CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL

Table of Contents

I. Introduction

A. Introduction and Qualifications of Panel Members

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

A. Milovan Blair, Robert Brantley, Patrick McHugh, Steve Parisi, and John Catuogno. The business address for all panelists is 4 Irving Place, New York, NY 10003.

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

A. **(Blair)**

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

I hold an MBA in information systems from St. John's University and a Bachelor of Science degree in electrical engineering from the City University of New York. I have completed the Senior Executive Program at Columbia University and the Siemens PTI Power Technology course. I currently serve on the executive board of the YMCA Bedford Stuyvesant Chapter and as a leadership council member of the City College of New York Grove School of Engineering.

(Brantley)

I am Robert Brantley, Vice President of Central Engineering for Con Edison. In my current role, I provide engineering leadership and oversight to maintain the safe and reliable operation and maintenance, including field support, of the electric transmission system, electric substations and steam generation and distribution systems. My organization also provides engineering services for Gas LNG plants and Company facilities. I joined the Company in 1993 as a management intern and have held positions of increasing responsibility including senior system operator, general manager in Substation Operations, chief engineer in Central Engineering, and most recently general manager of Manhattan Electric Operations. I hold a Bachelor of Engineering degree in electrical engineering from Cooper Union and a Master of Business Administration degree from

the Wharton School of Business at the University of Pennsylvania.

(**McHugh)**

I am Patrick G. McHugh, Senior Vice President of Electric Operations for Con Edison. I assumed this position in July 2021, after serving as Vice President of Engineering and Planning for Con Edison. I currently have overall responsibility for Con Edison's Electric Distribution Operations, Engineering and Planning, and Con Edison's Energy Services organization, which coordinates all aspects of the delivery of electric service to customers.

I have been with the Company for over 30 years after joining in 1991 as a Management Intern and have held various positions with increasing responsibility including Vice President of Engineering and Planning, Vice President of Brooklyn/Queens Electric Operations, Chief Engineer of Distribution Engineering, General Manager Protective Systems Testing, Senior System Operator, and Chief District Operator. I hold a Bachelor of Science degree in electrical engineering from Clarkson University, a Bachelor of Arts degree in physics from Plattsburgh State University, and a master's degree in electrical engineering from Clarkson

University. I have also completed the Siemens PTI Transmission course.

(Parisi)

I am Steven Parisi, Vice President of Engineering and Planning for Con Edison. I assumed this position in June 2021, after serving as Vice President of Engineering for Central Operations. My responsibilities include overseeing energy services, engineering, and quality assurance. Engineering and Planning is also responsible for designing and monitoring the performance of the electric distribution system. I joined the Company in 1989 as a management intern and have held general manager positions in System Operations, Electric Operations, and Substations. I hold a Bachelor of Science degree in electrical engineering from Polytechnic University. I have also completed the Siemens PTI Distribution course.

(Catuogno)

I am John Catuogno, Director of the Commodity Forecasting Department for Con Edison. I am on this panel solely to support the electric peak demand forecast. I graduated from Polytechnic University with a Bachelor of Science degree in Mechanical Engineering in 1991 and with a Master of Science degree in Management in 2002. I have also

completed the Siemens PTI Power System Transmission course/certification.

I am a licensed Professional Engineer in the State of New York and an Adjunct Assistant Professor in the Mechanical Engineering Department of Manhattan College, where I present graduate lectures on energy and sustainability.

I joined Con Edison in 1991 as a Management Intern and have held various positions of increasing responsibility in the Fossil Power, Nuclear Power Engineering, Steam Operations, and Energy Management Organizations. Since December 2013, I have been the Director of Energy Management's Commodity Forecasting. My responsibilities include oversight of daily peak, annual peak, monthly/annual energy revenue and volume forecasts for the electric, gas, and steam systems; and technical and analytical support for long range plans, strategies, and industry trends and issues that affect the Company.

I have submitted testimony in Case Nos. 21-G-0073, 21-E-0074, 19-E-0065, 19-G-0066, 18-E-0067, 18-G-0068, 16-E-0060, 16-G-0061, 13-S-0032, 09-S-0794, 09-S-0029, and 07-S-1315.

B. Purpose of Filing

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

A. We are presenting the Company's required electric projects and programs and their respective funding requirements. These investments are needed to: (1) maintain safe and reliable electric service, (2) enable clean energy, and (3) make our system more resilient.

Specifically, our testimony covers the electric peak demand forecasts that drive load growth and the capital and O&M funding requirements for the Company's transmission, distribution, and electric production functions. The transmission funding requirement, which includes the System and Transmission Operations ("S&TO") and Substation Operations ("SSO") groups, and the Electric Operations ("Distribution") funding requirements, are described together and are collectively referred to as Transmission and Distribution ("T&D"). The Electric Production funding requirement, the costs of which are shared with the steam system, is presented separately in Section V of this testimony. While we will highlight only a few of the Company's investments, each program and project for which the Company seeks funding is described in a "white paper" that includes scope of work, justification, cost, schedule, relationship to long-range plans, including climate change related goals where applicable, and discussion of alternatives.

Q. What period does this testimony cover?
A. This testimony presents the projects and programs planned for the 12-month period ending December 31, 2023 (“Rate Year” or “RY1”).
Q. Does your testimony look beyond Rate Year 1?
A. Yes. We also address the capital plant additions and other programs and initiatives planned for the two years following the Rate Year. For convenience, we will refer to the twelve-month periods ending December 31, 2024 and December 31, 2025 as “RY2” and “RY3,” respectively. As the Company’s Accounting Panel explains, the Company is not proposing a multi-year rate plan in this filing but is interested in pursuing one in settlement discussions with Staff and interested parties.
Q. What is the Company’s total capital expenditure for T&D and Electric Production in RY1, RY2, and RY3?
A. The Company’s total capital expenditure for T&D and Electric Production is $2,484.8 million in RY1, $2,522.5 million in RY2, and $2,563.0 million in RY3.

C. Key Principles

Q. What are the principles driving the Company’s funding request for electric operations?
A. The Company’s investments are based on three principles: 1) Core Investments to that are often multi-value to maintain

safe, resilient, and reliable electric service, 2) Clean Energy investments to help meet the State's clean energy goals, and 3) Resilience investments focused on preparing our electric system for more frequent and severe weather, including heat. As noted above, the Company always seeks to develop multi-value projects that serve more than one goal, which increases the cost efficiency of our capital investments.

Q. Can you elaborate on what you mean by multi-value projects?

A. Multi-value projects serve more than one need. For example, we may see a reliability need in a particular area. In designing a solution, we will, to the extent practicable, look for opportunities to enhance resilience or facilitate the State achieving the clean energy goals established in the Climate Leadership and Community Protection Act ("CLCPA"). We think multi-value projects are 'no regrets' investments that provide a variety of capabilities, such as additional 'headroom' to integrate renewables or flexibility to accommodate intermittent resources. Multi-value projects help us maximize customer value by increasing the cost-effectiveness of our projects.

Q. Do the Company's projects have other benefits?

A. Yes. The Company's projects serve to increase economic development in our area. In addition to the construction

jobs associated with Company projects, and the employees required to operate these projects, system expansion to accommodate anticipated load growth and accommodate clean energy investments supports further investments in homes, businesses, and renewable generation in the Con Edison service territory. These investments add jobs to the local economy in a myriad of areas, including clean energy jobs. Further, the Company's efforts to promote and facilitate the adoption of electric vehicles ("EVs"), through the make-ready program discussed in this testimony, leads to investments and jobs associated with EVs, EV infrastructure, and in the overall transportation infrastructure.

1. Core Investments

Q. What are Core Investments?

A. Core Investments are required for safe and reliable service and many of the projects also provide resiliency. Among other things, they include investments to address load growth, replace equipment and assets that can no longer be maintained, keep assets in safe working condition, and enhance physical and cybersecurity. They are essential to maintaining the electric transmission and distribution systems.

Q. What is the relationship between Core Investments and the clean energy future?

A. The clean energy future must be accompanied by a safe and reliable electric system. Our system must be capable of reliably delivering new sources of clean energy to customers and reliably serving increasing customer demand from electrification. For example, as more customers adopt electric heating, our system will begin to experience significant winter load along with a summer peak. We must begin the work now so our system is able to withstand such new patterns of usage, even though we do not expect to become a winter-peaking utility until the mid-2030s. In addition, increased demand year-round will shorten outage windows available to perform required upgrades and maintenance. Core Investments are necessary to keep the system safe and reliable now and prepare it for the clean energy future. Furthermore, many Core Investments will make the system more resilient in the face of extreme weather events.

Q. Can you give an example of a Core Investment?

A. Yes, the Queensboro Bridge Risk Mitigation project. This project will relocate existing feeders from the Queensboro Bridge to a new trenchless crossing underneath the East River. The Company has identified Queensboro Bridge as a

significant potential risk because failure could result in significant outages.

Q. Can you give an example of a Core Investment that is also a multi-value project?

A. Yes, the Williamsburg Network Improvement Project. That project will create two smaller load areas out of the Williamsburg Network by adding new distribution feeders connected to the Vinegar Hill Distribution Switching station. This will improve the reliability and resiliency of the Williamsburg Network, reduce average load per feeder, and accommodate future load growth in an area that has seen a 24 percent increase in load since 2014. At the same time, the project also contributes to meeting clean energy and resilience goals. For example, some of the future load growth in this area will come from building and transportation electrification; thus, the project is needed to accommodate the State’s clean energy policy. In addition, this project will address the need for future load relief driven by a forecasted increase in temperature at the time of peak load due to climate change. This will be further discussed in the forecasting section. The project will also give the Company the ability to use sectionalizing switches to provide opportunities to transfer load.

Q. Can you give an example of a Core Investment that maintains safety?

A. Yes. The public may come in to contact with our facilities which may be underfoot in roadways, pedestrian spaces, and outdoor dining areas. We are committed to making sure that the public remains safe through programs like the Vented Covers for Underground Structures program, which are discussed later in this testimony.

2. Clean Energy

Q. Please explain the Company's objective to Enable Clean Energy.

A. Con Edison is committed to being a next-generation clean energy company to help the State achieve its clean energy goals. The Company's planned investments in electric infrastructure are geared towards facilitating retirement of downstate fossil fuel-fired "peaking" generation units, opening pathways for renewable generation to reach constrained Transmission Load Areas,[1] enabling customers' ability to adopt distributed energy resources ("DER"), and

[1] CECONY's Transmission System is comprised of seventeen Transmission Load Areas (TLA). These TLAs were designated based on the identification of existing Transmission System constraints, where supply internal to the TLA is insufficient to meet the internal TLA load. As a result, the TLA is dependent on transmission to balance supply and load.

expanding the system to reliably meet the needs of customers as they adopt EVs and electrify their buildings. The Company has placed significant focus on understanding the electric system's vulnerability to climate change, the potential impacts to customers, and creating plans to adapt to the impacts of climate change, and these efforts are discussed throughout this panel's testimony. The CLCPA and Con Edison's overall Clean Energy Commitment are discussed in much greater detail in the Company's CLCPA Panel testimony.

Q. Please elaborate on how the Company plans to support CLCPA goals through investment in the Transmission System.

A. In 2020, the State passed the Accelerated Renewable Energy Growth and Community Benefit Act[2] ("Benefit Act"), which established a process to expedite the development of renewable energy in New York, particularly through increased transmission. Subsequently, the Commission issued its Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit

[2] *Accelerated Renewable Energy Growth and Community Benefit Act*. Full text of the legislation is available online. See https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf.

Act[3] accelerating the timeline for key T&D upgrades to accommodate large-scale renewables. In response, Con Edison developed the Reliable Clean City Projects ("RCCPs") to enable the retirement of peaker generation units and provide new delivery pathways for renewable power to reach customers. The Company described the projects in its petition for cost recovery,[4] which the Commission approved.[5]

In addition to providing the best viable solution to the reliability needs resulting from the peaker retirements, the RCCPs provide an off-ramp that, collectively, will enable 900 MW of renewable energy carried on the 345 kV system highway to be delivered to our service territory. Together these projects represent $480.4 million in capital expenditure in RY1 through RY3 to support CLCPA goals.

---

[3] Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) ("Order on Transmission Planning").

[4] See Case 19-E-0065, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Petition of Consolidated Edison Company of New York, Inc. for Approval to Recover Costs of Certain Transmission Reliability and Clean Energy Projects, filed December 30, 2020.

[5] See Case 19-E-0065, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Order Regarding Transmission Investment Petition, issued April 15, 2021, p. 19.

In addition to the RCC projects, a number of the Core Risk Reduction/Reliability and System Expansion Transmission System investments that this panel discusses are considered multi-value projects as they also enable access to future renewable generation for the service area and provide additional capacity to accommodate increased load due to electrification. For example, the Gateway Park Area Station project that will commence in 2023 will address load growth on the Brooklyn networks, a portion of which will be the result of customer transportation and building electrification.

Q. How do the investments discussed by the Panel support the electrification of transportation and buildings for customers?

A. As discussed above, the RCCP projects and other core System Expansion projects will provide additional capacity that can support load growth associated with the charging of EVs and conversion of space and water heating from natural gas to electric. The Company is also focused on New Business capital investments to support EV charging infrastructure as part of the Company’s EV Make-Ready Program. Portions of the program are also discussed in the Company’s Customer Energy Solutions Panel testimony.

3. Climate Change Resilience

Q. Please elaborate on the Company's Climate Change Resilience objective.

A. Con Edison's investments in its electric system are designed to meet customer expectations by maintaining and improving reliability under normal conditions and providing resiliency during extreme weather events such as more frequent and severe major storms and prolonged heatwaves. Con Edison has historically made investments in the electric system's resiliency. These have included $1 billion of expenditures in storm hardening and resilience projects between 2013 and 2016 following Superstorm Sandy. It also includes various initiatives to reduce system damage and customer outages and to improve restoration efforts following Winter Storms Riley and Quinn in early 2018 and tropical storm Isaias in 2020.

In the face of forecasted climate change, additional investment is needed to continue to meet customer's current expectations for reliability and resiliency. Over the past two years, Con Edison has been working to understand the impacts of climate change on the electric system and position the Company to continue to meet customer's expectations. This began with the development of the

Company's Climate Change Vulnerability Study[6] published in December 2019. The study describes historical and projected climate changes across Con Edison's service territory and evaluates 2019 design specifications and procedures against expected changes to better understand areas of vulnerability and risk. A year later the Company developed a Climate Change Implementation Plan ("CCIP").[7] Key areas addressed in the CCIP include:

- Climate change pathways;
- Climate risk governance;
- Load forecasting;
- Load relief planning;
- Reliability planning for the sub-transmission and distribution systems; and
- Asset management

[6] *Climate Change Vulnerability Study*, December 2019. See https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.

[7] See Case 19-E-0065, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Climate Change Implementation Plan, filed December 29, 2020.

Q. In what ways is the Company planning to adjust its planning and design criteria to account for the impacts of climate change?

A. In light of anticipated changes in climate and more frequent and severe weather, the Company has changed design standards and incorporated climate change impacts into its forecasts. As part of the CCIP, Con Edison adopted Representative Concentration Pathway (“RCP”) projections for use in its new Climate Change Planning and Design Guideline. Pursuant to the Guideline, the load forecasting team will consider the RCCP climate change projections for temperature, Temperature Variable (“TV”), Heating Degree Days (“HDD”), and Cooling Degree Days (“CDD”) in calculating the 10- and 20-year peak demand and volumetric forecasts annually. In addition, the Company plans to raise the TV design basis by one degree for 2030 and has begun the migration to a projected floodplain of FEMA +5. We will also use these climate projections as part of our power equipment ratings, load relief planning, reliability analysis, and cold weather design. In addition, the Company will incorporate the impacts of climate change into its coastal flood mapping, flood risk standard, and heavy rainfall considerations.

Q. Are any of the Company's proposed investments in this case the result of the Company changing its planning and design criteria to account for the forecasts contained in its Vulnerability Study?

A. Yes. Investments, or incremental portions of investments, are directly driven by these new design standards.

Q. Can you give some examples?

A. Yes, as discussed more fully in our testimony and respective white papers, our investments in the following programs, among others, are directly driven by our new design standards: Non-Network Reliability and Unit Substation ("USS") Switchgear Flood Protection, Critical Facilities, Selective Undergrounding, Primary Feeder Reliability, and Transformer Installation. These programs will increase the reliability and resiliency of electric system for customers in the face of more frequent and extreme weather events, warming temperatures, and sea level rise.

D. Testimony Format

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

A. Section II describes the Company's T&D electric system to provide context for the Company's planned projects and programs. Section III provides a summary of planned T&D

capital and O&M expenditures as well as a discussion of the Electric Load Growth Forecasts. Section IV covers the individual T&D projects and programs organized by categories of spend and then by type of work within each category. Section V describes planned Electric Production projects and programs. For sections IV and V, the Company provides a description of each spend category, lists all programs and projects in each category, and highlights select programs and projects in testimony. Additional detail on each program and project can be found in the respective white paper located in the EIOP exhibits. Finally, Section VI discusses special issues such as generator retirement, Reliability Performance Mechanisms, charges for special services, and tariff changes. Each special issue discussed in Section VI is listed in the Table of Contents.

Q. Is the Company describing all projects and programs in the testimony?

A. No. The Company is discussing the major projects and programs only in testimony. The other projects and programs are described in their whitepapers.

II. Electric System Description

A. Importance of Electric Infrastructure to Service Area

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

A. Since 1823 Con Edison has played the vital role of providing essential energy services to its customers and community. The electric service provided by the Company has been an engine for growth for New York City ("the City") and Westchester County, which have a combined population of over nine million people. The Company's service territory is home to two of the five largest cities in New York State – the City and Yonkers, and to businesses that are leaders in national and international commerce, finance, culture, health care, sporting events, and entertainment. The City is also an important center for international affairs as the host for the United Nations headquarters. The Company distributes electricity to approximately 3.5 million customer accounts.

With Con Edison's customers and the State embarking on efforts to electrify transportation and buildings, the Company's electric service will become even more essential. Customers expect safe and reliable electric service now and, moving forward will need electricity to heat their

homes and water, in addition to the power and cooling that they currently rely on. The Company is actively working to meet those expectations with its planned investments for the electric system.

The Company's electric system is also critical to meeting the State's CLCPA goals. The same electrification that makes electricity even more of an essential service for customers is also key to reducing GHG emissions by reducing customers' need to burn fossil fuels. In addition, Con Edison is making investments in the transmission and distribution system to enable the integration of utility-scale renewables and DERs while creating the conditions to allow for the retirement of polluting peaker generation units.

B. Description of T&D Systems

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

A. Con Edison's electric service territory covers 604 square miles and includes all of New York City, except the Rockaway Peninsula in Queens, and approximately two-thirds of Westchester County. The electric delivery system is comprised of approximately 96,800 miles of underground T&D lines and over 34,500 miles of overhead lines. The Company's underground T&D system is the largest in the

United States. Con Edison's service territory, while relatively small geographically, represents approximately 40 percent of New York State’s peak electricity demand.

The Company’s T&D systems are classified into three major categories: 1) System and Transmission Operations; 2) Substation Operations and 3) Distribution. Con Edison also has a small portfolio of facilities associated with its steam system that generate electric power, as discussed in Section V.

C. Transmission System

Q. Please describe the Company’s transmission infrastructure.

A. The transmission system includes both underground and overhead infrastructure. Con Edison's underground transmission system is the largest underground transmission system in the United States and delivers electric energy at 69 kilovolts (“kV”), 138kV, 230kV, 345kV, and 500kV from generating sources to Company substations located throughout its service territory. The transmission system plays a key role in delivering clean energy to the City and Westchester County and will therefore be pivotal to meeting the State’s CLCPA goals. About 85 percent of the underground transmission system is comprised of underground pipe-type cables, the largest system of its kind in the world. This type of cable system is composed primarily of

steel pipe that houses three paper-insulated cables and is filled and pressurized with 8.3 million gallons of dielectric fluid. The dielectric fluid provides insulation as well as cooling for the cables. Over 200 facilities, located throughout the system, pressurize, circulate, and cool the dielectric fluid. In addition to pipe-type cable, the remaining 15 percent of Con Edison's underground transmission system consists of other types of cable, such as self-contained, fluid-filled, and solid dielectric. The overhead transmission system, located in Dutchess, Putnam, Westchester, and Richmond Counties, consists of approximately 1,270 structures that support 370 circuit miles of cable situated along 113 miles of right-of-way. The Company also owns or jointly owns 387 structures that support 81 circuit miles in Orange and Rockland counties.

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

D. Transmission and Area Substations

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

A. Substations consist of components (circuit breakers, transformers, phase angle regulators, switches, relay systems, and communications systems) that are used to transform, sectionalize, control, and direct power on the electrical power system. On the Con Edison system, these substations are referred to as transmission stations and area substations or stations. Typically, transmission lines and generating units are interconnected to transmission stations, which step the voltage down using transformers, to deliver electric power to the area substations. Area substations receive power from the transmission stations and further step the voltage down to deliver electric power to the distribution system.

Currently, the Con Edison system has 40 transmission stations and 62 area substations. The transmission stations are operated at 345kV, 138kV, and 69kV. Of the 40 transmission stations, Academy, Mott Haven, Cricket Valley and West 49th Street are indoor Sulfur hexafluoride ("SF6") insulated stations; Dunwoodie is an outdoor SF6 insulated station; and all others are outdoor open-air insulated stations. Except for some of the older stations, most of the 62 area substations are indoor facilities, except for their power transformers. The area substations are operated at 33kV, 27kV, and 13kV.

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

E. Distribution System

Q. Please describe the Company's distribution infrastructure.

A. The electric system's 62 area substations supply 84 networks and 17 non-network load areas. The distribution system is composed of network and non-network systems operating at voltages of 4kV, 13kV, 27kV and 33kV. Staten Island systems operate at 4kV, 13kV, and 33kV; Brooklyn, Bronx, and Queens at 4kV and 27kV; Westchester at 4kV and 13kV; and Manhattan at 13kV. Approximately 2,300 primary voltage distribution feeders supply network and non-network load.

Con Edison's underground distribution system is the largest underground, low-voltage, network system in the world. It includes approximately 266,400 manholes and service boxes; 25,500 conduit miles of duct; 96,800 miles of underground cable; and approximately 27,000 network transformers that further step the voltage down from 33kV,

27kV, or 13kV to 265/470 volts and 120/208 volts to supply the low-voltage secondary distribution system.

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

The Company's (non-network) overhead distribution system includes approximately 198 auto loops; 217 unit substations; 11 multibank substations; approximately 202,000 poles; 51,800 overhead transformers; and approximately 34,500 miles of overhead wire including primary, secondary, and service wire. The non-network system uses a first contingency design, i.e., it is designed to sustain the loss of one distribution feeder under peak load conditions without any feeder overloads or adverse impact on service to customers.

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

F. Distributed Energy Resources

Q. Please describe the DER on the system today.

A. The term DER covers a wide range of resources including energy efficiency, demand response ("DR"), and distributed

generation (“DG”) that includes combined heat and power (“CHP”) generators, battery storage, and renewable energy such as solar.

Con Edison has over three decades of experience implementing programs and interconnecting these devices. Over this time, the Company has worked with its customers to increase the amount of DER connected to its system. Con Edison has made significant progress in advancing the State’s goals and building the capabilities that support greater DER adoption. Specifically, improvements to the interconnection process are providing enhanced value to developers by allowing viable projects that pass the State-developed screens to quickly advance to interconnection or using screening results to verify the need to perform a detailed study. These improvements have enabled the interconnection of over 202 MW of solar capacity connected to Con Edison’s distribution system since January 1, 2018, for a total of approximately 400 MW of distribution-connected solar. Similarly, distribution-connected energy storage has grown to 15.7 MW, representing an almost seven-fold increase since January 1, 2018.

The Company has and will continue to work with its customers to increase these resources through its initiatives. Additional information on the Company’s

efforts to integrate DER can be found in the Customer Energy Solutions Panel testimony.

G. Electric Load Growth Forecasts

Q. What is the purpose of discussing the electric load growth forecasts as part of this testimony?

A. The purpose is to explain the electric system peak and network independent summer peak demand forecasts that have increased and caused the need for the electric infrastructure discussed by this Panel and in accompanying whitepapers.

Q. What are the electric system peak and electric network independent peak summer forecasts?

A. The electric system summer peak demand forecast is a 10-year outlook of the net load growth of the electric system. This forecast considers the factors that increase and decrease the summer peak hour demand at design weather criteria. The electric network independent summer peak demand forecast is a 10-year outlook of the net load growth of specific load areas that comprise the electric system’s grid. This forecast considers the factors that increase and decrease the summer independent peak hour demand at design weather criteria for each individual load area. There are 83 Network Load Areas and 13 Radial Feeders, many of which peak at different hours.

Q. Are you presenting any exhibits as part of the forecast discussion?

A. Yes. We are providing an independent network peak demand forecast exhibit for the networks and radial feeders driving specific Load Relief, Non-wire Solutions, and major capital investments; and a specific load area exhibit to explain the need for the Gateway Park Area Station.

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

A. Electric system peak summer demand in Con Edison's service territory is forecasted to grow at a compounded annual growth rate of approximately 0.4 percent over the next five years (2022-2026) and at a compounded annual growth rate (“CAGR”) of 0.7 percent over the next 10 years (2022-2031). Both the electric system and independent network peak demand forecasts, when considering load growth, account for commercial, residential, and governmental new business; COVID-19 recovery, electric vehicles (“EV”), steam to electric chiller conversions, electrification of gas appliances, electrification of heating (“EoH”) (included in the winter peak forecasts), and adjustments for climate change. These forecasts also consider “negative load modifiers” such as Combined Heat and Power (“CHP”), distributed storage, photovoltaic (”PV”), conservation

voltage optimization (“CVO”), certain demand response programs (“DR”), and Energy Efficiency, which include programmatic, organic, and codes and standards. The forecasted electric system peak demand forecast is 12,570 MW for the summer of 2022, 12,590 MW for the summer of 2026, and 13,260 MW for the summer 2031. These forecasted values are net of all aforementioned load growth and negative load modifier contributions and are at design summer weather criteria. The current outlook is that our electric system and most of its network load areas will remain summer peaking for at least the next 15 years. As such the summer peak forecasts are the controlling peak demand forecasts.

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

A. The overall ten–year electric system peak demand CAGR is 0.7 percent and this is net of major demand side management efforts, storage, CVO, PV, and DG. However, the independent summer peak demand load growth in several key individual load areas is projected to be higher than the aforementioned electric system CAGR. Mixed-use neighborhoods throughout Brooklyn and Queens continue to see a steady increase in new small and medium-sized commercial and residential developments, and this growth

has accelerated over the last year. Major new projects in Midtown Manhattan such as Hudson Yards, the expansion of the 2nd Avenue Subway, and the Long Island Railroad ("LIRR") East Side Access are expected to drive load increases in their respective networks over the next five years. Additionally, much of the load reduction seen in Manhattan's Central Business District over the past two summers is expected to return as the New York City Region continues to recover from the impacts of the COVID-19 pandemic.

The Company also anticipates increased electric peak demand over the next 10 years due to the electrification of heating (only in the winter), electrification of gas appliances (stovetops, dryers, and hot water heaters), and transportation. With regards to electrification of heating, gas appliances, and light-duty vehicles, the associated load growth is expected to be most significant in lower density residential areas where the housing stock and geography is better suited for these respective technologies. In addition, widespread electrification of medium and heavy-duty vehicles will have very targeted impacts on electric networks where large transit or commercial vehicle fleets are based.

Q. Was the exhibit titled, "CECONY Network & Radial Feeder 10-Year Independent Summer Peak Demand Forecast (MW)" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-2

Q. Is the increase in the network or radial feeder summer independent peak forecast going to drive the need for additional capital investment over the next 5-to-10-year horizon.

A. Yes. Increases in the network and radial feeder summer independent peak demand forecasts are driving capital investments in new infrastructure in specific networks across the system. These include load areas served by the

- Brownsville 1 & 2 Area Stations (Crown Heights, Ridgewood, and Richmond Hill networks and the 9B91 – 9B94 radial feeders)
- Glendale and Newtown Area Station corridor (Borden, Sunnyside, Maspeth networks, Radial Feeders 6Q83 and 6Q84, and the Sunnyside Amtrak load)
- Plymouth and Water Street Area Stations (Williamsburg, Prospect Park, and Borough Hall Networks)
- Parkview Area Station (Triboro Network)

- Bruckner Area Station (West Bronx & Randall's Island Networks)
- West 42nd Street 1 Area Station (Pennsylvania Network)
- Jamaica Area Station and Network

Q. Was the exhibit titled, "Brownsville 1 & 2 - Changes Between 2021 & 2020 Summer Peak Demand Forecasts (MW)" prepared under your direction?

A. Yes, it was.

Q. What is driving the change in the load forecast for the networks and radial feeders served by the Brownsville 1 & 2 areas stations in the 2021 forecast relative to the 2020 forecast?

A. The 2021 cumulative 10-year electric load forecast for the networks and radial feeders served by the Brownsville 1 & 2 load area, whose networks and radial feeders generally peak during the same hour in the summer, increased by approximately 85 MW relative to 2020's forecast. This increase is due to several factors including: increases in proposed new business, a decrease in expected energy efficiency, and the inclusion of additional electrification technologies, including electric medium & heavy-duty vehicles and electrification of appliance gas in the Brownsville 1 & 2 load area. This exhibit represents the

reconciliation of the amounts of weather adjusted peak demand to our design weather criteria, new business, EV, electrification of appliance gas, EE, COVID-19 adjustment, climate change, CHP, energy storage, DR, CVO, and load transfers. The values in this exhibit are cumulative and rounded to the nearest MW. The primary drivers of the increase are discussed as follows:

- New Business: In the 2021 forecast, an additional 75 new large applications were active relative to the 2020 Forecast. The increase in overall applications is due to continued new development and latent demand for new construction occurring as the region continues to recover from the economic downturn driven by COVID-19, as described in the Electric Forecasting Panel testimony. The largest of these jobs is an affordable housing complex located in the Richmond Hill network.
- Energy Efficiency (EE): The Company reevaluated its load forecasting methodology prior to developing this year’s forecast. The Company determined that in areas with active Non-Wires-Solutions (NWS) programs (which includes the networks served by the Brownsville 1 & 2 Area Stations in the Brooklyn Queens Demand Management (“BQDM”) Program), we would not allocate any systemwide programmatic EE. This approach differs from previous years where programmatic EE

was allocated to all networks, regardless of their participation in an NWS program. The Company made this change because the prior approach did not consider possible competition between BQDM and CECONY systemwide programs or saturation of EE from a focused initiative like BQDM. The reduced negative load modifier resulted in an approximately 30 MW increase in the total forecast for these networks.

- Electrification: The 2021 forecast includes the impact of electrification of medium and heavy-duty vehicles and electrification of appliance gas.
  - While some distinct Medium and Heavy-Duty electrification efforts were considered in the 2020 forecast, a more wide-spread and higher magnitude of adoption of Medium and Heavy-Duty electric vehicles were included for the first time in the 2021 forecasts.
  - The electrification of appliance gas includes hot water heating, cooking, and dryer gas. This accounts for the impact of New York City’s gas ban which results in new heating load from new construction being almost exclusively electric. It also includes the impact of the conversion of existing heating appliances from gas to electric.

Q. How does this forecast affect the need for capital investment in the electric system?

A. Based on the outlook for the BQDM Load Area, there is a need to advance the development of the Gateway Park Area Station and, as such, the Company will begin engineering, planning, equipment procurement, and construction during the rate plan. The Gateway Park Area Station will eventually be supplied with renewable energy by the Brooklyn Clean Energy Hub and will address load growth in the area.

Q. Was this the only impact?

A. No, but this is the most significant direct impact. As is discussed elsewhere in this testimony, these peak demand forecasts demonstrate in general that significant changes should be expected from the clean energy transition, e.g., the move to electrification, and more extreme weather.

III. T&D Capital and O&M Summary

A. Summary

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

A. The Company is planning to spend $2,458.4 million in RY1, $2,500.0 million in RY2 and $2,543.4 million in RY3.

Q. What is the Company's T&D Operations and Maintenance ("O&M") expenditure for the historic test year (the period October 1st, 2020 through September 30th, 2021) for T&D?

A. The Company's total T&D O&M expenditure for the Historic test year for T&D is $455.4 million.

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

A. The Company is planning an increase of $22.7 million for program changes in RY1, an increase of $6.8 million for program changes in RY2, and an overall decrease of $6.6 million for program changes in RY3. All the amounts discussed above are exclusive of escalations, which are described by the Accounting Panel.

B. Program and Project Type Categories

Q. How will the Company present its projected T&D capital and O&M expenditure for specific programs and projects?

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

Q. How do these categories relate to the three expenditure priorities (Core Investments, Enabling Clean Energy, and Climate Change Resilience) discussed previously?

A. The categories describe the nature of a specific program or project and have been traditionally used by the Company to categorize investments. Because projects and programs can be multi-value, each category has projects and programs that reflect one or more of our three expenditure priorities.

Q. Please provide a description of each category.

A. Each of the Company's program and project type categories are described below:

a. Risk Reduction/Reliability – This category consists of projects and programs that support the reliability and/or availability of a facility or an operational function and that reduce or mitigate a risk associated with a facility or operation through proactive replacement/upgrade strategies. The Company will invest $957.1 million in RY1, $969.8 million in RY2, and $980.1 million in RY3 in this category.

b. New Business & System Expansion – New business consists of projects and programs that connect new customers to the Company's electric system. System Expansion consists of projects and programs that increase system

capacity or that address the impact of customer demand growth or supply retirements. The Company will invest $487.4 million in RY1, $553.2 million in RY2, and $729.1 million in RY3 in this category.

c. Replacement – This category consists of projects and programs to replace failed equipment or equipment that has degraded performance, has become difficult or costly to maintain, or is approaching the end of its useful life. The Company will invest $541.8 million in RY1, $555.8 million in RY2, and $558.8 million in RY3 in this category.

d. Equipment Purchases - This category consists of projects and programs for the purchase of necessary equipment such as transformers, network protectors, switches, and meters. The Company will invest $146.0 million in RY1, $159.6 million in RY2, and $159.6 million in RY3 in this category.

e. Safety and Security – This category consists of projects and programs primarily intended to reduce the likelihood of injury or risk to public safety, enhance physical or cyber security, or comply with regulatory requirements. The Company will invest $22.3 million in RY1, $22.6 million in RY2, and $22.7 million in RY3 in this category.

f. Environmental – This category consists of projects and programs primarily intended to enhance environmental performance, reduce environmental impact, or comply with environmental requirements. The Company will invest $51.9 million in RY1, $51.6 million in RY2, and $52.1 million in RY3 in this category.

g. Information Technology – This category consists of projects and programs to improve computer systems, system development, and information and communication systems. These investments are listed in the Information Technology section of this panel but detailed testimony and white papers can be found in the Company's IT Panel testimony.

C. Expenditure Summary

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

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-1

Q. What does this exhibit show?

A. This exhibit presents an overall summary of the total T&D capital expenditures that are presented in the Panel's testimony. The exhibit first presents a summary of the Company's planned capital and O&M expenditures for each of

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

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

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

First, Electric Operations' spend in the Risk Reduction and Reliability category represents 27 percent of its planned capital expenditure. The need for increased Core and Climate Change Resilience investments in this category is driven by the expected increase in severity and frequency of major weather events because of climate change. The need is furthered by increased customer

dependency on electricity from the ongoing adoption of EVs and electrification of buildings.

New Business projects to address increasing load also make up a significant portion, 19 percent, of Electric Operations' capital spend. Total electric demand in Con Edison's service territory is expected to grow at approximately 0.4 percent per year over the next five years (2022-2026). Significant load growth in specific residential and mixed-use neighborhoods coupled with increased electrification of buildings and transportation drives the need for investment in New Business projects. The full breakdown for Electric Operations is shown in Exhibit EIOP-1, Schedule 3.

Q. Please continue with a description of Transmission investments.

A. On the Transmission system, most of the spending is for Risk Reduction and Reliability projects, making up 53 percent of capital expenditures. Increased investments in Transformers, Protective Relay and Control Systems, Transmission Cables, and Other Energy Delivery Equipment are driven by the anticipation of additional stress on the system from extreme weather, electrification, and reduced maintenance/replacement windows. Additionally, the increase of remote monitoring will help the Company identify

equipment that requires replacement. The full breakdown for Transmission is shown in Exhibit EIOP-1, Schedule 3.

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

A. Exhibit EIOP-1, Schedule 2 shows the rate year O&M T&D budgets for S&TO, SSO, and Electric Operations. The major drivers of O&M increases during the rate years are the Safety Inspection Program, the Line Clearance/Vegetation Management Program, and Meters and Customer Equipment. The Panel discusses the increases in each of these programs in the proceeding Details of T&D Programs/Projects section.

Q. Does the Company plan to seek any funding for T&D infrastructure made available through the Infrastructure Investment and Jobs Act (“IIJA”) passed by Congress and signed into law November, 15, 2021?

A. The Company is currently reviewing potential grant opportunities as outlined in the IIAJ. As the Department of Energy develops these programs over the first half of 2022, the Company may identify current or new programs or projects that align with the grant programs that are developed and apply for grants if/when it is appropriate.

Q. Do all expenditures described by the Electric Infrastructure and Operations panel match those presented by the Company’s Accounting Panel?

A. No. The capital expenditure plans for aspects of our Area Substation Load Relief Program has been recently adjusted as a result of the Company's latest load forecast. Changes may include projects that are currently planned to be in service well beyond the rate years needing to be moved forward to a point where initial work on the projects (real estate, planning, etc.) may need to begin during the rate years. In addition, the Company will make adjustments as appropriate to address project changes and adjustments in response to any significant Commission orders, such as those that may relate to planned CLCPA projects. Finally, the Company's O&M forecast will require updates for O&M expenses associated with the purchase of new utility vehicles and the Company's Safety Inspection Program. Any required adjustments will be reflected in the Company's preliminary update, including white papers.

IV. Detail of T&D Programs/Projects

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

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

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-3

Q. What does Exhibit EIOP-3 show?

A. Exhibit EIOP-3, Schedules 1 and 2 list the capital program and project funding requirements and O&M program changes required to support the Company's Risk Reduction and Reliability work conducted by S&TO, SSO, and Electric Operations for RY1, RY2, and RY3. In addition, the exhibit contains white papers that provide more detailed information on each of the capital and O&M programs/ projects in this category.

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

A. Con Edison's Risk Reduction/Reliability programs and projects are designed to maintain the operational capability, reliability, and safety of the transmission, substation, and distribution systems. The Company's programs in this category address near and long-term reliability issues. The Company analyzes, assesses, and adjusts its capital programs to focus expenditures on systems and components most in need of attention, driven by risk and impact of asset failure, load growth, climate change impacts, building and transportation electrification, or other factors. Where necessary, Con Edison programmatically upgrades and proactively replaces system components before they become degraded or obsolete.

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

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

1. System Resilience

Q. Please describe the System Resilience category.

A. Investments in the System Resilience category are designed to strengthen the Company's electric distribution system, reducing the amount of damage sustained during severe weather events, lowering the number of customers impacted by component failures, and improving the Company's ability to repair damage and restore service after extreme weather events. This category takes on increased importance as the severity and frequency of major weather events is expected to increase.

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

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

- "Condition Based Monitoring Program" ($1.5 MM RY1, $15.0 MM RY2, $15.0 MM RY3)
- "Control Cable Upgrade Program" ($4.0 MM RY2, $4.0 MM RY3)
- "Critical Facilities Program" ($9.0 MM RY1, $9.0 MM RY2, $9.0 MM RY3)
- "Erosion Protection and Drainage Upgrade Program" ($5.0 MM RY2, $5.0 MM RY3)
- "Non-Network Reliability" ($73.6 MM RY1, $87.1 MM RY2, $87.1 MM RY3)
- "Non-Network Resiliency with FLISR" ($2.1 MM RY1, $2.1 MM RY2, $2.1 MM RY3)
- "Overhead Insulator Resiliency Program" ($6.7 MM RY1, $6.7 MM RY2, $6.7 MM RY3)
- "Pole Inspection and Treatment (PIT) Program" ($2.3 MM RY1, $2.3 MM RY2, $2.3 MM RY3)
- "Primary Feeder Reliability" ($75.5 MM RY1, $77.0 MM RY2, $78.5 MM RY3)
- "Queensboro Bridge Risk Mitigation" ($20.0 MM RY1, $80.0 MM RY2, $80.0 MM RY3)
- "Replacement of Feeders M51 and M52" ($10.0 MM RY3)
- "Selective Undergrounding" ($60.0 MM RY1, $80.0 MM RY2, $100.0 MM RY3)

- "Underground Secondary Reliability" ($25.5 MM RY1, $25.8 MM RY2, $29.7 MM RY3)
- "Upgrade Light and Power System Program" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "USS Switchgear Flood Protection" ($8.5 MM RY1, $8.5 MM RY2, $8.5 MM RY3)
- "Wainwright – Willowbrook Stepdown Transformer Installation" ($8.5 MM RY1, $1.0 MM RY2)

Q. Please describe some of the key capital programs in this category starting with the Primary Feeder Reliability Program.

A. The Primary Feeder Reliability Program is aimed at maintaining and improving the reliability and resiliency of Con Edison's networks and non-network load areas. The program relies on the Network Reliability Index ("NRI"), a measure used to gauge the reliability and resiliency of all 65 second contingency networks on the Con Edison distribution system. The lower the index, the less likely for that network to experience cascading feeder outages. In addition, poor NRI performance has been associated with the need for voltage reduction actions, which can negatively impact customer equipment, especially those of commercial, industrial, and government customers. Con Edison has

expended significant effort through Core Investments over the past decade to improve all its networks to below an NRI of 1.0, and as of summer 2021 the top 25 networks have an average NRI of 0.51. As a result, the probability that a voltage reduction action is needed is lowered.

Q. What factors impact NRI?

A. Factors that impact the NRI include the number of components in the network, component failure rates, expected periods of heat stress, feeder/network loading, and the load shifts during contingencies.

Q. Does Con Edison’s plan to raise the TV design basis by one degree Fahrenheit by 2030 to account for projected climate change affect NRI?

A. Yes. Raising the TV to account for projected climate change will have a direct impact on NRI, particularly as it relates to heat stress. Applying the increased TV to current network NRI calculations results in eight networks with NRI levels greater than 1.0 and the average of the top 25 networks rises from 0.51 to 0.87.

Q. Are these results driving any proposed investments?

A. Yes. Because increasing the TV for projected climate change raises the NRI, we need significant investments, during the rate plan, to maintain current NRI levels, namely an NRI below 1.0 on all networks and an average NRI for the top 25

networks that is close to the present 0.5. The work required between now and 2030 to maintain system reliability in the face of increased temperatures, load growth associated with electrification, and other factors falls into three broad categories: 1) Paper Insulated Lead Covered (“PILC”) cable replacement to reduce failure rates in summer months; 2) underground interrupter installation to allow isolation of a faulted segment of a feeder while the un-faulted portion remains energized; and 3) new and extended feeders to increase resiliency and accommodate future load growth, to include growth driven by electrification.

Q. Please continue by describing the USS Switchgear Flood Protection Program.

A. As a result of climate change, the Company’s service territory is facing an increased risk of coastal flooding. The USS Switchgear Flood Protection Program provides mitigation measures to minimize damage from flooding. Post-Sandy Storm Hardening efforts brought all stations in the 100-year flood plain to FEMA +3. Based on design standards adopted following the CCVS, the Company is already installing some assets based on a FEMA +4/5 standard, due to future increasing vulnerability to coastal flooding. Additionally, historic torrential rainfall, such as that

experienced during Hurricane Ida in 2021, puts unit substations outside of the floodplain at risk of flood damage.

To protect the unit substation switchgear from increased flood risk, this program upgrades the USS switchgear by installing new elevated recloser switches instead of traditional switchgear. Platforms will elevate critical switchgear components above anticipated flood levels to minimize exposure to flood waters. Use of standard and widely available recloser switch installations will enable fast repairs at a lower cost when damage does occur.

Few third-party specialty vendors can repair the Company’s custom designed unit substation switchgears. Limited vendor availability and long lead times associated with these repairs put customers at risk of prolonged outages while also adding significant cost. Recloser switches are self-contained devices that can be repaired or replaced individually, offering modular features that traditional switchgear breakers lack. Installing recloser switches will allow for expedited and lower cost repairs. These switchgear upgrades will improve resiliency in the presence of increased flooding risk while also providing

remote, secure access to digital data to prioritize system restoration.

Q. Please describe the Company's new Selective Undergrounding Program.

A. Con Edison's Selective Undergrounding Program is a significant part of the Company's climate adaptation strategy to mitigate the extent of customer outages resulting from major storms and generally increase system resiliency. The Company plans to spend $240 million during the rate years to convert approximately 24 miles of overhead distribution to underground distribution. With the expectation that major storms will increase in both severity and frequency because of climate change, the program will identify and prioritize sections (spurs) of Con Edison's overhead distribution system, where customers frequently experience outages caused by severe weather, for undergrounding. In addition to entirely avoiding some storm-related outages, the Selective Undergrounding Program will also improve the Company's major event restoration performance on a system-wide and local basis through the minimization of long-duration, low customer impacted outages, freeing restoration crews to address other outages. Finally, the program is consistent with the CLCPA because it prioritizes disadvantaged communities.

Q. Please elaborate on how the program prioritizes disadvantaged communities.

A. The Company's typical prioritization looks at the circuit performance as it relates to customer interruptions during normal and weather events. The model currently in use to analyze our circuit performance is called Overhead Program Optimization Tool ("OHPOT"). For Selective Undergrounding, we are incorporating disadvantaged community data into the OHPOT model and have created a weighting system to determine the prioritization of circuits.

Q. Will this be Con Edison's first time launching a selective undergrounding program?

A. No, we are currently conducting an undergrounding pilot program.

Q. Please discuss the pilot program and its status.

A. The pilots are in three locations 1) Queens, 2) Westchester, and 3) Staten Island. The Queens pilot included undergrounding portions of overhead primary and secondary distribution to improve the system reliability for 500 customers and was completed in January 2022. The Westchester pilot is undergrounding an overhead sub spur that has a history of outages caused by tree limb contact, including 244 hours of outage resulting from winter storms Riley and Quinn. Construction has commenced on the

Westchester pilot with an expected completion in mid-2022. Con Edison was not able to gain customer participation for the first location selected for the Staten Island pilot. The Company is currently in the process of engaging with customers for a second location. Per the settlement agreement approved by the Commission in Case 20-E-0422 et al., Con Edison agreed to pay from shareholder funds all costs customers would otherwise be responsible for under the pilot program up to $750,000. As of January 2022 the Company has paid approximately $236,000 in Customer Undergrounding Costs.

Q. Please describe the Non-Network Reliability Program.

A. The overhead distribution system is comprised of non-network circuits, including 4kV primary grids and 4kV, 13kV, and 27kV auto loops. This program increases reliability for customers by ranking non-network circuits and proactively investing in the lowest performing circuits. This program is a multi-value investment because it will make the non-network system more resilient in the face of more frequent and severe storms in addition to improving reliability.

Q. How does the Company conduct the non-network circuit ranking?

A. The Company uses standard industry metrics, combined with analysis of outages through the OHPOT system so that it can identify and target the lower performing networks for remediation.

Q. Please explain the work involved in this program.

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

Q. Please describe the Queensboro Bridge Risk Mitigation Project.

A. There are six 138kV feeders and six 69kV feeders that traverse the Queensboro Bridge. The bridge has been identified as a potential common mode failure and significant potential risk because failure could result in significant outages. If failure were to occur it would take out most of the supply to the east side of Manhattan. The 138kV feeders have previously experienced joint failures

and the 69kV feeders have experienced nitrogen leaks that are costly to repair and could impact cable life. This project will remove the six feeders and replace them with new cable in trenchless crossings underneath the East River. The 138kV feeders will be prioritized for replacement under the project but the design will consider the need to eventually move the remaining feeders off the Queensboro Bridge.

Q. Please describe the Company's plans to replace Feeders M51 and M52.

A. Feeders M51 and M52 were installed in 1974, and within the past ten years have seen over 250 leaks totaling 197,000 gallons of dielectric fluid released, roughly 25 percent of the total volume of dielectric fluid contained in the two feeders. As a result, the Company will replace both 345kV feeders M51 and M52 (each approximately 17 miles long) utilizing a new route to the W49th Street Substation. High pressure fluid filled ("HPFF") cable will be replaced with cross-linked polyethylene insulated ("XLPE") cable. The XLPE portion will be a combination of submarine cable and underground cable in duct banks.

Q. Please describe the importance Feeders M51 and M52.

A. Feeders M51 and M52 have been critical transmission assets moving upstate generation to the load center in New York

City. As more bulk renewables connect to the Con Edison transmission system, Feeders M51 and M52 will play an even more critical role as they will be integral to moving clean energy to other parts of the service territory.

Q. What are the environmental and cost benefits of replacing feeders M51 and M52?

A. Replacement of M51 and M52 with XLPE cable would eliminate dielectric fluid leaks in two of the worst performing feeders on the system and eliminate environmental risks associated with the Harlem River crossing. Feeders M51 and M52 also present a maintenance burden for the Company. The feeders average 1,500 to 2,000 hours per year in corrective maintenance, which is 3.5-5 standard deviations above the mean for the rest of the 345kV feeder population. Leak response and remediation has also required a considerable amount of funding, averaging approximately $5 million a year in recent years. The elimination of the maintenance and emergency response burden associated with Feeders M51 and M52 will reduce expenses and free up Company resources for other work on the system. Further, it would also make conduit available to facilitate the future transfer of clean energy into the area, supporting the State’s CLCPA goals.

Q. What is the Company’s funding request in this rate case?

A. The Company is requesting funding of $10 million in 2025 to begin a more detailed route study, involving test pitting and geotechnical surveys. Construction is estimated to be completed by the end of 2028.

Q. Please describe the Overhead Insulator Resiliency Program.

A. Through this program, which is a new program targeting system resiliency, the Company will systematically replace crack prone insulators on critical overhead transmission lines. Specifically, some porcelain insulators on the transmission lines have been found to be prone to cracks that can ultimately lead to failures. The program scope involves the replacement of 8,595 porcelain insulator bells on 573 insulator strings on lines that include critical overhead transmission feeders supplying power to the City and Westchester County. The replacement of these insulators will increase system resiliency by lowering the risk of load shedding and large-scale outages resulting from multiple failures during a high-load period or contingency, a risk that increases due to warming and more frequent and severe storms.

Q. Please describe the Condition Based Monitoring Program.

A. This program will install different monitoring devices on substation power transformers and other equipment. Some of these devices include temperature monitoring devices;

Intelligent Electronic Devices that interface with instruments and other equipment; monitoring devices for substation battery banks; Geomagnetically Induced Current monitoring devices that detect tank heating on select units; and in some cases associated software platforms.

Q. Why is this program important?

A. Substation power transformers are critical to delivering electricity and, along with battery banks, are essential to re-energizing a substation after an emergency. This program will allow us to more accurately receive data on temperatures and substation battery bank status without requiring and in-person reading. This enables operations to make the best possible decisions. It also provides the ability to understand the effects of climate change on equipment over the long term to improve planning in the form of ratings and replacement cycles. The lack of continuous data makes long-term decisions about transformer load and ratings more difficult. Moreover, during peak and/or contingency scenarios, the ability to remotely monitor transformer temperatures allows operators and engineers to make informed and timely decisions regarding operation of the system. The increased frequency, intensity, and duration of heat waves that are projected in the Company’s Climate Change Vulnerability Study and CCIP

make real-time monitoring of substation equipment more critical than ever.

Q. Please describe the Control Cable Upgrade Program.

A. This program will replace all the copper control cable in a substation as well as the troughs and raceways that house these cables as needed. Control cables represent a critical component within substations as they connect local cabinets at devices like breakers, transformers, and relay panels to the substation’s control and/or automation system, among other things. These cables can degrade over the life of the substation or as the result of extreme weather causing the insulation to break down, potentially providing an entry point for water that corrodes the copper and creates grounds. This program will begin in 2024, will target two substations at a time, and assumes each station will take 5 years to complete. Extreme weather, such as heavy rain events, poses a significant risk to substations that have pervasive problems with degrading control cabling. In order to adapt to changing weather patterns driven by climate change, this program is necessary to mitigate the risk of dropping customers as the result of a substation event.

Q. Since it also focuses on adapting to extreme weather, please continue by describing the Erosion Protection and Drainage Upgrade Program.

A. This program will install reinforcements and upgrade drainage systems in select substations to protect from erosion that may occur during extreme rain events. Extreme rain events, such as Tropical Storm Ida, have produced rainfall of 4 to 8 inches in just a few hours. This type of deluge can cause pooling and in some cases erosion that could undermine substation equipment. If extreme enough, these impacts could cause critical substation equipment to lose control power or inadvertently trip out, resulting in outages. Erosion caused by extreme rain events could also create unsafe conditions for substation personnel. The program will start in 2024 and will target upgrades at roughly two substations per year.

Q. Please describe the Non-Network Resiliency with FLISR Program.

A. This program will replace older sectionalizing equipment with new technology that will further enhance Fault Location, Isolation, and Service Restoration (“FLISR”) capabilities. Con Edison has progressively developed FLISR capabilities on the Non-Network portion of its distribution system through the deployment of protective devices like reclosers and sectionalizing switches. These devices allow the Company to locate faults, isolate the damaged conductors and/or equipment, and restore service to

customers on undamaged portions of the circuit(s). Work completed via this program will expand these capabilities through deployment of Smart Switches – i.e., devices with Supervisory control and data acquisition ("SCADA") capability and/or the ability to operate automatically without operator intervention.

The SCADA capability of the newer sectionalizing equipment provides greater visibility and remote control of the switch, and the dead front and enclosed bus design requires less maintenance, is safer for mechanics to work on, and is less prone to outages caused by animal infestation. The new smart switches will also provide additional information to the Outage Management System ("OMS"), which, along with additional controllable devices, will provide greater flexibility for restoration when a failure occurs.

2. Transformers, Breakers, and Other Energy Delivery Equipment

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

A. The Company's T&D systems transmit power through equipment located within substations and above or below the streets of New York City and Westchester County. Each type of

equipment has its own purpose, historical performance, and functional lifecycle. This rate filing contains projects and programs to address: 1) proactive upgrades and replacements of these assets and 2) replacements or upgrades when the equipment will exceed its design basis.

Q. Does the Company anticipate an increase in investment in transformers, breakers, and other energy delivery equipment in the rate years when compared to years past?

A. Yes. The increased investment is primarily driven by the projected impacts of climate change. Warming, including an increase in hotter days, along with increasing loads due to transportation electrification, will place additional stress on transformers, breakers, and other energy delivery equipment that could lead to higher failure rates and the need for more replacements prior to failure.

More targeted inspection programs and the introduction of remote monitoring has helped the Company identify an increasing number of pieces of equipment that require replacement.

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

A. The programs in this category include those that replace equipment based on asset management methodology, installations of equipment that enhance reliability, and

address equipment that has an elevated risk of failure or that is no longer supported by manufacturers.

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

- "4kV USS Switchgear House Replacement" ($13.2 MM RY1, $13.2 MM RY2, $13.2 MM RY3)
- "Area Substation Phased Replacement Program" ($30.0 MM RY1, $30.0 MM RY2, $30.0 MM RY3)
- "Area Substation Reliability" ($11.5 MM RY1, $11.5 MM RY2, $11.5 MM RY3)
- "Auxiliary Station Equipment Program" ($1.1 MM RY1, $1.1 MM RY2, $1.1 MM RY3)
- "Circuit Switcher Replacement Program" ($1.4 MM RY1, $1.4 MM RY2, $1.4 MM RY3)
- "Disconnect Switch Capital Upgrade Program" ($5.2 MM RY1, $5.2 MM RY2, $5.2 MM RY3)
- "Feeder 38R51 and 38R52 Replacement Project" ($122.0 MM RY1)
- "Feeder Replacement Program" ($2.5 MM RY1, $3.5 MM RY2, $3.5 MM RY3)

- "Gas Insulated Substation Replacement Program" ($13.0 MM RY1, $28.5 MM RY2, $28.5 MM RY3)
- "High Voltage Circuit Breaker Capital Upgrade Program" ($25.4 RY1, $23.4 MM RY2, $24.8 MM RY3)
- "High Voltage Test Set Program" ($2.8 MM RY1, $2.8 MM RY2, $2.8 MM RY3)
- "Other Capital Equipment Upgrades Program" ($3.5 MM RY1, $3.5 MM RY2, $3.5 MM RY3)
- "Joint Replacement Program" ($10.5 MM RY1, $13.0 MM RY2, $13.0 MM RY3)
- "Reinforced Ground Grid Program" ($6.1 MM RY1, $6.1 MM RY2, $6.1 MM RY3)
- "Substation Loss Contingency – Rapid Recovery of an Area Substation/Transmission Resiliency Transformers" ($4.0 MM RY1)
- "Substation Transformer Replacement Program" ($124.0 MM RY1, $124.0 MM RY2, $124.0 MM RY3)
- "Unit Substation Transformer Replacement Program" ($3.9 MM RY1, $3.9 MM RY2, $3.9 MM RY3)
- "U-Type Bushing Replacement Program" ($5.6 MM RY1, $5.1 MM RY2, $4.4 MM RY3)

Q. Please describe the two most significant investments in this category, starting with the Transformer Installation Program.

A. This program involves the replacement of electrical distribution equipment (primarily underground network transformers and their associated network protector, cable, conduit, and structures) that have defects indicative of failure or eventual failure. Defective equipment replacements account for approximately 55 percent of all transformer installations. These components are identified for removal based on equipment condition determined from visual inspection, dissolved gas in oil analysis, and remote sensors which report pressure, temperature, and oil level and prioritization based on the risk of failure.

Con Edison has instituted more comprehensive underground transformer inspection program and has also installed remote monitoring equipment on transformers to provide real-time pressure and temperature readings. As a result of this increased monitoring, the Company has identified an increased number of units needing replacement to maintain system reliability. This program improves reliability by identifying transformers for replacement prior to failure, avoiding the loss of multiple feeders in the same network, which could result in customer outages.

In addition, the program also improves public safety by reducing the risk of transformer ruptures.

Q. Please continue by describing the Substation Transformer Replacement Program.

A. This program is designed to proactively replace transformers that the Company has determined are nearing the end of their useful lives and cannot be maintained in reliable operating condition. There are 422 power transformers on the Con Edison system, of which 185 have been in service for over 40 years. As these units age, there is an increase in required corrective maintenance and the potential for malfunction, especially during high load periods and/or coincident with other outages. Replacing defective transformers prior to failure improves reliability. During the past two decades, an increased replacement frequency of power transformers is positively associated with a significant reduction in the number of failures comparing to those in the prior two decades.

Given the age of the transformer fleet, more proactive replacements per year will be needed to reduce in-service failures and maintain current reliability levels for customers. The Company’s analysis indicates that eight proactive replacements are required to maintain current reliability levels. Further, the Company’s CCIP suggests

that over the coming decades there will be more days per year with maximum daily temperature above 95 degrees Fahrenheit, potentially more than doubling from today's average. Increased frequency of high ambient temperature days will mean that transformers are operating in challenging conditions more often, as well as being more heavily loaded as hot weather translates to higher electrical demand. In addition, building and transportation electrification will increase demand on the electric system, particularly in the winter months, resulting in accelerated transformer aging. These factors could lead to an increase in transformer failure rates over the course of the next ten years. For these reasons, the Company must perform eight proactive transformer replacements per year for the next five years to maintain reliability. Failure rates will also be closely monitored to determine if increased proactive replacements are needed in the second half of the decade due to climate change and electrification.

Q. How does the Company determine, in a given planning period, which specific transformers to replace?

A. The Company uses a health index to prioritize units for replacement.

Q. What factors does the transformer health index consider?

A. The factors include, but are not limited to, dissolved gas in oil analysis ("DGOA"), insulation condition as indicated by oil analysis, the presence of leaks, and the insulation condition of units of the same vintage that have already failed in service or have been replaced.

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

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

- "Shunt Reactor" ($5.0 MM RY1, $5.0 MM RY2, $5.0 MM RY3)
- "Retrofit Overduty 13kV and 27kV Circuit Breaker Program" ($13.8 MM RY1, $13.8 MM RY2, $13.8 MM RY3)

3. Monitoring, Supervisory, Protection, and Auxiliary Systems

Q. Please provide a general overview of this category.

A. To reliably operate its T&D assets, the Company makes Core Investments to maintain monitoring, supervisory, protection, and auxiliary systems. Monitoring systems measure and communicate key parameters of operating performance to engineers and operators, who use this data

to proactively identify equipment maintenance issues and/or early stages of failure. Supervisory systems include automation systems for substation operators and systems that aid Energy Control Center (“ECC”) operators in reacting to system events, faults, and contingencies while balancing changes in generation and electrical demand. Auxiliary systems facilitate the operation and monitoring of various components of the transmission system and include direct current systems that provide control power to switching and protection equipment, pressurization systems that help maintain the dielectric properties of transmission feeders, and Capacitive Coupling Potential Devices (“CCPD”) that measure system voltages and power flow. Finally, to reliably operate its substation and transmission system, the Company uses over 60,000 protective relays, which sense system disturbances and irregularities and automatically remove equipment from service that may be at risk of damage or failure. The Company makes investments annually in its protective relay systems to improve their operation, maintain regulatory compliance, and reduce specific risks that may contribute to transmission system forced outages.

Q. What investments does the Company plan to make within the monitoring, supervisory, protection, and auxiliary systems category?

A. The Company has 21 capital projects to support the development and upgrade of its monitoring, supervisory, protection, and auxiliary. Details on each of these projects can be found in EIOP-3, Schedule 3.

- "138kV Disturbance Monitoring Program" ($4.8 MM RY1, $4.8 MM RY2, $4.8 MM RY3)
- "Category Alarm Program – Various" ($2.3 MM RY1, $2.1 MM RY2, $2.2 MM RY3)
- "DC System Upgrade Program" ($5.1 MM RY1, $5.1 MM RY2, $5.1 MM RY3)
- "Distribution Order Enhancements" ($0.3 MM RY1, $0.3 MM RY2, $0.4 MM RY3)
- "Dynamic Feeder Rating System" ($1.0 MM RY1, $1.5 MM RY2, $1.5 MM RY3)
- "East River Automation – Upgrade the 69kV Yard" ($3.0 MM RY1)
- "EMS DevOps Upgrade" ($2.5 MM RY1, $2.5 MM RY2, $3.3 MM RY3)
- "Fire Suppression System Upgrades" ($12.1 MM RY1, $12.4 MM RY2, $12.3 MM RY3)

- "Overhead Transmission Reliability Program" ($1.0 MM RY1, $1.5 MM RY2, $1.5 MM RY3)
- "Pothead Pressure Alarms Program" ($0.2 MM RY1, $0.2 MM RY2, $0.2 MM RY3)
- "Pressure, Temperature and Oil Sensors" ($2.0 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- "Protection, Control and Automation" ($38.5 MM RY1, $33.5 MM RY2, $20.0 MM RY3)
- "Pumping Plant Improvement Project" ($4.8 MM RY1, $3.9 MM RY2, $3.9 MM RY3)
- "Relay Modifications Program" ($78.4 MM RY1, $89.9 MM RY2, $76.4 MM RY3)
- "Relay Protection Communications Upgrade Program" ($16.5 MM RY1, $16.5 MM RY2, $16.5 MM RY3)
- "Remote Monitoring System" ($3.2 MM RY1, $3.2 MM RY2, $3.2 MM RY3)
- "RTU Upgrade Program" ($2.5 MM RY1, $2.5 MM RY2, $2.5 MM RY3)
- "Smart Sensors" ($15.1 MM RY1, $15.1 MM RY2, $15.1 MM RY3)
- "System Operations Enhancements" ($0.4 MM RY1, $0.4 MM RY2, $0.5 MM RY3)

- "Transmission Station Metering and SCADA Upgrades Program" ($3.2 MM RY1, $3.1 MM RY2, $3.1 MM RY3)
- "Unit Substation Modernization" ($0.6 MM RY1, $0.6 MM RY2, $0.6 MM RY3)

Q. Please describe some of the key programs in this category starting with the Remote Monitoring System Program.

A. This program replaces defective units and installs new Remote Monitoring System ("RMS") third and fourth generation transmitters at various network transformer vault locations in all regions. Third generation transmitters are data collection, consolidation, and transmission devices, and fourth generation transmitters have two-way communication. Both generations transmit data via power line carrier ("PLC") communication on the secondary of the transformer to the RMS database. An average of 2,000 third generation units and 1,500 fourth generation units will be installed per year by the Company.

The remote monitoring system provides insight into the health and operational status of network transformers. Data from this system can indicate an alive on backfeed ("ABF") condition, helping to expedite feeder restoration during an outage. Both third and fourth generation transmitters also communicate transformer oil levels, which could identify leaks before catastrophic failures. In addition, this

ongoing work is required to comply with the Reliability Performance Mechanism ("RPM") associated with the RMS mandated by the PSC.

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

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

Q. Have electrification, climate change, and renewable generation affected the significance of investing in relay protection and control systems?

A. Yes, electrification, climate change, and renewable generation all increase the importance of investing in relay protection and control systems.

Q. Please explain how electrification impacts investment in protection and control systems.

A. Electrification of buildings, along EV charging will place a much greater demand on system capacity for longer periods throughout the year. Consequently, seasons that were previously “off-peak” may now exhibit capacity demands that match or exceed previous summer peaks. The introduction of a significant winter load will reduce the available time to de-energize equipment for maintenance, replacement and/or testing. For relay protection and control systems, this means that the ability to retrieve, analyze and adjust performance parameters must be modernized and streamlined. Relay and control systems that must be locally and manually tested will become very difficult to maintain under the increased demand cycle that is coming with electrification. Conversely, relay and control systems that are self-diagnostic and can be remotely accessed by operators and engineers will streamline and reduce the necessity for planned outages.

Q. Please explain why increased investment in relay protection and control systems is important in light of climate change.

A. The increased frequency and variation of extreme weather events will require relay protection and control systems to

be weather hardened. Relay panels that are installed outdoors and in degraded condition are susceptible to water intrusion from extreme rain events. Along the same lines, degraded copper control wiring will exhibit grounds when water pools during these types of events. Installing weather hardened relay panels and fiber optic communication networks in substations will help adapt these systems to climate change.

Q. Please describe how renewable generation interconnecting to the transmission system affects investment in relay protection and control systems.

A. Renewable generation may subject the transmission system to more power swings, frequency excursions and lower fault currents. Adapting protection and control systems to handle these changes will require remotely accessible data and the ability to adjust system protection and control parameters quickly and efficiently. Adapting to these changes while using electromechanical relay systems, that are manually set and adjusted, will not only be inefficient but will also provide no advanced warning of improper settings. An expansion of cyber secure connections, microprocessor-based systems and data bases are required to meet the challenges of bulk renewables to the transmission system.

Q. Please describe the Company's three investments related to relays and control systems starting with the Relay Modifications Program.

A. This program replaces relays protection systems at area and transmission substations, continuing to target transmission relays that exhibit reliability issues. The program will also be expanded to include upgrades to area station bus and feeder protection, installations that eliminate single points of failure, and replacement for some early microprocessor relays. The Company plans for approximately eight transmission relay upgrades, eight to ten area station bus section/feeder upgrades, legacy microprocessor relay upgrades at eight stations, two single point of failure upgrades, and ten Under Frequency Load Shedding ("UFLS") panel upgrades per year.

The Company has always prioritized relay upgrades because of the vital role they play. However, events in recent years, such as the West Side Outage (2019) and Fresh Kills (2021) have shown that some strategic changes to relay upgrade philosophy, including more standardization and prioritizing area station relay systems, would be beneficial. Legacy systems with known reliability issues on the transmission system will continue to be prioritized for replacement under this program, but it will also be

expanded to focus on area station relays, USFL panel upgrades, and single point of failure projects, all critical to avoiding events like the West Side Outage and Fresh Kills in the future. In addition, the upgrade to relay systems that are either self-resetting or can be reset remotely will improve outage recovery times following extreme weather events, expected to become more frequent and severe due to climate change. Standardization, and the associated modularity, will also better facilitate the quick replacement of relay components following extreme weather events that may have caused their failure.

Q. Please continue by describing the Relay Protection Communications Upgrade Program.

A. The intent of this program is to replace older relay communications infrastructure. For most locations, this program will also provide two independent communication systems for relay protection. The work will take place at various locations throughout the system and will be divided into three categories: 1) upgrade of the Corporate Communication Telephone Network (“CCTN”), 2) upgrade of the Verizon communications infrastructure, and 3) upgrade of relay protection equipment.

The program’s primary objective is upgrade or replacement of relay communication lines that have

exhibited repeated disruptions or have failed. In addition, degraded communication infrastructure, particularly copper lines, are more vulnerable to extreme weather events. Flooding from extreme rain or other weather events can cause disruptions to communication lines that can lead to a loss of protection or potentially cause relay systems to mis-operate or delay recovery following events. The upgrade to CCTN is an important component of resiliency and the Company's Climate Change Resilience approach. Finally, eliminating single point mode of failure in the relay protection communication networks will also increase the reliability of the electric.

Q. Please describe the Protection, Control, and Automation Program.

A. This program will upgrade substation protection, control, energy management system ("EMS") interfaces, and/or operator interfaces. It includes upgrading the SCADA systems to human machine interface ("HMI"), microprocessor-based systems, replacing copper wiring with a fiber optic network, and weather hardening relay panels to protect from extreme weather and flooding. In addition, the installation of data diodes as part of this program will increase cybersecurity and facilitate NERC compliant data retrieval and event analysis capabilities at all substations.

Locations for upgrade will be prioritized based on substations that have exhibited reliability issues in the past and those in which upgrades will best facilitate the migration to the latest protection and control protocols. This program will also allow the Company to have remote, secure access to digital information to be able to make timely decisions and restore equipment to service as quickly as possible when system disturbances do occur.

Q. Please continue by describing the Smart Sensors Program.

A. Con Edison plans to build upon existing sensor platforms through new sensor hardware and analytical solutions. Specifically, the Company will focus on two main aspects of the program: 1) the Structure Observation System ("SOS") that monitors structures or any other asset for energized objects and manhole event precursor environmental changes, such as hot spots in cables or accessories or the presence of combustible gases, leveraging available sensor technology and 2) Network Protectors ("NWPs") that expand sensing capability by adding condition monitoring and enable software algorithms to improve reliability of the network protector.

The SOS is a general platform that includes both an integrated environmental monitoring solution as well as a platform for integrating other equipment sensor data and

algorithms. An example of the integration of devices and analytics is thermal imaging, which uses infrared sensors to identify hot spots and trigger a field response to make a repair on the defective condition. The Company is developing machine learning algorithms that analyze these images to automatically identify defects as images are received from sensors or inspections. Another example is the smart primary splice with embedded sensors that will provide information on the primary network and condition of primary cable and splices, which will improve public/employee safety, facilitate monitoring of the health of the network primary assets, and improve feeder restoration.

The NWP is a general platform that includes both the integrated pressure, temperature solution as well as a platform for integrating other equipment sensor data and algorithms. Historically pressure monitoring of network transformers has proven successful at maintaining equipment reliability. It is expected this same benefit will be extended by installing additional sensors. A specific example of a sensor to be installed is the NWP Pressure Sensor which will be added to submersible NWP housings to help determine if there is a leak or fault in the housing. Similarly, pressure and temperature sensors on transformers

will help the Company determine the status of network transformers and provide data to trigger a field visit. These data driven field visits are a more efficient and effective use of resources than time-based inspections. Another example is the NWP Auto Exercise capability which enables a self-diagnostic test of NWP functionality. Failed tests trigger a field visit for troubleshooting and repair. This can reduce ABF events by ensuring malfunctioning NWPs are addressed before an operation is needed. This acceleration of sensing technologies, currently deployed on a targeted reliability-focused basis, will provide greater situational awareness of the electric system and leverage data analytics and advanced management systems to more effectively plan and operate the system. The deployment of these sensors offers public safety benefits, operational efficiencies, and increased reliability and resiliency of the electric system.

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

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

A. The next type of equipment within the Risk Reduction/Reliability category includes non-power carrying assets that house or structurally support energy delivery,

supervisory, communication, or protection assets, or that support general T&D operations.

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

A. The Company is planning to invest in such systems to proactively address degraded structural support systems that, upon failure, would pose a risk to maintaining the availability of important energy delivery equipment. In addition, many of these projects enhance the safety and security of the Company's employees and the public. The Company's equipment, feeders, cables, and wires require structural support systems to maintain proper electrical clearances and support substantial assets such as power transformers. As with many other aspects of the system, Con Edison anticipates that structures, housings, buildings, and other miscellaneous assets will experience the impacts of climate change, especially major storms and torrential rain which are expected to become more frequent and severe in the coming years.

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

- "Overhead Transmission Structures Program" ($3.0 MM RY1, $3.0 MM RY2, $3.0 MM RY3)
- "Right of Way Roadway Access" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "Roof Replacement Program" ($4.8 MM RY1, $4.8 MM RY2, $4.8 MM RY3)
- "Stabilization of Pothead Stand Supports/Settlement" ($2.5 MM RY1, $2.5 MM RY2, $2.5 MM RY3)
- "Structural and Infrastructure Upgrades Program" ($6.7 MM RY1, $14.4 MM RY2, $14.4 MM RY3)
- "Substation Enclosure Upgrade Program" ($1.9 MM RY1, $1.9 MM RY2, $1.9 MM RY3)
- "Transformer Vault and Structures Modernization" ($41.1 MM RY1, $42.3 MM RY2, $43.5 MM RY3)
- "Unit Substation Upgrade and Improvement" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)

Q. Please describe the largest investment in this group, the Transformer Vault and Structures Modernization.

A. This program involves the proactive repair of structural deficiencies in deteriorated transformer vaults, manholes and service boxes. These structures are located in the streets and sidewalks throughout our service territory. Structural deficiencies include settlement, cracked

concrete, spalled concrete, collapsed walls, collapsed ceilings, corroded steel beams and columns, and corroded rebar. If unrepaired, structural deficiencies in deteriorated vaults present a risk of collapse that can be a hazard to the public and employees and can compromise system reliability by causing damage to electric infrastructure or delays in work on equipment and cables. Program funding has been increased to reduce the number of structures identified with deficiencies, while also helping to identify structures impacted by extreme weather and torrential rainfall driven by climate change.

5. O&M Program Changes

Q. Is the Company proposing any Risk & Reliability O&M program changes?

A. Yes. The Company is proposing changes to the Line Clearance/Vegetation Management Program and the Storm Emergency Vehicle Maintenance Program. The Company's Storm Response and Resilience Panel will discuss the maintenance for the Company's emergency response vehicles.

Q. Please discuss the Company's proposed changes to the Line Clearance/Vegetation Management Program.

A. The Company plans to increase funding for line clearance and vegetation management to further mitigate storm damage, as severe weather events are expected to increase in

frequency and severity because of climate change. Specifically, the Line Clearance/Vegetation Management Program will focus on cycle trimming, on right of way tree removals, tree toppings, tree related customer inquiry investigations, and hazardous tree removal. Much of the increased funding for this program will be driven by Company's plan to replace the current tree topping process with a full tree removal. Con Edison is currently in negotiations with the NYC Parks Department on the implementation of a Memorandum of Understanding ("MOU") to that effect. This program change will require an increase of $2.8 MM in RY1, $0.4 MM in RY2, and $0.4 MM in RY3.

6. Staffing

Q. Does the Company need additional staffing?

A. Yes. As described throughout this panel's testimony, the Company is planning to expand several programs to strengthen its electric distribution system, reduce the damage sustained during severe weather events, lower the number of customers impacted by outages, and improve the Company's ability to repair damage and restore service following extreme weather events. This additional work, which is explained in this testimony and associated whitepapers, requires additional personnel. For example, compared to 2022, our planned capital work volume is

expected to increase by over 45 percent by 2023. The Company estimates that it will need at least 200 new employees to complete this capital work and will need to purchase trucks and equipment for these employees, as described in the Shared Services Panel testimony. As noted in that testimony, we will be providing the number of employees to the Shared Services Panel, prior to the preliminary update so that Shared Services can update its capital request at that phase.

Q. Is this additional work Company labor, contract labor, or both?

A. Both Company labor and contract labor will be used to execute the additional work.

Q. What is the estimated cost associated with these additional positions?

A. The cost associated with these positions is included in the costs of the programs/projects we have discussed throughout this panel’s testimony. As explained by the Shared Services Panel, because we are still in the process of finalizing the number of new employees, we have not yet made final determinations about the equipment or vehicles needed to support them, and thus the Company has not yet estimated the O&M or capital associated with the new equipment and vehicles. The Shared Services Panel will provide the

capital information for the new vehicles and EIOP will provide the required O&M information when the Company files its preliminary update.

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

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

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

1. Investment Approach Overview

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

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-4

Q. What does Exhibit EIOP-4 show?

A. Exhibit EIOP-4, Schedules 1 and 2 list the capital program and project funding requirements and O&M program changes required to support New Business and System Expansion work conducted by S&TO, SSO, and Electric Operations for RY1,

RY2, and RY3. The exhibit also contains white papers for each capital and O&M program/project in this category that provide more detailed information, such as program and project work description, justification, alternatives, estimated completion date, current status, relationship to long-range plans, and forecasted funding.

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

A. As stated previously, the forecasted increase in customer demand and transportation and building electrification in certain networks results in forecasted capacity constraints that the Company must address. The Company must invest in its transmission system, substation infrastructure, and local distribution system to relieve those capacity constraints and serve the additional customer load. Following its well-established process, the Company uses the following approaches to mitigate capacity constraints on the system: 1) engage customers to reduce demand through non-wires solutions; 2) replace existing assets with ones that have higher capacity ratings; 3) install additional assets to increase system capacity, and 4) transfer load to other areas with spare capacity.

2. Non-Wires Solutions

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

A. When the Company identifies a system constraint driven by customer demand it evaluates the ability of an NWS to meet that need.

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

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

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

A. The Company starts by identifying areas of its system that have forecasted overloads and require load relief to maintain reliability. The Company then determines whether the identified need is a suitable candidate for a NWS by assessing it against the Company’s NWS suitability

criteria. The suitability criteria identify projects that: 1) are for load relief, 2) have enough lead time to pursue a NWS without foreclosing the opportunity to install a traditional solution if needed, and 3) meets the financial threshold. If the Company's suitability criteria are satisfied, the Company conducts a competitive solicitation for non-traditional solutions to determine if a NWS portfolio is feasible and cost beneficial.

Q. Has the Company identified any new NWS opportunities based on the NWS suitability criteria?

A. In addition to the Company's active NWS portfolios, Con Edison has identified two potential NWS opportunities related to the 1) Jamaica Substation - Replace Limiting 27kV Bus Sections Project and 2) the Parkview TR5 and Feeder 38M85 Project. These traditional solutions are each currently being evaluated for viability to defer with NWS.

3. Utility Solutions

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

A. The Company considers multiple approaches to cost-effectively mitigate capacity constraints on the system. During the rate plan years for this filing, the Company has projects that include one or more of the following traditional system expansion categories: 1) upgrade or

replace existing assets with ones that have higher capacity ratings; 2) install additional assets to increase system capacity, and 3) transfer load to other areas with spare capacity.

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

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

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

A. In cases where capacity constraints cannot be relieved through demand reduction or equipment replacement, the Company will install additional equipment to handle the increased load and relieve capacity constraints. This category includes the installation of additional assets such as equipment on primary feeder cables, transformers, secondary cables and wires, on-site utility energy storage equipment, as described further in the Company’s Customer Energy Solutions Panel, and underground and overhead services.

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

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

Q. Please list the capital programs within the New Business and System Expansion work category.

A. The Company's New Business and System Expansion investments include:

- "179th St Area Substation Reconstruction" ($0.5 MM RY1)
- "Amtrak PSA – OAK" ($5.0 MM RY1, $5.0 MM RY2)
- "Brownsville Area Load Relief" ($35.3 MM RY1, $26.0 MM RY2, $27.0 MM RY3)
- "Crown Heights Network Split" ($12.5 MM RY3)
- "Ed Koch Queensboro Bridge 13kV Riser Replacement" ($0.8 MM RY2, $1.6 MM RY3)

- "Emergent Load Relief Program" ($1.1 MM RY1, $1.1 MM RY2, $1.1 MM RY3)
- "Farragut STATCOM" ($22.0 MM RY1, $74.0 MM RY2, $34.0 MM RY3)
- "Gateway Park Area Station" ($30.0 MM RY1, $20.0 MM RY2, $200.0 MM RY3)
- "Goethals Shunt Reactor R26" ($1.0 MM RY1, $3.5 MM RY2, $5.5 MM RY3)
- "Jamaica Substation – Replace Limiting 27kV Bus Sections" ($2.0 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- "Light Duty Electric Vehicle Make-Ready Program" ($26.9 MM RY1, $39.4 MM RY2, $47.9 MM RY3)
- "Meter Installations" ($30.0 MM RY1, $30.0 MM RY2, $30.0 MM RY3)
- "Network Transformer Relief" ($10.8 MM RY1, $10.9 MM RY2, $11.0 MM RY3)
- "New Business Capital" ($179.3 MM RY1, $198.6 MM RY2, $195.1 MM RY3)
- "Newtown TR4 and 138kV Feeder 38Q05 from Vernon" ($10.0 MM RY1, $33.0 MM RY2, $33.0 MM RY3)
- "Non-Network Feeder Relief (Open Wire)" ($7.3 MM RY1, $7.3 MM RY2, $7.3 MM RY3)

- "Overhead Transformer Relief" ($2.3 MM RY1, $2.3 MM RY2, $2.3 MM RY3)
- "Parkview TR5 and Feeder 38M85" ($30.0 MM RY2, $72.0 MM RY3)
- "Primary Cable Crossing (B/W City Island, Riverdale, Croton River, and BQ Flushing)" ($21.5 MM RY1, $11.6 MM RY2, $2.5 MM RY3)
- "Primary Feeder Relief" ($10.4 MM RY1, $10.4 MM RY2, $10.4 MM RY3)
- "Secondary Mains Load Relief" ($7.1 MM RY1, $7.1 MM RY2, $7.1 MM RY3)
- "Vinegar Hill Distribution Switching Station" ($33.0 MM RY1)
- "W42nd St No. 1 to Astor Transfer" ($2.0 MM RY1, $2.0 MM RY2)
- "West Bronx/Randall's Island Reconfiguration" ($16.1 MM RY1, $4.1 MM RY2)
- "Williamsburg Network Improvement" ($17.8 MM RY1, $23.7 MM RY2, $23.8 MM RY3)
- "Yorkville Crossings and Feeder Relief" ($16.0 MM RY1, $10.5 MM RY2, $3.0 MM RY3)

Q. Please discuss the New Business Capital Program.

A. When the Company connects new load, it often finds that its distribution system is at or beyond its capability and that it cannot serve the new load by simply extending a service lateral from its distribution system. In fact, many new residential and commercial projects require the Company to make extensive infrastructure investments such as reinforcing secondary mains, extending primary feeders, and installing transformer vaults. The New Business Capital Program is the vehicle for these investments. As the Company determines the customer's summer and winter peaks loads for all electric heating projects, additional reinforcements and/or equipment may be required to handle winter peak loads. With these investments, the Company can provide service to new customers.

Q. Please describe the nature of new business projects driving the need for investment under the New Business Capital Program.

A. As discussed in the load forecast section of this testimony, the Company is experiencing growth in numerous areas of the five boroughs from new commercial and residential developments, rail and air transportation projects, and residential growth within existing communities. In addition, there continues to be large scale development along waterfront areas, particularly in

Brooklyn, Queens, and the Bronx. Two examples include the East River waterfront in Brooklyn (discussed below as part of the Williamsburg Network Improvement project) and along the Harlem River waterfront in the Bronx (discussed as part of the West Bronx/Randall's Island Reconfiguration project). However, there are a significant number of new business jobs that individually consist of relatively smaller loads but collectively make up a significant portion of new business work planned. Growth in specific neighborhoods as well as jobs postponed during the pandemic have all led to an increase in the number of jobs in the new business queue.

Q. How does the Company plan to adapt to the potential for extreme weather as part of the New Business Capital Program?

A. The Company will design new facilities in accordance with the Company's new Climate Change Planning and Design Guideline.

Q. Please continue with a description of the Light Duty Electric Vehicle Make-Ready Program.

A. This program provides incentives for make-ready infrastructure for EV charging stations for light-duty vehicles in the Company's service territory. As directed by the Order Establishing Electric Vehicle Infrastructure

Make-Ready Program and Other Programs[8] the Commission has authorized the Company to provide incentives for third parties to install 18,539 Level 2 and 457 Direct Current Fast Charging ("DCFC") charging plugs over the five-year program.

In addition to the incentives for work on customer property, the Make Ready Order authorized the Company to recover in rates two additional items – the "new business" costs and utility-side make ready incentives costs (also generally known as excess distribution facility ("EDF") charges associated with the electric infrastructure. These are utility-side grid infrastructure capital costs and utility future proofing costs for EV make-ready. These costs include, for example, utility electric infrastructure needed to connect and serve the load associated with new EV charger(s); any additional infrastructure that would have otherwise been paid by the Participant; and, any costs associated with installing additional infrastructure to accommodate future EV charging at the location.

[8] Case 18-E-0138, Proceeding on Motion of the commission Regarding Electric Vehicle Supply Equipment and Infrastructure, Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020)("Make Ready Order").

EVs are a critical component to achieving the emission reductions called for in the CLCPA, and EV charging stations will serve as a key element to support EV adoption. This program supports the acceleration of EV charging station deployment and contributes to the achievement of the State’s CLCPA goals.

Q. Given the complexity and quantity of capital initiatives, please provide a summary of the needs for Brownsville Substation load relief.

A. The long-term solution to Brownsville load relief is to construct the new Gateway Park Area Substation, to be supplied by the new Brooklyn Clean Energy Hub. The Company does not believe it is feasible to energize the new Gateway Park Area Substation prior to summer 2028. Because of the risk that subsequent load growth in the area will create a reliability issue before 2028, the Company must use other projects to provide interim load relief for the Brownsville Substation. Some of these interim measures include continued use of Customer Sided Solutions and small network transfers. The most significant interim measures are installing Feeder 38Q05 and a fourth transformer at Newtown Substation and the Brownsville Area Load Relief Program.

Q. Why does the Company need the Gateway Park Area Substation?

A. The Company first identified the need for a new substation to provide relief for the Brownsville Substation in 2014. Since then, the Company has been successful in deferring the need through its BQDM Program, which uses a combination of traditional infrastructure and non-wires alternatives. Prior load forecasts showed BQDM deferring the need for a new substation until 2032. But, as discussed in the load forecast section above, the Company's annual demand forecast now shows that the Company must construct the new Gateway Park Area Station by summer 2028.

Q. What is driving load growth in the area?

A. The load growth in the area is partially driven by near-term electrification of light-, medium-, and heavy-duty vehicles and early adoption of building electrification. Thus, the project is needed to reliably facilitate electrification. In addition, the Gateway Park Area Station will help the State meet CLCPA goals by facilitating the delivery of renewable energy through the Brooklyn Clean Energy Hub, reducing the dependency on local fossil fuel plants. The project will also support future energy storage projects and programs for disadvantaged communities.

Q. Earlier, the Gateway Park Area Station was referred to as the long-term solution for Brownsville load relief, please describe this project in more detail.

A. The Gateway Park Area Station will be a new indoor 27kV substation supplied from the new Brooklyn Clean Energy Hub via four new 138kV sub-transmission feeders. The land procurement process is expected to begin in 2022, engineering and long lead equipment procurement will begin in early 2023, construction is expected to begin in 2025, and the projected in-service date is May 2028.

Q. What other work will the Company do in conjunction with the Gateway Park substation?

A. After completing the Gateway Park Area Station, this project will split the Crown Heights network into two load areas, 3B North (Crown Heights) and 3B South (Remsen). The new Remsen network will be supplied by the Gateway Park substation, transferring 117 MW of load from Crown Heights to the new substation. This transfer will alleviate overloads on the 138kV feeders supplying the Brownsville load pocket projected to occur as a result of increased new business, EV adoption, and building electrification. The Crown Heights Network Split will create capacity headroom in the Brownsville substation. The establishment of the Gateway Park Area Station will also allow the Company to de-load the Bensonhurst load pocket if it becomes necessary. In addition to relieving forecasted overload, by splitting the network into smaller pockets fed by separate

substations, the Company will increase reliability and resiliency as the two smaller load pockets are transferrable from one station to the other and vice-a-versa. Further, the Crown Heights Network Split will facilitate customer's electrification of transportation and buildings, supporting the State meeting its CLCPA goals.

Q. Please describe the interim measures the Company will take, starting with a description of the Newtown Transformer 4 and Feeder 38Q05 project and an explanation of how the project provides load relief for Brownsville Substation.

A. This project will install a new 138kV sub-transmission feeder (38Q05) from Vernon Substation to Newtown Substation along with a fourth 138kV/27kV transformer there. Newtown Substation is currently supplied by three 138kV feeders that also originate from the Vernon Substation. These three feeders (38Q02, 38Q03 and 38Q04/Q04T) also supply, along with Feeder 38Q01 from Vernon Substation, the Glendale Area Substation. The addition of Feeder 38Q05 to supply Newtown Substation increases the available capacity on Feeders 38Q01-38Q04 and, thus, the capacity at Glendale Substation. This increased capacity at Glendale Substation allows it to accept a 60MW network transfer from Brownsville Substation (Brownsville Area Load Relief Program) to provide load relief for the latter.

Q. Is load relief for Brownsville Substation the only benefit of the project?
A. No, it is not the only benefit. As a result of the anticipated increase in customer load related to new business, EV adoption, and electrification, the Newtown 27kV area station is projected to exceed its station capability by 2029. This creates the need for 38Q05 and Transformer #4 at Newtown Substation.
Q. So the need for Brownsville load relief is only accelerating the service date of Newtown Transformer #4 and Feeder 38Q05?
A. Yes, the Brownsville need is accelerating the service date of the project from 2029 to 2027.
Q. Please continue discussion of the interim measures by describing the Brownsville Area Load Relief Program.
A. As previously discussed, load relief solutions must be implemented to provide near-term relief while the Company works to place Gateway Park Area Station into service by 2028. The Company plans to implement four measures to address forecasted near-term load growth. First, the Company will transfer two MTA transit rectifier stations, for a total of 6MW, to nearby networks. Second, the Company will transfer 60MW from Brownsville No.1 substation to the Glendale substation, which has the capacity to support the

load relief while also being close in proximity, minimizing the extent of conduit and cable installation required. The third measure connects the new load to the Flatbush network to avoid furthering existing constraints at Brownsville No.2 substation. Lastly, the program will install a number of capacitor banks that will provide approximately 20MVAr resulting in approximately 5 to 6MW of effective load relief. Collectively, this program will focus on measures to address the significant near-term load growth in the area, including the adoption of electric vehicles and electrified heating, until the Gateway Park Area Station can be completed and is able to accommodate the continued growth.

Q. Please discuss other key System Expansion projects, starting with what factors are driving the need for the Williamsburg Network Improvement Project.

A. Over the last few years, the Williamsburg network has underperformed other networks in terms of NRI and reliability. Within the current ten-year forecast, it is expected that the Williamsburg network will exceed the upper limit of 1.0 for NRI. The Williamsburg area has seen a 24 percent increase in load since 2014 and it is expected to grow another 19 percent by 2030. Sixteen of the 20 primary distribution feeders are running at over 90 percent

on base and ten feeders are running over 90 percent of the emergency rating. Further, by 2028 an estimated 560 sections will be overloaded.

Q. Please continue by describing the Williamsburg Network Improvement Project.

A. This project will create two smaller load areas out of the Williamsburg Network through the establishment of multiple new distribution feeders facilitated by the Vinegar Hill Distribution Switching station. Eight new feeders will be established out of the Water Street Substation in four feeder bands, with the separation line between the two load areas being Flushing Avenue. The load pocket north of Flushing Avenue will consist of sixteen feeders, and the south load pocket will consist of twelve feeders. After the eight new feeders are established, the load will be rebalanced to create two independent secondary load pockets. Through the utilization of newer design primary Interrupter switches, additional resiliency is created by the transferability of load between these two load pockets.

The introduction of the eight new feeders is critical for supplying the expected load growth and will also improve NRI, and in turn reliability. This work will also de-load existing feeders and minimize the risk of cascading feeder failures. In addition, it will prepare this network

to accommodate future development in this area of Brooklyn, prepare for increased electrification of buildings and transportation, and increase reliability and resiliency in the face of rising summer temperatures driven by climate change.

Q. Please discuss the Parkview TR5 and Feeder 38M85 Project.

A. Forecasted loads for the Parkview 13kV Substation are expected to exceed the station's design capability by the summer of 2027. Rapid load growth in the near term is primarily driven by the expansion of the Metropolitan Transportation Authority's ("MTA") 2nd Avenue Subway line along with associated economic activity in the area. This project will construct 138kV supply feeder 38M85 from the Mott Haven 345kV Substation to the Parkview 13kV Substation and includes the installing a fifth 138/13kV transformer at Parkview Substation and a fifth 345/138kV transformer at the Mott Haven 345kV Substation. Engineering and long lead equipment procurement will begin in 2024, construction is expected to begin in 2025, and the projected in-service date of this project is May 2027.

Q. Please continue by describing the Farragut STATCOM Project.

A. The Company has identified Fault-Induced Delayed Voltage Recovery ("FIDVR") issues on the Con Edison 138 kV transmission system. The FIDVR issues are attributable to

future load growth, including building and transportation electrification. FIDVR issues may also result from, among other things, the retirement of local units, which Con Edison is supporting through the development of local transmission projects such as the three Reliable Clean City Projects, in line with the State's CLCPA goals. The installation of a static synchronous compensator ("STATCOM") unit will provide dynamic voltage support to address reliability needs driven by FIDVR issues. The Company will build a 425 MVA STATCOM at the Farragut 345kV Substation, remove Phase Angle Regulator TR12 and Shunt Reactor R12, and modify and reserve the currently out-of-service 345 kV feeders B3402 (Farragut to Hudson in New Jersey) and C3403 (Farragut to Marion in New Jersey). Engineering and long lead equipment procurement will begin in 2022, construction is expected to begin in late 2022, and the projected in-service date of this project is May 2025.

Q. What factors are driving the need for the Yorkville Crossings and Feeder Relief Project?

A. The Yorkville network, located in Manhattan, is supplied from 29 13 kV distribution feeders that originate from the Hellgate Area Substation located in the Bronx. The distribution feeders reach Manhattan via six active

underwater crossings. Four of these crossings span across the Harlem River near the Willis Avenue and Third Avenue Bridges, containing 23 of the 29 feeders that supply the Yorkville network. The fifth and sixth crossings route the distribution feeders via Randall's Island, and these crossings contain the remaining six primary feeders that supply the Yorkville network as well as the distribution feeders that supply the Randall's Island network.

The four underwater crossings that span between Manhattan and the Bronx all have high duct occupancy and have few remaining spare conduits. Spare conduits are critical in maintaining the reliability and resiliency of the Yorkville network for both accommodating future load growth and for cable replacements due to failures. With the complete loss of any of these four crossings, there are not adequate spares to reroute the distribution feeders and place them back in service without significant temporary reroutes. As a result, the loss of one of the Yorkville feeder crossings represents a significant high impact, low probability risk since recovering from the loss of one of the feeders would be particularly difficult and could lead to a protracted network shutdown. In addition, the majority of the distribution feeders that supply the Yorkville network are heavily-loaded. By 2030 approximately 60

percent of the distribution feeders will operate at or above 90 percent of their normal rating and more than 40 percent of the feeders will operate at above 95 percent of their normal rating. The risk of losing one of the crossings completely could lead to a network shutdown that would be difficult to recover from.

Q. Please describe the Yorkville Crossings and Feeder Relief Project.

A. A new underwater crossing beneath the Harlem River between Manhattan and the Bronx will be established and the existing 13 kV primary feeders will be diversified by the creation of an additional crossing. The addition of this crossing helps to mitigate the risk of network shutdown due to the loss of one of the Yorkville feeder crossings and helps maintain the reliability of the network. Increasing the feeder diversity, via new underwater crossings, is the most effective tool in reducing feeder overloading under second contingency conditions. Construction activities for the crossings will begin in 2022 and last until 2023 with the new systems completed and commissioned prior to the end of 2024.

Q. Please describe the West Bronx/Randall’s Island Reconfiguration Program.

A. The ten-year load forecast projects load growth on the West Bronx (2X) network of 1-2 MW per year due to electrification and significant new business load along the Harlem River. To avoid overloading the distribution feeders, the West Bronx/Randall's Island Reconfiguration Program will extend four feeders from the Randall's Island (14M) network and two feeders from the West Bronx (2X) network. Using primary interrupter switches, the Company will operate the Randall's Island and West Bronx network as one network with the ability to separate during contingencies. This load relief program will allow for continuous load growth, preventing equipment damage and service interruptions associated with distribution feeder overloads. An alternative approach to addressing these overloads was proposed in the Company's previous rate case, but during the design review, Company engineers developed a more comprehensive and resilient solution at a lower cost. The new approach involves the installation of two underground interrupters per 14M feeder to allow for separate processing of load from both networks, creating a more resilient design that could help prevent a network shutdown.

Q. Please continue with a description of the W.42nd No. 1 to Astor Transfer.

A. Based on an analysis of the area substations and sub-transmission feeders in the W.49th Street load pocket, Con Edison projects the W.42nd Street No. 1 Substation will exceed its capability by the summer of 2024. The main driver of this new demand is significant new business load growth in the Pennsylvania Network. This network serves many large customers including Hudson Rail Yards, Brookfield Properties, the Javits Center expansion, Moynihan Station, and several skyscrapers along the newly constructed Hudson Blvd. Additionally, the No. 7 Subway Line extension to W.34th Street and 11th Avenue is expected to attract new tenants to the neighborhood. To serve this new load without overloading that substation, the Company plans to transfer 55 MW of load from W.42nd Street No. 1 Substation in the Pennsylvania Network to Astor Substation. As a result of this transfer, the W.42nd Street No. 1 Substation will be operating within its capability while maintaining capacity for future load growth, improving network reliability. The project will also relieve the feeder breaker capability in order to supply the new business growth at the Hudson West Yard.

4. O&M Program Changes

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

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

Q. Please begin by describe the changes to the Meters and Customer Equipment Program.

A. Since most customer meters have now been replaced as part of Con Edison's Advanced Metering Infrastructure ("AMI") deployment, the Company is establishing meter maintenance and test cycles to comply with the PSC's mandate and to ensure proper functionality and accuracy of metering equipment. This program will fund several different expenses/work activities associated with customer requests, meter and customer premises work, a variety of tasks pertaining to the inspection and testing of meters on the customer's premises, and the work associated with disconnecting and/or reconnecting meters. This program change will require an increase of $4.5 MM in RY1, $1.2 MM in RY2, and $0.1 MM in RY3.

Q. Please describe the Transmission Operations Capital Projects O&M program change.

A. As described above, the Company is planning several projects to accommodate load growth and electrification and to facilitate the delivery of electricity from large-scale renewable resources to the Con Edison service territory. The Transmission Operations organization is responsible for planning and implementing all activities for the successful

construction, testing, and energization of major projects and programs in the Transmission capital portfolio. To implement the Company' planned projects, including the Brooklyn Clean Energy Hub, Gateway Park Area Station, and the Parkview TR5 and Feeder 38M85 Project, Transmission Operations will require an increase in staffing and associated vehicles. These specific staffing requirements include ten Splicers, twelve Mechanics, and two Welders. Management oversite of these positions needed include one Planner, three Supervisors and two Chief Construction Inspectors. Associated vehicles include eleven box trucks, two welding trucks, and six Management vehicles. This additional staffing will facilitate site preparation, construction of underground facilities, welding activities, cable pulling of both pipe and solid dielectric 345kV cable, associated splicing activities, and testing for planned projects.

Q. Please continue by describing Transmission Planning Staffing Needs to Support Clean Energy Agenda O&M program change.

A. In addition to the resource needs described above, three new positions are needed to support the planned transition to the clean energy future. Employees in these positions will be responsible for, among other things, implementing

CLCPA and Con Edison Transmission Master Plan requirements; studying and planning for offshore wind, solar, energy storage, and associated transmission system upgrades; coordinating, reviewing, and performing interconnection studies for large-scale renewables; and analyzing the retirement of fossil generation and the impact of intermittent resources connected through inverter-based interconnections.

C. Replacement Capital Expenditure Requirements

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

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-6

Q. What does Exhibit EIOP-6 show?

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

Funding for each program under the Replacements category is based on the historical failure or degraded

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

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

A. Through the programs in this category, the Company replaces failed transmission and substation equipment, including transmission and sub-transmission class feeders, transformers, reactors, and phase angle regulators. The program also funds the replacement of potheads, circuit breakers, bus enclosures, instrument transformers, and equipment monitoring and control devices. In addition, the program funds the replacement of distribution system equipment, including burned-out underground and overhead primary and secondary cable or wire, conduit, transformers, and meters and services. Examples of this work are cable and splice abnormalities (AKA “C” or “D” faults) or transformers that need to be taken off the system due to leaks or other serious defects. Other types of work covered by this program include repair and upgrade of overhead

poles, wire, and equipment that fails during storms or other emergencies.

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

A. The Company plans to invest in the following projects. Additional detail on each of the projects below can be found in their respective white papers in Exhibit EIOP-6, Schedule 2.

- "Failed Substation Equipment Other than Transformers" ($11.5 MM RY1, $11.5 MM RY2, $11.5 MM RY3)
- "Failed Substation Transformer Program" ($46.5 MM RY1, $46.5 MM RY2, $46.5 MM RY3)
- "Hellgate Dock Refurbishment" ($15.6 MM RY1)
- "Overhead Emergency Response" ($61.5 MM RY1, $72.2 MM RY2, $74.0 MM RY3)
- "Primary Cable Replacement (OAs, FOTs, C&D Fault)" ($98.7 MM RY1, $101.9 MM RY2, $101.9 MM RY3)
- "Secondary Open Mains" ($128.7 MM RY1, $140.8 MM RY2, $142.0 MM RY3)
- "Service Replacements (Temporary Services and Bridges)" ($68.5 MM RY1, $72.4 MM RY2, $72.4 MM RY3)
- "Streetlights (Including Conduit)" ($27.2 MM RY1, $27.2 MM RY2, $27.2 MM RY3)

- "Targeted Direct Buried Cable Replacement" ($14.0 MM RY1, $14.0 MM RY2, $14.0 MM RY3)
- "Telecom – Underground Facilities" ($0.3 MM RY1)
- "Transformer Installation" ($51.2 MM RY1, $51.2 MM RY2, $51.2 MM RY3)
- "Transmission Feeder Failures" ($15.0 MM RY1, $15.0 MM RY2, $15.0 MM RY3)
- "Transmission Feeder Failures – Other" ($3.0 MM RY1, $3.0 MM RY2, $3.0 MM RY3)

Q. Please elaborate on the Failed Substation Transformer Program.

A. This ongoing program provides funding for the restoration work required to replace transformers in Area and Transmission Substations on an emergency basis. This program covers the cost of replacing three failed transformers (transformers, phase angle regulators and reactors) per year, and the basis for that projection is the historical average number of failures per year from 2011 to 2020. Power transformers in substations are critical components of the transmission and distribution systems. The Company has a separate Substation Transformer Replacement Program to proactively replace eight transformers per year before they fail. This program is

discussed elsewhere in this testimony. Nevertheless, some transformers will likely fail in service and must be replaced on an emergency basis in order to maintain reliability. Further, the increasing frequency of heat events projected by the Company in its Climate Change Vulnerability and CCIP may accelerate the effective aging of power transformers, resulting in an increased likelihood of transformer failures. The criticality of this program will only increase with more extreme weather events.

Q. Please continue by describing Hellgate Wharf Refurbishment.

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

Con Edison's review and analysis of the wharf identified numerous structural issues that the Company plans to address. In the heavy lift area, the concrete encased beams exhibit corrosion, spalling, and/or cracking. Currently all ten pier walls within this vicinity show signs of significant deterioration, including concrete

spalling and erosion and steel rebar corrosion. Conditions in this area of the wharf have diminished load capacity, restricting use of the wharf to lighter loads. The Flush Truck Facility portion of the wharf exhibits similar deficiencies to those identified in the heavy lift area. The northernmost of the three bays is missing mooring hardware and fenders and the Company has deemed it unsafe for personnel to access. The full list of specific repairs and installations can be found in the corresponding white paper.

The refurbishment of the Hellgate Wharf will allow for the long-term offloading of effluent from the Flush Truck Facility and the movement of heavy equipment, such as transformers, in a safe and efficient manner from the SSO portion of the wharf. The expansion of the heavy lift area will allow more flexibility in positioning the existing multi-axle trailers and allow the use of longer transport vehicles in the future. The project will benefit the Company by reducing the likelihood of personnel injuries and establishing a more reliable offloading facility.

The Hellgate Wharf Refurbishment project was first introduced in the Company’s previous rate case filing, but unanticipated permitting requirements have delayed the start of the project. Due to the nature of the project, the

required permitting involves review and approval from the US Army Corp of Engineers, DEC, NYC Department of Buildings, and NYC Department of Small Business Services ("NYC SBS"). The DEC process to review the scope of work resulted in delays because of a moratorium on shoreline work put in place to protect Striped Bass migration. After discussing the project scope with the DEC, a period of time for construction has been agreed upon. Presently the Company is in the review process with NYC SBS.

Q. Please describe the Overhead Emergency Response Program.

A. This program funds high-priority emergency work to replace non-network overhead infrastructure and associated equipment after failure or when imminent failure is identified. Diagnostic testing such as infrared, ultrasonic, or visual inspection are used to identify potential failures of cable, overhead transformers, and open-wire along the associated structures and accessories. Climate change, specifically more frequent and severe major storms and rising temperatures, will likely increase the stress on existing infrastructure and equipment and thus increase the need for replacement. These replacements will improve reliability by shortening or avoiding customer interruptions associated with equipment failure and minimize the time the system is in a vulnerable

configuration. This program also helps mitigate public safety risk including hazards associated with downed wires and hit poles as well as the environmental impact associated with leaking and/or damaged transformers and other equipment. The Overhead Emergency Response Program supports the achievement of PSC reliability performance goals (SAIFI and CAIDI).

D. Equipment Purchase Capital and O&M Expenditure Requirements

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

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-7

Q. What does Exhibit EIOP-7 show?

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

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

A. Through the programs in this category, the Company purchases necessary equipment such as transformers, network protectors, switches, and meters. These purchases support various programs, including both proactive replacements and those that take place after failures.

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

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

- “Equipment Purchase” ($10.0 MM RY1, $20.0 MM RY2, $20.0 MM RY3)
- “Transformer Purchase” ($136.0 MM RY1, $139.6 MM RY2, $139.6 MM RY3)

Q. Please further describe the Transformer Purchase Program.

A. This program will fund the purchase of new and reconditioned capital electrical distribution equipment, to include underground network transformers, overhead transformers, padmount transformers (including mini-pads), capacitor banks, emergency generators, and network protectors to support distribution system relief, reliability, emergency, and load growth programs. These purchases provide electrical distribution equipment in order to complete active and planned burnout, new business, and system relief and reinforcement projects, supporting

the Transformer Installation Program, the Network Transformer Relief Program. The budget for this program is expected to increase in the rate years, driven by the need for additional equipment to serve new EV charging and electrified space heating load, purchase of more submersible dry type transformers and other submersible equipment, and increasing replacements. The purchase of more submersible equipment will allow for the Company to comply with its new Climate Change Planning and Design Guideline, specifically the eventual migration to a projected floodplain of FEMA +5. The introduction of more submersible equipment will also help harden the system against more frequent and severe torrential downpours driven by climate change. Con Edison has instituted more targeted underground transformer inspection programs utilizing remote monitoring equipment on transformers to provide real-time pressure and temperature readings. As a result, the Company has identified an increased number of units needing replacement in order to maintain system reliability.

Transformer purchases and replacements improve public safety and system reliability by removing defective transformers, and in turn the number of unplanned feeder outages is also reduced, since every transformer failure

results in de-energization of the entire feeder that supplies it. This program and the associated replacements also reduce the probability and frequency of violent equipment failures, which decreases the risks of injury to the public and Company employees along with damage to property. Con Edison purchases transformers that offer the best safety and environmental performance, such as high fault energy tank and dry type transformers. In addition, the purchase and installation of more submersible equipment increases resiliency as the Company adapts to the impacts of climate change.

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

Q. Was the exhibit titled, “T&D Safety and Security” prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-8

Q. What does Exhibit EIOP-8 show?

A. Exhibit EIOP-8, Schedule 1 lists the capital program and project funding requirements to support Safety and Security work conducted by S&TO, SSO, and Electric Operations. In addition, the exhibit contains white papers for each capital program/project in this category that provide more detailed information, such as program and project work

descriptions, justifications, alternatives, estimated completion dates, current status, and forecasted spending.

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

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

Q. Please describe the Company's efforts related to the security of the electric system.

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

Q. What types of programs make up the Safety and Security work category?

A. This category includes a number of programs that increase both physical and cyber security for substations and the electric system. Some examples include physical security enhancements at the Company's control centers, upgrades to mitigate physical security threats and vulnerabilities at substations, and cyber security enhancements at substations to align with NERC CIP version 6 requirements. See the Company's Information Technology and Shared Services Panel testimony for details on the Company's enterprise cyber and physical security efforts respectively.

Q. Please list the capital programs within the Safety and Security work category.

A. The Company's Safety and Security investments include:

- "Cable Termination Platform Program" ($0.6 MM RY1, $0.6 MM RY2, $0.6 MM RY3)
- "Cap and Pin Insulator Replacement Program" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "Critical Infrastructure Protection (NERC) Cyber Security Upgrade Program" ($1.0 MM RY2, $1.0 MM RY2, $1.0 MM RY3)
- "Cyber Security and NERC Compliance" ($1.3 MM RY1, $1.6 MM RY2, $1.6 MM RY3)
- "ECC and AECC Facility Security Enhancements" ($0.4 MM RY1, $0.4 MM RY2, $0.5 MM RY3)

- "Overhead Tower Rapid Rail" ($5.0 MM RY1, $5.0 MM RY2, $5.0 MM RY3)
- "Substations Security Enhancements Program" ($12.0 MM RY1, $12.0 MM RY2, $12.0 MM RY3)
- "Vented Covers for Underground Structures" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)

Q. Due to its importance, please describe the Vented Covers for Underground Structures Program.

A. This program funds the targeted installation of vented metallic covers on structures located in publicly accessible locations such as roadways, street crosswalks, and sidewalks. The program entails identifying structures that have elevated risk to public safety and replacing solid with vented versions of the covers. While many covers have been replaced, approximately 90,000 unvented structures remain on the system. Covers are prioritized for replacement by the following factors: 1) structures located in higher pedestrian traffic areas; 2) based on past events, new data analytics, or geographical and logistic concerns; and 3) structures with cables and cable combinations that have elevated failure rates. The installation of vented covers helps reduce the buildup of combustible gases associated with events on the low-voltage

secondary system, thereby reducing the severity of underground events and enhancing public safety. Since the inception of the vented cover program, there have been approximately 135,000 vented covers installed. The total count of manhole events in 2021 was 24 percent lower than the previous five-year average (2016-2020), which equates to approximately 538 fewer events. There was a 24 percent reduction in Smoking Manholes; a 23 percent reduction in Manhole Fires; and a 29 percent reduction in Manhole Explosions compared to their respective five-year averages. Manhole Explosions causing public impact are at the lowest since the inception of the program in 2004 and is a 47 percent reduction from 2020. The use of vented latched covers is also currently being explored for explosion mitigation. These covers could further decrease the risk to the public in the case of a more severe event occurring.

Q. Are there additional projects that contribute to safety and security?

A. Yes. In addition to the investments listed above as part of the Safety and Security category, numerous other Con Edison projects and programs contribute to safety and security. For example, the Pressure, Temperature, and Oil Sensors Program and other transformer failure mitigation programs help identify and replace equipment prior to failure,

decreasing the risk of violent failures and the risk to public safety. Another example is the Smart Sensors Program, discussed in the Risk Reduction/Reliability section of this panel testimony, which provides real-time data for facilities and equipment for which failure, damage, or an error in operation or maintenance could jeopardize public and employee safety.

Q. Are there any O&M program changes to discuss in the safety and security category?

A. Yes, the Company is proposing one O&M program change related to safety.

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

A. The Safety Inspection Program includes the inspection of all Company-owned underground/underground residential development ("UG/URD") structures. Starting in 2021 UG structures were classified as High, Medium, and Low Priority and inspected on five-, eight-, and ten-year cycles respectively. URD structures remain on a five-year inspection cycle. This program includes enhanced inspection techniques using infrared and current readings. The increase in O&M funding in rate year 1 is partially driven by the increased number of inspections to comply with the Commission's directive to prioritize completion of the

facilities not yet inspected under the previous eight-year cycle. The previous eight-year cycle would have ended in 2022. Those structures that are in the Low Priority group are inspected on a 10-year cycle, and facility inspections that would have taken place in 2021 and 2022 are now due for inspection during the rate years. At the end of the inspection cycle, costs tend to increase as the Company works to complete inspections on structures that could not be completed during routine inspections. These inspections, referred to as “stopped inspections,” could not be inspected because they have been paved over or are blocked by equipment or structures installed by others. Increased costs are also associated with the completion of backlogged repairs prior to the end of 2024. This program change will require an increase of $7.5 MM in RY1, $0.9 MM in RY2, but a decrease of $11.4MM in RY3 once the overlapping cycle inspections conclude.

F. Environmental Capital and O&M Expenditure Requirements

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

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-9

Q. What does Exhibit EIOP-9 show?

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

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

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

spills, detecting and responding to dielectric fluid spills, and upgrading facilities and containments so that dielectric fluid leaks or spills can be captured before they affect the environment.

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

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

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

- "Environmental Enhancements" ($0.9 MM RY1, $0.9 MM RY2, $0.9 MM RY3)
- "Mobile Program for Transmission Feeder Leak Detection" ($0.3 MM RY1, $0.3 MM RY2, $0.3 MM RY3)
- "Oil Minders" ($1.7 MM RY1, $1.7 MM RY2, $1.7 MM RY3)
- "Pipe Enhancement Program" ($28.0 MM RY, $29.3 MM RY2, $29.8 MM RY3)

- "Substation EH&S Risk Mitigation Program" ($15.5 MM RY1, $14.0 RY2, $14.0 RY3)
- "Underground Transmission Structure Modernization" ($5.4 MM RY1, $5.4 MM RY2, $5.4 MM RY3)

Q. Please describe some of the key programs within this category starting with the Pipe Enhancement Program.

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

Dielectric fluid leaks in pipe-type cable are a problem from both an environmental and reliability perspective. Mitigating the release of dielectric fluid to the environment is a critical component of the Company's efforts to achieve environmental excellence. In addition, dielectric fluid leaks can result in the Company removing feeders from service. If the leak rate exceeds the flow rate capability of the fluid pressurization pumps, the

Company might need to take an extended outage to complete repairs. In cases where fluid pressure can be maintained, a feeder with a large leak may still be forced out of service to clamp and repair the leak. These issues can have detrimental effects on overall system reliability, especially during high load periods.

Work packages appropriated under this program to date have focused on suspect areas of Feeders M51 and M52 since they contribute the highest percentage of dielectric fluid lost to the environment of any feeders on the Con Edison Transmission System. The Company will focus a large majority of this program’s funding in 2022-2023 on addressing portions of M51 and M52 that have shown leaks in recent years.

By addressing corrosion issues in suspect areas before the pipe leaks occur, Con Edison will be able to reduce the amount of dielectric fluid that is lost to the environment and the associated costs for emergency leak response and remediation. For these suspect areas, this program also provides increased reliability, extends the life of existing pipe-type feeder facilities, and prevents or reduces the likelihood of dielectric fluid release from the pipe-type feeder system.

Q. Please continue by describing the Environmental Enhancements Program.

A. This program will cover the installation of cathodic protection rectifiers along select High Pressure, Fluid Filled Feeders to supplement existing pipe cathodic protection. Buried sections of pipe-type cables are cathodically protected to prevent corrosion that can result in dielectric fluid leaks. The Company also plans to expand monitoring capabilities through new sensors that either utilize infrared imaging, can detect dielectric fluid in manholes, or measure cathodic protection voltages. This program will reduce the likelihood of dielectric fluid leaks which can improve environmental performance and feeder availability. The Company plans to target approximately four feeder group installations per year.

Q. Are there other projects or programs that help support the Company’s efforts to achieve environmental excellence?

A. Yes. In addition to the investments listed above as part of the Environmental work category, numerous other Con Edison projects and programs contribute to minimizing the Company’s environmental footprint. For example, the Gas Insulated Substation Replacement Program replaces switches, bus sections, and ancillary equipment at existing gas insulated substations (“GIS”), eliminating GHG emitting

equipment, and replacing it with components with a smaller overall SF6 footprint. Similarly, the High Voltage Circuit Breaker Capital Upgrade Program replaces or upgrades 33kV, 69kV, 138kV, and 345kV breakers, including addressing those with SF6 leaks and installing more modern breakers with a lower volume of SF6. Another example is the Unit Substation Upgrade and Improvement Program, which includes preventative measures and corrective actions to repair deteriorating conditions affecting transformer moats to avoid oil spills or leaks that could cause environmental harm and the need for soil remediation work. The Company is also introducing biodegradable dielectric fluid in some cases to further minimize the environmental impact of a potential fluid release.

G. Information Technology Capital and O&M Expenditure Requirements

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

A. Con Edison uses a number of sophisticated technology applications. The Company continues to explore opportunities to employ the latest technologies to improve performance and streamline work processes.

Q. Are there projects described in the Company's IT Panel testimony that will support Con Edison's electric system?

A. Yes, a number of the projects described by the IT Panel will enhance the operation of the Company's T&D system.

Q. Please provide a list of some of the more significant IT projects related to T&D operations.

A. The following IT projects are sponsored by the IT Panel. Details on the projects can be found in Exhibit IT-1 and Exhibit IT-4.

Central Operations Battery Monitoring Systems - The Company will invest in systems that will continually assess the condition of some substation battery banks.

Distribution Equipment Management System ("DEMS") Replacement Project – The Company is proposing to replace the legacy DEMS to enable better automation and data accuracy.

Electric ARM Replacement (Phase 0) – The Company is proposing to conduct a Phase 0 assessment to determine the feasibility and scope to migrate the Electric Work and Asset Management ("WMS") system to the enterprise Maximo WMS platform to realize the full benefits of a true enterprise solution across all business areas.

Electric ARM Replacement – The Company is proposing to migrate the Electric WMS system to the enterprise Maximo

WMS platform. This is in keeping with IT organization's strategy of moving to a "One Enterprise" Work and Asset Management solution for all Con Edison's business areas.

Outage Management System IT System Hardening – The Company is proposing to address the technical and systematic issues experienced during winter storms Riley and Quinn identified by Storm Assessment Team and a study performed by McKinsey and Company. The proposed enhancements will enable high availability architecture mitigating the need for prolonged maintenance outages for patching, significantly reduce disaster recovery times during failover, facilitate regulatory required testing requirements, and set the building blocks for future integrations, enhancements, and testing.

Operations Network for EMS – The Company is proposing to improve and expand the network infrastructure at the primary and alternate Energy Control Centers to support operational reliability of System Operation's computer systems. This project will allow the Company to implement best security practices and meet NERC CIP Standards

Outage Management System (Phase 4) - The Company is proposing to continue efforts to identify and incorporate enhancements within the modules used by the OMS to

supplement efforts to better identify opportunities for enhanced operator training.

Protective Relay Settings Repository – The Company will procure a software package that will store all protective relay settings and asset registry information. This project will facilitate improved understanding of relay performance and lifecycle management.

Substation Technology Improvements – The Company will continue to make upgrades that automate substation processes to improve maintenance, data collection and data storage.

WMS Sustainability Project - In order to support the current electric WMS until it is migrated to an enterprise Maximo WMS platform the Company is proposing to add enhancements and interfaces required by the Company's new Customer Service System ("CSS") and eGIS. A number of additional automations and interfaces that will facilitate efficiency and cost savings are also planned. This investment is necessary to maintain the efficient functioning of the WMS until its replacement which is estimated to be 2027.

V. Electric Production

A. Electric Production Overview

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

A. The Electric Production facilities are: 1) cogeneration unit East River 6/60, which is comprised of Turbine Generator 6 and Boiler 60; 2) unit East River 7/70, which is comprised of Turbine Generator 7 and Boiler 70; and 3) five gas turbines ("GT"s), one located at the 59th Street Generating Station ("59th Street"), two located at the 74th Street Generating Station ("74th Street"), and two located at the Hudson Avenue Generating Station ("Hudson Avenue"). Five GTs are planned for retirement in 2023 to 2025 timeframe as a result of the DEC Peaker Rule (Part 227-3) regulation which goes into effect in May of 2023. Electric Production also covers O&M for East River Units 1 and 2 combustion turbine generators, (also referred to as the East River Repowering Project ("ERRP")). Details on ERRP O&M are provided by the Company's Accounting Panel.

B. Summary

Q. Was the exhibit titled, "Electric Production" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-10

Q. What does Exhibit EIOP-10 show?

A. Exhibit EIOP-10, Schedules 1 and 3 lists the Company's projected capital expenditures and O&M program changes required for Electric Production for each of the rate years. The exhibit also includes white papers for all capital expenditures listed in this section of testimony. O&M program changes for Electric Production in the rate case years are also included in the exhibit.

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

A. The Company projects to spend approximately $26.4 million in RY1, $22.5 million in RY2, and $19.6 million in RY3. The Company's proposed Electric Production capital spending varies based on the outage schedule for East River 6/60 and 7/70. Boiler 60 has capital turbine projects in RY1. Boiler 70 has planned capital turbine projects and boiler projects in RY2, which results in a capital expenditure increase in RY2. The planned expenditure levels decrease from RY2 to RY3, as there are no capital investments currently scheduled for RY3.

Q. What are the Electric Production capital programs for which the Company is seeking funding?

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

- "East River Balance of Plant Replacement Projects" ($0.4 MM RY1, $1.0 MM RY2, $2.5MM RY3)
- "East River Civil & Structural Projects" ($2.1 MM RY1, $2.0 MM RY3)
- "East River Instrumentation & Control Replacement Projects" ($1.9 MM RY1)
- "East River Major Equipment Replacement Projects" ($0.4 MM RY1, $16.0 MM RY2, $6.0 MM RY3)
- "East River Power Distribution Replacement Projects" ($4.8 MM RY1, $1.0 MM RY2, $9.0 MM RY3)
- "74th Street Environmental" ($0.5 MM RY1, $0.5 MM RY2, $0.1 MM RY3)
- "59th Street Environmental" ($0.5 MM RY1)
- "East River Environmental" ($16.0 MM RY1, $4.0 RY2)

C. Details of Programs/Projects

Q. What are the Electric Production project category used by the Company?

A. The Company divides projects into four categories that support Electric Production: 1) Replacement, 2) Risk Reduction, 3) Environmental, and 4) Safety and Security.

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

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

- Major Equipment
- Balance of Plant
- Power Distribution Equipment
- Instrument and Controls
- Civil and Structural

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

A. This subcategory includes the replacement of boilers, furnace tubes, reheaters, superheaters, brick, refractory, insulation, lagging, and casings. Boilers produce the steam required to drive the Company’s turbine generators and produce electricity and account for a significant portion

of the total work performed in this subcategory on Electric Production assets.

The furnace walls within boilers are lined with banks of tubes that help maximize the efficiency of converting water to steam. These tubes degrade over time. To maximize the efficiency and reliability of the boilers, the Company replaces degraded tubes. The capital work that the Company has currently planned for the boilers involves replacing tubes along the furnace walls in Boiler 60, replacing tubes in the reheater and superheater in Boiler 70, and is based on the schedule for respective Boiler’s capitalized maintenance.

Q. Please describe the next Replacement subcategory, Balance of Plant Equipment.

A. This subcategory includes the replacement of pumps, valves, heat exchangers, air compressors, and tanks that are necessary to generate steam.

Q. Please provide additional details regarding East River Log Screens 4/5/6 Replacement.

A. Con Edison will remove the Log Screens in Bays 4, 5, and 6 and replace them with new upgraded stainless-steel screens, coated with epoxy to protect from corrosion. Log Screens were installed in 2013 and have significantly corroded due to continuous immersion in salt water. Loss of the panel

inserts leaves the traveling screens, which are located downstream of the log screens, exposed to floating debris and risk of damage.

Q. Please describe the next Replacement subcategory, Power Distribution Equipment.

A. This subcategory typically includes the replacement of electrical equipment such as switchgear, transformers, batteries, uninterruptible power supplies, inverters, breakers, motors, cables and backup generators. The Company has identified a number of these systems – including load centers, emergency battery systems, and uninterruptable power systems ("UPS") – for capital replacement because they are nearing the end of their useful life. Load centers and their associated switchgear comprise the electric supply for critical station equipment, such as circulator pumps ("CP"), boiler feed pumps ("BFP"), and forced draft ("FD") and induced draft ("ID") fans. Load centers and switchgear also power many of the plant's primary and auxiliary components. If a plant's auxiliary power supplies are interrupted, the battery systems and UPS systems provide emergency power.

Q. Please describe the next Replacement subcategory, Instrumentation and Controls Systems.

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

Q. Please describe the type of planned Replacement projects in the Instrumentation and Controls subcategory.

A. Replacement projects related to several auxiliary electrical systems are listed below and represent typical projects that would be captured in the Instrumentation and Controls program going forward.

Q. Please explain the Civil and Structural subcategory.

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

Q. Please describe the type of planned Replacement projects in the Civil and Structural subcategory.

A. Replacement projects in the Civil and Structural subcategory are listed below and represent the typical projects that would be captured in the Civil and Structural program going forward.

Q. Please describe the type of project in the Company's Risk Reduction category.

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

- Balance of Plant Equipment
- Power Distribution Equipment
- Instrumentation and Controls
- Civil and Structural

Q. Please explain the Balance of Plant Equipment subcategory for Risk Reduction and the risks being addressed.

A. This subcategory includes the replacement of pumps, valves, heat exchangers, air compressors, and tanks. To avoid the likelihood of potential de-rating or unit shutdowns, the Company plans overhauls to replace and refurbish equipment components of boilers and turbines based on manufacturer and industry guidelines, actual length of operation, unit performance, inspections, and engineering assessments. Additionally, equipment improvements are required to address malfunctions and failures that could potentially lead to unreliable operations and contribute to plant unavailability.

Q. Please describe the Power Distribution Equipment subcategory for Risk Reduction and the risks being addressed.

A. This subcategory typically includes upgrades of electrical equipment such as switchgear, transformers, batteries, uninterruptible power supplies, inverters, breakers, motors, cables, and backup generators. The Company upgrades or replaces these systems to also reduce the likelihood or impact of forced outages.

Q. Please describe the Instrumentation and Controls subcategory for Risk Reduction and the risks being addressed.

A. This subcategory typically includes upgrades to control systems, including transmitters, digital control systems, control panels and terminals, monitoring instrumentation, and wiring. Proper operation and dependability of the instrumentation and control systems is a cornerstone to the overall reliability and performance of the Electric Production assets. Failures of these systems could result in forced outages and deratings. Additionally, the Company will periodically identify control equipment and systems such as protective relays, instrumentation, and programmable logic controllers (“PLCs”) that are obsolete or present a cyber or operational risk. The Company upgrades or replaces these systems to also reduce the likelihood or impact of forced outages.

Q. Please describe the capital expenditures under Environmental.

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

projects that will be captured in the Environmental program moving forward.

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

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

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

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

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

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

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

Q. Please describe the conversion process.

A. First, the Company will pump down, clean, and inspect the fuel oil storage tanks at East River. Second, the Company will install equipment required for the conversion. Lastly, the Company will commission, test and tune the equipment to optimize operation. The Company’s fire risk assessment determined that it must upgrade the East River Tank Farm to

store No. 2 oil; specifically, it must upgrade the tank internal foam system, the external foam monitor system, the fire detection system, and install a redundant water supply from a separate city water main.

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

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

This involves capping, closing, and retiring the steam piping supplies and returns, and adding fuel oil piping where the fuel oil heaters are located.

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

D. O&M Program Changes

Q. Is the Company proposing any Electric Production O&M program changes?

A. Yes. The Company is proposing one change related to East River Units 6/7 Major Overhauls. The steam turbines and generators of East River Units No. 6 and No. 7 are overhauled on an approximate 50,000 operating hour frequency and a nine-to-twelve-year basis respectively. The next overhauls for Unit No. 6 are scheduled in 2022 when the Low-Pressure (“LP”) Turbine will be opened and

inspected and 2023 when the High-Pressure ("HP") Turbine, and the HP and LP generators will be overhauled. The overhauls for Unit No. 7 are scheduled as follows, 2024 HP Turbine and HP/LP generators, 2025 LP Turbine, and 2026 Intermediate Pressure Turbine. The degradation of a steam turbine is not typically detected through performance evaluations or limited inspections, so opening the steam turbine to remove, inspect, and repair its components is required to ensure its continued reliable operation. Conducting major overhauls at pre-determined intervals increases steam turbine generating assets reliability and minimizes the risk that the assets will be unavailable because of emergent and unforeseen repairs.

VI. Special Issues

A. Generator Retirement

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

A. Yes. Third-party generators may retire or announce their retirements during RY1, RY2, or RY3. Generators may retire as a result of market forces. They may also be affected by environmental regulations, such as the CLCPA. Some aspects of CLCPA implementation are still being developed, meaning the full picture of what ultimately will be required for CLCPA compliance is not yet clear and depends on

forthcoming guidance from the Climate Action Council and the New York State Department of Environmental Conservation ("DEC"). The resulting guidance could force earlier retirement of fossil fuel generators. The recent denial of the DEC Air permits for the Astoria Gas Turbine Replacement Project exemplifies the magnitude and pace of change to power generation that comes with CLCPA. Generator retirements or retirement announcements may create reliability needs that the Company has to address during the term of the rate plan through upgrades to its electric delivery system. As the Company cannot know in advance whether generator retirements will occur, or the precise upgrades required, it is proposing to recover through a surcharge the costs for any upgrades necessary to maintain reliability because of a generator retirement, to the extent not otherwise recovered, as described in more detail in the Accounting Panel.

B. Reliability Performance Mechanisms

Q. Please describe the cases in which the Company would like to change existing metrics for System Average Interruption Duration Index (SAIDI.)

A. The Company proposes to replace its SAIFI and CAIDI metrics with SAIDI for both non-network and network systems.

Q. Why is the Company proposing to adopt SAIDI and to eliminate SAIFI and CAIDI?

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

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

SAIFI measures how many customers, on average, are interrupted. It does not account for how long customers are

out of service when interrupted. So, like CAIDI, it provides and incomplete measure of the customer experience.

For the reasons described above, neither SAIFI nor CAIDI are independently meaningful measures of system performance. SAIDI, in contrast, measures both frequency of interruption and duration. In other words, SAIDI measures the average of customer interruptions for all customers, taking into account that some customers experience no interruptions at all.

Q. What SAIDI thresholds is the Company proposing?

A. For the same reasons previously stated, the Company proposes the network SAIDI threshold be set at 8.30 minutes, which is one standard deviation above the Company's ten-year historical performance. The chart below shows the Company's performance over the last ten years.

Network SAIFI CAIDI SAIDI without Storms

	SAIFI	CAIDI Hours	SAIDI Minutes	**SAIDI + 1 SD**
2012	12.08	6.35	4.60	8.30
2013	12.44	5.62	4.19	8.30
2014	13.96	6.57	5.50	8.30
2015	16.12	6.75	6.53	8.30
2016	16.18	6.88	6.68	8.30
2017	16.72	6.51	6.53	8.30
2018	17.42	6.31	6.60	8.30
2019	22.25	5.41	7.22	8.30
2020	85.82	1.78	9.17	8.30
2021	17.02	3.56	3.64	8.30

Total	**230.01**	**55.74**	**60.66**	
Average	**23.00**	**5.57**	**6.07**	

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

A. Yes.

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

A. The non-network SAIFI and CAIDI targets should be replaced by SAIDI. SAIDI is calculated by multiplying SAIFI times CAIDI in minutes. The Company proposes to set the threshold at 69.06 minutes, which is one standard deviation above the Company's ten-year historical performance. The chart below shows the Company's performance over the last ten years.

Non-Network SAIFI CAIDI SAIDI without Storms					
	SAIFI	CAIDI (Hours)	CAIDI (Min)	SAIDI (Minutes)	**SAIDI + 1 SD**
2012	0.358	2.02	121.2	43.39	69.06
2013	0.396	2.02	121.2	48.00	69.06
2014	0.334	1.84	110.4	36.87	69.06
2015	0.349	1.95	117	40.83	69.06
2016	0.435	1.87	112.2	48.81	69.06
2017	0.357	1.93	115.8	41.34	69.06
2018	0.398	1.91	114.6	45.61	69.06
2019	0.526	2.73	163.8	86.16	69.06
2020	0.469	1.89	113.4	53.18	69.06
2021	0.488	1.93	115.8	56.51	69.06

Total	**4.11**	**20.09**	**1205.4**	**500.70**	
Average	**0.411**	**2.01**	**120.54**	**50.07**	

C. Charges for Special Services

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

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

- Reinspection Charge:
  - Increase to $279.00 (currently $260.00)
- High potential proof test
  - Per visit to the premises, up to four hours: $2,076.00 (currently $1,740.00)
  - For each additional hour or portion thereof: $519.00 (currently $435.00)
- Megger Test
  - Two people for one hour: $519.00 (currently $435.00)
- Dielectric Fluid Test
  - First sample: $1,066.00 (currently $1,168.00)
  - Each additional sample taken at the same time: $670.00 (currently $836.00)
  - Each sample taken by the Customer: $547.00 (currently $733.00)

Q. What is the basis for the proposed charges?

A. These charges were last updated January 1, 2018. The proposed charges reflect the Company's 2021 cost for labor, vehicles, corporate overhead, and chemical lab. The change in costs for these charges is the result of the overhead allocation to these tasks. Please see the Electric Rate Panel Testimony for the specific Tariff language related to these changes.

D. Tariff Changes

Q. Is the Company supporting any tariff changes as part of this panel?

A. Yes. This panel is supporting three tariff changes related to 1) the Selective Undergrounding Program, 2) Street and Sidewalk Service, and 3) the Charge for Replacement of Damaged AMI Meters.

1. Selective Undergrounding Program

Q. In what ways does the Company's Selective Undergrounding Program require adjustments to the current tariff so that the installation cost, including the cost on the customer side of the meter, is socialized to all customers?

A. The Company is proposing to add a new provision to General Rule 7.1 – Customer Wiring and Equipment (Leaf 64). This provision stipulates that for customers served by the Company's Selective Undergrounding Program, the Company will bear the cost of furnishing and installing customer

wiring and equipment provided that the customer will maintain the wiring and equipment. This tariff change will eliminate the need for an individual customer to bear the installation costs of equipment associated with the undergrounding their service when part of the Selective Undergrounding Program.

Q. Why does the Company believe that this cost should be recovered in rates?

A. First, as discussed in the Storm Panel, enhanced storm response is a high priority, and one way for the Company to enhance restoration is to move this program forward by socializing the cost of undergrounding on the individual customer. We note that all customers benefit when there are fewer outages resulting from a major storm. The fewer outages there are from the storm's impact, the quicker the Company will be able to restore remaining customers. In addition, if there are fewer outages, then the Company's storm restoration cost will ultimately be lower. Finally, as further justification for socializing this cost through rates, disadvantaged communities are included in the model used to determine prioritization of circuits for undergrounding.

Q. What specific Tariff language does the Company propose?

A Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added to General Rule 7.1.

2. Street and Sidewalk Service

Q. Please describe proposed General Service Rule 5.2.8, Street or Sidewalk Service.

A. Proposed General Rule 5.2.8 is a new tariff section that prospectively addresses the installation and maintenance of overhead and underground facilities providing service to structures and equipment in the public right-of-way. Facilities such as newsstands, bus shelters, kiosks, communication equipment, computers, advertising and other display panels will receive service under the Street or Sidewalk Service provision. These customers will be required to pay in advance to the Company the estimated cost of the Company's service installation. The Company will charge the customer for removal costs when the equipment is removed.

Q. Why is the new tariff section for Street and Sidewalk Service needed?

A. Under General Rule 5.2.1, Con Edison installs electric services, in most instance at no cost to the customer, when the service is provided to a building or premises. All other customers are only eligible for temporary service

under General Rule 5.2.7. The Company anticipates that the number and types of customers requiring service in the public right of way will increase prospectively. These types of equipment have long been considered temporary service customers. In order to clarify the tariff since the Company expects this type of equipment to increase, the Company is proposing this new section to make clear that customers that install facilities within a public right-of-way, as opposed to premises, and are subject to removal by the local municipalities, must bear the costs of service installation.

Q. Please explain how the Company’s proposed tariff change will distinguish between Temporary Service and Street or Sidewalk Service.

A. Previously, the Company provided an electric service to all customers with non-permanent structures under the Temporary Services tariff section. Going forward, customers that need service for construction sites, street fairs, other temporary activities or non-permanent structures will continue to receive Temporary Service. The customer pays the estimated cost of installation and removal in advance. The defining characteristic of Street and Sidewalk Service is that customers locate their equipment and structures in the Public right-of-way. While rules vary by municipality,

street and sidewalk occupants are generally subject to removal, relocation, or replacement. Street and Sidewalk Service customers will pay the installation costs up front and the removal costs when the service is removed. These customers are not eligible for reimbursement for service installation costs because the risk or removal, relocation, or replacement of their equipment is a possibility for the duration of their occupancy in the Public right-of-way.

Q. Why are you proposing that Street and Sidewalk Services customers pay for a service installation in advance?

A. Because the public right-of-way is the inalienable property of the local municipality, the customer’s right to occupy the public right-of-way will be for a limited term, and the customer’s equipment will be subject to removal or re-location. Therefore, the Company does not have reasonable assurances that it will recover the costs for the service installation due to risk of relocation or removal.

Q. Are there any other changes related to the proposed Street and Sidewalk service.

A. In General Rule 5.2.7, the Company has removed the term “non-recoverable.” Going forward, the non-recoverable costs for temporary service such as construction sites and street is the full cost of the installation. This is what was intended by this provision but the word non-recoverable has

been subject to misinterpretation. There are also several minor additional changes. In General Rule 5.1 the definition for “Applicant” has been updated to include a customer requesting service “at a location in the Public right-of way.” Also, in General Rule 5.2.7, the types of customers receiving temporary service is clarified. Finally, General Rule 17.2, Special Services at Cost, has been updated to include installation and removal of Street and Sidewalk Service, and removal of Temporary Services.

Q. What specific Tariff language does the Company propose?

A Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added.

3. Charge for Replacement of Damaged AMI Meters

Q. Are there proposed changes to the charges for replacing a damaged meter?

A. Yes. We propose to modify General Rule 16.1 to update the cost of replacing a damaged meter. Currently, the Tariff imposes a charge of $282 to replace a demand meter damaged because the customer did not exercise reasonable care, or the meter was damaged due to tampering.

Q. Why do the costs need to be updated?

A. The Company has updated these costs and the costs have gone down. The updated labor cost plus the average cost of an AMI meter is $262.

Q. What specific Tariff language do you propose?

A. Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added to General Rule 16.1.

Q. Does this conclude your direct testimony?

A. Yes. It does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

ELECTRIC STORM RESPONSE AND RESILIENCE PANEL

Table of Contents

I. Introduction

A. Introduction and Qualifications of Panel Members

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

A. Patrick McHugh, Matthew Sniffen, and Gurudatta Nadkarni. The business address for all panelists is 4 Irving Place, New York, NY 10003.

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

A. (McHugh)

I am Patrick G. McHugh, Senior Vice President of Electric Operations for Con Edison. I assumed this position in July 2021, after serving as Vice President of Engineering and Planning for Con Edison. I currently have overall responsibility for Con Edison's Electric Distribution Operations, Engineering and Planning, and Con Edison's Energy Services organization, which coordinates all aspects of the delivery of electric service to customers.

I have been with the Company for over 30 years after joining in 1991 as a Management Intern and have held various positions with increasing responsibility including Vice President of Engineering and Planning, Vice President of Brooklyn/Queens Electric Operations, Chief Engineer of

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

(Sniffen)

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

My current responsibilities include, but are not limited to, the development of emergency response plans inclusive of drills and exercises designed to ensure readiness for corporate emergencies for all commodities. I currently share Incident Commander role for the Company's Pandemic Team. Prior to my current role, I held the position of Chief Engineer of Regional Engineering. In that role, I was responsible for developing Electric Distribution's asset investment strategy and justifying its

capital projects and programs in support of the Company's budget and general rate case processes. I was also a central figure in Electric Distribution's post-Sandy storm hardening program. I hold a Bachelor of Science in Mechanical Engineering from Manhattan College.

(Nadkarni)

I am Gurudatta Nadkarni. I am employed by Con Edison and currently hold the position of Vice President, Strategic Planning. I am responsible for the Company's long-range planning, climate risk and resilience, strategic initiatives, and mergers and acquisitions efforts. The most recent Long-Range Plans were completed January 2022. Before joining Con Edison, I held a number of positions in corporate strategy and development including Managing Director of growth at Duke Energy and a management consultant at McKinsey & Company. I was also a Senior Research Scientist at International Paper. I graduated from Vassar College with a Bachelor of Arts degree in Physics and Mathematics-Computer Science. I earned Master of Science degrees in Physics and Colloid, Polymer and Surface Science, and a Ph.D in Physics from Carnegie Mellon University. I also earned a Master of Business Administration degree in Finance and Marketing from the

University of Chicago. I joined Con Edison as Vice President, Strategic Planning in 2008.

B. Purpose of Testimony

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

A. Our purpose is to present the Company's proposals to align its Major Storm Cost Reserve and Reliability Performance Mechanism with its proactive approach to storm restoration and to provide the Company with appropriate cost recovery for its storm restoration efforts. We also propose to eliminate the Outage Notification Information Mechanism, which has been superseded by new communication requirements. We explain how the Company will implement the requirement in the Tropical Storm Isaias Settlement in Case 20-E-0422 et al. to absorb 12 months of operations and maintenance ("O&M") expenses, up to $2 million, for up to 100 additional bucket trucks for out-of-State storm crews that arrive by plane to assist in storm restoration. Finally, we will summarize the Company's electric resilience investments, which are discussed by the Electric Infrastructure and Operations Panel.

Q. Has the Company enhanced its major storm response activities in recent years?

A. Yes. Most notably, the Company has entered into new contracts for storm response crews and created a program to

fly crews in from outside New York State and equip them with bucket trucks when they arrive, removing driving distance as an impediment to obtaining assistance on a timely basis. Also, the Company has begun a pilot and has proposed in this rate case a selective undergrounding program to reduce the number of overhead customers that lose electric service during severe weather. In addition, the Company's current rate plan includes a program to remove hazardous trees from private property, at no expense to the customer, when such trees pose a risk to the Company's distribution equipment. From 2020 to date, the Company has removed nearly 2,600 hazard trees and spent $4.8 million on this program.

Q. How are major storm restoration and resilience related?

A. Major storm restoration refers to the Company's preparation for a potential major storm and its efforts to restore service in the storm's aftermath if a major storm materializes. Resilience refers to changing the design of the electric system to increase its ability to withstand more frequent and severe weather and, when adversely affected, recover quickly and safely. Increasing the resilience of the electric system will facilitate major storm restoration by preventing some customers from losing

service, allowing us to focus more resources on those that do, and thereby, restoring those customers more quickly.

Q. What is the Company's approach to Climate Change and the potential for increased extreme weather events or major storms?

A. Con Edison worked with stakeholders on a Climate Change Vulnerability Study for over three years, holding numerous stakeholder and working group meetings. The Company's study and its subsequent implementation plan have been referred to as the "gold standard." (Climate Crisis Catches Power Companies Unprepared," N.Y. Times, Aug. 6, 2021). The study found that "a growing body of evidence suggests that many extreme events will increase in frequency and intensity as a result of climate warming." In addition, that report states it "is neither efficient nor cost-effective for Con Edison to harden its systems to withstand every type of extreme event. Instead, Con Edison must use a broader suite of adaptation strategies to absorb and recover from the inevitable disruptions caused by extreme events exceeding their design." This testimony summarizes the Company's suite of strategies that it is proposing for this rate filing. In addition, the Company proposes the appropriate regulatory framework for these strategies.

C. Testimony Format

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

A. Section II describes the Company's major storm restoration staffing enhancements. Section III describes the Company's proposals regarding the Major Storm Reserve. Section IV describes the Company's proposal to revise the Reliability Performance Mechanism. Section V discusses the Company's proposal to eliminate the ONIM. Section VI discusses the Company's plan to implement the storm truck O&M requirement from the Isaias settlement. Section VII discusses how the Company is incorporating climate change resiliency into the planning and operation of its electric system and summarizes its resilience investments, as sponsored by and described in the Electric Infrastructure and Operations Panel. Finally, Section VIII discusses the Company's plans for staffing for its Climate Risk and Resilience Group and funding for additional climate change studies.

II. Major Storm Restoration Staffing Enhancements

Q. How does the Company build up its staffing for a major storm?

A. The Company uses three categories of workers for major storm restoration: (1) its employees and on-site

contractors; (2) storm response contractors; and (3) mutual aid crews released from other utilities.

Q. How does the Company obtain storm response contractors?

A. The Company has two different types of contracts with storm response contractors.

1. Retainer Agreements

The Company maintains retainer contracts with local storm response contractors who are committed to respond for the Company whenever adverse weather is predicted to impact the service territory. The Company executed its first retainer contracts in 2018 for 70 storm response workers which increased to 120 storm response workers in 2020. After Tropical Storm Isaias, the Company signed additional retainer contracts to secure 430 storm response workers from four different contractors. Currently the Company has retainer agreements with four contractors for 510 storm response workers.

2. Right of First Refusal

The Company also has contracts with six contractors that obligate the contractors to offer their services to the Company first when adverse weather is predicted to impact the service territory. Currently, these right of first refusal contracts give the Company access to an additional 530 storm response workers.

Q. What other recent efforts has the Company made to increase the number of storms crews available to assist in major storm restoration?

A. In 2019, the Company created a pilot program to fly in storm restoration workers from across the country and equip them with overhead bucket trucks when they arrive. In 2020, the Company purchased 90 bucket trucks reserved for use by storm restoration workers flown in for storm response. This program increases available storm crews by removing driving distance as an impediment to assisting in timely restoration.

Q. Has the Company used this program?

A. Yes. The Company used this program to obtain over 100 storm restoration workers for Tropical Storm Isaias in August 2020, approximately 120 workers for Tropical Storm Henri in August 2021, and approximately 120 workers for Hurricane Ida in September 2021. For these mobilizations, the Company flew in storm restoration workers from Alabama, Arizona, Arkansas, California, Florida, Minnesota, Missouri, Nevada, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Utah, and Washington.

Q. Does the Company pre-mobilize for storms?

A. Yes. Pre-mobilization has long been a part of the Company’s storm preparation.

Q. How has pre-mobilization changed after Tropical Storm Isaias?

A. Consistent with customer and stakeholder expectations, including expectations that the Company will Staff up even for potential major storms that do not materialize, the Company has increased its pre-mobilization for those storms.

Q. Are other panels discussing storm response investments?

A. Yes. As sponsored and discussed more fully by the Information Technology Panel, the Company is proposing over the next three years the following investments to aid storm restoration:

Outage Management System Project – Phase Four – Con Edison is proposing to invest $20.0 million to further enhance the operational performance and resiliency of the Company's Outage Management System ("OMS"). Among other things, the enhancements include operator ease of use and additional automation capabilities. This upgrade will also introduce a new OMS mobile platform, with damage assessment, crew management and Estimated Time of Restoration field update capabilities.

Enterprise Geographical Information System – Con Edison is proposing to invest $140.0 million to implement an enterprise Geographical Information System, of which

one benefit will be improved visibility and coordination during outages.

In addition, and as sponsored and discussed more fully by the Customer Operations Panel, the Company is proposing to invest over the next three years in the:

Outage Communication Program – As part of its Strategic Customer Experience Portfolio of projects, Con Edison is proposing to invest $4.7 million to build new technology platforms to provide more detailed information to targeted groups of customers before, during, and after outage events to meet safety and customer satisfaction goals.

Site Safety Program – During an electric emergency, Con Edison dispatches Site Safety resources to downed wire locations to make the area safe and stay at the location until additional Company personnel arrive who can fix or de-energize the downed wire. Con Edison is proposing to invest $1.1 million for updates to all Site Safety program training material (e.g., eLearning, training videos, customer materials) and system applications (i.e., Site Safety Management System and mobile app). The enhanced Site Safety Management System and mobile app will enable the Company to automatically track down wire tickets and

resources, account for Site Safety personnel's time in the field, and enhance communication between Site Safety management teams and wire guards in the field. These systems will also allow for automatic distribution of work/tickets to wire guards, eliminating manual distribution. In addition, contractors will have access to the new systems, giving them more complete information and the ability to communicate with the management team.

In addition, Con Edison is planning to hire at least 200 additional employees to support programs that increase the reliability and resiliency of the electric distribution system as well as storm and outage response. These additional personnel and their associated vehicles are discussed further by the Company's Electric Infrastructure and Operations Panel and Shared Services Panel. The Company will update the additional employee headcount at preliminary update.

III. Major Storm Cost Reserve

Q. Is the Company proposing any changes to how it charges the major storm reserve?

A. Yes. As we explain further, the Company is subject to deductibles both for O&M costs for major storms that do not materialize and for major storms that do materialize.

Whether or not a storm materializes, all mobilization costs are O&M costs that are charged to the storm reserve or absorbed by the Company because of the deductibles. The inability to charge a material portion of these O&M costs to the storm reserve because of the deductibles creates a significant O&M impact on the Company that we believe is contrary to the State's policy, and customer and stakeholder expectations, for a more robust storm response.

A. Pre-staging and Mobilization Costs

Q. How does the Company's current electric rate plan treat cost recovery for pre-staging and mobilization costs?

A. The Company is currently able to defer a portion of the costs it incurs to obtain contractors and/or utility mutual assistance in anticipation of a major storm that will affect its electric operations, but which ultimately does not materialize. There are currently two "deductibles" per event associated with this cost recovery. First, the Company has a deductible of $500,000 per event for pre-mobilization and staging costs. Costs between $500,000 and $2.5 million per event may be charged to the major storm reserve. Second, for costs above $2.5 million per event, the Company charges 85 percent to the major storm reserve and is required to absorb the remaining 15 percent.

Q. Does the Company propose to modify treatment of pre-staging and mobilization costs?

A. Yes. The Company proposes that all pre-staging and mobilization costs be chargeable to the major storm reserve.

Q. Why does the Company seek this change?

A. As discussed, the inability to charge all pre-staging and mobilization costs to the major storm reserve negatively impacts the Company's O&M, which is designed and funded for required repairs and programs, not major storm response. This impact is inconsistent with customer and stakeholder expectations that the Company will mobilize early if a major storm may affect the Company's service territory and with the Company's enhanced mobilizations in response to these expectations. This negative impact is becoming more acute as storms become more frequent, severe, and unpredictable, requiring the Company to mobilize more often. In addition, because other utilities in our region are now under similar pressure, the Company has been and will be competing for resources with utilities who are also under increased scrutiny for their storm response. The Company may therefore need to bring in more expensive contractors and/or mutual aid crews from farther away to

mobilize appropriately. This can exacerbate the negative impact to the Company's O&M, which, as stated above, is contrary to State policy and customer and stakeholder expectations.

Q. Please provide an example a recent event where the Company implemented a significant mobilization effort where a major storm did not materialize for the Company's service territory.

A For Tropical Storm Henri, portions of the Con Edison service territory remained inside the National Hurricane Center's forecast cone until 24 hours prior to actual landfall. In preparation, the Company responded to stakeholder expectations and secured 2122 mutual assistance storm workers and spent $34 million to mobilize for the storm. Of the $34 million the Company spent, its O&M budget absorbed $5.1 million for the deductible which was the $500k per event deductible plus $4.6M of the cost sharing deductible (e.g. 15% above $2.5M). In other words, for Henri, the Company mobilized for a potential major storm to meet customer and stakeholder expectations and had to absorb a significant cost due to the deductibles.

B. Major Storm Deductible and Cost Recovery

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

A. Yes, the Company is proposing to eliminate the two percent deductible for major storms that do materialize.

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

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

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

A. As we understand from prior proceedings, Staff’s position is that the deductible is necessary to recognize that some portion of the storm restoration activities for which the Company will be compensated pursuant to the reserve mechanism will reduce the Company’s future O&M costs.

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

A. This deductible results in the same negative impacts to the Company’s O&M budget as the pre-staging and mobilization deductibles. In addition, the rationale for the deductible rests on an incomplete picture. Although the Company acknowledges that some portion of the repairs made during storm restoration may reduce future O&M expense, the two percent deductible fails to consider other factors associated with the Company’s response to storms that

result in the Company having higher, unreimbursed O&M costs over the course of the year. Specifically, the application of the deductible does not account for higher costs the Company will incur to: 1) complete planned O&M work not completed because resources are diverted during storm restoration; 2) make permanent repairs to equipment on which temporary repairs were made during restoration. In addition, there will be additional unreimbursed O&M expense to effectuate storm restoration.

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

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

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

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

C. Surcharge Recovery of the Major Storm Reserve

Q. Does the Company propose to change recovery of the major storm reserve?

A. Yes. For the reasons discussed by the Company's Accounting Panel, the Company proposes to surcharge actual major storm costs that vary from the rate allowance by more than $7 million in a given year. Once the $7 million variance is triggered, the Company would be allowed to recover the entire variance up to 2.5% of delivery revenues each year through surcharge. Surcharge recovery is further detailed in the Direct Testimony of the Company's Electric Rate Panel.

IV. Reliability Performance Mechanism

Q. Does the Company propose to modify the RPM?

A. Yes. The Company proposes to align the RPM with its current increased pre-storm mobilization practice by updating the list of exclusions. Specifically, the Company proposes an exclusion for the aboveground radial CAIDI and SAIFI RPMs for storms where the Company pre-mobilizes more than 100 contractor or utility mutual aid storm restoration workers, even if the storm ultimately does not constitute a major storm.

Q. Why is the Company making this proposal?

A. The current RPM is inconsistent with Company's proactive approach, which is consistent with customer and stakeholder expectations that the Company should significantly increase staffing for potential major storms even if they do not ultimately materialize.

Q. Please explain.

A. The current RPM excludes a major storm, which is defined in part as an adverse weather event that results in customers being without electric service for at least 24 hours. Because the Company's proactive pre-mobilization policy may result in the Company restoring service after a severe weather event before the 24-hour mark, that severe weather event would not qualify as an excludable major storm, even though it likely would have resulted in outages of at least 24 hours but for the Company's increased mobilization.

While returning customers to service faster is the Company's desired outcome and what customers and stakeholders expect, the current RPM would potentially penalize the Company for restoring service faster by counting the storm against the Company's annual performance metrics if all of the outages are restored within 24 hours. This anomaly could contribute to the Company receiving a negative revenue adjustment for its annual reliability outage metrics. This result would be manifestly contrary to the goal of reducing the duration of customer outages, which the Company, customers, the Commission, and other stakeholders all share.

Q. Please explain the RPM impacts.

A. The primary impact to the Company would be an unjustified increased potential for a negative revenue adjustment for not meeting the radial CAIDI metric. Storms that had caused customer outages of up to 24 hours, but which are now restored faster through increased mobilization, would now count against the Company's annual average customer outage duration measure. But these outages also impact the radial SAIFI measure because storm caused outages are also counted against the annual average frequency measurement. Outages that do not meet the major storm definition due to the Company's increased mobilization efforts should not impact

either SAIFI or CAIDI. Our proposal corrects these inconsistencies. The Company's overhead SAIFI and CAIDI annual average scores should not be measured using outages caused by these storms, because those metrics are intended to measure day-to-day operations.

Q. Is Con Edison proposing any other changes to the RPM?

A. Yes. Under the RPM, the Company is subject to a program standard for the Non-Network Reliability program in Westchester County. Under this RPM, the Company was required to spend approximately $25 million annually, and $75 million in total, over the current three-year rate plan. By its terms, the RPM was limited to the spending authorized in the current rate plan. The Company met the RPM spending requirements in 2020 and 2021 and is on track to complete the spending requirements for 2022. As a result, the RPM will be complete by year end 2022 and should be discontinued because these investments will be subsumed within the Company's general resilience programs described later in this testimony.

In addition, as the Electric Infrastructure and Operations Panel explains, the Company proposes to replace its SAIFI and CAIDI metrics with SAIDI for both non-network and network systems. We note here that the principle of exclusions for bringing in 100 mutual assistance workers

for storms that do not materialize would apply the same to SAIDI as it does for SAIFI and CAIDI.

The Company is not proposing other changes. We note, however, that the Company is beginning to use AMI data to more accurately identify the time and duration of customer outages, and that the results may require future changes in RPM targets.

V. Outage Notification Incentive Mechanism

Q. What is the Outage Notification Incentive Mechanism (ONIM)?

A. The ONIM, established by the Commission in 2002 in Case 00-M-0095, establishes communication requirements applicable to Con Edison after the numbers of electric outages reach a certain threshold. Among other things, the ONIM addresses communications with State and local government representatives, issuing media releases, updating telephone broadcast messages, and notifying life sustaining equipment customers and large/sensitive customer accounts. The timing of the communications depends on the number of customers impacted (i.e., 20K, 40K or 70K), the amount of time the customers have been out of service (i.e., one, two, or three hours) and whether the outages are in one or multiple load areas.

Q. What is the Company proposal regarding the ONIM?

A. As stated by the Company's Customer Operations panel, the Company is proposing to eliminate the ONIM from the Customer Service Performance Mechanism.

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

A. Since 2002, the Commission has established State-wide communication requirements for New York State utilities. The communication requirements are detailed in the Department's Estimated Time of Restoration (ETR) Protocols and the ETR Protocols are included in utility emergency response plans, including Con Edison's. The ETR protocols essentially supersede the ONIM, as they are comprehensive and many of the ONIM activities are duplicative or conflict with the ETR protocols.

Q. Please provide an example.

A. Under the ONIM, the Company is required to begin its communication activities when 20,000 customers are out of service for three consecutive hours when the outage occurs in "a single load area served by a single load area substation." The ETR Protocols are activated when more than 5,000 customers are out of service for more than 30 minutes in a utility division. Similarly, under the ONIM, the Company is required to begin communication activities when 40,000 customers are out of service at the same time for

more than two hours “in more than one load area.” The ETR Protocols are activated when more than 20,000 customers are out of service company-wide for more than 30 minutes. Because the ETR Protocols are uniform State requirements and are duplicative of many ONIM requirements, the ONIM should be eliminated to avoid conflicting requirements.

Q Has the Commission recently addressed the applicability of the ONIM to Con Edison?

A. Yes. In its July 15, 2021 Order approving utility electric emergency response plans in Case 20-E-0618, the Commission sought input on whether the ONIM should be eliminated given similar communication requirements in Con Edison’s ERP. When Con Edison filed its emergency response plan for 2022, the Company indicated that it would seek elimination of the ONIM in its next rate filing.

VI. Isaias Settlement Storm Truck O&M Implementation

Q. Does the Company plan to obtain additional utility trucks for storm response?

A. Yes. The Company plans to use reasonable business efforts to purchase up to 100 additional trucks.

Q. Why does the Company plan to obtain additional storm response trucks?

A. We plan to purchase up to 100 additional storm response trucks to increase the number of out-of-State workers we can fly in to assist in restoring service after a storm. When a storm travels up the East coast, other utilities are likely to retain their crews for restoration and clean-up in their service territories and only release them for mutual aid later. This may delay their ability to come quickly to New York to assist in storm restoration. Similarly, the Company must compete for storm response contractors with other utilities likely to be affected by the storm, including those likely to be hit first or with a higher probability of severe impact. Increasing the number of trucks available for out-of-State workers increases the Company's options for assistance by increasing the number of restoration workers the Company can fly in from locations where driving distance would impair their ability to render timely aid. In addition, the Company can use the trucks for other customer purposes when necessary and practicable.

Q. Has the Company disclosed its plan to purchase these trucks before?

A. Yes. As discussed below, the settlement agreement approved by the Commission in Case 20-E-0422 notes the Company's

plan to use reasonable business efforts to purchase up to 100 new trucks for out-of-State storm response workers.

Q. What is the Company's plan for purchasing the trucks?

A. As explained by the Shared Services Panel, there is currently a nationwide supply chain shortage for utility trucks. As a result, the Company will attempt to buy 30 trucks in 2023, 30 in 2024, and 40 in 2025.

Q. What are the capital expenses associated with the trucks?

A. The Shared Services panel currently estimates the three-year total cost of purchasing up to 100 trucks to be $31 million. The Shared Services panel explains, however, that the costs of the trucks are not currently included in the revenue requirement because there are nation-wide supply chain shortages for utility construction equipment with no availability in 2022 and that the Company is continuing to refine its estimate and will include its capital request in the revenue requirement at the preliminary update stage of this proceeding.

Q. How will the Company handle the O&M for the trucks considering the Tropical Storm Isaias Settlement Agreement?

Q. As part of the settlement agreement approved by the Commission in Case 20-E-0422, et. al., the Company agreed

to absorb 12 months of O&M expenses, up to $2 million, for up to 100 additional bucket trucks for out-of-State storm crews that arrive by plane to assist in storm restoration. The settlement agreement noted that the Company planned to use reasonable commercial efforts to obtain up to 100 additional utility trucks but recognized that the Company may not be able to purchase that many. To comply with the settlement, the Company will absorb 12 months of O&M costs, up to $2 million, in 2026, which will be the first year after the Company completes its reasonable business efforts to purchase up to 100 trucks.

Q. What about O&M from 2022 through 2025?

A. O&M prior to 2026 will be funded through rates. The Company included $2 million in the revenue requirement. Those costs are included in Exhibit EIOP-3. As noted, by the Shared Services panel, however, the Company is continuing to refine its estimate regarding the cost of the trucks and will include its capital request in the revenue requirement at the preliminary update stage of this proceeding. Similarly, we will continue to refine our O&M estimate and will update the revenue requirement, if warranted, at the preliminary update stage of this proceeding.

VII. Resilience Programs and Projects

Q. What is Con Edison's approach to resilience?

A. Con Edison has a long history of incorporating resilience into its system design and making resilience-related investments. As early as 1882, Thomas Edison built the world's first underground electric grid in lower Manhattan because it would be more resistant to extreme weather. And, within the last decade, Con Edison implemented a $1 billion storm hardening plan in response to Superstorm Sandy. Now, the Company is investing to make its system more resilient to forecasted climate change impacts. Our resilience investments fit into the following framework:

1. Prevent: harden energy infrastructure and assets against projected climate conditions to prevent outages
2. Mitigate: modify system design and flexibility to mitigate disruptions to customer service
3. Respond: operational improvements to reduce recovery timeframe in response to extreme weather

Q. How is the Company making its system more resilient to the effects of projected climate change?

A. Using the Company's Climate Change Vulnerability Study and Climate Change Implementation Plan, Con Edison has changed design standards to incorporate climate change's potential

impacts into its forecasts. In addition, the Company is incorporating these potential impacts into its coastal flood mapping, flood risk standard, and heavy rainfall considerations. The changes to planning and design criteria are discussed further in the Company's Electric Infrastructure and Operations Panel.

Q. Is Con Edison proposing new electric resilience investments as part of this electric rate filing?

A. Yes. Below is a summary of the Company's proposed electric resilience investments over the next three years. These investments are sponsored and explained more fully by the Electric Infrastructure and Operations Panel:

Primary Feeder Reliability –Con Edison is proposing to invest $231.0 million to maintain and improve the reliability and resiliency of the Company's networks to adapt to more frequent and severe extreme weather events and to accommodate future load growth from electrification.

USS Switchgear Flood Protection Program – Con Edison is proposing to invest $25.4 million to provide mitigation measures to minimize damage from flooding.

Selective Undergrounding – As discussed more fully by the Electric Infrastructure and Operations Panel, Con Edison is proposing to invest $240.0 million to

identify and prioritize the undergrounding of overhead spurs based on historic outage data and disadvantaged community data.

Non-Network Reliability Program – Con Edison is proposing to invest $247.7 million to increase reliability for customers by proactively improving circuits with the lowest performance and further storm hardening its overhead system in anticipation of more frequent and severe storms.

Protection, Control, and Automation Program – Con Edison is proposing to invest $92.0 million to upgrade substation protection, control, and energy management system ("EMS") interfaces, and/or operator interfaces providing increased weather-hardening, improved reliability, and greater operational visibility.

Overhead Insulator Resiliency Program – Con Edison is proposing to invest $20.1 million to systematically replace insulators on critical overhead transmission lines that can be prone to cracks to lower the risk of load shedding and large-scale outages due to severe weather events.

Condition Based Monitoring Program –Con Edison is proposing to invest $31.5 million to install a variety of monitoring devices on substation power transformers

and other equipment to better understand real-time equipment status and improve planning associated with ratings and replacement cycles.

Control Cable Upgrade Program –Con Edison is proposing to invest $8.0 million to replace copper control cables in order mitigate the risk of dropping customers as the result of a substation event.

Erosion Protection and Drainage Upgrade Program –Con Edison is proposing to invest $10.0 million to install reinforcements and upgrade drainage systems in select substations to provide protection from erosion issues that may occur during extreme rain events.

Non-Network Resiliency with FLISR Program –Con Edison is proposing to invest $6.3 million to replace older sectionalizing equipment with new technology that will further enhance fault location, isolation, and service restoration capabilities to limit the number of customers impacted by equipment damage from extreme weather.

Critical Facilities Program –Con Edison is proposing to invest $27.0 million to further enhance circuit hardening to critical facilities located and fed via non-network distribution circuits to enhance reliability and maintain electric service for

essential services as much as possible during a severe weather event.

Substation Transformer Replacement Program –Con Edison is proposing to invest $372.0 million to proactively replace transformers that the Company has determined are nearing the end of their useful lives in order to reduce the risk of transformer failures.

Line Clearance/Vegetation Management Program –Con Edison is proposing to increase O&M spending to further expand the Company's tree removal efforts.

VIII. Climate Risk and Resilience Group

Q. Please describe the Company's Climate Risk and Resilience Group ("CRRG")?

A. The Company established the CRRG as part of its Climate Change Implementation Plan, which the Company filed with the Commission in December 2020. In the Climate Change Implementation Plan, the Company explained its governance structure for managing climate change impacts including its new corporate instruction, Climate Change Planning and Design Guideline, executive level oversight committee, and the CRRG.

Q. Please describe the Company's funding request for the CRRG.

A. The Company is seeking a $4 million increase in O&M, over a three year plan, for five full time employees for the CRRG

and for additional climate change studies. The Company has staffed the CRRG with existing employees that split their time between the CRRG and their other responsibilities. Of the $4.0 million, the Company proposes to use $2.2 million to hire a staff of five full time employees, $1.6 million for climate change studies related to deluge rain and wind, and to perform additional climate change vulnerability studies, and approximately $200K for consultants to assist with reviews of emerging climate change topics. Additional details are provided in Exhibit ESRR - 1.

Q. Does that conclude your testimony?

A. Yes.