2020. For gas customers, the net benefits realized in calendar year 2018 are to be passed back over three years beginning January 2019.

Line 8, Former Employees/Contractor Proceeding: (E, G) Reflects a refund over a five-year period of residual Former Employees/Contractor Proceeding in accordance with the Joint Proposal in Cases 09-M-0114 and 09-M-0243.

Line 9, Interest on Rate Case Deferrals: (E, G) Reflects recovery from electric customers and refunds to gas customers over a five-year period of interest on various regulatory asset and liability balances.

Line 10, Interest Rate True-Up (Auction Rate/ LT Debt): (E, G) Reflects the recovery from electric customers and gas customers over five years of variable rate debt interest cost reconciliations.

Line 11, Interference: (E, G) Reflects the recovery over a five-year period of electric and gas interference costs. The regulatory assets are comprised of recoveries related to the previous rate plans (Cases 13-E-0030 and 13-G-0031) and recoveries related to the current rate plans (Cases 16-E-0060 and 16-G-0061).

Line 12, Management Variable Pay: (E, G) Reflects the refund to electric customers and gas customers over a five-year period of the difference between the Company’s actual expense for non-officer management variable pay and the targeted amounts in rates.

Line 13, NYSIT Rate Change: (E, G) Reflects a recovery from electric customers and refunds to gas customers over a five-year period due to the effect of a change in the NYS income tax rate.

Line 14, Pensions/OPEBs: (E, G) Reflects a recovery from electric customers and refunds to gas customers over a five-year period of the pensions/OPEBs costs. The electric deferred pension and OPEB regulatory liability at September 30, 2018 of $41.6 million is projected to become a regulatory asset of $28.3 million by the start of the Rate Year. The gas deferred pension and OPEB regulatory liability at September 30, 2018 of $ 20.8 million is projected to decrease to a regulatory liability of $12.0 million by the start of the Rate Year. Deferral accounting for pension and OPEB costs is provided for by the Commission's Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions issued September 7, 1993 in Case 91-M-0890.

Line 15, Positive Incentive Revenue Adjustments: (E, G) This item reflects the amounts to collect from customers as a result of financial incentives, achieved under the Company's current electric and gas rate plans. Please note that the Company reflected one hundred percent of the incentives earned in 2017 and anticipated to be earned in 2018 as a deferral balance to be recovered from customers even though only a portion will be recognized in the financial statements prior to the end of the current rate term. The lag in financial statement recognition is due to the alternative revenue program guidance within Accounting Standards Codification ("ASC") 980, Regulated Operations. The Company's proposal for recovery of future earnings adjustment mechanisms ("EAMs") and positive and negative revenue adjustments is discussed within Section XVIII.A of this testimony.

Line 16, Prop Tax Refund Town: (E, G) Reflects a refund over a five-year period of the residual balance at September 30, 2018 for deferred property tax refunds.

Line 17, Property Tax Deferrals: (E, G) Reflects a recovery from electric customers and gas customers over five years of the amount of Property Tax expense in excess of the projected expense incurred as determined by applying the property tax deferral mechanism under the current rate plans.

Line 18, Sale of Property – Gain on 708 1st Ave – insurance proceeds: (E, G) The Company received an insurance refund based on a policy that was purchased in conjunction with the sale of a property on 708 1st Ave. The amount reflects the pass-back to electric customers and gas customers over five years for the gain.

Line 19, SIR net of Shared Earnings: (E, G) Reflects the recovery from electric customers and gas customers over five years for SIR Expenditures including MGP, Superfund, Appendix B, Astoria, Underground Storage Tank, and Other remediation sites. The amounts presented in this amortization reflect both the amortization of the projected deferral balance in the account as of December 2019 (inclusive of any shared earnings deferrals recorded prior to September 2018), as well as amortization of projected spending during the Rate Year. Note that this amount is presented within the O&M section of the revenue requirement.

Line 20, WTC Incident System Restoration Interest Accrued: (E, G) Reflects the recovery from electric customers and the refund to gas customers over five years for interest accrued on WTC Incident System Restoration costs.

Line 21, Brooklyn Queens Demand Management Program ("BQDM"): (E) Reflects the recovery from electric customers over an eight-year period for BQDM. The eight-year recovery reflects the average remaining recovery period for the deferred charges inclusive of new charges projected during the Rate Year. The Company estimates that it will have $48 million in unrecovered expenditures by the beginning of the Rate Year. Consistent with the BQDM Order, the cost recovery through the MAC and the New York Power Authority ("NYPA") surcharge ceased with the implementation of new rates on January 1, 2017, and recovery will continue through base rates. Note that this amount is presented within the O&M section of the revenue requirement.

Line 22, BQDM & REV Demo Carrying Charge Deferral: (E) Reflects forecasted refunds to electric customers over five years of carrying charges on BQDM & REV Demonstration project costs that under-run the rate base target during the current rate plans.

Line 23, Deferral of NYS Brownfield Credit: (E) Reflects refunds to electric customers over five years of tax benefits from Brownfield environmental tax credits.

Line 24, DSM Liquidated: (E) Reflects refunds to electric customers over five years of the terminated Demand Side Management ("DSM") contract liquidation payments received by CECONY and associated accrued interest.

Line 25, Electric Service Reliability Rate Adjustment (CAIDI/ SAIFI): (E) Reflects a recovery over a five-year period of residual balance at September 30, 2018.

Line 26, Electric Vehicle: (E) Reflects the recovery from electric customers over a ten-year period for Electric Vehicle Projects. Pursuant to the Commission's rate order in Case 16-E-0060, electric rates are designed for the Company to recover the costs of the equipment portion of the EV Program over ten years, including the overall pre-tax rate of return on such costs. Therefore, the revenue requirement reflects recovery of these costs over ten years through base rates. Note that this amount is presented within the O&M section of the revenue requirement.

Line 27, Electric Vehicle Rate Incentive Expense True Up: (E) Reflects refunds of projected underspend on Electric Vehicles Rate Incentive Expense to electric customers over five years.

Line 28, Interest on Headroom Capacity: (E) Reflects refunds of the residual regulatory liability balance of the Headroom Capacity Refund. The Company received a payment from Bayonne Energy Center for its use of headroom related to the East River upgrades, which it has been refunding to customers in its current electric rate plan. The remaining balance, including interest, is being refunded to customers over five years.

Line 29, MTA work: (E) Reflects the recovery from electric customers over a five-year period for Commission ordered work on the MTA system. As discussed in more detail later in this testimony and in the EIOP, pursuant to the Commission's November 10, 2017 Order in Case 17-E-0428, the Company was required to take certain steps to safeguard and maintain adequate utility service to the MTA Subway System. The electric regulatory asset at September 30, 2018 of $189.2 million is projected to grow to $243.4 million by the start of the Rate Year, inclusive of interest on incurred costs.

Line 30, Property Tax Settlement - 74th Street (86% customer portion): (E) Reflects the refund to electric customers over five years of property tax refunds received in connection with the NYC Settlement on 74th Street Steam Facility.

Line 31, Property Tax Settlement - 59th Street (86% customer portion): (E) Reflects the refund to electric customers over five years of property tax refunds in connection with the NYC Settlement on 59th Street Steam Facility.

Line 32, Rate Case EE and DM Programs Carrying Charge Deferral: (E) Reflects refunds to electric customers over five years of carrying charges on EE and System Peak Reduction project costs that under-run the rate base target during the current rate plans.

Line 33, REV Demonstration Projects: (E) Reflects the recovery from electric customers over a nine-year period for REV Demonstration Projects. The

Commission's December17, 2015 Order in Case 15-E-0229 directed the Company to recover REV Demonstration costs in a manner similar to its recovery of BQDM costs (*i.e.*, recovery over ten years). The nine-year recovery reflects the average remaining recovery period for the deferred charges inclusive of new charges projected during the Rate Year. Note that this amount is presented within the O&M section of the revenue requirement.

Line 34, Gain on Sale of Kent Ave: (E) Pursuant to the Commission's September 14, 2018 Order in Case 17-M-0755, the Company is deferring a majority of the gain on the sale of the Company's Kent Avenue property for the benefit of electric customers. This amortization reflects refunding the customers' share of the gain to electric customers over five years.

Line 35, Sale of Property Liability: (E) Reflects a refund over a five-year period of residual regulatory liability on sales of properties.

Line 36, Sale of Property - Verplanck Quarry: (E) Reflects a refund to electric customers over five years of the customers' share of the gain on the sale of the Company's Verplanck Quarry property.

Line 37, Sale of Property - Windmill Road - North Castle: (E) Reflects the refund to electric customers over five years of the customers' share of the residual gain on the sale of the Company's Windmill Road - North Castle property.

Line 38, Smart Grid Demonstration Grant: (E) Reflects the recovery from electric customers over a five-year period of the residual deferred Smart Grid Demonstration Grant costs in excess of the amounts recovered in rates.

Line 39, System Peak Reduction: (E) Reflects the recovery from electric customers over a ten-year period for System Peak Reduction Projects. Pursuant to the Commission's rate order in Case 16-E-0060, electric rates are designed for the Company to recover the costs of the system peak reduction projects over ten years, including the overall pre-tax rate of return on such costs. Therefore, the revenue requirement reflects recovery of these costs over ten years through base rates. Note that this amount is presented within the O&M section of the revenue requirement.

Line 40, Verizon Joint Use Settlement: (E) Reflects a recovery over a five-year period of the residual regulatory asset balance related to the Verizon Joint Use Settlement.

2. Additional Gas Only Items

Q. Please identify and explain the items of deferred credit and deferred charge items on Exhibit AP-3, Schedule 4 that pertain only to gas.

A. The items are as follows:

Line 21, Building Meter Conversion Study: (G) Reflects a recovery over a five-year period of the residual regulatory asset balance related to this item.

Line 22, Gas Peak Demand Reduction Collaborative: (G) Reflects a recovery over a five-year period of the residual regulatory asset balance related to this item.

Line 23, Gas Service Line: (G) Reflects the recovery from gas customers over a five-year period for costs deferred for incremental inspection and repair work incurred as a result of the change in the definition of "Gas Service Line." The gas regulatory asset at September 30, 2018 of $9.3 million is projected to grow to $27.4 million by the start of the Rate Year.

Line 24, Inside Gas Meters: (G) Reflects the recovery from gas customers over a five-year period for incremental costs incurred during the current rate plan to relocate and install gas meters that are located inside a customer's premises outside when performing any planned service line replacements, new service installations, or under other circumstances that offer the customer and the Company the opportunity to relocate meters outside.

Line 25, Interest on Deferred POR: (G) Reflects a recovery over a five-year period of residual regulatory asset balance for the interest on deferred POR program costs.

Line 26, Meadowlands Heaters: (G) Reflects the recovery from gas customers over a twelve-year period the remaining balance for Meadowlands Heaters Projects. Pursuant to the Commission's rate order in Case16-G-0061, the Company is required to defer the cost as a regulatory asset and recover the cost over the 15-year period that began January 1, 2017.

Line 27, Negative Revenue Adjustments: (G) Reflects the refund to gas customers over a five-year period for any negative revenue adjustments incurred in the current rate plan. See Section XVIII.A of this testimony for the Company's proposal for changing the mechanism by which the Company would credit customers for any negative revenue adjustments in the Rate Year.

Line 28, Oil to Gas Conversion: (G) Reflects a recovery from gas customers over a five-year period of residual regulatory asset balance from certain oil to gas conversions that are deferred pursuant to the previous gas rate plan.

Line 29, Penalties on Off-Peak/ Interruptible Customers: (G) Reflects the refund to gas customers over five years of penalties assessed to off-peak and interruptible customers for not switching to alternative fuel sources when required.

Line 30, Pipeline Integrity: (G) Reflects the refund to gas customers over five years related to the annual reconciliation of KeySpan pipeline integrity costs allocable to the Company pursuant to the New York Facilities Agreement.

Line 31, R and D Recon: (G) Reflects the recovery from gas customers over a five-year period for the reconciliation of Gas Research and Development ("R&D") costs.

Line 32, Unauthorized Use Charge- Divested Stations: (G) reflects the refund to gas customers over five years of revenues it received related to the unauthorized use of gas at divested stations.

C. Other Operating Revenues (Exhibits AP-3, Schedule 5)

Q. Is the Accounting Panel presenting data on Other Operating Revenues of the Company?

A. Yes. Schedule 5 of Exhibits AP-3 shows the detail of Other Operating Revenues in the Historic Year and the Rate Year.

Q. Please briefly explain what is meant by Other Operating Revenues and how they affect the amount of the revenue requirement.

A. Other Operating Revenues include revenue collected by the Company from customers or third parties such as late payment charges and facility rents. Increases in such revenues serve to reduce the Company's base rate revenue requirement and decreases in such revenues serve to increase the Company's base revenue requirement.

Q. Please summarize the projected net changes to the level of Other Operating Revenues from the Historic Year to the Rate Year.

A. For electric, the Historic Year level of $787 million is forecast to decrease by $576 million, for a Rate Year level of $211 million.

For gas, the Historic Year level of $197 million is forecast to decrease by $163 million, for a Rate Year level of $33 million.

The line items included in these totals, and their corresponding figures, are specified on Exhibits AP-3, Schedule 5,

Q. Are the types of Other Operating Revenues the same for electric and gas?

A. No, although there are some types that apply to both commodities. Below are detailed descriptions of each type of expense and a designation to which commodity(ies) it applies (E- Electric, G- Gas). For the Historic Year amount, any adjustments, and the Rate Year forecast for each line item, please see Exhibits AP-3, Schedule 5.

1. Electric and Common Revenue Types

Q. Please explain the items of Other Operating Revenues that pertain to electric or are common to electric and gas shown on Schedule 5 of Exhibits AP-3.

A. The items are as follows:

Line 1, Miscellaneous Service Revenues: (E, G) This represents the Company's forecast of various charges to customers resulting from miscellaneous tariff charges. The charges are for "no access," meter recovery, meter reconnection, collection charges for field calls and others. The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2015 through September 30, 2018).

Line 2, Transmission of Energy: (E) This represents revenues from the transmission of energy under bundled "grandfathered" firm transmission agreements with NYPA and LIPA. The forecast remains at the current level, as approved in the Company's 2016 electric rate case.

Line 3, Transmission Service Charges ("TSC"): (E) This represents daily transmission wheeling transactions scheduled through the NYISO. The Rate Year forecast reflects the current level that was approved in the Company's 2016 electric rate case.

Line 4, Maintenance of Interconnection Facilities: (E) This reflects a projection for the net reimbursement of certain expenses the Company incurs for interconnecting customers to the Con Edison system. The Rate Year forecast reflects a small increase in carrying charges from customers.

Line 5, Excess Distribution Facilities: (E) This represents tariff payments from customers for distribution facilities provided by the Company in excess of those normally provided. The Rate Year forecast is the average of these revenues for the prior three years (*i.e*., October 1, 2015 through September 30, 2018).

Line 6, Late Payment Charges: (E, G- Line 4) This includes revenues from residential and non-residential customers. The Rate Year forecast is based on the Historic Year ratio of late payment charges to sales revenues. The Company applied that factor to the Rate Year sales revenue forecast to arrive at late payment charges.

Line 7, NYSERDA On-Bill Recovery Financing Program: (E) When homeowners obtain a loan from the New York State Energy Research and Development Authority ("NYSERDA"), they can repay the loan through their utility bill by using the on-bill recovery financing program. The Company then remits the money to NYSERDA. NYSERDA pays the Company a one-time fee of $100 for each loan and a fee of one percent of the amount of each loan to defray costs directly associated with implementing the program The Rate Year forecast is the average of these revenues for the prior three years (*i.e*., October 1, 2015 through September 30, 2018).

Line 8, Revenues From The Learning Center: (E, G- Line 5) These revenues result from providing training and conference services to outside parties. The Rate Year forecast is the average of these revenues for the prior three years (*i.e*., October 1, 2015 through September 30, 2018).

Line 9, Facilities Fees – NRG: (E) This line item represents fees NRG pays for its use of Company's equipment. There will not be a forecast for the Rate Year since such agreement with NRG ended in February 2015. Reversal of payments received afterwards were recorded in December 2017.

Line 10, Proceeds from Sales of TCCs: (E) This represents projected auction proceeds from the sale of Transmission Congestion Contracts ("TCC"). The Rate Year forecast is based on the current level that was approved by the Commission in the Company's 2016 electric rate case. Variances between the actual amount of revenues achieved and the levels included in rates are surcharged or passed back to customers through an existing tariff mechanism in the MAC.

Line 11, POR Discount: (E, G-Line 6) This represents the discount on receivables purchased by the Company from energy services companies ("ESCOs"). The Rate Year forecast reflects the current Historic Year level.

Line 12, Substation Operation Services (E) These are revenues associated with work done for third parties. The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2015 through September 30, 2018).

Please note that the Company performs accommodation billings pursuant to General Rule 17.2 of the Company's electric tariff based on the elements of cost identified in General Rule 17.3. The Electric Rate Panel has updated a number of tariffs that outline the overhead rates currently applied to accommodation billings. If the updated overhead calculations and associated tariff are approved by the

Commission, the Company would reflect these updates effective at the start of the Rate Year.

Q. Would you like to make additional comments regarding the electric accommodation work that the Company performs for third parties?

A. General Rule 17.3 of the Company's electric tariff lists the elements of cost charged for special services performed by the Company pursuant to General Rule 17.2.

The Company is modifying the percentages to be applied to certain cost elements based on the average of work performed for the 12 months ended 2016, the 12 months ended 2017 and the 8 months ended August 2018. The stores handling rate will increase from 8.5 percent to 11 percent; the overhead rate for Electric Engineering and Administrative and General ("A&G") will decrease from 16 percent to 15 percent; the overhead rate for A&G only will decrease from 2 percent to 1 percent; and when Construction Management Oversight ("CMO") is required, the overhead rate for CMO, Electric Engineering and A&G will decrease from 43 percent to 19 percent.

As indicated in the Electric Rate Panel's testimony, the tariff leaf for General Rule 17.3 (Leaf 126) has been updated to reflect these new percentages.

Q. What additional comments would you like to make regarding the gas accommodation work that the Company performs for third parties?

A. General Information IV. 2 of the Company's gas tariff lists the elements of cost charged for special services performed by the Company.

The Company is modifying the percentages to be applied to certain cost elements based on the average of work performed for the 12 months ended 2016, the 12 months ended 2017, and the 8 months ended August 2018. The stores handling rate will increase from 8.5 percent to 11 percent; the overhead rate for Gas Engineering and A&G will decrease from 11 percent to 7 percent; the overhead rate for A&G only will decrease from 2 percent to 1 percent; and when CMO oversight is required, the overhead rate for CMO, Gas Engineering and A&G will decrease from 22 percent to 13 percent.

As indicated in the Gas Rate Panel's testimony, the tariff leaf for General Information IV. 2 (Leaf 117) has been updated to reflect these new percentages.

Line 13, Net Unbilled Revenues: (E, G-Line 7) This item represents the change in the unbilled revenue level recorded on the Company's books and records during the 12 months ended September 30, 2018. The accounting for unbilled revenues has no impact on the revenue requirement.

Line 14, Reconnection Fee: (E, G- Line 2) This represents reconnection fees applied to customers who require service restoration. The Rate Year forecast reflects the Company's proposal to eliminate reconnection fees for electric customers with AMI meters, as described in the testimony of the Customer Operations Panel.

Line 15, Reconnection Fee Waiver: (E, G- Line 3) This line represents waiver of reconnection fees for low income customers who require service restoration. The

Rate Year amount represents targets developed by Customer Operations. Refer to Customer Operations Panel's testimony for discussion of such targets.

Line 16, Miscellaneous: (E, G- Line 9) This line includes various small items. The Rate Year forecast is based on the Historic Year level.

Line 17, Rent from Electric Property: (E) This represents amounts billed by the Company to third parties for their use of Company property such as poles, easements, and transmission and distribution facilities. The forecast of revenue reflects an analysis of the terms of the Company's rental agreements.

Line 18, Interdepartmental Rents: (E, G-Line 10) This represents carrying charges billed to one department of the Company for its use of facilities by another department of the Company. Joint use facilities include the head house at Hell Gate Station (E, G), facilities at the East River station (electric and steam) and the Hudson Avenue Tunnel (electric and steam). Carrying charges include components of rate of return on net plant investment, depreciation, and taxes. Changes in revenues for one department are offset by changes in interdepartmental rent expense for other departments.

Note for Following Line Items: Lines 19 through 25, and line 43 are offset in other places on the income statement, such as sales revenues or included in the MSC / MAC. Lines 26 through 40 are deferrals/reconciliations. Unless otherwise noted, no activity is projected for these items for the Rate Year.

Line 19, RDM Reconciliation: (E, G-Line 23) This represents the accounting adjustments recorded by the Company to implement the Revenue Decoupling

Mechanism ("RDM") in place under its current electric and gas rate plans. It relates to the deferral of the variation between the actual delivery revenues billed and the established target level.

Line 20, Indian Point Energy Center Programs: (E) This represents the carrying cost on the deferred expenditures related to the Indian Point Energy Center programs. This cost is recovered through the MAC.

Line 21, NEIL Dividend: (E) This item reflects the Nuclear Electric Insurance Limited ("NEIL") dividend received by the Company. This item is refunded to customers through the MAC.

Line 22, MFC – Lost Supply Revenues: (E) This represents the variation between the level of Merchant Function Charge ("MFC") supply revenues collected from full service customers and the actual amounts received during the Historic Year. The variation is the result of customers switching to ESCOs, who provide energy to those customers.

Line 23, Hedging Program Interest: (E, G- Line 19) This line reflects Historic Year reclassification of interest assessed on funds advanced for the program to interest income.

Line 24, ESCO/Marketers – Bill Charges: (E, G- Line 20) These are billing and payment processing charges the Company collects from ESCOs for consolidated billing services. These revenues were excluded from the Rate Year forecast of Other Operating Revenues and are included in Sales Revenue.

Line 25, Sale of Fuel Oil: (E) This line represents losses associated with the sale of fuel oil that are recovered through the MAC.

Line 26, Property Tax Reconciliation: (E, G- Line 36) This represents the deferral of property tax expense over-runs as compared to the target levels reflected in rates. The amortization or recovery of the forecast deferred balance at December 31, 2019 is shown in Schedule 4 of Exhibits AP-3.

Line 27, Interest Rate True-Up: (E, G- Line 40) This represents the net variation between the cost of variable rate long-term debt reflected in rates and the Company's actual cost during the Historic Year. The interest rates for variable rate long-term debt will be reset in this case and, as a result, this variation is assumed to be zero in the Rate Year.

Line 28, Net Plant Carrying Charges: (E, G-Line 38) This represents amounts deferred for credit to customers resulting from net additions to utility plant being less than reflected in rates.

Line 29, Customer Cash Flow Benefits – Bonus Depreciation: (E, G-Line 35) This item includes the carrying charges the Company has deferred for the benefit of customers resulting from cash flow benefits received from the change in tax depreciation rates referred to as Bonus Depreciation.

Line 30, Amortization Various Deferred Costs: (E, G-Line 34) This reflects the amortization of various deferred costs that were amortized under the current rate plan.

Line 31, Management Variable Pay: (E, G-Line 41) This item represents revenues deferred under the Management Variable Pay reconciliation mechanism included in the current rate plans.

Line 32, Accounting Reserve: (E, G-Line 37): This item represents reserves set up by the Company for various purposes, including shared earnings accruals.

Line 33, 18-a Working Capital Reconciliation: (E) This item represents an under-collection of the 18-a regulatory assessment working capital target.

Line 34, ERRP Major Maintenance: (E) The Company's current electric rate plan reflects $10.704 million for the ERRP maintenance costs per year. This item represents accounting entries related to the reconciliation of actual ERRP maintenance costs with the amount included in rates.

Line 35 Retention Property Tax Incentive: (E) This relates to the Company's retention for shareholders of 14 percent of various property tax refunds as allowed under its current and past electric rate plans. Because these revenues are retained by the Company, they are not included in the Rate Year revenue requirement.

Line 36, AMI Customer Engagement Plan and AMI Rate Pilots Reconciliation: (E) This represents deferrals resulting from reconciling actuals to target levels set in the current rate plan for AMI Customer Engagement Plan and AMI Rate Pilots programs.

Line 37, Carrying Charge on Energy Efficiency Programs: (E)**; Line 38, Electric Vehicle Program Reconciliation:** (E) These lines represent deferrals resulting from reconciling actuals to target levels set in the current rate plan for

EE related programs (*i.e.*, System Peak Reduction and Energy Efficiency), Electric Vehicle Programs, the BQDM program, and REV demonstration projects.

Line 39, Climate Study: (E) This represents expenses incurred for the Climate Change Vulnerability Study that is collected through the MAC.

Line 40, GRT Public Utility Tax: (E & G – Line 33) This line reflects gross receipts taxes on revenues other than the sale of gas. No activity is projected for the Rate Year.

Line 41, Revenue Imputation - Cases 09-M-0114 and 09-M-0243: (E & G – Line 42) This represents the revenues recorded by the Company to offset the revenue requirement effect of certain capital expenditures in order to limit recovery to the level approved by the Commission in its April 20, 2016 Order in Cases 09-M-0114 and 09-M-0243. The Company will adjust this amount on update, if and to the extent necessary and appropriate, consistent with Commission's Order.

Line 42, Revenue Imputation - 2004-2007 Capital Overspend: (E) represents the revenue recorded by the Company to offset the revenue requirement effect of capital expenditures in order to limit recovery to the level directed by the Commission's March 26, 2010 Order in Case 07-E-0523.

Line 43, NYPA Related Revenue: (E, G - Line 43) This line represents NYPA related revenues that are forecasted in sales revenues. Therefore, the Historic Year level of this item is normalized in this schedule.

2. Additional Gas Only Revenues Types

Q. Please explain the items of Other Operating Revenues representing revenue collected by the Company from customers or third parties that pertain only to gas shown on Schedule 5 of Exhibit AP-G3.

A. They are as follows:

Line 8, Reimbursement To National Grid – Governor's Island: (G) This represents National Grid's share of the revenues earned from gas sales to the United States Coast Guard in accordance with the Governors' Island agreement and serves to offset the gross amount (including National Grid's share) recorded in sales revenues. Embedded in the sales forecast is the historic level of revenue from National Grid. The Rate Year forecast was kept at the Historic Year level.

Line 11, New York Facilities: (G) This represents carrying charges billed by Con Edison to National Grid in accordance with the provisions of the New York Facilities Agreement. Such revenue is passed back to the customers through the MRA mechanism.

Line 12, Real Estate Rents: (G) This revenue primarily represents the gas department's share of rental income from leasing property at the Company's central headquarters building.

Line 13, NYPA Variable and Maintenance and Line 14, Steam Department – ERRP Incremental Charges: (G) These two items, which are grouped under the heading "transmission system reinforcement recoveries" represent recoveries of CECONY's share of gas transmission facilities reinforcement costs from the generators that use gas that is delivered by the Company. Line 13 represents payments from generators for variable operating costs and upkeep of the Hunts Point Compressor. The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2015 through September 30, 2018). Line 14 represents recoveries of reinforcement costs from the Steam Department. There are no additional recoveries from the Steam Department projected. As a result, the Rate Year forecast for these revenues remains at the Historic Year level.

Note for Following Line Items: Lines 15 through 32 are offset in energy and other clauses, such as the MFC / MRA. Line 39 is a deferral/reconciliation. Unless otherwise noted, no activity is projected for these items for the Rate Year.

Lines 15-17, Non-Firm Revenues: (G) These revenues are generated from serving non-firm customers and from efforts to maximize the value of assets obtained to meet the Company’s firm customer requirements. These revenues are currently subject to the non-firm revenue sharing mechanism set forth in the current gas rate plan, which the Company is proposing to continue without change. The Company’s filing reflects a $65 million imputation in base rates.

- Line 15, Gas Purchased from Transportation Customers: This line represents “cash out” transactions with gas marketers.
- Line 16, Gas Penalties – Off Peak/Interruptible: This line represents penalties assessed to off-peak and interruptible customers for not switching to alternative fuel sources when required.

- Line 17, Non-firm Interruptible Sales Credit: This line represents service fees related to off-system gas sales.

Line 18, Asset Management Revenue: (G) This item reflects revenues received for capacity releases. We do not reflect a Rate Year amount for this item in Other Operating Revenues because it is included as part of the non-firm revenue target.

Line 21 Gas Interference Cost Sharing: (G) These revenues are recorded to make the Company whole by offsetting certain refunds made to customers through the MRA for gas interference. An interference cost sharing agreement between NYC and the Company has been in effect since 1989 and provides for the City's assumption of 51 percent of the cost of gas interference work occasioned by water and sewer projects performed by the NYC Municipal Water Finance Authority. It also provides for the refund to customers through the MRA of payments rendered by the City to the Company to comply with its cost-sharing obligation. Because the Company's estimate of MRA revenues does not include this refund, we did not forecast an offsetting item in other operating revenues.

Line 22, R&D True-Up and Surcharge (Millennium Fund): (G) This line reflects the deferrals related to the R&D reconciliation that was implemented as part of the current gas rate plan. Such deferrals were normalized from the Historic Year. The line also contains deferral and matching of revenues collected from customers through the MRA to fund certain gas R&D projects pursuant to the Commission's order dated April 4, 2000 in Case 99-G-1369 with projected R&D expenses. The revenues are referred to as the "Millennium Fund," and the

R&D projects to be funded by these revenues are discussed by the Shared Services Panel. The forecast for the Rate Year includes program changes discussed by the Shared Services Panel.

Line 24, Low Income Program: (G) This line represents the accounting entries related to the deferral of low income discounts under the current gas rate plan.

Line 25, Gas In Storage Reconciliation: (G) This line represents the reconciliation of actual working capital for gas in storage compared to the level set under the current gas rate plan. Working capital on gas in storage is recovered volumetrically through the MFC and the MRA, instead of through base delivery rates. The revenues derived for working capital on gas in storage is calculated using the Company's allowed rate of return on the "base" or lowest inventory level of gas in storage during the year and the current other cost of capital rate on the average balances above the base amounts. In order to eliminate any impact on the Company's revenue requirement from resulting from differences on the carrying cost of gas in storage, we have eliminated both the gas in storage surcharge revenues from the forecast and the historic level of storage gas from rate base as shown in Exhibit AP-G2.

Line 26, Credits and Collections: (G) This line represents the accounting entries related to the deferral of the MFC Credits and Collections charges under the current gas rate plan.

Line 27, Gas SBC Revenue Deferral: (G) This line represents an accounting entry related to the gas System Benefit Charge. The accounting entries record any over/under collection from customers for amounts expensed.

Line 28, Supply Related Charge Revenue: (G) This line represents the accounting entries related to the deferral of the difference between target and actual amounts collected for MFC-related charges approved by the Commission.

Line 29, Gas Daily Delivery Service: (G) This line represents the accounting entries related to the Gas Daily Delivery Service Program passed through the GCF.

Line 30, Transportation Gas Adjustment: (G) This line represents the accounting entries related to the collection of the transportation gas adjustment through the MRA.

Line 31, SBU Balancing Charges: (G) This line reflects the revenues recorded for gas transportation and balancing service to the Company's Steam Business Unit.

Line 32, Gas Adjustment Clause ("GAC") Interest: (G) The balance represents the accrued interest applicable to the GAC surcharge/refund. If the cost of gas to the Company that is recoverable from firm customers exceeds or falls below the total amount actually recovered through both the base rates and GAC revenues, the difference between the recoverable amount and the amount actually recovered is deferred, and is subsequently charged or refunded to customers, as appropriate.

Pursuant to 16 New York Codes Rules & Regulations ("NYCRR") Section 720-6.5, interest is accrued on these balances in the deferral accounts.

Line 39, Pipeline Integrity Deferral: (G) This line represents the reconciliation of pipeline integrity costs under the New York Facilities Agreement pursuant to the current gas rate plan. As the discussed by the GIOSP, the agreement has been amended and the Company proposes to recover all costs associated with the New York Facilities Agreement, including pipeline integrity costs, through the MRA in lieu of base rates and to terminate this reconciliation.

D. O&M Expenses (Exhibits AP-3, Schedule 6)

Q. Please explain the development of O&M Expenses shown on Schedule 6 of Exhibits AP-3.

A. Detailed calculations of the O&M amounts are shown on Schedule 6 of Exhibits AP-3. This page shows the derivation of the projected expenses in the Rate Year from the Historic Year expense. Various Company witnesses, including the Accounting Panel, will explain any adjustments.

Q. Please summarize the projected net changes to the level of O&M Expenses during the Historic Year to the Rate Year.

A. For electric, the Historic Year level of $3,744 million is forecasted to decrease by $627 million for a Rate Year level of $3,117 million.

For gas, the Historic Year level of $1,035 million is forecasted to increase by $121 million for a Rate Year level of $1,156 million.

Please note that these figures represent overall electric and gas O&M expenses, which include fuel and purchase power and that normalizes a number of other types of reconciled costs in the Rate Year that do not impact the revenue requirement. For both electric and gas services, the non-reconciled portions of O&M expenses are increasing from the Historic Year to the Rate Year.

1. Development of O&M

Q. How did the Company develop O&M costs for the Rate Year?

A. The Company began with Historic Year O&M costs and then made adjustments to bring the costs forward to the Rate Year. Adjustments made to expense levels were due to normalizations, program changes, wage escalation, and general escalation. The Company's approach to each adjustment is described below beginning with how we developed general and labor escalation factors.

a. General Escalation (Exhibits AP-3, Schedule 14)

Q. Please describe how you escalated costs due to inflation.

A. The general escalation rate is applied to costs anticipated to increase at the rate of inflation as measured by the Gross Domestic Product ("GDP") price deflator. The labor component was removed from each element of expense and then the residual amounts were escalated using the GDP price deflator for most elements of expense subject to escalation. For certain expenses, the escalation factor is specifically tailored to the particular expense item, such as medical insurance costs, as addressed by the Company's Compensation and Benefits Panel.

Additional detail on generally escalated costs is included in Schedule 14 of Exhibits AP-3.

Q. Please describe how the Company applied the general escalation rate in developing projected revenue requirements.

A. The GDP deflator published by the U.S. Bureau of Economic Analysis, used to escalate various non-labor elements of the cost of service as addressed throughout our direct testimony and the direct testimony of other witnesses, are based on actual data through the third quarter of 2018. The forecast for the fourth quarter of 2018 and the annual forecasts for 2019, 2020 and forward are from the Blue Chip Economic Indicators dated October 10, 2018. Using these forecasts, the projected cumulative effect of inflation for the 27 months from the Historic Year to the Rate Year is 5.29 percent.

b. Labor Escalation (Exhibits AP-3, Schedules 15.1-15.3)

Q. Please describe the labor cost escalation factor used to develop Rate Year labor cost.

A. The development of the labor escalation factor is presented in Schedules 15.1, 15.2, and 15.3 of Exhibits AP-3 for RY1-3, respectively. We applied the calculated labor escalation factor to Historic Year labor expense amounts, labor expense normalizations, and labor expense program changes to determine the total Rate Year level of labor expense for electric and gas services.

Q. How was the labor escalation factor calculated?

A The labor escalation factor is meant to reflect the labor expense increase associated with an average employee from the Historic Year to the Rate Year, independent of the effects of normalizations and program changes. As shown in the exhibits, the labor escalation factor is the weighted average of increase in management and weekly average straight time salaries and wages from the Historic Year to the Rate Year. For weekly employees, we included a general wage increase of 3.0 percent effective in July of each year. Semi-annual progression increases of 0.5 percent in October and February of each year are also included, but applied to only 60.7 percent of total weekly employees. The annual and progression wage increase rates are all pursuant to the collective bargaining agreements with union employees. The 60.7 percent figure is based on a five-year (2014-2018) average of the actual number of weekly employees that received progression increases as employees already at the maximum pay rate for their job title do not receive progressions. For management employees, we assumed annual 3.0 percent merit increases in April of each year.

Q. Did the Company apply a one percent productivity adjustment?

A. No. As discussed in Section IV of this testimony, the Company is incorporating the anticipated savings of its BCO Program, which far exceeds the imputation customers would receive with the one percent productivity adjustment.

c. Normalization (Exhibits AP-3, Schedule 16)

Q. Please describe the normalization of O&M costs for the Rate Year.

A. The Company eliminated from the elements of expense ("EOE") those amounts that are nonrecurring, out of period, or for which the Company has decided to not seek recovery in this proceeding. The Company also annualized amounts that were not fully recognized in the Historic Year in order to develop Rate Year costs. Additional detail on normalized costs is found within Schedule 16 of Exhibits AP-3.

d. Program Changes (Exhibits AP-3, Schedule 16)

Q. Please describe how the Company adjusted O&M costs to reflect program changes.

A. The Company adjusted O&M costs based on documented, planned program changes that are driven by the business needs of the Company. Estimated costs associated with these programs and additional detail regarding these costs are included in Schedule 16 of Exhibits AP-3.

e. Common Expense Allocation

Q. Please explain how common O&M costs are allocated among electric, gas, and steam services for the Rate Year.

A. The Company used existing allocation factors the Commission approved in the Company's current rate plans. Customer Operations and Customer Services expenses were allocated 84 percent to electric and 16 percent to gas. A&G expenses were allocated 77.60 percent to electric, 15.95 percent to gas, and 6.45 percent to steam.

Q. How did you allocate common expenses among electric, gas and steam services if they applied to O&R as well as CECONY?

A. The Company used the existing common expense split between CECONY and O&R, which is 92.45 percent allocated to CECONY and 7.55 percent allocated to O&R. This rate is updated annually by the Company using a three-part formula of revenues, assets, and payroll. To calculate the common expense allocation between electric, gas and steam services if they applied to O&R as well as CECONY, we took CECONY's existing allocation factor for each service (*i.e.*, Customer Operations and Customer Service expense – 84 percent electric, 16 percent gas; A&G expense – 77.60 percent electric, 15.95 percent gas, 6.45 percent steam) and multiplied it by CECONY's share of 92.45 percent. This resulted in Customer Operations and Customer Service expenses being allocated 77.66 percent to CECONY electric, 14.79 percent to CECONY gas, with the remaining 7.55 percent allocated to O&R, and A&G expenses being allocated 71.74 percent to CECONY electric, 14.75 percent to CECONY gas, 5.96 percent to CECONY steam, with the remaining 7.55 percent allocated to O&R.

Q. Is the Company proposing any adjustments to its methodology for allocating common expenses incurred at the parent company, Consolidated Edison, Inc. ("CEI"), and passed down to its subsidiaries?

A. Yes. To the extent that there are charges incurred at the CEI level that are to be allocated to all CEI subsidiaries, a three-factor allocation is applied using an average of operating revenue, segment payroll, and assets based on guidance from

Cost Accounting Standard 403. The Company is proposing a change in the way that operating revenues are included within the formula.

Q. Please explain further.

A. Under the Company's current methodology, when applying the three-factor allocation, the Company includes revenues appearing on the income statements of the CEI subsidiaries. Because of the accounting rules for equity method investments, wherein only the Company's share of net income is recorded on the income statement, the revenues and expenses of CET's equity method investments (*i.e.*, New York Transco LLC, Mountain Valley Pipeline, LLC, and Stagecoach Gas Services LLC) are not presented on CET's financial statements. As a result, for these investments, the formula reflects $0 for the revenue factor. In this proceeding, the Company is proposing to instead include CET's proportionate share of its equity method investments' revenues within its allocation formula.

Q. Where is the Company obtaining its revenue information for these investments?

A. The Company is using the 2017 audited financial statements for each of the three entities, which are the most recent audited annual financial statements available as of the time of this filing.

Q. How is this change reflected in the Company's filing?

A. The Company has included a program change in the Intercompany Shared Services Element of Expense within its O&M expenses that quantifies the change in shared CEI expenses allocated to CECONY as a result of the change in allocation approach.

Q. Is the Company proposing any changes to how it applies the other factors to CET's equity method investments?

A. No. The assets on CET's balance sheet already reflect the Company's investment in its equity method investments, so no adjustment is necessary to that factor. With respect to payroll, it is appropriate that the payroll factor is $0 for CET's equity method investments. Employees of the investments are not paid by the Company nor do they make use of any of the Company's human resource functions. In addition, the employees of the investments are not managed on a day to day basis by Company personnel. Furthermore, payroll information is not included on the audited financial statements of the investments.

2. Line Item Descriptions (Exhibits AP-3, Schedule 6)

Q. Please describe the various line items set forth in Exhibits AP-3, Schedule 6.

A. We set forth below detailed descriptions of each type of expense and a designation to which commodity(ies) it applies (E- Electric, G-Gas). For those line items that include common expenses, we indicate the total Company common expense amount and the portion allocated to electric and gas services. The remaining unstated amounts are allocated to steam service. For the Historic Year amount, any adjustments, and the Rate Year forecast for each line item, please see page 3 of Schedule 1.

Line 1, Fuel and Purchased Power: (E, G) This item tracks projected fuel and purchased power costs. The Rate Year forecast includes program changes discussed in detail in the direct testimony of the Electric and Gas Volume and Revenue Forecasting Panels.

Line 2, A&G, Health Ins. Cap: (E, G) This line represents the capitalized portion of A&G overhead costs applicable to construction activities, including general office salaries and expenses, and health insurance premiums. The Company escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year level.

Line 3, Advanced Metering Infrastructure: (E, G) This item represents historic costs and program changes reflecting the implementation and maintenance of the AMI systems and communications infrastructure. Expenses and program changes also reflect customer engagement expenses covering the AMI deployment period. Further discussion of the AMI program changes can be found within the Customer Energy Solutions Panel testimony. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 4, Bargaining Unit Contract Cost: (E, G) This item represents a program change for annualized costs associated with negotiation and strike contingency efforts discussed in detail in the direct testimony of the Shared Services Panel. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 5, Bond Administration & Bank Fees: (E, G) This item includes expenses for charges such as bank fees, revolving credit fees, line of credit fees, and credit rating agencies fees. The Historic Year expense is adjusted by a program change to reflect a three-year average of costs and escalated by the general escalation factor to arrive at the Rate Year level.

Line 6, Company Labor- Advanced Metering Infrastructure: (E, G) This item reflects labor charges related to the Company's AMI program (non-labor AMI costs are discussed above on Line 3). The Rate Year forecast for electric and gas include program changes discussed in detail in the direct testimony of the Customer Energy Solutions Panel. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 7, Company Labor- Central Engineering: (E) This item reflects labor charges related to the Company's Central Engineering departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 8, Company Labor- Construction Management: (E, G) This item reflects labor charges related to the Company's Construction Management departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 9, Company Labor - Corporate & Shared Services: (E, G) The Company's Corporate & Shared Services departments include, among others, Finance, Environmental Health & Safety, Emergency Management, Energy Management, Facilities & Field Services, Government Relations, Human Resources, Information Technology, Learning & Inclusion, Legal Services, Public Affairs, Office of the Secretary, President & Staff, R&D, Security, Strategic Planning and Supply Chain.

The total Rate Year forecast includes the below-listed program changes, which are discussed in detail in the direct testimony of the Shared Services Panel. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

- A program change related to Management Variable Pay ("MVP") to adjust Historic Year expenses to projected Rate Year expenses by applying the weighted average MVP award rate to Historic Year management straight time payroll. A select number of employees who are not eligible for MVP because they are being paid commissions for their work within the EE group have been adjusted out of the Company's MVP calculation. Discussion of the commission-based variable compensation proposal can be found in the Customer Energy Solutions Panel's testimony (as discussed in that testimony, we propose to recover this commission-based variable compensation through surcharges). We also note that Executive MVP awards are normalized from the Historic Year – see the discussion of Line 30, Executive MVP, below.

- A program change to fund staffing to support REV and Energy Policy Programs within Resource Planning & Forecasting, Electricity Supply, and Gas Supply. This program change is discussed further within the testimony of witness Kimball.
- A program change related to hiring two employees to provide ongoing support and administration of a new Enterprise Project Management Software. Further details of this proposal can be found within the associated white paper, a copy of which is included in Exhibit AP-7.
- A program change related to costs associated with software maintenance and steady state IT support of a new estimating software product. Further details of this proposal can be found within the associated white paper, a copy of which is included in Exhibit AP-7.

Line 10, Company Labor – Customer Energy Solutions (E, G)

This item reflects labor charges related to the Company's Customer Energy Solutions group. The total Rate Year forecast includes the following program changes, which are discussed in detail in the direct testimony of the Customer Energy Solutions Panel. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

- A program change related to EEDM DSP;
- A program change related to Energy Storage – REV;
- A program change to support the increased EEDM portfolio; and
- A program change related to the Company's Innovation Initiative

Line 11, Company Labor – Customer Information System (E, G)

This item reflects labor charges related to the Company's Customer Information System ("CSS"). The total Rate Year forecast includes a program change related to New CSS costs. The program change is discussed further within the Customer Energy Solutions Panel. We then escalated the Historic Year expense and the program change by the labor escalation factor to arrive at the Rate Year amount.

Line 12, Company Labor - Customer Operations: (E, G) This item reflects labor charges related to the Company's Customer Operations departments. The Rate Year forecast for electric and gas include the following program changes discussed in detail in the direct testimony of the Customer Operations Panel and noted below. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

- A program change related to Bill Redesign.
- A program change related to DCX;
- A program change related to C3 IoT Revenue Protection – Support;
- A program change related to AMI savings for meter reading;
- A program change related to AMI savings for field services;
- A program change related to AMI savings within the call center;
- A program change related to AMI savings in billing; and
- A program change related to AMI savings for Replevin.

Line 13, Company Labor- Electric Operations: (E, G) This item relates to labor charges related to the Company's Electric Operations departments. The

Rate Year forecast for electric includes program changes discussed in detail in the direct testimony of the EIOP and noted below. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

- A program change related to Emergency Response;
- A program change related to Tree Trimming;
- A program change related to Engineering & Other Services;
- A program change related to Structures/Poles; and
- A program change related to Meters & Other Customer Equipment.

Line 14, Company Labor- Gas Operations: (E, G) This item relates to labor charges related to the Company's Gas Operations departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 15, Company Labor- Production: (E) This item relates to labor charges related to the Company's Production departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 16, Company Labor- Steam Distribution: This item relates to labor charges related to the Company's Steam Distribution departments. This is not applicable to electric or gas, but was included in the O&M schedules because the same element of expense line items are expected to be used for future steam rate case submissions as well.

Line 17, Company Labor- Substation Operations ("SSO"): (E) This item relates to labor charges related to the Company's SSO departments. The Rate Year forecast for electric includes Cricket Valley Substation costs discussed in detail in the direct testimony of the EIOP. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 18, Company Labor- System & Transmission Operations ("STO"): (E) This item relates to labor charges related to the Company's STO departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 19, Corporate and Shared Services: (E, G) This item relates to non-labor charges for the Company's Corporate & Shared Services departments that are not already covered in another line item (*e.g.*, Line 21, Environmental Affairs, Line 25, Facilities & Field Services, Line 26, Finance & Accounting Operations, Line 29, Information Technology, Line 61, Research & Development, and Line 62, Security). These departments include Emergency Management, Government Relations, Human Resources, Learning & Inclusion, Legal Services, Public Affairs, Office of the Secretary, President & Staff and Supply Chain.

The Rate Year forecast for electric and gas reflects a program change related to the Learning & Inclusion's Digital Learning Transformation program, which is discussed in detail in the direct testimony of the Shared Services Panel.

The Rate Year forecast for electric and gas also reflects a program change related to Energy Management implementing a Gas Transaction System and nMarket Replacement, both of which are discussed in the direct testimony of the GIOSP. We escalated the Historic Year expense and program changes discussed above by the general escalation factor to arrive at the Rate Year amount.

Line 20, Corporate Fiscal Expense: (E, G) This item includes costs of annual reporting services and meeting, trustee and committee fees including equity grants, as well as stock transfer agent fees and stock exchange registration fees. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 21, Customer Energy Solutions: (E, G) This item relates to non-labor charges for the Company's Customer Energy Solutions departments not already reflected in the AMI or Customer Information System line, which includes departments such as Demonstration Projects, EE, Rate Engineering, and Utility of the Future. This item includes a number of program changes discussed further in the Customer Energy Solutions Panel's direct testimony including:

- Funding to expand the Company's integration of Energy Storage into its network;
- A program to advance the Company's Innovation Initiative,
- Funding for the Company's proposed Distributed System Platform ("DSP") programs, including a Demand Management Tracking System,

Web Services Interface, and Demand Management Analytics Platform; and

- Support for the Company's expanded EE portfolio.

We escalated the Historic Year expense and program changes discussed above by the general escalation factor to arrive at the Rate Year amount.

Line 22, Customer Information System: (E, G) This line item represents O&M costs associated with implementing the Company's new CSS. The program change is discussed further within the Customer Energy Solutions Panel.

Line 23, Dynamic Load Management ("DLM"): (E) The Rate Year forecast is normalized to remove from the revenue requirement an expense that is recovered through surcharge. This surcharge recovers costs for programs such as the Commercial System Relief Program, Distribution Load Relief Program, Direct Load Control, and Smart AC programs. The Company's filing does not include any projected recovery of the cost of DLM through surcharge, thus there is no impact on the Company's revenue requirement.

Line 24, Demand Response Programs: (E) The Rate Year forecast is normalized to remove from the revenue requirement an expense that is recovered through surcharge. The Company's filing does not include any projected recovery of the cost of demand response programs through surcharge, thus there is no impact on the Company's revenue requirement.

Line 25, Duplicate Misc. Charges: (E, G) This item is comprised of credits for charges made to operating expenses or other accounts for the Company's own use of utility service. The Rate Year amount was held constant at the Historic Year expense.

Line 26, Employee Welfare Expense: (E, G) In its direct testimony, the Company's Compensation and Benefits Panel discuss costs and programs totaling $188 million in the Rate Year ($156 million allocated to electric and $32 million allocated to gas). In addition to the amounts supported by the Compensation and Benefits Panel, other employee welfare related fees such as service awards and administration support are included in this line and escalated using the labor escalation factor. In addition, costs associated with the Deferred Income Plan are normalized out of the historic period because this pertains to officers' benefits. The Company is not seeking to recover these costs through rates in this proceeding, but the Company reserves its rights to seek the recovery of such costs in future rate proceedings.

Line 27, Energy Efficiency: This item relates to the non-labor charges related to the Company's EE departments. The line item is not being used in this case as EE costs are allocated to other elements of expense.

Line 28, Environmental Affairs: (E, G) This item relates to the non-labor charges related to the Company's Environmental Health & Safety departments. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 29, ERRP Major Maintenance: (E) ERRP Major Maintenance costs are fully reconciled. The Rate Year expense of $10.703 million is consistent with the level included in the Company's current electric rate plan. The Company recorded a normalization to present both the cost and reconciliation to rate level of ERRP major maintenance as expense rather than partially as a reduction to other operating revenue. The Company will revisit the five-year forecast for major maintenance expenses during the preliminary update to determine whether refinement of the annual allowance is appropriate.

Line 30, Executive MVP: (E, G) The Company normalized the Rate Year forecast to eliminate the cost of the executive variable pay plan and long-term equity grants. The Company is not seeking to recover these costs through rates in this proceeding, but reserves its rights to seek the recovery of such costs in future rate proceedings.

Line 31, External Audit Services: (E, G) The Company contracts for services provided by PwC, such as auditing, research, and training. The Rate Year forecast includes a normalization of one-time costs in the historic year related to Sarbanes-Oxley Act of 2002 ("SOX") optimization efforts and a program change to reflect the latest audit fee schedule available. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 32, Facilities and Field Services: (E, G) This item relates to the non-labor charges related to the Company's Facilities and Field Services departments, such as building maintenance and janitorial services. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 33, Finance & Accounting Operations: (E, G) This item relates to the non-labor charges related to the Company's Finance and Accounting Operations departments and select other corporate charges. The Company made a normalization adjustment to adjust for expenses that were reimbursed during the Historic Year resulting from the Company providing support to Puerto Rico's hurricane recovery efforts. Another normalization was made to remove charges paid during the Historic Year to the Company's BCO consultant. In addition, we made changes to account for a program change related to ongoing support and administration of a proposed Enterprise Project Management Software, a program change related to cloud hosting fees and support of a new estimating software product, and software support costs of a proposed regulatory accounting software tool. Further details of these proposals can be found within the associated white papers included as part of Exhibit AP-7. We then escalated the Historic Year expense adjusted for the normalization adjustments and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 34, Indian Point Contingency: (E) The Indian Point Contingency plan addresses the potential reliability concerns that may arise upon the retirement of electric generation facilities, notably the Indian Point Energy Center. In response to the Commission's request, on February 1, 2013, the Company and NYPA filed a joint proposal to conduct Energy Efficiency/Demand Reduction/Combined Heat and Power programs. Pursuant to the Commission's Order, the Company is authorized to recover all costs through the MAC on a deferred basis over a ten-year period. This normalization adjustment removes the $28.5 million in amortization costs for the Historic Year.

Line 35, Information Technology: (E, G) This item relates to the non-labor charges related to the Company’s IT departments, such as technology support, software maintenance and application services as well as mainframe computers in general. The total Rate Year forecast includes program changes including funding for Oracle license support, cybersecurity, a proposed analytics center of excellence, a digital factory initiative, mainframe upgrades, cloud-based services, and a robotic process automation initiative. These program changes are all discussed in detail in the direct testimony of the IT Panel. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 36, Informational Advertising: (E, G) This item relates to informational advertising directed to customers. The Historic Year expense was adjusted by a program change to reflect budgeted expenses and escalated by the general escalation factor to arrive at the Rate Year amount.

Line 37, Injuries & Damages/ Workers Compensation: (E, G) In accordance with prior practice in rate case filings, the Company forecasted the Rate Year level of injuries and damages and workers compensation expenditures based on the average net claim payments for the most recent three-year period (*i.e.*, October 2015 through September 2018), escalated using the general escalation factor.

Line 38, Institutional Dues & Subscription: (E, G) This item includes membership fees paid to the American Gas Association ("AGA"), Edison Electric Institute ("EEI"), and other association dues and membership fees. The Rate Year forecast includes program changes to reflect a three-year average of costs. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount. Consistent with the Commission's requirements, the Company excluded from its proposed revenue requirement all trade association lobbying costs.

Line 39, Insurance Premium: (E, G,) This item includes insurance premiums the Company incurs for items such as property insurance, liability insurance, Directors and Officers insurance, and cyber security insurance. A program change was recorded to align expenses with the latest premiums and then escalated using the general escalation factor.

Line 40, Intercompany Shared Services: (E, G) This item reflects intercompany billing between the Company and CEI. A normalization adjustment eliminates the Company's portion of the insurance premiums expense from the Historic Year, so such expense, which is included in Line 39, Insurance Premiums, in this section of the testimony, is only included once. A program change was also recorded to reflect a proposed change in the way that CEI common expenses are allocated to subsidiaries. See the above discussion on "Common Expense Allocation" for further detail. We then escalated the Historic Year expense, normalization, and program change by the general escalation factor to arrive at the Rate Year amount.

Line 41, Load Dispatching and PJM Wheeling: (E) This item represents the accounting entries to defer and amortize the recovery of PJM OATT costs for the Historic Year. This program change to electric matches expenses that are collected as a separate surcharge through the MAC with the related MAC revenues to avoid a revenue requirement effect. At this point, there is no longer a PJM wheeling contract and the credit to expense and reduction of revenue represents the estimated return of prior overbillings which will be refunded to customers through the MAC.

Line 42, New York Facilities: (G) On July 27, 1950, the Company, Brooklyn Union Gas Company and Long Island Lighting Company, (which are now known as KEDNY and KEDLI, respectively) executed the New York Facilities Agreement to facilitate the introduction of natural gas into the New York area. The Commission approved the exchange payment and line loss reimbursement provisions of the most recently updated version of the New York Facilities Agreement on October 18, 2018. The New York Facilities Agreement provides, among other things, for the apportionment of costs for participants' use of other participants' facilities. As discussed in the GIOSP testimony and in section XVII.B of the Accounting Panel testimony below, the Company is proposing to change recovery of receipts and payments under the New York Facilities Agreement from base rates to the MRA. Therefore, we reflected a normalization adjustment for costs and revenues associated with this item in the revenue requirement. We escalated the remaining Historic Year level of costs by the general escalation factor to arrive at the Rate Year amount.

Line 43, Ops-Central Engineering: (E) This item relates to the non-labor charges related to the Company's Central Engineering departments. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 44, Ops-Construction Management: (E, G) This item relates to the non-labor charges related to the Company's Construction Management departments. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 45, Ops-Customer Operations: (E, G) This item relates to the non-labor charges of the Company's Customer Operations departments. The Rate Year forecast includes program changes discussed in the direct testimony of the Customer Operations Panel, including changes to the manner in which the Company collects the costs of credit card payment of utility bills. Further program changes request funding to implement bill redesign, and enhance the DCX, revenue protection, and replevin. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 46, Ops-Electric Operations: (E, G) This item relates to non-labor charges related to the Company's Electric Operations departments. The Rate Year forecast for electric includes program changes discussed in detail in the direct testimony of the EIOP, including program changes for emergency response, tree trimming, engineering and other services, and structures/poles. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 47, Ops-Gas Operations: (E, G) This item relates to non-labor charges related to the Company's Gas Operations departments. The Rate Year forecast for gas includes program changes discussed in detail in the direct testimony of the GIOSP including costs related to additional inspections and repairs due to an amendment to the definition of "gas service line" and a program change to perform methane detector maintenance. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 48, Ops-Interference: (E, G) The Company has an extensive system of electric and gas infrastructure within the streets of its service territory. As discussed in the direct testimony of the Municipal Infrastructure Support Panel, when a municipality plans to perform work and is unable to complete the proposed plan absent our relocating Company facilities that are "in the way," the Company bears all the costs to locate, move, support, protect and/or relocate the facilities affected by the municipality's construction activity. These costs are referred to as "interference costs." The Rate Year forecast includes a program change discussed in the direct testimony of the Municipal Infrastructure Support

Panel. We then escalated the Historic Year expense and the program change by the general escalation factor to arrive at the Rate Year amount.

Line 49, Ops-Production: (E) This item relates to non-labor charges related to the Company's Production departments. The Rate Year forecast includes a program change related to work that needs to be completed to comply with Local Law 11, which is discussed in further detail within the EIOP Panel. This line also includes a program change to reflect the projected Rate Year amount of other fuel charges for electric. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 50, Ops-Steam Distribution: This item relates to non-labor charges related to the Company's Steam Distribution departments. This line item is not applicable to electric or gas but was included in the O&M schedules because the same element of expense line items are expected to be used for future steam rate case submissions as well.

Line 51, Ops-Substation Operations ("SSO"): (E) This item relates to non-labor charges related to the Company's SSO departments. The Rate Year forecast for electric includes program changes discussed in detail in the direct testimony of the EIOP related to the substation EH&S risk mitigation program, Hellgate wharf refurbishment, Cricket Valley substation, and a roof and structural repairs program. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 52, Ops-System & Transmission Operations ("STO"): (E) This item relates to non-labor charges related to the Company's STO departments. A normalization was recorded to exclude non-recurring costs associated with PSE&G Feeder B3402. The Rate Year also reflects program changes related to physical/cyber security, a 345kv shunt reactor priority study, and specialized transmission planning studies, all of which are explained in further detail within the EIOP testimony. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 53, Other Compensation (Long-Term Equity): (E, G) This line includes the executive variable pay plan, and officer and non-officer long-term equity grants, which is made up of time based and performance based restricted stock expenses. The Rate Year program change for non-officer time based and performance based restricted stock expenses are based on the stock price of $81.99 and the number of outstanding shares of 89,500 at December 4, 2018. We escalated the program changes by the general escalation factor to arrive at Rate Year amounts.

We normalized the Rate Year amount to reflect elimination of costs associated with the executive variable pay plan and long-term equity grants. The Company is not seeking to recover these eliminated costs through rates in this proceeding, but, as noted above, reserves its rights to seek the recovery of such costs in future rate proceedings.

Line 54, Outside Legal Services (E, G) This item includes the cost of outside legal counsel. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year estimate.

Line 55, Pension and OPEB: (E, G) This line reflects the actuarially determined level of expenses for employee pensions and OPEBs, which was based on two studies performed by the Company's actuary, Buck Consultants, dated November 26, 2018 for both pensions and OPEBs. The studies incorporate the Company's actual historical experience supplemented by assumptions of future activity. Assumptions used in the forecast of pensions were a discount rate of 4.5 percent and an expected return on plan assets of 7.0 percent. OPEB projections were based on a discount rate of 4.40 percent, return on assets of 7.0 percent for the 401(h) account, 7.6 percent for the Management Life Insurance VEBA, 7.1 percent for the Management Health VEBA and 6.6 percent for projecting the assets for the Weekly Health VEBA from January 1, 2019.

Q. Please summarize the estimate of the Rate Year employee pensions/OPEBs expense.

A. The net amount of the actuarially determined level of expense for employee pensions/OPEBs and other payments, net of capitalization, for all three commodities for the Historic Year is $216 million, with $163.9 million allocable to electric and $35.9 million allocable to gas. The Rate Year estimated cost is $147 million ($114 million allocable to electric and $23.4 million allocable to gas). This $69 million decrease ($49.8 million allocable to electric and $12.5

million allocable to gas) in accounting cost is attributed to multiple factors. One key driver for the decrease in the accounting cost from the Historic Year to the Rate Year is the change in the discount rate. The pension discount rate was 4.25% for the three months ended December 31, 2017, and was 3.70% for the nine months ended September 30, 2018. For the Rate Year, the projected pension discount rate is 4.50%. A higher discount rate results in a lower level of expense. This was partially offset by a decrease in the expected return on plan assets, from 7.50% expected in the Historic Year, to 7.00% for the Rate Year.

Q. Does this line item include Supplemental Retirement Income Plan ("SRIP") costs?

A. Yes. Officer and non-officer SRIP costs are included in this line item, as they relate to the Company's long-term performance-based compensation for management employees.

Line 56, RCA- Amort. of MGP/Superfund: (E, G) The program change associated with this line item is to align expenses with the level of SIR cost amortization as addressed in Section XVII (Reconciliations & Deferred Accounting) of our direct testimony.

Line 57, RCA- Amort. of Energy Efficiency Programs: (E, G) The program change associated with this line item is to align expenses with the level of EE program amortization as addressed in XVII (Reconciliations & Deferred Accounting) of our direct testimony.

Line 58, Regional Gas Greenhouse Initiative ("RGGI"): (E) We normalized the Rate Year forecast to remove the Historic Year expense because it is collected through the MAC.

Line 59, Regulatory Commission Expense-18A: (E, G) We normalized the Rate Year forecast to remove the 18-a Surcharge Assessment during the Historic Year. The 18-a Surcharge Assessment was discontinued effective January 1, 2018.

Line 60, Regulatory Commission Expense-All Other: (E, G) This item includes costs of participating in regulatory proceedings (*e.g.*, consultants, outside legal counsel). The Rate Year forecast reflects a three-year average of costs escalated by the general escalation factor to arrive at the Rate Year amount.

Line 61, Regulatory Commission Expense-General and R&D: (E, G) We forecasted the Rate Year Commission Assessment based on the latest Commission Assessment letter dated February 2018, excluding refunds, for the 2018-2019 State fiscal year ending March 31, 2019. We then escalated it by using the general escalation factor to arrive at the Rate Year forecast. The Company will update this element of expense based on any additional Commission Assessment letters received during these proceedings.

Line 62, Renewable Portfolio Charges: (E) There are no expenses incurred in the Historic Year and no expenses projected in the Rate Year for this element of expense.

Line 63, Rents – ERRP: (E) This expense, which is recovered through the MAC, is an interdepartmental rent that is offset in steam's Other Operating Revenues.

Because the Company is not filing for new steam rates to be effective January 1, 2020 concurrent with the electric and gas filings, the $77.218 million of revenues in steam rates, reflected in RY3 of the current steam rate plan, will continue to be reflected in steam rates. Under the current electric rate plan, the Commission authorized the Company to defer the impact of the change in expense to steam, starting in 2017 and annually thereafter (until steam base rates are reset), whether positive or negative, to continue the "earnings neutral" nature of these revenues to the Company.

Line 64, Rents-General: (E, G) This item represents general rents paid to lease various properties or land on which the Company operates. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year estimate.

Line 65, Rents-Interdepartmental: (E, G) The Rate Year forecast for electric includes a program change primarily attributable to increases to the book costs of the Ravenswood, Flushing and Astoria tunnels, which are part of Gas Plant, and an increase to the book cost of the Hudson Avenue Tunnel, which is part of Steam Plant.

Line 66, Research & Development: (E, G) This item relates to non-labor charges related to the Company's R&D department. We escalated the Historic Year expense level using the general escalation factor to arrive at the Rate Year amount.

Line 67, Security: (E, G) This item relates to non-labor charges related to the Company's Corporate Security department. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 68, Storm Reserve: (E) The Company is proposing to maintain the Historic Year level of storm reserve expenditures, as increased by the general escalation factor, to arrive at the Rate Year amount. Please also see the Deferrals and Reconciliation section for additional detail on the major storm reserve target.

Line 69, System Benefit Charge: (E, G) This line item is normalized because the System Benefit Charge is collected as a separate surcharge.

Line 70, Uncollectible Reserve-Customer: (E, G) This item represents a provision and write-off of customer accounts receivables which are not expected to be recovered by the Company. The Company's uncollectible factor, *i.e.*, write-offs as a percent of revenues, for electric and gas equates to $0.46/$100 for the Historic Year. We applied this factor to the Rate Year levels of sales revenues and late payment charges. For electric, this resulted in uncollectible accounts expense of $36,229,000 before accounting for the proposed rate increase. For gas, applying the same $0.46/$100 rate results in the Rate Year level of uncollectible accounts expense of $9,690,000 before accounting for the proposed rate increase.

Line 71, Uncollectible Reserve-Sundry: (E, G) This item represents a provision and write-off of miscellaneous accounts receivables which are not expected to be collected by the Company. The Rate Year amount includes a program change to reflect a twenty-four month annualized average for the period October 2016 through September 2018.

Line 72, Worker's Comp NYS Assessment: (E, G) This line item represents assessment payments by employers to the NYS Workers' Compensation Board ("WCB"). The assessment rates are determined by the WCB each year and the Company estimates its expenses based on the latest available rates and projected payroll levels. The Company recorded a program change to reflect the latest available estimates as of the time of the filing. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 73, All Other: (E, G) This line item includes miscellaneous and general expenses that did not fit into other categories of expense discussed above. We then escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 74, Business Cost Optimization ("BCO") - Labor: (E, G) This line item reflects the customer share of labor-related savings associated with the Company's BCO Program. As discussed within the BCO section of this testimony, the amounts presented on this line consist of program changes for the projected net O&M savings partially offset by a program change representing the Company's proposed share of savings.

Line 75, Business Cost Optimization – Non-Labor: (E, G) This line item reflects the customer share of non-labor-related savings associated with the

Company's BCO Program. As discussed within the BCO section of this testimony, the amounts presented on this line consist of program changes for the projected net O&M savings partially offset by a program change representing the Company's proposed share of savings.

Line 76, Company Labor – Fringe Benefit Adjustment: (E, G) This adjustment represents the increase in employee welfare expenses and workers' compensation related to the increase or decrease in employees through program changes as sponsored by various Company witnesses, including the Accounting Panel. We escalated the program change by the general escalation factor to arrive at the Rate Year amount.

E. Depreciation and Amortization (Exhibits AP-3, Schedule 7.1 & 7.2)

Q. Please describe Schedules 7.1 and 7.2 of Exhibits AP-3 relating to Depreciation and Amortization.

A. Schedule 7.1 shows the depreciation and amortization amounts at current depreciation rates, with no additional recovery of the reserve deficiency for the period from September 2018 to December 2022. Schedule 7.2 shows the depreciation and amortization amounts at current depreciation rates after increasing the annual recovery of the reserve deficiency for the same period. Rate Year depreciation and amortization is based on projected plant balances through the Rate Year and composite depreciation rates for current plant accounts. Both are discussed in detail in the Depreciation Panel's testimony.

Q. Please summarize the projected net changes to the level of Depreciation and Amortization from the Historic Year to the Rate Year as shown in Schedule 7.1.

A. For electric, the Historic Year level of $966.3 million is forecast to increase by $163.5 million for a Rate Year level of $1,129.8 million.

For gas, the Historic Year level of $199 million is forecast to increase by $79.2 million for a Rate Year level of $278.2 million.

Q. Please summarize the projected net changes to the level of Depreciation and Amortization from the Historic Year to the Rate Year as shown in Schedule 7.2.

A. For electric, the Historic Year level of $966.3 million is forecast to increase by $183.5 million for a Rate Year level of $1,149.8 million.

For gas, the Historic Year level of $199 million is forecast to increase by $87.2 million for a Rate Year level of $286.2 million.

Q. Please summarize the Company's proposed depreciation and amortization expense.

A. These figures reflect existing electric and gas depreciation rates and a $20 million recovery of reserve deficiencies for electric and an $8 million recovery of reserve deficiencies for gas, as explained by the Depreciation Panel.

Q. Please explain why the Company is not proposing to increase its depreciation rates, as found warranted in the Company's Depreciation Studies.

A. The Company is filing with existing depreciation rates in order to mitigate the proposed rate increase.

F. Taxes Other than Income Taxes (Exhibits AP-3, Schedule 8)

Q. How did you calculate the Property Taxes component of Taxes Other Than Income Taxes for the Rate Year shown on Schedule 8 of Exhibits AP-3?

A. Historic Year property taxes consist of NYC real estate and special franchise taxes and Westchester County and other upstate county property taxes. The Rate Year forecasts were provided to us by the Company's Property Tax Panel and are described in its direct testimony.

Also shown on Schedule 8 of Exhibits AP-3 are amounts representing the reconciliation of actual property taxes to the levels established in base rates during the Historic Year under the Company's current electric and gas rate plans, which are normalized for the Rate Year.

Q. How did you calculate the Payroll Taxes component of Taxes Other than Income Taxes as set forth on Schedule 8 of Exhibits AP-3?

A. We determined the payroll taxes by applying the employer payroll tax rate to the forecasted direct labor increases.

Q. How did you calculate the Revenue Tax component of Taxes Other Than Income Taxes for the Rate Year shown on Schedule 8 of Exhibits AP-3?

A. We determined the Revenue Taxes based on the estimated revenue for gas and electric multiplied by the effective tax rate (provided by the Company's Electric and Gas Forecasting Panels).

Q. Please explain the Taxes on Health Insurance shown on Schedule 8 of Exhibits AP-3.

A. New excise taxes are scheduled to become effective under the Affordable Care Act in 2022. The forecasts for Taxes on Health Insurance are based on thresholds that are subject to change based on future Consumer Price Index change. See also "Taxes on Health Insurance" in section XVII (Reconciliations & Deferral Accounting) of this testimony.

Q. Please explain the Sales and Use Tax component of Taxes Other Than Income Taxes shown on Schedule 8 of Exhibits AP-3.

A. These are the state and local sales and use taxes paid by the Company when acquiring a broad range of goods and services. The amount shown is the portion of such taxes chargeable to expense as opposed to being capitalized. A normalization adjustment was recorded to reflect sales and use tax refunds recorded during the Historic Year. We have escalated the Historic Year amounts to recognize general inflation in the cost of goods and services. The forecast does not assume any change in sales tax rates.

Q. Please describe the All Other Taxes component of Taxes Other Than Income Taxes shown on Schedule 8 of Exhibits AP-3.

A. All Other Taxes represents minor taxes such as commercial rent and occupancy tax, motor vehicle taxes, state gasoline tax, state highway use tax, federal diesel and gasoline taxes, the NYS tax on insurance premiums and hazardous waste. The Company estimates the Rate Year level for such taxes to be the Historic Year amount plus escalation at the general inflation factor.

G. State and Federal Income Taxes (Exhibits AP-3, Schedules 9 and 10)

Q. Please describe the calculation of income taxes shown on Schedules 9 and 10 of Exhibits AP-3.

A. Schedule 9 details the NYS income tax computation. We calculated the NYS income tax expense using a 6.5 percent tax rate.

Schedule 10 details the federal income tax computation. The federal income taxes are computed using the 21 percent tax rate. The Schedule shows the amortization of excess deferred FIT ("EDFIT") broken out in the following four categories: protected plant, unprotected plant, accelerated unprotected plant and non-plant. The EDFIT represents the difference in the amounts the Company collected from its customers at a 35 percent tax rate to pay future income taxes, and the Company's future tax liabilities at a 21 percent tax rate. The Company proposes to refund the protected component over the remaining lives of the underlying plant assets and the unprotected and non-plant components over five years.

Schedule 10 also reflects a credit to customers for an estimated amount of an R&D tax credit (testified to by the Income Tax Panel) that reduces the Company's federal income tax expense in the Rate Year.

XI. FUND REQUIREMENTS AND SOURCES (Exhibits AP-3, Schedule 12)

Q. Please describe Exhibits AP-3, Schedule 12.

A. This schedule reflects the Company's forecast of capital fund requirements and sources of capital funds, as well as certain financial statistics, for the Rate Year.

We have determined that capital funds required during the Rate Year will exceed internal sources by $247 million.

Q. Please describe the items contained in the schedule under the heading "Internal Sources of Funds."

A. The first item is estimated retained earnings. For the Rate Year, net income for common stock is projected at $1,389 million and new issuances are projected at $625 million, offset by projected common stock dividends of $930 million. The second item is depreciation. The third item is the amortization of net accounting credits. The fourth item is net working capital requirements. The fifth item, deferred tax accruals, are funds provided principally by the use of tax depreciation subject to normalization. Our projections show internal sources of funds will provide $2,750 million.

Q. Please describe the next section of the schedule.

A. The next section, "External Sources of Funds," shows the Company's projected debt issuances and changes to short-term borrowings for the Rate Year. These external sources of funds will provide $247 million.

Q. Please describe the items contained in the schedule under the heading "Use of Funds."

A. The first item, requiring the largest amount of capital funds, is Construction Expenditures of $2,997 million. This amount is consistent with the Company's five-year forecast of construction expenditures, as set forth in Exhibits AP-4.

The second item shows there are no long-term debt maturities during the Rate Year, consistent with what is shown in Exhibits AP-5.

XII. INTEREST COVERAGE – S.E.C. BASIS PER BOOKS (Exhibits AP-3, Schedule 13)

Q. Is the Accounting Panel sponsoring an exhibit to show the calculation of interest coverage ratio for the interest paid on long-term debt and other items?

A. Yes, we are sponsoring Schedule 13 of Exhibits AP-3. The schedules contain identical information because the information is presented on a corporate rather than a commodity basis.

Q. Please describe these exhibits.

A. Schedule 13 of Exhibits AP-3 show the ratio of the Company's earnings before interest and taxes to the amount of fixed charges it had to pay for each of the prior five years.

Fixed charges includes interest on long-term debt, amortization of debt discount and expense, the interest component of rentals and "other interest," which is comprised of interest paid on customer deposits, commercial paper, customer overpayments and other miscellaneous items.

Q. Does the Company currently have available lines of credit?

A. Yes. The Company, along with CEI and O&R, has agreements with various banks for revolving credit lines totaling $2,250 million. Assuming that CEI and O&R have not used their assigned portions of this credit, $1,000 million and $300 million, respectively, the Company can use the entire $2,250 million.

XIII. NET PLANT INVESTMENT (EXHIBITS AP-4)

A. Projected Net Plant Balances (Exhibits AP-4, Schedules 1 & 2)

Q. Has the Accounting Panel prepared projections of net plant balances from the end of the Historic Year (*i.e.*, September 30, 2018) through the Rate Year (*i.e.*, December 31, 2020) appraising the impact of the current construction and retirement programs on electric and gas rate base?

A. Yes, that information is presented in Exhibits AP-4.

Q. What is shown on Schedule 1 of Exhibits AP-4?

A. Schedule 1 of these exhibits contains three pages. Page 1 of Schedule 1 shows projected net plant balances for the Rate Year, with the depreciation reserve reflecting accruals at currently effective rates. Page 2 of Schedule 1 shows projected net plant balances for the Rate Year, with the depreciation reserve reflecting accruals at the currently effective rate, plus $20 million in reserve deficiencies recovery for electric and $8 million in reserve deficiencies recovery for gas. Page 3 of Schedule 1 shows the projected monthly net plant balances from the end of the Historic Year to the start of the Rate Year, which served as a basis for our Rate Year projections.

Using projected capital expenditures provided to us by various witnesses in these proceedings, we estimated transfers to plant in service. We then added the estimated transfers to the actual plant in service account balances at September 30, 2018 and deducted the projected book cost of plant retired to give us a book cost of plant. In order to develop net plant balance, we deducted accumulated depreciation from book cost of plant.

Q. What is shown on Schedule 2 of Exhibits AP-4?

A. Schedule 2 of these exhibits contains two pages. Page 1 of Schedule 2 shows projected CWIP in rate base for the Rate Year. Page 2 of Schedule 2 shows CWIP in rate base from the end of the Historic Year to the start of the Rate Year. Each page shows non-interest bearing CWIP that is included in rate base and the balance subject to AFUDC, or interest bearing CWIP, that is not included in rate base.

Q. Please describe how you developed the non-interest bearing CWIP projections included in electric and gas rate base.

A. Using projected capital expenditures provided to us by various witnesses in these proceedings and the Company's books and records for CWIP balances as of the end of the Historic Year, we estimated transfers to plant in service and the resulting CWIP balances.

Q. Are the net plant and non-interest bearing CWIP rate base amounts in Exhibits AP-4 reflected in the total rate base amounts shown in Exhibits AP-2?

A. Yes.

Q. What is shown on Schedule 3 of Exhibits AP-4?

A. Schedule 3 shows the capital expenditure projections for calendar years 2019 through 2023 reflected in our net plant and CWIP forecasts.

B. Allocation of Common Plant Investment (Exhibits AP-4, Schedule 3)

Q. How is the cost of common plant allocated between Con Edison and O&R?

A If a common plant project benefits O&R, the portion of the project applicable to O&R will be charged to an O&R capital account through the affiliate billing process. If there is not another basis to allocate costs, the intercompany shared services percentage discussed above will be used.

Q. Do the net plant rate base amounts for electric and gas include amounts related to common net plant?

A. Yes. Con Edison's portion of common plant is allocated 83 percent to electric operations and 17 percent to gas operations. Steam operations is charged an interdepartmental rent charge for common plant used in steam operations. That charge to steam operations is credited to the electric and gas departments.

XIV. RATE OF RETURN (EXHIBIT AP-5)

Q. Is the Accounting Panel sponsoring an exhibit regarding the required rate of return?

A. Yes, along with Company witness Saegusa, we are sponsoring Exhibits AP-5. These exhibits contain identical information for electric and gas because the information is presented on a corporate rather than a commodity basis.

Q. Please describe Schedule 1 of Exhibits AP-5.

A. Schedule 1 of these exhibits shows the actual capital structure for the Company as of the end of the Historic Year, the average cost rate for each component of the capital structure and the related cost of capital. The Company's overall weighted cost of capital at the end of the Historic Year was 6.81 percent for both electric and gas.

Q. Please describe Schedules 2, 3 and 4 of Exhibits AP-5.

A. These schedules show the projected average capital structure, the average cost rate for each component of the capital structure and the related cost of capital for the Rate Year and the two following twelve-month periods ending December 31, 2021 and 2022, respectively. The Company's overall weighted cost of capital for the Rate Year is projected to be 7.29 percent.

Q. What capital structure is the Company proposing to use for the Rate Year?

A. The Company proposes a 50.00 percent common equity ratio for the Rate Year. Witness Saegusa explains in her testimony that this equity ratio is appropriate and necessary to address the Company's recent credit downgrade and weakened cash flow profile.

Q. How did you derive the amount of average long-term debt for each period?

A. To derive the average long-term debt for the each of the Rate Years presented in this filing, we determined the amount of long-term debt outstanding at the end of each month from the end of the Historic Year through December 31, 2022. We then used these figures to calculate the average balance of long-term debt outstanding for each period.

Q. How was the amount of long-term debt outstanding each month determined?

A. We estimated changes in the outstanding amount of debt each month from the end of the Historic Year forward based on the forecasted funding requirements.

Schedules 5, 6, 7, and 8 of Exhibits AP-5 list the actual long-term debt balance as of the end of the Historic Year and the projected monthly balances. The forecasted average amount of long-term debt for the Rate Year is $15,623 million as shown on Schedule 6 of Exhibits AP-5.

Q. Please explain how you derived the average customer deposits amounts, set forth on Schedules 2, 3 and 4 of Exhibits AP-5.

A. With respect to customer deposits, we started with the actual average balance during the Historic Year of $335 million. The balance is expected to grow by approximately two percent per year making the average balance of customer deposits for the Rate Year $352 million. The two percent annual growth rate is based on the actual average annual change in customer deposits for the Historic Year.

Q. Please explain the average balance for common equity for each of the periods.

A. As explained by Company witness Saegusa and as set forth in Exhibits AP-5, Schedule 2, the forecasted capital structure for the thirteen months ending December 31, 2020 includes a common stock equity ratio of 48.53 percent. Schedules 3 and 4 of Exhibits AP-5 show that the Company's equity ratio would increase to 48.63 percent for the twelve-month periods ending December 2021 and 2022, respectively. To the extent that the recommended equity ratio of 50.00 percent is agreed upon, the Company would modify its debt and equity issuances to work toward achieving that ratio.

Q. What average cost rate for long-term debt is reflected in the overall rate of return?

A. Con Edison's long-term debt consists of tax-exempt debt issued through NYSERDA and debenture bonds. The average annual cost rate of this debt is calculated by dividing the annual interest requirements for all long-term debt issues, including the annual amortization of the net amount of any premiums or discounts realized when the securities were sold and the cost and expense of issuance, by the amount of long-term debt outstanding. As shown on Schedules 6 through 8 of Exhibits AP-5, the average cost of long-term debt for the Rate Year is 4.86 percent, 4.90 percent for the twelve months ending December 31, 2021 and 4.95 percent for the twelve months ending December 31, 2022.

Q. What cost rate for customer deposits is reflected in the overall rate of return?

A. We reflected the current rate as set by the Commission of 2.45 percent. The Commission reviews this rate annually.

Q. What rate of return on common equity is reflected in the overall rate of return?

A. As noted above, we have used a return on common equity of 9.75 percent to calculate the overall rate of return. For the Rate Year, the overall rate of return is 7.29 percent, which we used in determining the revenue requirement for the Rate Year.

Q. Will the rate of return be updated in this proceeding?

A. The Company may update the rate of return as part of the Company's rebuttal and update testimony if financial conditions at that time warrant such an update.

Q. Who determines what Con Edison's dividend payments to CEI will be?

A. CEI's Board of Trustees makes that determination.

XV. ALLOCATION OF ELECTRIC RATE INCREASE (Exhibit AP-6)

Q. Did the Accounting Panel determine how much of the total increase in the electric revenue requirement of $485,415,000 was allocable to delivery service and how much was allocable to the MAC?

A. Yes. Exhibit AP-E6 reflects this allocation.

Q. Please describe this exhibit.

A. Exhibit AP-E6 includes four schedules. Schedule 1 summarizes the proposed $485,415,000 increase as allocated between delivery service rates and the MAC. The required increase in delivery service revenues is $478,722,000; the accompanying increase in required MAC revenues is $6,693,000. Schedules 2 and 3 present the state and federal income taxes related to the production function. Schedule 4 shows the average rate base allocated between the delivery and the MAC components.

XVI. FINANCE DEPARTMENT O&M PROGRAMS AND CAPITAL PROJECTS (Exhibit AP-7)

A. Finance Capital Projects

Q. Has the Accounting Panel prepared and presented in its exhibits projections of any capital projects?

A. Yes, we have developed projections for capital projects used by the Finance department, which are shown in Exhibits AP-7. These exhibits contain identical information because the information is presented on a corporate rather than a commodity basis

The Finance capital projects are the:

- Enterprise Project Management Software Project, which aims to improve project management capabilities for capital construction projects;
- Regulatory Accounting Application Upgrade, which will enable the Company to better manage the process of preparing rate cases and other regulatory filings;
- Estimating Software Development Project, which will enable the Company to better prepare estimates for project appropriations, cost management functions and project administration purposes;
- Budget and Forecast Analytics Project, which will provide the Company with the capability to leverage actual data when developing budgets and forecasts to generate analysis and trending;
- BI Enhancements Project, which aims to enhance the Oracle Business Intelligence reporting module and upgrade its predictive analytics-enabled decision-making tools;
- Oracle Financial Close and Consolidation Project, which will implement a new consolidation system to enhance automation and integration of the systems supporting the financial statement close process; and
- PowerPlan Application Cloud Migration/Upgrade, which will migrate the Company’s Fixed Asset, Lease, and Tax accounting software system from an on-premise tool to a cloud software solution as well as provide necessary upgrades to prevent obsolescence.

Q. Have you provided supporting documentation for each project?

A. Yes. Each project is supported by a white paper that includes a description of the project, projected costs, and an explanation of the business need for the project. These white papers are included in Exhibits AP-7.

XVII. RECONCILIATIONS AND DEFERRED ACCOUNTING

Q. Does the Company currently employ deferred accounting as permitted under Accounting Standards Codification 980, Regulated Operations?

A. Yes. The Commission has authorized the Company to employ deferred accounting to match the recognition of expenditures with the recovery of certain costs when they are either beyond the Company's direct control and therefore not subject to reasonable estimation, the timing of the actual expenditure is not certain, or in furtherance of State and/or Commission policy objectives. The Commission similarly employs deferred accounting regarding the Company's actual, potential or unexpected receipts of various revenues and credits. The approach is intended to protect the interests of customers and investors by avoiding a "windfall" for one or the other and the approach of amortizing the costs over subsequent periods serves the purpose of minimizing rate volatility.

A. Net Plant Reconciliation

1. Electric and Gas Net Plant

Q. Please describe electric and gas net plant reconciliation under the Company's current rate plans.

A. The revenue requirement impact of actual electric net plant (excluding AMI) is subject to downward-only reconciliation. The revenue requirement impact of actual gas net plant (excluding AMI) is subject to full downward reconciliation, with the possibility of limited upward reconciliation of certain municipal infrastructure support (interference) costs as specified in the rate plan.

Q. What is the Company's proposal regarding net plant reconciliation for the Rate Year?

A. The Company proposes that the current electric and gas net plant reconciliation mechanisms continue, each with a modification to reconcile fully all interference capital as explained below. In addition, the Company proposes an adjustment to electric net plant reconciliation to account for certain NWS, as discussed by the Customer Energy Solutions panel and in our testimony below.

Q. Please explain why the Company is proposing to reconcile interference capital.

A. As explained by the Municipal Infrastructure Support Panel, interference costs are mandatory expenditures incurred to support local and state government projects. As such, they are beyond the Company's direct control. Moreover, NYC, Westchester County municipalities, and NYS are all planning projects that will cause the Company to incur significant interference costs in the upcoming years. These project plans are still under development and, in the case of NYC's coastal resiliency program project, NYC is currently pursuing a new entirely different alternative design, further hampering the Company's ability to reasonably forecast its interference costs. It is clear from the scope of the projects that these costs will be significant. The Company has included projected interference costs in these rate filings that are considerably higher than in past cases. For instance, total projected capital interference costs for RY1-RY3 are $604 million for electric and $327 million for gas. Capital interference costs for the three years of the current rate plans totaled $376 million for electric and $244 million for gas. Accordingly, a change in a project plan could have a significant impact on the Company's overall capital spending plan. In order to avoid a situation where this impairs the Company's ability to manage its portfolio of capital projects effectively, the Commission should permit the Company to reconcile fully its interference capital costs.

Q. Please explain how your proposal for full reconciliation for interference capital would operate within the context of a single overall net plant target for electric and gas.

A. If actual aggregate net plant including actual interference net plant is at or below the aggregate net plant target, there would be no separate reconciliation of interference net plant. If capital expenditures resulting from interference costs above the forecasted amount cause the Company to exceed its aggregate net plant target, the Company would be permitted to recover carrying charges on the amount of net plant that exceeds the aggregate net plant target through a surcharge subject to audit.

2. AMI Net Plant

Q. Please describe AMI net plant reconciliation under the Company's current rate plans.

A. Net plant reconciliation for AMI capital expenditures is currently implemented for a single category of AMI capital expenditures that includes amounts allocated to both electric and gas customers, and is subject to a $1.285 billion overall project cap.

Q. What is the Company's proposal regarding net plant reconciliation of AMI-related expenditures for the Rate Year?

A. The Company proposes that the current AMI reconciliation mechanism continue without modification.

3. Non-Wires Solutions ("NWS") and Non-Pipeline Solutions ("NPS")

Q. Please describe how cost recovery of NWS and NPS is structured under the Company's current electric and gas rate plans.

A. Under the Company's current electric rate plan, costs of any new NWS (*i.e.*, those not included in rate base) are recovered over ten years through the MAC and NYPA OTH Statement. The rate plan further provides that to the extent an NWS results in the Company displacing a capital project included in its electric net plant target, the Company nets the carrying charge associated with the displaced capital project against the surcharge recovery of the NWS project. Any remaining credit is deferred for the benefit of customers. The current gas rate plan does not address recovery of NPS projects.

Q. What is the Company's proposal regarding cost recovery of NWS and NPS for the Rate Year?

A. As discussed by the Customer Energy Solutions Panel, the Company is actively evaluating NWS. In its preliminary update filing, the Company may include costs for certain NWS in base rates. To the extent an NWS is included in base rates and does not successfully displace a traditional electric project (and that traditional project is not reflected in the electric net plant target), the Company proposes to increase the electric net plant target to account for the cost of the traditional project. If the Company determines that the NWS currently being evaluated are not feasible, it will account for the cost of the traditional project in the preliminary update.

To the extent that the Company proposes costs for NWS to be deferred as regulatory assets and recovered in base rates, the Company will also propose a rate base reconciliation of such costs. This reconciliation would make customers whole for any underspending on NWS relative to anticipated costs in the event the Company transitions back to a traditional project from an NWS.

For any new NWS that arises during the term of the rate plan (*i.e.*, one not included in base rates), the Company proposes that cost recovery continue under the ratemaking framework established in the Company's current electric rate plan, as discussed above.

Recovery of NPS will be governed by the Commission's order issued August 9, 2018 in the Smart Solutions proceeding (Case 17-G-0606).

4. Investment Related to Generation Retirements

Q. What is the potential generation retirement project and what is the Company's proposal for cost recovery related to that project?

A. As discussed by the EIOP, constraints and reliability issues may emerge if third-party generators retire due to market forces or regulations adopted by the New York State Department of Environmental Conservation ("DEC") regulations. These generator retirements, if they occur, may require the Company to invest in upgrades to its transmission, substation and/or distribution systems to solve reliability issues. Because of the uncertainty associated with market forces, the DEC regulations and the potential generation retirements, EIOP cannot forecast the project or the costs that the Company would incur to implement such a project. Accordingly, the costs of the project(s) that could result from such retirements is not reflected in the electric net plant target. The Company accordingly proposes to recover the revenue requirement impact of this project through a surcharge subject to audit if it occurs.

B. Other Deferral Accounting and Reconciliation Mechanisms

Q. What is the Company proposing regarding the use of deferral accounting and reconciliation mechanisms for expenses not related to utility plant?

A. The Company is proposing to continue all deferral accounting and reconciliation mechanisms that are in effect during the current electric and gas rate plans unless otherwise noted below. The deferral and reconciliation mechanisms that are proposed to continue include, but are not limited to, the existing supply rider provisions (*e.g.*, MSC, MAC, GCF, MRA) and deferral and reconciliation mechanisms for such items as property tax expense, pensions and OPEBs, SIR costs, East River station maintenance costs, AMI Customer Engagement Plan and AMI Rate Pilots, REV demonstration projects, BQDM, Pipeline Safety Act, low income discounts, the weighted average cost of variable rate long-term debt and changes in costs as a result of legislative, regulatory and/or related actions. The Company is also proposing to implement new deferral accounting or reconciliation mechanisms, as addressed below.

Q. Why is the Company proposing the continuation of the existing reconciliation mechanisms?

A. Those reconciliation mechanisms are related to costs that are significant, highly variable even in the near term, and not subject to reasonable estimation, protect the interests of customers and investors and are appropriate. We note in that regard that the Company is subject to the Commission's Policy Statement on Pensions and Other Post-Employment Benefits and is required to true-up its annual pension and OPEB costs to the levels provided in base rates. Others, such as those related to the System Benefits Charge and Low Income customer charge discounts, are in furtherance of public policy objectives. Moreover, continuing these true-ups in connection with a one-year rate determination could enable the Company to delay the need for rate relief at the expiration of the Rate Year.

1. Modified Deferral or Reconciliation Mechanisms

a. Property Tax Reconciliation (Electric and Gas)

Q. Does the Company propose modifications to the Property Tax Reconciliation Mechanism?

A. Yes. The Company proposes a full and symmetrical reconciliation of property taxes applicable separately to electric and gas. Such a reconciliation for property taxes is needed regardless of whether a single year rate order or multi-year rate plan is adopted by the Commission in these proceedings.

Q. Please explain the basis for this proposal.

A. The Company's Property Tax Panel explains at length why property taxes are not subject to reasonable estimation and why a full reconciliation is appropriate. The Company's property taxes are subject to, among other things, the vagaries of municipal management and economic circumstances.

Absent the full and symmetrical reconciliation mechanism we propose, similar circumstances may result in significant windfall for either customers or the Company, at the expense of the other. As the Company's Property Tax Panel explains, the Company has historically sought to minimize its taxes and that continues on an ongoing basis – it is a normal course of business for the Company, even during times when a full reconciliation was in effect.

b. Interference Reconciliation (Electric and Gas)

Q. Does the Company propose a modification to the existing reconciliation mechanisms for interference O&M expense?

A. Yes. For the reasons explained in the direct testimony of the Company's Municipal Infrastructure Support Panel, the Company is proposing that a full and symmetrical reconciliation mechanism replace the partial and asymmetrical reconciliation mechanism currently in effect under the Company's rate plans for Municipal Infrastructure Support O&M expenses.

Q. Is the current interference reconciliation mechanism flawed?

A. Yes. As discussed in the direct testimony of Municipal Infrastructure Support Panel, interference costs are outside the Company's direct control and cannot be reasonably forecasted. Moreover, the current projects contemplated by NYC and NYS are notably larger than typical and changes in their project plan could have a significant impact on costs that the Company must incur. As a result, the Company proposes that O&M costs be fully reconciled to protect both the Company and customers from any windfalls resulting from deviations from current cost projections, at the expense of the other. As the Company's Municipal Infrastructure Support Panel explains, the Company has historically sought to minimize its interference expenses and that continues on an ongoing basis – it is a normal course of business for the Company, even during times when a full reconciliation was in effect.

c. Energy Efficiency ("EE") (Electric and Gas)

Q. Is the Company proposing to modify the reconciliation for its EE program?

A. Yes. The ratemaking framework established in the Company's current electric rate plan provides for the recovery of forecasted EE costs over ten years using the overall pre-tax rate of return. The revenue requirement associated with electric EE costs are subject to a downward-only reconciliation on an annual basis. The Company proposes to implement a comparable regulatory asset for gas EE costs and apply downward reconciliation to the Company's aggregate total revenue requirement impact of electric and gas EE spending over a three-year period (*i.e.*, 2020-2022) so as to facilitate flexibility between the electric and gas EE programs.

In these rate filings, the Company has included both EE program costs and ETIP costs that are being moved from a surcharge to base rates as electric and gas EE regulatory assets. The reconciliation for this combined program would be implemented similar to the reconciliation of AMI costs, where costs would be fully reconciled to the amounts included in electric and gas revenue requirements, but subject to the aggregate revenue requirement established by the Commission for the combined portfolio.

As explained in the testimony of the Customer Energy Solutions Panel, in light of the timing of the. Commission's December 2018 Order in Case 18-M-0084 on EE, the Company did not have adequate time to complete its review and evaluation of its EE program prior to finalizing its revenue requirements. The Customer Energy Solutions Panel explains that the Company may submit adjustments to its EE programs at the preliminary update stage of these proceedings, which would change the revenue requirements associated with those programs.

d. Electric Vehicles ("EV") (Electric)

Q. Is the Company proposing to modify the reconciliation mechanism for the regulatory asset associated with its EV program?

A. Yes. The ratemaking framework established in the Company's current electric rate plan, provides for the recovery of forecasted EV costs over ten years using the overall pre-tax rate of return. The EV costs are subject to a downward-only reconciliation on an annual basis. The Company proposes to modify the mechanism to apply downward reconciliation to the Company's aggregate EV spending over a three-year period (*i.e.*, 2020-2022).

e. Major Storm Reserve (Electric)

Q. Are you proposing to update the target, or base rate allowance level, for the major storm cost reserve applicable to electric operations?

A. Yes. The Company is proposing to maintain the Historic Year level of storm reserve expenditures, as increased by the general escalation factor, to arrive at the Rate Year amount.

The Company is also proposing to continue forward the major storm reserve balance. The storm reserve balance as of September 30, 2018 is approximately $7 million. In the Company's last electric base rate case, Case 16-E-0060, the Staff Accounting Panel recommended that the Company's major storm reserve balance continue forward to fund future storms, noting that "[s]ince it is difficult to predict the timing and extent of damage a major storm may inflict on the Company's operations, it is important that the Company maintain a reserve balance." The same rationale applies in this case. The Company's current storm reserve balance represents a relatively small proportion of reserve dollars initially set aside for storm recovery during the electric rate plan. In the event of another major storm event similar to winter storms Riley and Quinn, the Company could need to draw on the balance to respond effectively to the storm--particularly in light of the Company's proposal to allow it to charge the reserve for all pre-staging and mobilization costs for major storms that do not occur (discussed further below and in the testimony of the EIOP). As such, it is appropriate to continue forward the balance of the storm reserve, while maintaining the current storm reserve level, as increased by the general escalation factor.

Q. Does the Company propose a modification to the existing framework for major storm reserve costs?

A. Yes. The Company is seeking to (i) eliminate the $3.0 million annual cap associated with cost recovery for mobilization for a forecasted major storm that does not occur and (ii) remove the two percent deductible for eligible expenses. The business justification for both changes is discussed in the testimony of the EIOP.

f. Gas Service Lines (Gas)

Q. Is the Company proposing to modify the deferral of the costs associated with its implementation of a change to the gas service line definition?

A. Yes. As discussed in the testimony of the GIOSP, the costs to implement the change in gas service line definition are still uncertain. For instance, there is a NYC regulation under consideration that may impact the Company's gas inspection responsibilities. Although the Company has included an estimated amount in its gas revenue requirement, the actual amounts incurred could differ significantly given the uncertainties associated with the leakage survey and corrosion inspection requirements. As a result, the Company is proposing to modify the existing mechanism to permit the Company to reconcile fully actual expense above or below the estimated amounts.

2. New Deferral Or Reconciliation Mechanisms

Q. Does the Company propose to establish any new deferral or reconciliation mechanisms?

A. Yes. The Company proposes the new deferrals or reconciliations detailed below.

a. MTA (Electric)

Q. Do the electric revenue requirements reflect costs incurred by the Company to comply with Commission's orders in Case 17-E-0428 to safeguard and maintain adequate utility service to the subway system ("MTA-related costs")?

A. Yes. As explained in the EIOP testimony, 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." The Commission directed the Company to take actions in two orders in Case 17-E-0428, one the Commission issued on August 16, 2017 ("August Order") and a second the Commission issued on November 10, 2017 ("November Order").

Q. Did either of these Orders discuss the Company's recovery of these MTA-related costs?

A. Yes. The November Order stated as follows (p.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.

Q. What actions did the Company take in response to the November Order?

A. As provided in the November Order, the Company deferred for future recovery from customers all costs incurred pursuant to the Commission's Orders except for the capital expenditures and O&M expenses incurred by the Company to inspect, repair, replace and/or improve Con Edison facilities that were affected by the Orders, which the Company sought to accommodate within existing rate allowances.

As to the above-described work on Con Edison facilities, pursuant to the November Order's pronouncement that "[a]ny deferral will be considered in light of the level and nature of spending within existing rate allowances," capital expenditures (which amounted to approximately $30 million through RY2) were considered with the Company's other electric capital expenditures for purposes of the net plant reconciliation calculation in Rate Year 1 and Rate Year 2 under the current electric rate plan.

As to the O&M expenses incurred by the Company for the above-described work on Con Edison facilities (which amounted to approximately $1 million), the Company decided to not defer or otherwise seek recovery of these O&M expenses in this rate proceeding. Our decision should not be interpreted as the Company accepting that it is not otherwise entitled to recover these prudently-incurred costs.

Q. What is the cost of Commission-ordered work on MTA facilities that the Company proposes to recover in this proceeding?

A. During Rate Years 1, 2 and 3 of the Company's current electric rate plan, the Company expects to incur $243 million of MTA-related costs other than for work on Con Edison facilities, including interest at the Commission's Other Customer Provided Capital Rate. The Company proposes to recover these costs over a five-year period, starting in RY1, in order to mitigate customer bill impacts and further notes that this five-year period aligns with our proposed period for crediting customers with excess deferred taxes, as discussed in the Income Tax Panel's testimony.

Q. What is the basis for the Company's recovery of these costs?

A. The above excerpt from the November Order draws language directly from the "new laws" provision of the Company's current electric rate plan, which provides as follows:

> If at any time any other law, rule, regulation, *order*, or other requirement or interpretation (or any repeal or amendment of an existing rule, regulation, order or other requirement) of the federal, State, or local government or courts, including a requirement that Con Edison refund its tax exempt debt, *results in a change in Con Edison's annual electric* or *gas costs or expenses not anticipated in the forecasts and assumptions on which the rates in this Proposal are based in an annual amount, calculated and applied separately for electric and gas, equating to ten (10) basis points of return on common equity or more, Con Edison will defer on its books of account the full change in expense, with any such deferrals as credits or debits to be reflected in the next base rate case or in a manner to be determined by the Commission*. [emphasis added]

As discussed in the EIOP testimony, all of the MTA-related costs, including the work on MTA facilities, are the result of Commission-ordered actions in the August Order and November Order.

Q. Is the ten-basis point threshold applicable to any of the Rate Years under the current electric rate plan?

A. It is expected to be applicable to Rate Year 3.

Q. Please explain.

A. The Company currently expects to incur $9.1 million in MTA costs during Rate Year 3 for incidental work, which is less than the 10-basis point threshold for Rate Year 3 under the current electric rate plan (which is estimated to be $16.5 million measured at the 35 percent federal income tax rate, or $13.6 million measured at the 21 percent federal income tax rate). However, this threshold should be waived and the Rate Year 3 costs fully recovered.

Q. Why should the Commission waive the threshold for Rate Year 3?

A. The November Order specifically provides for waiver of this threshold "if Con Edison can demonstrate that it has sufficiently expedited the emergency work in a cooperative and prudent manner." As explained in the EIOP testimony, the Company met the standard established by the Order for the waiver of this threshold, as it diligently undertook efforts to expedite all MTA-related work in a cooperative and prudent manner.

b. Taxes on Health Insurance (Electric and Gas)

Q. Has the Company included any Taxes on Health Insurance in the electric and gas revenue requirements in this rate filing?

A. No. However, as discussed in the direct testimony of the Compensation and Benefits Panel, new excise taxes are scheduled to become effective under the Affordable Care Act in 2022. The excise tax is based on thresholds that are subject to change based on future Consumer Price Index changes. Due to the uncertainty in the threshold amounts, there could be considerable variation from the actual taxes incurred and the level forecasted in rates. Moreover, there continue to be attempts to overturn provisions of the Affordable Care Act through legislative or judicial action. As a result, it is possible the excise tax will not become effective at all. Given such ambiguity, a reconciliation mechanism would be appropriate in a rate plan that covers RY3 for both gas and electric service to protect the interests of both the Company and customers.

3. Terminated Deferral or Reconciliation Mechanism

Q. Does the Company propose to terminate any deferral or reconciliation mechanisms?

A. Yes. The Company proposes to terminate the deferral or reconciliation mechanisms discussed below.

a. World Trade Center ("WTC") (Electric and Gas)

Q. The current rate plans continued deferral accounting for WTC-related capital costs in excess of insurance and other recoveries. Is the Company proposing to terminate this mechanism going forward?

A. Yes. The revenue requirements in these cases do not include any deferrals or amortizations related to WTC costs as the prior amortizations have expired and no additional costs or insurance or other recoveries are projected. As a result, the Company proposes to terminate this reconciliation.

b. New York Facilities Charges – Pipeline Integrity Costs and Amended New York Facilities Agreement Reconciliation (Gas)

Q. Under the current gas rate plan, the Company reconciles the difference between revenues/payments made for pipeline integrity programs under the original New York Facilities Agreement and the amount included in gas rates. Is the Company proposing to terminate this mechanism going forward?

A. Yes. As discussed by the GIOSP, the original New York Facilities Agreement has been amended. The Company is proposing that net payments and receipts under the amended New York Facilities Agreement (including those for pipeline integrity costs) among the Company, The Brooklyn Union Gas Company d/b/a National Grid NY ("Brooklyn Union"), and KeySpan Gas East Corporation d/b/a National Grid ("Gas East"), be moved from base rates to be recovered or refunded through the MRA. As a result, the reconciliation for pipeline integrity costs will no longer be necessary. Thus, provided amended New York Facilities Agreement costs are recovered/refunded through the MRA, the Company proposes to terminate the existing reconciliation.

Q. Under the current gas rate plan, the Company is also reconciling the difference between all revenues/payments under the amended New York Facilities Agreement (including line losses) and the amount included in gas rates. Is the Company proposing to terminate this mechanism going forward?

A. Yes. As explained above, the Company is proposing that net payments and receipts under the amended New York Facilities Agreement (including those for pipeline integrity costs and line loss) among the Company, The Brooklyn Union Gas Company d/b/a National Grid NY ("Brooklyn Union"), and KeySpan Gas East Corporation d/b/a National Grid ("Gas East"), be moved from base rates to be recovered or refunded through the MRA. As a result, the reconciliation will no longer be necessary. Thus, provided amended New York Facilities Agreement costs are recovered/refunded through the MRA, the Company proposes to terminate the existing reconciliation.

c. System Peak Reduction (Electric)

Q. Under the current electric rate plan, funding for the System Peak Reduction program is subject to a downward-only reconciliation. Is the Company proposing to terminate this reconciliation going forward?

A. Yes. The Company is no longer pursuing a System Peak Reduction program. As a result, the reconciliation is no longer necessary.

d. Electric Vehicles-O&M (Electric)

Q. Under the current electric rate plan, EV O&M funding is subject to a downward-only reconciliation. Is the Company proposing to terminate this reconciliation going forward?

A. Yes. As explained in the Customer Energy Solutions testimony, the Company proposes to recover all EV program costs through the regulatory asset associated with EV programs. As a result, the EV-related O&M reconciliation is no longer necessary.

e. Gas R&D Reconciliation (Gas)

Q. Under the current gas rate plan, gas R&D funding is subject to a downward-only reconciliation. Is the Company proposing to terminate this reconciliation going forward?

A. Yes, for the reasons explained in the Shared Services Panel testimony.

XVIII. OTHER ACCOUNTING ISSUES

A. Accounting for Positive/Negative Revenue Adjustments and EAMs

Q. Is there accounting guidance necessitating accounting and ratemaking changes in this proceeding?

A. Yes. Under ASC 980, Regulated Operations, positive and negative revenue adjustments stemming from the Company's gas, electric and customer service performance mechanisms fall under the definition of alternative revenue programs. Under this guidance, the recording of deferred revenue related to alternative revenue programs may not be recorded for GAAP reporting until the collection is determined to be within 24 months from the end of the annual period in which they are recognized. As such, the Company is proposing a recovery mechanism that will allow for recording of revenues at the time the revenue adjustments are assessed (as opposed to deferral/credit until the next base rate case).

Q. What does the Company propose regarding the timing recognition of these alternative revenue items?

A. In order to resolve the timing issue described above, the Company proposes to collect future positive and negative revenue adjustments through the MAC/MRA, as applicable. The Company currently reports on whether it has met the targets in its electric, gas and customer service performance metrics in the first quarter of each calendar year and calculates whether any negative or positive revenue adjustments are appropriate. The Company's Electric and Gas Rate Panels further discuss collection of the revenue adjustments through the MAC/MRA. The collections will be subject to adjustment if the Commission determines that the Company's calculations should be corrected or if an alternative disposition is applicable.

The current rate plans indicate the Company will defer/credit any positive and negative revenue adjustments for the 2017-19 rate years and address them in the next base rate filing. For the 2017 and 2018 rate years , the Company included the credits/deferrals in these filings. For the 2019 rate year, the adjustments will not be known until RY1. As such, the Company plans to note in its annual performance mechanism reports for 2019 that, because the collection/refund will occur beyond the term of the existing rate plans, the Company will collect any revenue adjustments through the MAC/MRA.

EAMs also fall under the definition of alternative revenue programs. The Company currently collects any earned electric and gas EAMs through the MAC/MRA, respectively, within 24 months of their being earned. The Company proposes to continue the cost recovery scheme for the electric and gas EAMs as proposed in the Customer Energy Solutions Panel's testimony.

B. Property Tax Refund Sharing

Q. What do you propose regarding the sharing between the Company and its customers of any property tax savings the Company might obtain?

A. The Commission should continue the 86% customer / 14% Company sharing mechanism for property tax refunds, including credits against tax payments or similar forms of tax reductions (intended to return or offset past overcharges or payments determined to have been in excess of the property tax liability appropriate for Con Edison), net of costs incurred to achieve them, that exists under the current electric and gas rate plans with one modification. In many instances, the Company determines it is less costly (and thus better for customers) to negotiate future assessment reductions in a property tax settlement because a municipality is unable or unwilling to provide a cash refund or credit. The alternative is to pursue lengthy litigation in an attempt to obtain a refund award that could strain the municipality's finances. The nature of these reductions are fundamentally the same as cash refunds, to which the sharing mechanism plainly applies. As such, the sharing mechanism should be modified to include savings from both cash refunds/credits and reductions in future assessments. The Company's approach to calculating savings and its underlying rationale for proposing to share in such savings is explained by the Company's Property Tax Panel.

This modification to the tax sharing mechanism is consistent with established Commission practice to incent utilities to pursue property tax reductions. Moreover, as explained by the Company's Property Tax Panel, the Company's recent property tax settlements have produced material future benefits for customers.

Q. The Company is also proposing full reconciliation of property taxes for both gas and electric operations. How would this sharing mechanism operate in conjunction with those reconciliation mechanisms?

A. During the term of the rate plans, the Company will pass the benefit of any credit/reduced tax assessment to customers through the full reconciliation mechanisms. When base rates are reset, the full benefit of any continuing lower assessments would be passed through to customers because it is captured in the Test Year data and reflected in the Company's forecasts.

Under the sharing mechanism, the Company will receive 14 percent of any credit in the year the credit is received. In the case of an annual reduction in property taxes under a settlement agreement, the Company will receive the 14 percent share for the term of the settlement agreement. The Property Tax Panel explains that this will put the Company in the same position regardless of the form of tax relief - a one time credit or reduced assessments over a longer period of time. This will incentivize the Company's to continue to aggressively pursue tax reductions that benefit customers without litigation, when appropriate. In order to share in the value of the reduced assessment (as well as demonstrate their actual receipt), the Company will file a petition and make annual compliance filings, as described in the testimony of the Property Tax Panel.

XIX. MULTI-YEAR RATE PLAN

Q. Has the Company included forecasted financial information for periods beyond the Rate Year in its filing?

A. Yes. The Company has included, for illustrative purposes only, financial information for two annual periods beyond the Rate Year. Details of the revenue requirement for the Rate Year and the two following twelve-month periods, ending December 31, 2021, and December 31, 2022, are presented within Exhibits AP-3.

Q. What is the basis of the financial information presented in Exhibits AP-3?

A. Various Company witnesses have presented forecasts extending beyond the Rate Year. There are also proposals by various witnesses, including the Accounting

Panel, which would affect periods beyond the Rate Year, such as amortization periods for deferred costs and credits.

Q. Is the Company proposing a multi-year rate plan for adoption by the Commission?

A. No. This filing seeks Commission approval of what is commonly referred to as "one-year rates" for electric and gas services. The Company is, however, interested in pursuing, through settlement discussions with Staff and interested parties, multi-year rate plans.

XX. FINANCE BCO

Q. In your testimony above, you discussed the Company's efforts to mitigate the cost of providing electric and gas service by implementing the BCO Program. Please discuss the general type of costs that the Finance organization incurs and how it developed its BCO Program initiatives.

A. The majority of costs incurred by the Finance organization are O&M expenses; Company labor accounts for approximately 90 percent of these expenses. The Finance organization incurs a relatively small amount of other non-labor O&M, as well as capital expenditures related to periodic upgrades and enhancements of the Company's financial systems *(e.g.*, Oracle Finance and Supply Chain, PowerPlan Fixed Assets software, PowerTax,). Generally, these capital expenditures relate to projects involving outside contractors. For the BCO Program, we therefore focused our efforts on identifying opportunities to reduce labor expenses within the Finance organization.

Q. Please describe the main BCO cost reduction opportunities that you identified.

A. We identified opportunities to realign our organizational structure, streamline existing processes, and automate many manual functions. We undertook an assessment of the Financial Planning and Analysis ("FP&A") department's functions, including opportunities to reorganize the department to optimize its performance. This effort evaluated work functions and processes, organizational structure and resource capability, as well as the technology and systems employed by FP&A. Through this effort we were able to identify various improvements that would streamline FP&A, including the execution of more efficient and effective processes. For example, after analyzing the reports produced by FP&A, we were able to reduce the number of reports, as well as the effort required for management reporting on a weekly and monthly basis. We improved upon our forecasting process, by reducing forecasting time and effort by setting clearer process roles and responsibilities. We also eliminated redundant forecasting-related activities.

The Finance organization has also launched a project to implement Robotic Process Automation software capable of performing manual, routine tasks. Our initial scope includes the automation of setting up projects in our financial systems, processing transfers and corrections, sending hold receipt notifications, and reviewing the application of sales tax on Company purchases.

In addition, we engaged in an effort to review and rationalize the inventory of key controls that the Company audits and tracks pursuant to SOX requirements. This enabled our Auditing department to streamline its audit plan for 2019 and to focus on higher risk areas, thereby reducing the audit effort in the process.

Finance organization cost savings are expected to materialize through lower staffing requirements. For each BCO cost savings opportunity, we assessed the current employee effort required to complete the identified activities, then estimated the future employee effort that will be required upon the implementation of all our planned organizational, process, and technology improvements. We based the cost savings amount on the difference between the current and future number of employees, priced out at an average salary for the Finance organization.

Q. What challenges does the Finance organization face in implementing these changes and realizing their cost reduction opportunities?

A. Over the past several years, the Company's implementation of enterprise-wide systems -- such as PeopleSoft Human Resources and Payroll, Oracle Finance and Supply Chain, and PowerPlan Fixed Assets -- allowed us to reduce headcount in many areas of the Finance organization. Each incremental future headcount reduction requires relatively more effort and time to achieve.

Moreover, as discussed further in Section IV of this testimony, many BCO cost savings are tied to changes in how labor is organized and deployed and the timing of when the Finance organization will realize the associated cost savings is uncertain. Whether a cost reduction opportunity is tied to a change in organizational structure, process redesign, work elimination, or activity automation, the cost savings associated with each opportunity cannot be realized until the employees related to that opportunity have been redeployed in some manner. Positions must be available for these employees to be re-assigned to, and employees who are being re-assigned to other work likely need to be trained and transitioned prior to assuming their new positions. These factors will affect the timing of cost savings.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DEPRECIATION PANEL

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Would each member of the Depreciation Panel please state their name and business address?

A. My name is Matthew Kahn. My business address is 4 Irving Place, New York, New York.

My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. Mr. Kahn, by whom are you employed and in what capacity?

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") and, for Con Edison and its regulated affiliates, I manage the functions related to book and tax depreciation. I also support the income tax compliance and accounting functions for Con Edison and its regulated affiliates.

Q. Mr. Kahn, please briefly outline your educational background and business experience.

A. I graduated from Bentley College (now Bentley University) in 2004 with an undergraduate degree in accounting, and completed a master's degree in taxation at Bentley University in 2010. I have been employed by Con Edison since 2010. Prior to my employment at Con Edison, I worked in various roles within the accounting industry and in the field of taxation with PricewaterhouseCoopers, LLC, and subsequently as an analyst with American Tower Corporation. I am a member of the Society of Depreciation Professionals ("SDP").

Q. Mr. Allis, by whom are you employed and in what capacity?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"), where I am Vice President. I am responsible for conducting depreciation, valuation and original cost studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies. I am also responsible for Gannett Fleming's proprietary depreciation software, training of depreciation staff, and the development of solutions for technical issues related to depreciation.

Q. Mr. Allis, please briefly outline your educational background and business experience.

A. I have a Bachelor of Science degree in Mathematics from Lafayette College in Easton, PA. I am a member of the SDP and am the current president of SDP. I am certified as a depreciation expert by the SDP, which has established national standards for certification via an examination that I passed in September 2011. I was re-certified as a depreciation professional in March 2017.

I became employed by Gannett Fleming in October 2006 as an Analyst. My duties included assembling basic data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. In March 2013, I was promoted to the position of Supervisor, Depreciation Studies. In March 2017, I was promoted to Project Manager, Depreciation and Technical Development. In January 2019, I was promoted to my current position of Vice President.

Q. Have any members of the Depreciation Panel previously testified before any utility commission on the subject of utility plant depreciation?

A. **(Kahn)** Yes. I have testified on the subjects of depreciation and income tax before the New York Public Service Commission (“Commission”) on behalf of Con Edison and its affiliate, Orange and Rockland Utilities, Inc. (“O&R”).

(Allis) I have testified on the subject of depreciation before the Commission, the Florida Public Service Commission, the Nevada Public Utilities Commission, the District of Columbia Public Service Commission, the New Jersey Board of Public Utilities, the California Public Utilities Commission, the Connecticut Public Utilities Regulatory Authority, the Rhode Island Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC").

Q. What is the purpose of your direct testimony in this proceeding?

A. The Depreciation Panel's direct testimony:

- Presents the depreciation study performed by Gannett Fleming for the Company's electric, gas and common plant;
- Presents annual depreciation accruals based on the Company's existing rates, as well as the depreciation rates recommended in the depreciation study;
- Identifies the Accumulated Provision for Depreciation recorded on the Company's books ("book reserve") at December 31, 2017, the computed reserve (also referred to as the "theoretical reserve" or "calculated accrued

depreciation") based on existing depreciation factors, and the computed reserve based on the recommended depreciation factors for electric, gas and common plant;and

- Discusses the reserve variations for the Company's electric and gas accounts and presents a recommendation for addressing the Company's electric and gas book depreciation reserve deficiencies.

Q. Is the Depreciation Panel sponsoring any exhibits in these proceedings?

A. Yes, the Depreciation Panel is sponsoring the following three exhibits, all of which were prepared under the Depreciation Panel's supervision and direction:

- Exhibit ___ (DP-1) entitled: "Consolidated Edison Company of New York, Inc., Depreciation Study, Electric, Gas and Common Plant as of December 31, 2017" ("Depreciation Study");
- Exhibit ___ (DP-2) entitled: "Consolidated Edison Company of New York, Inc., Electric, Gas and Common Plant, Summary of Annual Depreciation Rates at December 31, 2017;" and

- Exhibit ___ (DP-3) entitled: “Consolidated Edison Company of New York, Inc., Summary of the Computed Reserves for Depreciation at December 31, 2017.”

Q. Are there any subjects addressed in the Depreciation Panel’s testimony that are not, and should not be construed to be, testimony by all members of the Panel?

A. Yes. The Company has taken various steps in this filing to mitigate the rate request, and one of those steps is to not request any changes to the Company’s current depreciation rates. Additionally, the Company’s proposed treatment of reserve deficiencies has also been moderated to mitigate the overall rate request. For purposes of the initial filing in these proceedings, the Company has considered these subjects to be within the sole purview of Company management as ratemaking approaches rather than depreciation study subjects. Mr. Allis and Gannett Fleming Valuation and Rate Consultants, LLC have no responsibility for the Company’s decisions on these subjects as filed in these proceedings whether in testimony, discovery responses or pleadings of any nature and express no view on them.

Q. Please summarize the Company's proposed changes to depreciation expense levels for the twelve months ending December 31, 2020 (the "Rate Year").

A. As detailed below, the Depreciation Study supports a $133 million increase in electric depreciation expense and a $41 million increase in gas depreciation expense for the Rate Year. However, in order to facilitate the resolution of the issues in these proceedings and mitigate the impact of the rate increases on customers, the Company's filing applies existing rates to establish the depreciation expense level in the Rate Year. In addition, the Company has reflected increases to the depreciation expense for electric and gas in the amounts of $20 million, and $8 million.

Q. Please describe the nature of the increases to depreciation expense.

A. These proposed increases reflect a $20 million recovery of reserve deficiencies for electric and an $8 million recovery of reserve deficiencies for gas.

Q. Are these proposed increases to address the reserve deficiencies consistent with the results of the depreciation study performed by the Company in this rate proceeding?

A. No. The results of the depreciation study, which are more fully described below, would have resulted in greater increases to the depreciation expense in the Rate Year. However, in an effort to facilitate the resolution of the issues in these proceedings and mitigate the impact of the rate increases on customers, the Company's proposes to address only a portion of the reserve deficiencies for electric and gas.

Q. What is the Company's proposal for the electric reserve deficiency amortization?

A. For electric, the Company proposes to address in this rate filing only 4.5 percent of the deficiency, as calculated by the depreciation study, over a 20 year amortization. With this approach, the Company will recover approximately $404 million of the reserve deficiency over a 20-year period (approximately $20 million annually) if there were no changes in future rate years.

Q. What is the Company's proposal for the gas reserve deficiency amortization?

A. For gas, the Company proposes to address in this rate filing only 9 percent of the deficiency, as calculated by the depreciation study, over a 20 year amortization. With this approach, the Company would recover approximately $159 million of reserve deficiency over a 20-year period (approximately $8 million annually) if there were no changes in future rate years.

Q. Are these amounts replacing the amortizations of reserve deficiency previously approved by the Commission and reflected in the Company's electric and gas rates?

A. No. In the Company' current electric rate case (Case 16-E-0060), the Commission approved annual amortizations in the amount of $11.6 million for electric reserve deficiency and an additional $3.8 million specific to Hudson Avenue. The Company's proposed $20 million amortization will be an incremental increase to these amounts. There is no current amortization of reserve deficiency for gas.

II. DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the Company is not protected by insurance. Among the causes to be given consideration under the Uniform System of Accounts are wear and tear, decay, and action of the elements, inadequacy, obsolescence, “changes in the art,” changes in demand and the requirements of public authorities.

Q. Who performed the Depreciation Study?

A. The Depreciation Study was performed on behalf of the Company by Gannett Fleming under the direction of Mr. Allis.

Q. In preparing the Depreciation Study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Are the methods and procedures used in the Depreciation Study consistent with the Company’s past practices?

A. Yes. The methods and procedures used to calculate annual depreciation rates and accruals in the Depreciation Study are consistent with those employed in the Company’s past depreciation studies, as well as depreciation studies presented by other utilities in rate proceedings before the Commission. The

Depreciation Study used the straight line method and the broad group average service life procedure using the whole life technique. For mass property accounts, we used survivor curves to estimate service lives. The Company uses the life span method, in which survivor curves are truncated at the date of probable retirement, for the Company's electric production and gas liquefied natural gas ("LNG") plants. The Company used the life span method in the depreciation study it submitted in the Company's previous base rate cases and for the Company's current depreciation rates.

Q. Please describe the presentation of the Depreciation Study in your exhibits.

A. The Depreciation Study in Exhibit ___ (DP-1) is presented in nine parts. Part I, Introduction, presents the scope and basis for the Depreciation Study. Parts II through V include descriptions of the methods and procedures used for the estimation of survivor curves and net salvage, and the calculation of annual depreciation and the theoretical reserve. Part VI, Results of Study, presents a description of the results and a summary of the depreciation calculations. Parts VII through IX present graphs and tables relating to the service life analyses, the net salvage analyses and the detailed depreciation calculations.

The tables on pages VI-4 through VI-7 of Exhibit ___ (DP-1) present, for each plant account or subaccount, the estimated survivor curve, the net salvage percent, the original cost of plant and the book depreciation reserve at December 31, 2017, and the calculated annual depreciation accrual and applicable depreciation rate. The section beginning on page VII-1 presents the results of the retirement rate analyses prepared as the historical bases for the average service life estimates. The section beginning on page VIII-1 presents the results of the net salvage analysis. The section beginning on page IX-1 presents the depreciation calculations related to surviving original plant cost as of December 31, 2017. We note that common plant is presented at 100% in this exhibit rather than at the allocated electric and gas levels.

Q. Please explain how Gannett Fleming performed the Depreciation Study.

A. The Depreciation Study used the straight line whole life method of depreciation, with the broad group average service life procedure. The annual depreciation rates and accruals recommended in the

Depreciation Study are based on a method of depreciation accounting that seeks to distribute the service value (*i.e.*, original cost of plant assets plus estimated costs of removal less estimated salvage at the time of retirement) over the estimated useful life of each unit, or group of assets, in a systematic and rational manner.

Q. How did you determine the recommended annual depreciation accrual rates?

A. We first developed estimates of the average service life and net salvage factors that were determined for each depreciable group - that is, each plant account or subaccount identified as having similar characteristics. We then calculated the annual depreciation accrual rates using the applicable average service lives and net salvage factors.

Q. What part does the average service life play in the determination of depreciation rates?

A. The estimated average service life is the period (*i.e.*, number of years) over which the original cost of plant should be depreciated. For example, with an average service life of 25 years, using the whole life technique, annual depreciation is 1/25th, or 4%, of the original cost of the plant before taking into account the net salvage factor.

Q. What is the effect on annual depreciation expense of a change to an average service life?

A. The depreciation expense accrual varies inversely with the underlying average service life. All else equal, the longer the average service life, the lower the annual depreciation rate and therefore the lower the annual depreciation expense. Conversely, the shorter the average service life, the higher the annual depreciation rate, and therefore, the higher the annual depreciation expense.

Q. What part does net salvage play in the determination of depreciation rates?

A. Depreciation is intended to recover the full cost of the Company’s assets over the period of time they are providing service. The full cost of an asset includes both the original cost when the asset was installed and the net salvage at the end of the asset’s life. Thus, in addition to providing for recovery of the original cost of plant over its estimated average service life, annual depreciation rates include an estimated net salvage factor. The purpose of this estimated net salvage factor is to reflect, over the life of the plant, the expected gross salvage value of plant less the expected cost of removal upon retirement. With very few exceptions, most plant assets result in negative net salvage upon retirement with removal costs exceeding salvage value. Salvage and removal cost values are netted and expressed as a percentage of original cost of plant and included in the annual depreciation rate. As a result, and in accordance with basic depreciation principles and the Commission's Uniform System of Accounts, the service value of an asset, which is the original cost of the asset along with the expected net salvage value, is allocated evenly over the estimated useful life of the asset.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the average service life and net salvage factor for each plant account or subaccount.

A. The average service life and net salvage study consisted of compiling historical data from records related to the Company's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; making visits to various sites to view the physical condition of facilities; and interpreting these data and information along with the average service lives and net salvage factors used by other utility companies to form judgments of average service lives and net salvage factors applicable to the Company's plant and equipment.

Q. You mentioned that in preparing the Depreciation Study, members of the Depreciation Panel visited certain Company facilities. What is the significance of these visits?

A. Field reviews of property as part of the Depreciation Study were performed during December 2018. Field reviews were also conducted for the Company's previous depreciation study during November 2014 and October 2015. Depreciation studies should not be limited only to statistical analysis or visual comparisons of smoothed survivor curves to the historical data because other factors also need to be considered. Informed judgment should be used for the process of fitting survivor curves to the historical data and estimating net salvage, and knowledge of the property studied forms an important component of this judgment.

Field reviews, including discussions with operating and engineering personnel, are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. What historical data did the Company analyze for the purpose of estimating survivor curves, from which average service lives are derived?

A. The Company analyzed accounting entries that record plant asset transactions during the period 1938 through 2017. The transactions included additions, retirements, transfers and the related balances.

Q. What method did the Company use to analyze these data?

A. The Company used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the Depreciation Study. It is also the method the Company used in its past depreciation studies and is the predominant approach used in depreciation studies across the country when aged data is available.

Q. Please describe how the retirement rate method was used to analyze the Company's service life data.

A. The Company used the retirement rate method to analyze each different group of property (generally a particular plant account) in the study. For each property group, the Company used the retirement rate method to form life tables which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating future average service lives. We used standard survivor curves, such as the Iowa-type survivor curves and the h-system of survivor curves, to perform these interpretations.

Q. What is an "Iowa-type survivor curve" and how can such curves be used to estimate the average service life characteristics for each property group?

A. Iowa-type survivor curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa-type survivor curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa-type curves can be used to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode.

Q. What is the mode?

A. The mode describes the height of the frequency curve, which is a plotting of the percentage of assets retired in a given year. The lower the mode, the wider the dispersion pattern for the survivor curve (*i.e.*, a smaller percentage of retirements will occur at ages closer to the average service life). The higher the mode, the more narrow the dispersion pattern for the survivor curve (*i.e.*, a larger percentage of retirements will occur at ages closer to the average service life).

Q. Now that you have explained mode, please provide examples of what the designation means.

A. Iowa 50-R1.5 indicates an average service life of fifty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 1.5, for the mode (possible modes for R type curves range from 0.5 to 5).

We more fully describe survivor curves in Part II of Exhibit ___ (DP-1).

Q. What is the “h-system” of survivor curves?

A. The h-system of survivor curves was developed in 1947 by Bradford Kimball of the Commission. Similar to the Iowa curves, the h-curves are labeled in accordance with the relative height of the modes of the associated retirement frequency curves. Thus, for example a 50-h3.0 indicates a 50-year average service life and a mid-mode curve (modes for the h-system curves range from 0.0 to 5.0).

Q. What type of survivor curves did you use for the Depreciation Study?

A. For the Depreciation Study, we used Iowa type survivor curves. This represents a change from the h-type curves used in the Company's previous depreciation study. However, the Iowa curves are, to our knowledge, used in every U.S. jurisdiction, including in New York by O&R, Central Hudson Gas and Electric, Rochester Gas and Electric, New York State Electric and Gas, National Fuel Gas and Niagara Mohawk. In contrast, the h-curves, to our knowledge, are not used anywhere outside of New York. Further, the h-curves tend to have long "tails," meaning that these curves forecast that a portion of property will survive much longer than the average service life of a given depreciable group. These types of life characteristics are not common for most types of utility property. In part for this reason, the Iowa curves typically provide a more reasonable retirement dispersion pattern for most types of utility assets.

Q. What approach did you use to estimate the lives of significant facilities such as production plants?

A. We used the life span method to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. The life span method was used for electric production plants and the gas LNG facility. In this method, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as the retirements of piping, pumps, boiler tubes, and turbine blades that occur during the life of a facility such as a power plant. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the multiple years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. Has the Company previously used the life span method?

A. Yes. The Company used the life span method for the same facilities as in the Company's previous depreciation study. The life span method has been accepted by many public utility commissions across the United States and Canada, including the Commission.

Q. What are the bases for the probable retirement dates that you have estimated for each facility?

A. The bases for the probable retirement years are life spans for each facility, which are based on judgment that reflects consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other utilities for similar facilities. For certain facilities, the life spans result in probable retirement years that are many years in the future. The retirements of these facilities are not yet subject to specific management plans, as such plans would be premature. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the facility may be performed and the results incorporated in the estimation of the facility's life span.

However, in order to allocate the costs of these facilities properly, a probable retirement date must be estimated based on the information available today.

Q. Are the recommended life spans similar to those the Company used in the depreciation study it submitted in its previous rate cases?

A. Yes. For electric steam production and gas LNG accounts, the recommended life spans are the same as those used in the previous depreciation study. For electric other production accounts, the life spans have been modified somewhat to incorporate the current outlook for the Company's electric peaker generation facilities.

Q. Is the life span method consistent with the whole life technique?

A. Yes. The life span method is a method of determining the average service life and dispersion pattern for each vintage of plant within a depreciable group. This method can therefore be used with either the whole life or the remaining life technique. When using the life span method with the whole life technique, as is used in the Depreciation Study, the average service life is calculated for each vintage based on the estimated retirement date and interim survivor curve. The average service life is then used to calculate depreciation expense.

Q. Please provide an example of how the annual depreciation accrual rate for a particular plant account is presented in the Depreciation Study.

A. We will use electric plant Account 367, Underground Conductors and Devices, as an example because it is the largest depreciable account.

The Company used the retirement rate method to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1938 through 2017 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1938-2017 and 1978-2017 experience bands are presented on pages VII-84 through VII-91 of Exhibit ___ (DP-1). The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-84 shows $60,901,042 retired at age 0.5 years with $7,078,876,479 having been exposed to retirement. Consequently, the retirement ratio is 0.0086 ($60,901,042/$7,078,876,479) and the survivor ratio is 0.9914 (1 – 0.0086). These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 50-R0.5 on page VII-83.

The calculation of the annual depreciation accrual and the theoretical reserve related to the original cost of plant for Account 367 at December 31, 2017 is presented on pages IX-58 through IX-61. The calculations are based on the 50-R0.5 survivor curve and 90% negative net salvage factor, and the attained age for each vintage. The tabulation sets forth the installation year, the original cost, average service life, calculated annual depreciation rate and accrual, average remaining life, and calculated accrued depreciation factor and amount (that is, the theoretical reserve ratio and theoretical reserve).

The total annual accrual of $240,270,815 and theoretical reserve of $2,097,947,790 for the account are brought forward to the table on page VI-5. The reserve variation of negative $864,053,940 shown on page VI-5 is calculated by subtracting the $2,097,947,790 theoretical reserve from the book reserve for the amount of $1,233,893,850. A negative variation indicates that there is a book reserve deficiency for this account.

Q. Please describe how the Company determined the net salvage factors.

A. The Company determined the net salvage factors using informed judgment that considered relevant factors such as the results of historical net salvage analyses, the existing net salvage rates in effect, the Company's current practices with regard to net salvage and the net salvage factors used by other electric companies.

Q. Please describe the statistical net salvage analyses.

A. In the statistical net salvage analyses, net salvage is expressed as a percentage of the book cost of plant retired by calendar year. The analysis of historical net salvage as a percentage of the book cost of plant retired provides a statistical basis for the level of net salvage that can be expected to occur in the future. Thus, consistent with well-established industry practices, we have made estimates of net salvage expressed as a percentage of original plant cost retired that are based on informed judgment that incorporates the net salvage analyses.

Q. Are the net salvage analyses and approach you used to reflect net salvage in depreciation rates consistent with authoritative depreciation texts?

A. Yes. The National Association of Regulatory Utility Commissioners' *Public Utility Depreciation Practices* ("NARUC") and Wolf and Fitch's *Depreciation Systems* ("Wolf and Fitch") are well-regarded texts that are considered to be authoritative depreciation sources by depreciation professionals. These texts describe the method of estimating net salvage and explain that expected net salvage at the time of retirement of plant assets is expressed as a percentage of original cost of the plant that will be retired and is estimated using the same methods we have employed. Moreover, the Commission's Uniform System of Accounts requires that the service value (*i.e.*, original cost less net salvage) of the Company's assets be allocated in a systematic and rational manner over the assets' service lives. The method of estimating net salvage we have used is consistent with this requirement.

Q. Are the methods the Company used in the Depreciation Study for the net salvage analyses widely accepted in the industry?

A. Yes. The net salvage analysis the Company used in the Depreciation Study is explained in authoritative texts on depreciation and is used almost exclusively in the utility industry. In the vast majority of jurisdictions, a portion of depreciation expense includes a provision for the prospective recovery of future net salvage over the service life of the underlying assets, and the net salvage factors are estimated using the same methods used in the Depreciation Study submitted by the Company in these proceedings. This is consistent with the Commission's Uniform System of Accounts, depreciation texts such as *Public Utility Depreciation* Practices and *Depreciation Systems* and ratemaking practices used by most state and federal regulatory commissions.

Although other approaches have been proposed in New York, the Commission has traditionally followed the predominant approach by including a net salvage factor in depreciation rates with the net salvage factor being based on the same methods as used in the Depreciation Study. This methodology achieves the objective of allocating the estimated net salvage value expected at the time of retirement of plant assets over the estimated useful lives of the assets in a systematic and rational manner.

III. HISTORICAL TREATMENT OF RESERVE DEFICIENCIES

Q. Please provide background information on depreciation reserve variations.

A. In order to test the adequacy of the book reserve for depreciation, the Company compared the book reserve at year-end to a theoretical reserve calculated using average service lives, survivor curves and net salvage factors based on the Depreciation Study. The results of that comparison are summarized in Exhibit ___ (DP-3) and discussed later in this direct testimony. The variation between the book and theoretical reserves can be expressed both in total dollars and as a percentage of the theoretical reserve. Results of such a study can indicate either a positive variation (sometimes referred to as a "book reserve excess") or a negative variation (sometimes referred to as a "book reserve deficiency"). For example, a book reserve of $190 and a theoretical reserve of $200 would result in a book reserve deficiency of $10, or 5%.

Q. What factors could lead to a book reserve deficiency?

A. The deficiency may be the result of historic depreciation rates set at a level lower than required to provide for the level of annual depreciation expense necessary to match actual experience. Reasons for "inadequate" depreciation rates can be average service lives that are too long to recover the plant at a fast enough rate, and thus do not allow for the timely recovery of the investment, or a negative net salvage component of the depreciation rate that does not provide an adequate level of recovery for removal costs. In addition to service lives and salvage factors, the actual dispersion of retirements (*i.e.*, when retirements occur in relation to average service lives) may have changed or varied from the historical pattern that led to the selection of the survivor curves being used.

Q. Is it common to have a reserve variation?

A. Yes. Service life and net salvage estimates can change over time, and these estimates are updated when a new study is performed. It is expected that there will be some variation between the book and theoretical reserves. However, because New York uses whole life rates, rather than remaining life depreciation rates (which automatically correct for any reserve variations), corrective action is often required. At a minimum, corrective action should be taken when the variation is large. In New York corrective action has typically been taken when the variation exceeds 10% of the theoretical reserve. The objective of depreciation is to allocate the cost of plant and the expected future costs to remove it over the time the plant is used to provide utility service. When that is accomplished, customers pay only for the cost of plant they have “consumed” when taking service. With a reserve deficiency, future customers will be required to pay for any historic shortfall in depreciation expense.

Q. Is there a book reserve deficiency related to the Company’s electric, gas and common plant?

A. Yes. There is a reserve deficiency for electric, gas and common plant.

Q. Has the Commission previously taken action to address the large and persistent reserve deficiency for the Company’s electric plant?

A. Yes, but only for a portion of the deficiency. In Case 07-E-0523, due to concern about the potential size of the rate increase, the Commission, in its Order Establishing Rates for Electric Service (issued March 25, 2008), stated (p. 75) it would “limit the recovery of the depreciation reserve deficiency to a 15-year amortization of $162.5 million which is the amount in excess of the minus 10% level of the tolerance band that we have traditionally employed to measure the significance of reserve deficiencies.” The Commission employed a similar approach in Case 09-E-0428 when an incremental amount of deficiency was again set for amortization and recovery as a result of the settlement of issues in that case.

The Company's most recent case that included a depreciation study (Case Nos. 16-E-0060 and 16-G-0061) resulted in a settlement. That settlement agreement resulted in an annual amortization of approximately $11.6 million for electric service (plus an annual amortization of approximately $3.8 million for the unrecovered costs of the Hudson Avenue Station). No amortization for gas service resulted from that settlement.

Q. What has been the result of the approach to the Company's reserve deficiencies that the Commission has adopted in previous proceedings?

A. Because the Company's reserve deficiencies have not been adequately addressed, they have continued to increase. Figures 1 and 2 below show the reserve deficiencies resulting from the three most recent depreciation studies (including the current study) and illustrate that the reserve deficiencies have grown significantly (*i.e.*, the reserve variations have become more negative) from 2011 to 2017. For electric service, the reserve deficiency has grown from approximately $680 million to $2.8 billion since 2011. For gas service, the reserve variation has changed from a $92 million reserve “excess” to a $380 million reserve deficiency over the same period. For both gas and electric service, the reserve deficiencies have grown as a percentage of the theoretical reserve, as well as in absolute dollar amounts.

Figure 1: Electric Plant Reserve Variations

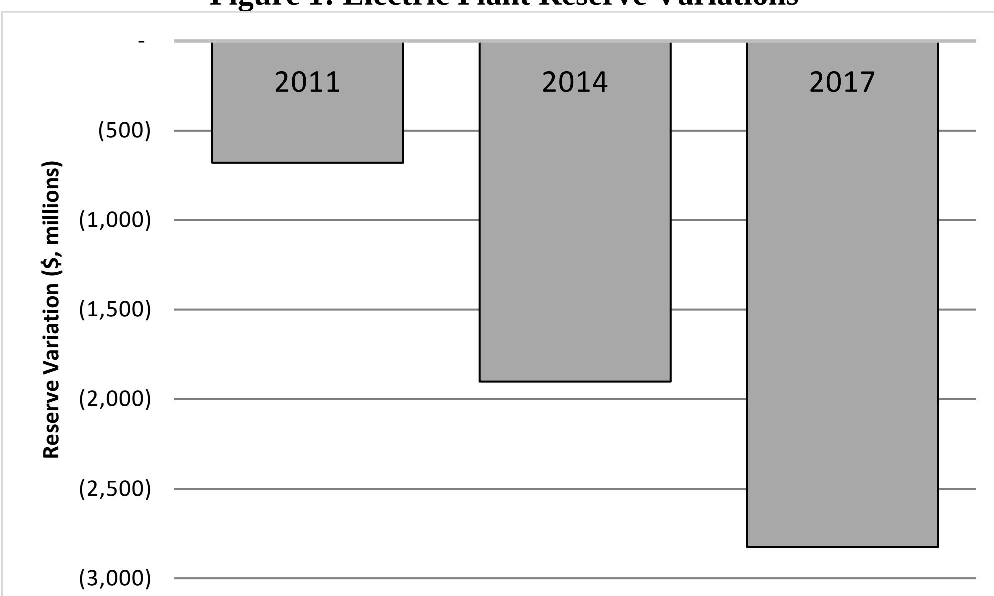
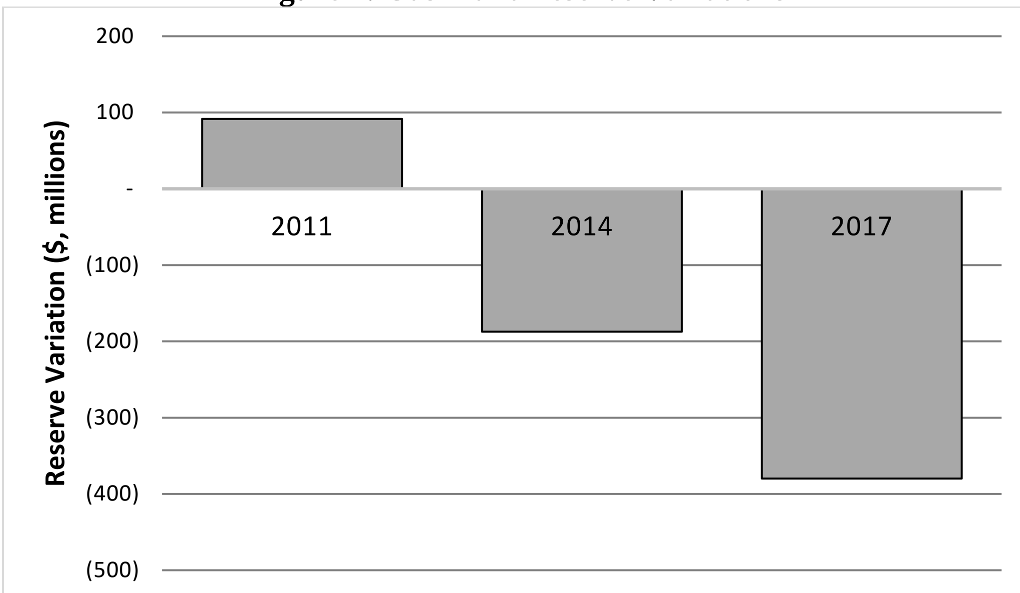


Figure 2: Gas Plant Reserve Variations



Q. Given the growth in the reserve deficiencies for both electric and gas service, it is important that the Commission address reserve deficiencies?

A. Yes. It is important to keep in mind that because depreciation is largely an issue of the timing of cost recovery , deferring the recovery of reserve deficiencies does not reduce rates in the long run. Rather, by pushing costs out into the future, depreciation deferrals increase costs in the long run. This is both because more costs need to be recovered through depreciation or amortization of reserve deficiencies in the future. In addition, because accumulated depreciation is a reduction to rate base, customers pay a return on any reserve deficiencies, which is an increase to cost in both the short and long run.

Based in part on these concepts, we recommend addressing reserve deficiencies over the remaining lives of the Company’s assets. Our recommendation for addressing the reserve deficiencies will be discussed in more detail in the next section.

IV. TEST OF THE BOOK RESERVES

Q. Have you compared the book and theoretical reserves as part of your analyses for this proceeding?

A. Yes. Using data as of December 31, 2017 we determined that a large electric plant book reserve deficiency, which has been persistent for the last 15 years, has grown. The Depreciation Study also estimates that gas and common plant have reserve deficiencies.

Q. Please describe the results of your analyses comparing the book reserves and theoretical reserves.

A. For each type of plant there is a book reserve deficiency because the accumulated depreciation reserve per books for each service is less than the related theoretical reserve.

As shown on Exhibit ___ (DP-3), as of December 31, 2017, at existing depreciation rates, the total reserve deficiency for electric plant is approximately

$1,145.9 million and the reserve deficiency for gas plant is approximately $90.9 million. Common plant at existing depreciation rates indicates a reserve excess of $34.1 million. Those amounts may also be expressed as a percentage of the theoretical reserves and equate to book reserve deficiencies of 15.71% and 6.06% for electric and gas plant, respectively.

Q. In your judgment, does the reserve deficiency based on existing depreciation rates reasonably reflect the magnitude of the existing deficiency?

A. No. Based on the results of the Depreciation Study, we find the deficiency as calculated on that basis to be understated for all types of plant. The Depreciation Study shows that the total book reserve deficiency for electric plant is approximately $2,824.4 million, the total book reserve deficiency for gas plant is approximately $380.7 million, and the total book reserve deficiency for common plant is approximately $60.3 million as of December 31, 2017. Expressed as a percentage of the theoretical reserves, the variations equate to book reserve deficiencies of 31.47%, 21.23%, and 7.42% for electric, gas, and common plant, respectively. We note that the reserve deficiency for electric plant includes approximately

$72.8 of unrecovered costs for Hudson Avenue, which are recovered through a separate amortization of $3.8 million per year.

Q. What does the Depreciation Study show are the major drivers of the reserve deficiency being higher than that which would be calculated using currently effective depreciation rates?

A. The drivers of the increase in the reserve deficiency are service lives, survivor curves and net salvage factors that that differ from those adopted in Cases 16-E-0060 and 16-G-0061. The Depreciation Study demonstrates the need for higher negative net salvage factors for many of the Company’s electric and gas plant accounts. A higher negative net salvage factor results in a higher theoretical reserve and, consequently, a greater reserve deficiency. In addition, our analyses of the data indicate that for many accounts, changes toward shorter average service lives, appropriate Iowa curves, or a combination of both, are appropriate. Many of these changes result in a higher reserve deficiency.

Q. Would continuing the current depreciation factors, rather than revising them in order to reduce the electric and gas book reserve deficiencies, be an appropriate approach?

A. No. As we have explained earlier in our testimony, there are certain accounting and ratemaking objectives associated with establishing depreciation factors. In order to meet these objectives, depreciation factors should be updated to incorporate the results of the most recent depreciation study. Reserve imbalances need to be corrected based on rates that appropriately allow for full recovery while the underlying assets are providing utility service. The failure to make such corrections leads to intergenerational inequity by causing customers in the future to pay for assets being consumed by current customers.

Q. What do you conclude as a result of your depreciation reserve analyses?

A. These analyses indicate that a more effective approach to addressing the book reserve deficiency is needed. As indicated earlier, the Commission has previously recognized and taken steps to address the persistent depreciation reserve deficiency by providing for limited recovery over a relatively short time period. A long-term solution is required in order to first relieve the Company of the burden of carrying costs that should have been recovered in the past and relieving customers of the burden of paying carrying costs on the unrecovered costs that remain in rate base. The sooner that first step is accomplished the better for future customers. After fully addressing the recovery of the existing deficiency, a second step to remediate the potential for additional future deficiencies will be for the Company to propose depreciation rates under a remaining life technique in a future base rate proceeding, rather than continuing to use a method based on the whole life technique. The remaining life technique is used by the majority of jurisdictions in the United States. Under the remaining life technique, any reserve variation is effectively amortized automatically over the remaining life of each depreciable group. Such a practice avoids determining reserve variations each year because the applied depreciation rate trues-up annual depreciation expense for unrecovered costs (unlike the whole life technique).

Q. Please summarize the Panel's recommendation regarding the book reserve deficiencies in these proceedings.

A. The Company's Depreciation Study recommends that the reserve deficiency of $2,751.6 million for electric plant exclusive of Hudson Avenue (*i.e.*, the $2,824.4 million reserve deficiency less the $72.8 million reserve deficiency for Hudson Avenue) be amortized over the remaining life of electric plant (*i.e*., 41.9 years). For gas plant, the Depreciation Study recommends that the reserve deficiency of $379.7 million be recovered over the remaining life of gas plant (*i.e*., 58.3 years). The recommendation for common plant is that the Commission take no remedial action addressing the reserve deficiency at this time because the amount of the deficiency is within the 10% range of variation that has been considered acceptable and reasonable in New York.

Q. Is it common to amortize a book reserve deficiency over the plant’s remaining life?

A. Yes. The remaining life amortization period is one of the generally accepted approaches to addressing a book reserve deficiency.

VI. CONCLUSION

Q. Please summarize the depreciation results.

A. The depreciation rate changesare summarized on Exhibit ___ (DP-2) and Exhibit ___ (DP-3). In addition, the study and our discussion above indicates that an additional $65.67 million, and $6.51 million would be necessary to provide for annual amortizations of the electric and gas reserve deficiencies.

Q. Are these results reflected in the Company's proposed depreciation expense levels for the Rate Year?

A. No. As discussed in Section I above, in order to facilitate the resolution of the issues in these proceedings and mitigate the impact of the proposed rates on customers, the Company's filing reflects existing depreciation rates and a further $20 million recovery of reserve deficiencies for electric and an $8 million recovery of reserve deficiencies for gas.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
DIRECT TESTIMONY OF
INCOME TAX PANEL

TABLE OF CONTENTS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
DIRECT TESTIMONY OF
INCOME TAX PANEL

I. INTRODUCTION AND PURPOSE

Q. Would the members of the Income Tax Panel ("Panel") please state their names and business addresses?

A. Jeffrey Kalata and my business address is 4 Irving Place, New York, New York.

Matthew Kahn and my business address is 4 Irving Place, New York, New York.

Michael Rufino and my business address is 4 Irving Place, New York, New York.

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

(Kalata) We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company"). I am the Vice President of Tax at Con Edison.

I have a Bachelor of Science degree in Business Administration with a concentration in accounting from Bowling Green State University. I joined Coopers & Lybrand LLC in 1986 and held a number of financial and audit positions before leaving as Senior Manager of Business Assurance in 1997 to serve as Group Accounting Manager for North American Refractories Co. with responsibilities for all financial reporting, accounting and tax functions. I joined FirstEnergy Corp. ("FirstEnergy") and was elected Assistant Controller in October 1999. At FirstEnergy, I had responsibilities for various accounting areas (accounts payable, payroll, property accounting and budgeting/planning), and was responsible for oversight of the external financial reporting and accounting research activities for FirstEnergy and its subsidiaries. In 2007, I transferred to FirstEnergy's tax department as Director, Tax, to head the tax accounting function over income taxes and general taxes. In 2013, I joined Con Edison's tax department as Director, Tax, and directed activities over the income tax accounting and compliance groups, as well as the book and tax depreciation groups. I was elected Vice President of Tax in December 2018.

I have testified as an expert witness in utility rate cases in Ohio and assisted in the preparation of rate cases in New York, Pennsylvania, New Jersey and West Virginia. I took an active role in Con Edison's implementation of the provisions of the Federal Tax Cuts and Job Act of 2017 ("TCJA"), particularly relating to the New York Public Service Commission's ("Commission") proceeding to consider the impact of the TCJA on the tax liabilities of New York's utilities.[1] I am an active member of the Edison Electric Institute's Taxation Committee and American Gas Association Taxation Committee. I am a Certified Public Accountant in the State of Ohio and a member of the American Institute of Certified Public Accountants, the Ohio Society of Certified Public Accountants and Chartered Global Management Accountants.

(Kahn) I am a Section Manager in the Tax Department at Con Edison, with responsibility for the book and tax depreciation functions. I graduated from Bentley College (now Bentley University) in 2004 with an undergraduate degree in accounting and completed a master's degree in taxation at Bentley University in 2010. I have been employed by Con Edison since 2010. Prior to my employment at Con Edison, I worked in various roles within the accounting industry and in the field of taxation with PricewaterhouseCoopers, LLC ("PWC"), and subsequently as an analyst with American Tower Corporation. I am a member of the Edison Electric Institute's Taxation Committee,

[1] Case 17-M-0815, *Proceeding on Motion of the Commission on Changes in Law that May Affect Rates* ("Case 17-M-0815").

American Gas Association Taxation Committee and the Society of Depreciation Professionals.

I have testified as an expert witness in utility rate cases in New York and New Jersey. In addition, I have actively participated on behalf of Con Edison in Case 17-M-0815.

(Rufino) I am the Department Manager for the Company's Income Tax Accounting group and have been since 2014. I have a Bachelor of Science degree in Business Administration with a concentration in accounting from Pace University and am pursuing a master's degree in taxation from Rutgers University. I have been employed by Con Edison since 2011 and am responsible for all income tax accounting matters, including monthly and quarterly tax provisions and financial reporting, for Consolidated Edison, Inc. ("CEI") and its regulated subsidiaries (including Con Edison). Prior to joining Con Edison, I held various positions in the income tax and financial accounting sections at PWC, Plainfield Asset Management, and Deloitte.

Q. What is the purpose of your direct testimony in these proceedings?

A. The Panel's direct testimony:

1. Discusses the proposed mechanisms the Company is employing/will employ to refund the 2018-19 transition period regulatory liabilities resulting from the TCJA to its electric and gas customers.
2. Discusses the proposed mechanisms, as well as the appropriate time period, the Company will employ to refund excess deferred Federal income taxes ("EDFIT") resulting from the TCJA to its electric and gas customers.
3. Discusses the potential changes that would impact the amount of EDFIT the Company will refund to its electric and gas customers.
4. Discusses the potential impact of bonus depreciation included in the Department of Treasury's proposed regulations that may require an adjustment to the Company's electric and gas rate filings.
5. Provides a basis for the amount of the Research & Development ("R&D") tax credit that the Company is refunding to its electric and gas customers in the Rate Year (*i.e.*, January 1 through December 31, 2020).

6. Discusses the Company's historical income tax accounting for Cost of Removal ("COR") and the current Commission proceeding addressing that topic.[2]

[2] Case 18-M-0013, *In the Matter of a Focused Operations Audit to Investigate the Income Tax Accounting of Certain New York State Utilities* ("COR Audit Proceeding").

II. TRANSITION PERIOD

Q. Please discuss the Company’s transition period regulatory liability resulting from the TCJA’s reduction in the Federal income tax rate from 35 percent to 21 percent.

A. This reduction in the Federal income tax rate became effective as of January 1, 2018. The terms of the Company’s current Commission-approved electric and gas rate plans extend through December 31, 2019. In its Order issued August 9, 2018,[3] the Commission directed how the Company should recognize the net benefits realized in calendar years 2018 and 2019 due to the TCJA’s reduction in the Federal income tax rate. For the Company’s electric business, the Commission directed the Company to continue to defer the net benefits realized in calendar year 2018 (“2018 Electric Benefits”). The 2018 Electric Benefits will be used to help offset projected deferral costs and cost increases that will be addressed in this electric rate case. The Commission did order the Company to provide customers with the net benefits realized in calendar year 2019 by means of a sur-credit to commence on January 1, 2019.

[3] Case 17-M-0815, Order Determining Rate Treatment of Tax Changes (issued August 9, 2018) (“August 2018 Order”)(pp. 42-44)

As for the Company’s gas business, in the August 2018 Order, the Commission directed the Company to provide customers with the net benefits realized in calendar years 2018 and 2019 by means of a sur-credit to commence on January 1, 2019.

Q. What does the Company propose regarding 2018 Electric Benefits that it is currently deferring?

A. The Company proposes to refund the 2018 Electric Benefits to its electric customers by means of a straight-line amortization over a three-year period, commencing at the beginning of the Rate Year. This is consistent with the amortization period ordered by the Commission for the pass back of net benefits realized in 2018 for gas.

III. EXCESS DEFERRED FEDERAL INCOME TAX (“EDFIT”)

Q. Please explain the impact of the TCJA on the Company’s accumulated deferred income tax balances.

A. Deferred income taxes result from normalization accounting for book and tax timing differences. The majority of deferred tax balances on the Company’s balance sheet are associated with its investment in plant. The difference between the federal income tax expense recorded for financial purposes and the actual current tax payable in any one year is deferred federal income tax ("DFIT"), that accumulates as a liability known as accumulated deferred Federal income tax liability ("ADFIT"). The TCJA's reduction of the corporate federal income tax rate from 35 percent to 21 percent results in EDFIT. Specifically, EDFIT represents the difference in the amounts the Company collected from its customers at a 35 percent tax rate to pay future income taxes, and the Company's future tax liabilities at a 21 percent tax rate.

Q. Did the Commission's August 2018 Order address the Company's refunding of EDFIT to its customers?

A. Yes. The Commission recognized that deferred Federal income taxes are included in the income tax component of the Company's electric and gas cost of service. Accordingly, as a result of the TCJA, EDFIT will result in a net regulatory liability that must be refunded to both the Company's electric and gas customers. In the August 2018 Order (p. 43), the Commission allowed the Company to continue to defer both the protected EDFIT balances and the unprotected EDFIT balances for its electric business. The Commission ordered the Company to address in its next electric base rate case (*i.e.*, this proceeding) how its EDFIT balances will be refunded to its electric customers. For its gas business, the Commission directed that the January 1, 2019 sur-credit include an amortization of the protected and unprotected excess EDFIT balances over the life of the plant assets. The Order notes that in the next gas rate case (*i.e.*, this proceeding), an alternative amortization period for the remaining unprotected balances may be determined to be appropriate.

Q. How does the Company propose to refund its unprotected EDFIT balances to its electric and gas customers?

A. The Company proposes to refund the unprotected EDFIT balances to its electric and gas customers over a five-year amortization period, commencing at the beginning of the Rate Year. The five-year straight-line amortization period is the same time period over which the Company proposes to recover deferred costs in this proceeding, *i.e.*, the Company proposes to use the period for debits and credits. For the gas service, this is a change (as allowed by the August 2018 Order) to accelerate the amortization of the unprotected EDFIT balance to customers.

Q. How does the Company propose to refund its protected EDFIT balances to its electric and gas customers?

A. The Company will employ the Average Rate Assumption Method ("ARAM") to refund the protected EDFIT balances over the remaining lives of the plant assets, in accordance with the normalization rules under Internal Revenue Code ("IRC") §168(f).

IV. EDFIT BALANCES

Q. Please describe the nature of any potential changes that would impact the EDFIT balances to be refunded to the Company's electric and gas customers.

A. As noted above, there are two components of the EDFIT balances to be refunded to the Company's electric and gas customers – protected and unprotected EDFIT balances. The Company originally based both protected and unprotected EDFIT balances on the 2017 year-end income tax provision estimates, which were trued-up to actual upon the filing of the Company's 2017 Federal income tax return. Protected EDFIT balances are subject to the normalization rules under the IRC and are required to be refunded to customers over the remaining life of the plant assets. These balances are reversing subject to ARAM rates. The annual reversal of protected EDFIT balances will be updated every time that the Company calculates its deferred taxes associated with its investment in plant. Generally, the Company updates these amounts quarterly in calculating the provision for Federal income tax expense. Unprotected EDFIT balances may be refunded over a shorter period. As noted above, the Company proposes that they be returned to electric and gas customers over a five-year period commencing at the beginning of the Rate Year.

Q. Has the Company prepared supporting documentation for the current balances of EDFIT that will be refunded to its electric and gas customers?

A. Yes. Please see Exhibit ITP-1, which contains the original Day 1 amounts recorded in the 2017 year-end accrual for income tax along with return-to-provision adjustments subsequently recorded in connection with the Company's filing of its 2017 Federal income tax return in October 2018.

Q. Will the unamortized protected and unprotected plant EDFIT balances reduce the Company's electric and gas rate base amounts?

A. Yes.

Q. Are there additional events that may affect the EDFIT balances the Company will refund to its electric and gas customers?

A. Yes. The Internal Revenue Service ("IRS") has not completed its examination of Con Edison's 2017 Federal income tax return, and the Treasury Department has not yet finalized its proposed regulations on first-year depreciation related to the TCJA. Any potential post-filing adjustments to this tax return by the IRS, as well as the provisions of the Treasury Department's final regulations, could affect Con Edison's protected and unprotected EDFIT balances.

V. BONUS DEPRECIATION

Q. Please discuss how the Company addresses the issue of bonus depreciation in its electric and gas rate filings.

A. The Company's current balances of accumulated deferred income taxes are based on the Treasury Department's proposed regulations issued in August 2018 pertaining to bonus depreciation for utility companies in the fourth quarter of 2017, as well as the transition rules in tax years 2018 and 2019. Under these proposed regulations, utility companies are entitled to bonus depreciation for qualifying additions that were originally under contract prior to September 27, 2017 and placed into service during the 2018 and 2019 tax years. In applying the proposed regulations to the calculation of tax depreciation and associated deferred income taxes, the Company has computed estimated amounts of bonus depreciation for both 2018 and 2019. This additional tax depreciation increases the balance of accumulated deferred income taxes, and therefore, reduces rate base in the Rate Year.

Q. How much additional deferred income tax has the Company included in the Rate Year, due to the inclusion of bonus depreciation for years 2018 and 2019?

A. The Company has calculated estimated bonus depreciation in the amount of $330 million for 2018 and $50 million for 2019. Of these amounts, the electric service's depreciation deduction is estimated to be $179 million in 2018 and $38 million in 2019. This results in additional accumulated electric deferred income taxes of $38 million in 2018, and $8 million in 2019. The gas service's depreciation deduction is estimated to be $151 million in 2018 and $12 million in 2019. This results in additional gas accumulated deferred income taxes of $32 million in 2018 and $2.5 million in 2019.

Q. Has the Company prepared supporting documentation for the calculations of estimated bonus depreciation specific to electric and gas?

A. Yes. Please see Exhibit ITP-2.

Q. What impact would the Treasury Department's final regulations have on these amounts of deferred income taxes?

A. In the event that prior to a final Commission rate order in these proceedings, the Treasury Department issues final regulations that affect the Company's estimated amounts of bonus depreciation, if practicable, the Company will update its rate filing to reflect the impact of the final regulations. If the Treasury Department does not issue final regulations in time to be reflected in the Commission’s final rate order in these proceedings, the Company will continue to accrue a carrying charge (*i.e.*, income) on the difference in accumulated deferred federal income taxes as a result of any change in final Treasury regulations.

VI. R&D TAX CREDIT

Q. How does the Company establish the amount of the income tax reserve for uncertain tax positions related to the R&D tax credit?

A. The Company establishes the reserve for uncertain tax positions related to the R&D tax credit in the same manner that it establishes income tax reserves for other uncertain tax positions. The Company establishes the amount of this reserve through an exercise of professional judgment, made in collaboration with its experienced service provider (*i.e.*, KPMG), which reflects the guidelines of ASC 740, as well as the Company’s past experience in negotiating and settling with the IRS.

Q. Is the Company's income tax reserve for the R&D tax credit subject to reconciliation?

A. No. The Company establishes its income tax reserve for the R&D tax credit each year based on the Company's judgment in accordance with ASC 740-10-25-7 accounting principles. Upon resolution with the IRS, the Company will reverse its income tax reserve and adjust the R&D tax credit, as appropriate.

Q. What provision of the IRC governs R&D Tax Credit claims?

A. The Company files its claims for R&D tax credits under Section 41 of the IRC.

Q. In its rate filings, did the Company include in its calculation of Federal income tax expense an amount of tax credits associated with its investment in qualified R&D activities, as provided for under IRC section 41?

A. Yes. Please see Exhibit ITP-3. The Company has calculated an estimated amount of R&D tax credit and has reduced its Federal income tax expense in the Rate Year by this estimated tax credit.

Q. Please explain how the Company has calculated the estimated R&D tax credit.

A. The Company used an historical five-year period (*i.e.*, 2012 – 2016) of actual data to serve as an estimate for the Rate Year because there is too much uncertainty associated with a forecast. The Company performed this calculation for both its electric and gas lines of service.

Q. What amount does the Company propose to impute as a Federal income tax credit?

A. Based on a five-year average of actual R&D income tax credits, the Company proposes to include a Federal income tax credit of $2.5 million for electric and $0.6 million for gas in the Rate Year.

VII. INCOME TAX ACCOUNTING FOR REMOVAL COSTS

Q. What is the status of the Commission's COR Audit Proceeding relating to the Company's historical income tax accounting with respect to COR?

A. On January 11, 2018, in the COR Audit Proceeding, the Commission issued an order approving the issuance of a request for proposals seeking a third-party to conduct a focused operations audit to investigate the income tax accounting relating to COR of the Company, its affiliate, Orange and Rockland Utilities, Inc., and other New York

State utilities ("COR Audit"). Specifically, the COR Audit focuses on determining whether errors in income tax accounting occurred with respect to COR and whether the Company's customers received the benefit of the lower income tax expenses in rates as a result of the claimed errors. The Company will reflect any findings agreed to by the Company and Staff or ordered by the Commission in an appropriate submission depending upon the timing of the resolution.

Q. Does this conclude your direct testimony?

A. Yes, it does.