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I. INTRODUCTION

A. Introduction and Qualifications of Panel Members

Q. Would the members of the Gas Infrastructure, Operations and Supply Panel ("GIOSP" or "Panel") please state your names and business addresses?

A. Our names are Katherine Boden, Nicholas Inga, Amr Hassan, Robert Massoni, Christine Cummings, Ivan Kimball and Kathleen Trischitta.

Our business address is 4 Irving Place, New York, New York 10003.

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

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

(Boden) I am the Senior Vice President of Gas Operations.

(Hassan) I am the Vice President of Gas Engineering.

(Inga) I am the Vice President of Gas Operations.

(Cummings) I am the General Manager of Project Management and Customer Programs.

(Massoni) I am the General Manager of Manhattan Gas Operations.

(Kimball) I am the Vice President of Energy Management.

(Trischitta) I am the Director of Commodity Operations.

Q. Please state your educational background.

A. **(Boden)** I hold a bachelor's degree in Electrical Engineering from Polytechnic University, and a Master of Business Administration in Management from Hofstra University. I have also completed PTI's Power Technology Course, PTI's Electric Distribution System Engineering Course, and Gas Technology Institute's ("GTI") Registered Gas Distribution Professional Course.

(Hassan) I hold a bachelor's degree in Mechanical Engineering from the Cooper Union, and a Master of Business Administration in Finance from NYU Stern. I have also completed GTI's Registered Gas Distribution Professional Course.

(Inga) I hold a Bachelor of Science Degree in Mechanical Engineering from Polytechnic University, and a Master of Business Administration Degree in Corporate Finance from Fordham University. I have also completed PTI's Power Technology Transmission and Distribution Systems programs, and a Project Management certificate course through the Company's program with Stony Brook University.

(**Cummings**) I hold a Bachelor of Science degree in Economics from Queens College. I have also completed GTI's Registered Gas Distribution Professional Course.

(Massoni) I hold a bachelor's degree in Business Management from the University of Phoenix.

(**Kimball)** I hold a Bachelor of Science degree and a Master of Science degree in Nuclear Engineering from Rensselaer Polytechnic Institute.

(Trischitta) I hold a bachelor's degree in Electrical Engineering from the State University of New York at Stony Brook.

Q. Please describe your work experience.

A. (**Boden**) I joined Consolidated Edison in 1990 as a Management Intern. I have held various positions of increasing responsibility in Construction, Operations, and Engineering in Electric Operations. In 2005, I was promoted to Vice President Manhattan Electric Operations a position that I held through 2010. In 2010 I was assigned to Gas Operations as Vice President. In 2017, I was assigned to Gas Engineering as Vice President. In 2021, I was promoted to my current position as Senior Vice Present Gas Operations.

(Hassan) In 1993, I joined the Company's Corporate Intern Program and have since held various positions of increasing responsibility mainly in Gas Operations, with some assignments in Energy Management and Corporate Planning. In January 2013, I was promoted to General Manager Gas Operations, where I was responsible for the Construction and Distribution Services groups in regions of our service territory. In November 2019, I became the Chief Distribution Engineer, and in September 2021, I assumed my current position as Vice

President of Gas Engineering.

(Inga) In 1992, I joined the Company's Corporate Intern Program and have since held various positions of increasing responsibility in Gas Operations, Treasury, and Shared Services. In April 2008, I was promoted to General Manager of Stores Operations, where I was responsible for the Company's supply inventory and order fulfillment processes. In June 2011, I was appointed to the position of Director of the Gas Conversion Group. In January 2015, I was assigned to Manhattan Gas Operations as General Manager. In 2017, I assumed my current position as Vice President of Gas Operations.

(**Cummings**) In 2001, I joined the Company as a Management Associate following a previous career in global transportation, including roles in auditing and compliance, customer service, and corporate training. Since joining the Company, I have held various positions of increasing responsibility in Government Relations (Corporate Affairs) and the Gas Conversion Group. In January 2015, I was promoted to Director of the Gas Conversions Group. In 2018, I assumed my current position of General Manager of the Project Management and Customer Programs group.

(Massoni) In 1981, I joined the Company as a member of the union and have since held various positions of increasing responsibility in Central Operations, Shared Services and Gas Operations. In March 2011, I was promoted to General Manager of Astoria Operations, where I was responsible for several groups including the Logistics Operations Control Center responsible for supporting the Company operating groups during storm response and recovery. In January 2016, I was assigned to Bronx Gas Operations as the General Manger, and then in December 2017, moved to Manhattan as the General Manager of Gas Operations.

(Kimball) I joined Con Edison in 1987 as a Management Intern and held various positions of increasing responsibility until December 1998 when I was transferred to Consolidated Edison Energy, Inc. ("Con Edison Energy"). My responsibilities as Director of Asset Management included day-to-day scheduling, fuel procurement, electricity market sales and planning, and associated regulatory and accounting matters of generating facilities owned by Consolidated Edison Development, Inc. ("Con Edison Development") and other contracted generating facilities. In August 2008, I returned to Con Edison as Director of Electricity Supply. In that position I was responsible for day-to-day electricity supply operations, including the scheduling of generation and load bids with the New York Independent System Operator ("NYISO") and neighboring control areas;

developing the overall electric power procurement plans for full service customers; developing and implementing Con Edison's electric hedging program; strategically evaluating and participating in capacity and transmission congestion contract ("TCC") auctions; managing contractual rights with various non-utility generators; and processing monthly invoices for wholesale purchases and sales of capacity, energy, and TCCs for Con Edison and its affiliates, Orange and Rockland Utilities, Inc. ("ORU") and Rockland Electric Company ("RECO"). In July of 2012, I was promoted to my present position of Vice President of Energy Management.

(Trischitta) I joined Con Edison in 1993 as a Management Intern in Gas Operations and have held various positions of increasing responsibility in Con Edison's Gas Operations, Fuel Supply, Unregulated Retail Operations and Energy Trading and Energy Management organizations. In 1995, I joined Fuel Supply's newly formed off-system sales organization with responsibility for developing and implementing some of the Company's first strategies for gas asset optimization. In 1997, I transferred to the newly formed unregulated subsidiary Con Edison Solutions and was responsible for the implementation of the retail gas business. Immediately prior to assuming my current position in January 2016, I was Managing Director of the Energy

Trading organization within Con Edison Energy, another unregulated subsidiary of Con Edison, responsible for the oversight of electricity, gas, oil, and renewable energy credit trading.

Q. Please describe your current responsibilities.

A. **(Boden)** In my current position as Senior Vice President for Gas Operations, I am responsible for the overall Con Edison Gas Operations, Engineering, and Compliance and Quality Assessment groups.

(**Hassan)** In my current position as Vice President of Gas Engineering, I am responsible for the Technical Operations, Project Management & Customer Programs, Gas Distribution Engineering and Gas Transmission Engineering groups.

(Inga) In my current position as Vice President of Gas Operations I am responsible for leading and managing both Company employees and contractor personnel in the safe and effective execution of, primarily, the following work: leak response, leak repair, compliance inspections, main replacement, and service installations.

(**Cummings**) In my current position as General Manager of Project Management and Customer Programs Group, I am responsible for the overall management of the capital projects and programs and for leading and managing the

Company's program to connect customers. As such, I am responsible for the engineering, operations planning, and customer liaison activities related to customer connections and safety-related inspection programs in customers' premises.

(**Massoni)** In my current position as General Manager of Manhattan Gas Operations I am responsible for leading and managing both Company employees and contractor personnel in the safe and effective execution of leak response, leak repair, compliance inspections, main replacement, and service installations, in Manhattan.

(**Kimball)** I am responsible for providing the overall strategic planning and direction for forecasting service area demand, evaluating electric, natural gas, and steam resource options, and procuring electricity, natural gas, oil and renewable attributes. I perform these functions for the customers of Con Edison, ORU, and RECO.

(**Trischitta)** In my current position as Director of Commodity Operations, I lead three sections comprised of (i) commodity purchasing and scheduling; (ii) gas planning and transportation services; (iii) commodity hedging. I am responsible for the functions of gas transportation services, gas transportation planning financial hedging, physical procurement and associated scheduling of gas, fuel oil and renewable attributes. I oversee these areas for Con Edison and its corporate affiliate, ORU. I also oversee the procurement of gas and fuel oil for Con Edison-owned generation. Annual natural gas expenditures overseen by my areas are over $700 million dollars per year.

Q. Do you belong to any professional organizations?

A. **(Boden)** Yes, I am a member of the Board of Solar One, the Board of a start-up called I-GIT (Institute of Gas Innovation and Technology) with Stony Brook University, the Board of the Northeast Gas Association ("NGA") and the American Gas Association ("AGA") Leadership Council. I am engaged in a number of research and development ("R&D") initiatives, most notably the Electric Power Research Institute ("EPRI")-GTI Low Carbon Resources Initiative. I am the outgoing president and member of the Executive Committee of the Society of Gas Lighting.

(Hassan) Yes, I am a member of the Operations Management Committee ("OMC") of the NGA, AGA Executive Pipeline Safety Management System ("PSMS") Committee and the GTI Operations Technology Development ("OTD") Board.

(Inga) Yes, I am currently a member of the AGA Operations Managing Committee and former Chair of the AGA Field

Operations Committee. I am also a member of the Society of Gas Lighting, and a former member of various NGA technical committees, as well as the Gas Utilization Advisory Group.

(**Cummings**) Yes, I am currently a member of Women in Communications and Energy and a committee member of the AGA.

(Massoni) I am a member of the AGA Field Operations Committee and the Society of Gas Operators.

(**Kimball)** No.

(**Trischitta)** I am a member of Women in Communications and Energy and the Society of Gas Operators.

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

A. **(Boden)** Yes, I testified before the Commission in the 2004 Electric Rate Case on the Infrastructure Investment Panel when I was the Chief Electric Distribution Engineer (Case 04-E-0572) and in the previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 16-G-0061 and Case 19-G-0066).

(Hassan) No, I have not testified previously before the Commission.

(Inga) Yes, I testified before the Commission in previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 13-G-0031, Case 16-G-0061 and

Case 19-G-0066).

(Massoni) No, I have not testified previously before the Commission.

(Cummings) Yes, I testified before the Commission in previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 13-G-0031, Case 16-G-0061 and Case 19-G-0066).

(Kimball) Yes, I have testified before the Commission as the witness in previous electric and gas rate case proceedings (Cases 09-E-0428, 13-E-0030, 16-E-0060, 16-G-0061, 19-E-0065 and 19-G-0066).

(Trischitta) Yes, I have testified before the Commission as the Gas Supply witness in cases 18-G-0068, 19-G-0066 and 21-G-0073.

B. Purpose of Filing

Q. Please summarize and briefly explain the purpose of the Panel's testimony.

A. This is not a "business-as-usual" gas filing. Con Edison recognizes that use of its gas system must change over time in response to the State's policy to reduce greenhouse gas emissions and is moving in that direction. Our testimony describes our programs to reduce greenhouse gas emissions and to take steps to decarbonize the gas system by 2050. We will manage this transition and continue to provide safe, reliable and resilient service to our 1.1 million existing customers. We will explain how our main replacement program not only provides important safety benefits, but also is an important contributor to reducing methane emissions. We will also explain what we are doing to enhance the program to provide even more methane emission reductions without sacrificing safety. Additionally, to support electrification, we are the first utility in the State to propose removing many financial incentives for new gas customer connections. We are also recommending other changes to the gas tariff to align with the New York State Climate Leadership and Community Protection Act ("CLCPA") goals.

While we expect use of our gas system to decrease, we must make the investments necessary to continue to operate a safe gas system. Accordingly, this Panel will discuss the importance of, and overall need for, infrastructure, operations, and technology investments to enhance safety. We emphasize here that the overwhelming majority of our gas capital investments are devoted to making our gas system safer, and we understand this is our core responsibility. As identified in Exhibit ___ (GIOSP-1), programs focusing on safety make up approximately 85% of the overall capital investment request (excluding Municipal Infrastructure).

We will also continue to serve our customers reliably, including any new customers who choose gas notwithstanding our electrification education and incentive programs. Finally, the Panel recommends the continuation of most of our current performance measures, with some modifications to better align the performance measures with the work the Company plans to undertake.

Q. What period does this testimony cover?

A. The Panel will present the projects and programs planned for the 12-month period ending December 31, 2023 ("Rate Year" or "RY1"); the following 12-month period ending December 31, 2024 ("RY2"); and the following 12-month period ending December 31, 2025 ("RY3").

C. Key Themes

1. Core

Q. How does the Company plan to make investments that maintain a safe and reliable system?

A. We first want to emphasize that the overwhelming majority of our capital investments, and our increased operation and maintenance ("O&M") expense, are devoted to making our gas system safer. Our efforts to maintain a safe system are core to Gas Operations. Throughout the Company's Gas Operations projects, programs, and daily activities we strive to achieve high standards for planning, engineering, execution, and response which support effective Company operations. This focus on core service enables the Company to accomplish our most important goal, making the gas system safe for our customers, employees, and the public. Core also includes our programs for maintaining reliability for our existing customers and any new customers who choose gas notwithstanding our electrification education and incentive programs.

Q. What are some examples of the types of capital programs the Company plans to undertake to maintain a safe system?

A. The Company's main replacement program, federally-mandated transmission projects, natural gas detector program, and regulator station improvement projects, are the initiatives that will serve to reduce system risk and improve customer and system safety. On a smaller scale, our reliability upgrade and winter load relief projects will also maintain reliability. We will discuss these later in this testimony.

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

A. The Company's gas safety and risk reduction efforts span a wide array of programs and processes. Our risk reduction strategy focuses on programs that enhance prevention, detection, and response to gas leaks. The American Petroleum Institute's Recommended Practice (API RP 1173) lays out the elements of an effective and holistic gas Pipeline Safety Management System ("PSMS") for pipeline operators. Through our PSMS, we follow a Plan-Do-Check-Act cycle for our daily activities, which promotes continuous improvement and feedback loops to our existing practices, procedures, and management systems. The application of this standard can be seen throughout our Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP"). Our Integrity Management Programs support efforts to identify emerging areas of risk and allow the Company to take proactive steps to address them.

Q. How does the Company's Integrity Management Program reduce risk and enhance safety?

A. Both DIMP and TIMP use data analytics, root cause analysis, open communication, and standardization to examine risk and improve existing programs or create new ones.

Additionally, the Company incorporates lessons learned from industry events and compliance directives to further advance our processes and business practices.

DIMP analyzes the distribution system to target distribution mains and services for replacement, refurbishment, or abandonment. TIMP focuses on transmission risk reduction and compliance programs, including identifying specific transmission mains for replacement. We discuss these and associated integrity management programs and projects in more detail below.

Q. In addition to the Company's traditional leak response/repair programs and efforts to identify and prioritize leaks emitting the most gas, what advanced leak detection technology is the Company investing in?

A. The Company began installing remote Natural Gas Detectors ("NGDs") inside customers' homes or buildings near where the gas pipe enters the building in 2018. The Company is proposing to continue this program, with the installation of additional Advanced Metering Infrastructure ("AMI") enabled NGDs. This will allow for the Company to complete initial deployment of all NGDs to all buildings that opt-in by the end of a three-year rate plan, if adopted. The Company will install these detectors indoors. They are designed to detect natural gas and send an alarm to our Gas Emergency Response Center ("GERC"). The GERC then contacts the fire department and dispatches a Company emergency response crew. The use of these detectors will be for both indoor and outdoor meter configurations. Detection of gas leaks through state-of-the-art technology and public awareness is critical to our comprehensive approach to risk management and commitment to public safety. Through early/enhanced leak detection, we can respond and remediate quickly, thereby reducing risk, keeping the public safe, and protecting the environment by reducing methane emissions.

Another example of the Company's investment in advanced leak detection technology is the Piccaro Surveyor, which the Company currently proposes to use for a new high emissions leakage survey and will be discussed in more detail below.

Q. Have other safety regulators acknowledged the benefits of NGDs?

A. The installation of NGDs is considered a program with very high safety benefits. The National Transportation Safety Board ("NTSB") has listed the installation of methane-detection systems in residential occupancies as an item on their "Most Wanted List of Transportation Safety Improvements."[1]

2. Clean and Resilient

Q. Why is the Company focusing on reducing methane emissions?

A. Natural gas contains methane, a greenhouse gas that once

[1] See https://www.ntsb.gov/Advocacy/mwl/Pages/mwl-21-22/mwl-rph-01.aspx

emitted into the air is 86 times more potent than carbon dioxide, if modeled on a 20-year time frame used in the CLCPA. Methane is the largest component of natural gas, and it can be emitted during normal operating activities during transportation, or prior to combustion. Known as fugitive emissions, the Company is committed to reducing these emissions whenever possible.

Q. How do the Company's investments advance its clean and resilience goals?

A. To achieve the Company's Clean Energy Commitment as well as help the State comply with CLCPA requirements, we are implementing or proposing to implement a number of greenhouse gas emission reduction initiatives. The following clean investments are significant in limiting the amount of natural gas emissions into the environment:

- Main Replacement Program & Service Replacement
  - o Abandons or replaces the most leak prone assets on the gas system, which reduces fugitive emissions; this program is responsible for reducing our emissions by 53% from 1990 to 2020 based on the methodology required by the EPA for companies to use to calculate their emissions. Given that the goal of the CLCPA is to reduce overall GHG emissions by 40% by 2030, we can

say that the contribution to that goal from our main replacement program is far outpacing the CLCPA goal. Additionally, the newly constructed replacement pipes will provide reliability for our existing customers and can accommodate blended or completely low-carbon fuels in the future.

- o Use of non-pipeline alternatives instead of main replacement when possible removes potential future emissions by downsizing the system;

- Vacuum Purging Technology
  - o Captures gas typically lost to the atmosphere during purging of gas lines and reintroduces it back into the gas system;
- Natural Gas Detectors and Leak Alarms
  - o Installation of NGDs near where the gas pipe enters the building is another resource to allow us to find gas leaks more quickly, thereby reducing emissions and keeping customers safe;
- Local Renewable Natural Gas (“RNG”)
  - o Natural gas supply from non-fossil sources (*e.g.*, food waste) that reduces the greenhouse gas impact; and
- Certified Natural Gas
  - o Pilot the procurement of natural gas that is certified to have followed the best environmental practices,

including lower emissions, in production.

Q. In what other ways is the Company furthering its Clean Energy Commitment through its gas operations?

A. Besides the Company’s capital projects, there are also tools, processes, and programs in place to help make our system safer that also support the reduction of natural gas emissions:

- Leak Detection
  - Monthly leakage surveys of our gas mains help find and address leaks in a rapid manner. The Company’s program provides 11 more leak surveys per year than required under Commission regulations;
- Leak Response and Repair
  - Goals to repair 85% of leaks within 60 days, which includes leaks the Company is not obligated to repair under Commission regulations.
- High Emitter Survey
  - Development of a new high emitter surveillance program to find leaks, using advanced leak detection tools with the highest calculated standard cubic feet per hour (“SCFH”), and prioritize them for repair. Currently, the Picarro Surveyor technology is being utilized for this work;

- Internally coated pipe
  - Prevents the loss of odor to newly installed steel mains. This significantly reduces the pickling process which would purge gas to the atmosphere, in order to odorize the main;
- Purge Burners
  - Burn off planned natural gas releases (combusting natural gas that would have been released to the atmosphere reduces the greenhouse gases associated with these releases due to the higher global warming potential of methane); and
- Damage Prevention Plan
  - Plan to reduce the number of damages, which in turn would reduce the number of unplanned natural gas releases.

Q. Is the Company also making investments to improve its resiliency to extreme weather events?

A. In addition to the greenhouse gas reductions, the Company recognizes that systems built today need to be resilient in the face of more frequent and severe weather than our service territory has experienced in the past. To account for these risks, the Company has expanded its flood zone criteria to identify and target additional gas assets with the greatest risk of flooding and water infiltration. These assets will be replaced as part of our main replacement program. Additionally, the Company's Climate Change Planning and Design Guideline is being used in conjunction with our specifications to design and plan projects to the projected future changes in climate. The Company is continually reviewing new data and information to determine if additional resiliency investments may be required.

The Company is also addressing environmental change and resiliency by incorporating higher flood elevation considerations into our design criteria, with the Company's Climate Change Planning and Design Guideline. Additionally, the Main Replacement Program will support climate resilience activities by replacing low pressure gas mains in flood-prone areas, using a FEMA+3 feet area. The Company will increase our targeted mileage of flood-prone gas main replacement per year.

3. Enhancing the Customer Experience

Q. How will the Company's planned investments enhance the customer experience?

A. The customer experience will be enhanced through new technology and tools designed to provide customers with the information they need to make effective decisions about their energy services. In order to align with the corporate, city and state's clean energy initiatives, all potential new gas customers will be offered information about clean alternatives to natural gas.

The Company is also proposing an investment in a new Gas Outage Management System. When implemented, this new system is expected to help identify outages quicker, track outages with advanced technology, improve efficiency in the restoration process, and provide timely and accurate information to customers when they need it most.

D. Gas System Description

Q. Please provide a high-level overview of the Company's natural gas transmission and distribution system.

A. A gas distributor since 1823, Con Edison currently provides natural gas service to more than 1.1 million customers in Manhattan, the Bronx, parts of Queens, and Westchester County. Con Edison manages a large, complex underground natural gas transmission and distribution system. This system contains approximately 4,400 total miles of gas main with approximately 375,000 service pipes that transport more than 330 million dekatherms of natural gas each year. The approximately 4,400 miles of gas mains consist of 97 miles of mains operating at pressures greater than 125 psig and 4,300 miles of distribution mains operating at pressures less than 100 psig. Approximately 300 miles are large-diameter distribution mains, greater than or equal to 16 inches that mostly connect the transmission mains to approximately 4,000 miles of smaller-diameter distribution mains.

Q. Please provide a general description of the parameters within which the Company designs its gas system.

A. We design our gas transmission and distribution system to meet state and federal gas safety requirements and the load requirements of all firm customers 365 days per year, 24 hours per day, based on the forecasted peak hourly load.

Q. What are the Company's gas infrastructure replacement objectives.

A. The Company's primary replacement objectives are to reduce risk, maintain safety, enhance reliability and resilience, and reduce fugitive methane emissions from the distribution system. By replacing leak prone pipe, we reduce the number of cracks and corrosion that could cause methane leaks. This provides an obvious safety advantage, reduces outages caused by flooding and, as discussed earlier, reduces emissions.

Additionally, certain projects, such as the Transmission replacement items, are required for regulatory compliance, in addition to risk mitigation.

Q. How does the Company implement these objectives?

A. One method of reducing risk is our distribution main replacement program ("MRP"), which proactively replaces 12-inch and smaller cast iron, wrought iron, and unprotected steel mains.

In addition to replacing the leak prone pipe, we have an aggressive leak management program whereby we routinely seek, find and fix leaks in a timely fashion, rather than waiting to prioritize lesser hazardous leaks (*i.e.*, Type 3's) with future main replacement plans.

The Company seeks to combine as much of this work together with infrastructure replacement, in order to minimize costs to our ratepayers; however, with a multi-year MRP ending by 2040, and a need to safeguard our environment now, we cannot allow less hazardous leaks to go unchecked and unrepaired. There will be more discussion of our safety and environmental risk reduction efforts through inspections and leak management programs in subsequent sections of this testimony.

II. CAPITAL AND O&M SUMMARY INFORMATION

Q. What is the Company's projected capital investment for the three rate years?

A. We are planning to invest $905.1 million in RY1, $924.2 million in RY2, and $890.2 million in RY3, excluding Municipal Infrastructure expenditures.

Q. What are the Company's projected O&M expenditures for the three rate years?

A. We are planning to spend $179.34 million in RY1, $182.12 million in RY2 and $184.65 million in RY3. Of these amounts, O&M program changes account for a $40.1 million increase in RY1, with decreases of $811,000 in RY2 and $1.1 million in RY3.

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2023-2025 GAS CAPITAL PROGRAMS" prepared under the Panel's direction and supervision?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-1).

Q. Please describe this exhibit.

A. This exhibit summarizes Gas Operations' three-year capital expenditures for RY1, RY2, and RY3. These capital expenditures are organized into the functional areas shown on the exhibit. This exhibit also includes the "White Papers" associated with the three-year capital expenditures. The white papers provide the description of work, justification, alternatives, milestones, benefits and funding requirements for each capital program and project.

Q. How did you organize your testimony to address the programs and projects in Exhibits ___ (GIOSP-1)?

A. The testimony is broken down into the main areas set forth below:

- Distribution System Improvement Programs;
- Transmission Programs and Projects;
- Customer Connections;
- Technical Operations; and
- Gas Information Technology.

Q. Have you prepared an exhibit entitled "GAS OPERATIONS – O&M CHANGES BY CATEGORY"?

A. Yes, we have.

Q Was this exhibit prepared under your supervision and direction?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-2).

Q. Please explain what is reflected in Exhibit ___ (GIOSP-2).

A. This exhibit shows the Company's incremental O&M expenditures, compared to the 12-month period ended September 30, 2021 ("Historic Year"), for RY1, RY2 and RY3.

Q. Do the Company's capital and O&M funding projections include funding for municipal infrastructure projects?

A. Yes, they do. However, these Public Improvement/Interference expenditures are not addressed in this testimony. These expenditures instead are addressed in separate testimony provided by the Company's Municipal Infrastructure Support Panel.

III. ANNUAL CAPITAL PROGRAMS

Q. Please summarize the gas capital request.

A. The Panel will identify major capital programs and projects to be conducted during the rate years. Each program and project is aligned with an exhibit or associated "white paper" that describes the scope of work, cost, schedule, and justification. As shown in Exhibit ___ (GIOSP-1), the Company projects overall capital expenditures are: $905.1 million in RY1, $924.2 million in RY2, and $890.2 million in RY3, excluding Municipal Infrastructure expenditures. This will provide for capital investments in:

- Programs/projects to reduce risk, enhance safety, and reduce methane emissions including main replacement efforts to eliminate 12-inch-and-under cast iron and unprotected steel gas main over the next 20 years;
- Programs/projects to improve system reliability, including Winter Load Relief and various system and regulator station upgrades;

- Transmission project and program investments to continue pipeline integrity management and meet regulatory requirements; and
- Information technology projects to reduce administrative and operational risk and achieve improved efficiencies and management of operations, programs and projects.

Q. Please describe the nature of the gas capital expenditures the Company is planning, why the work is necessary, and the major drivers of the projected increase in capital expenditures.

A. The Company recognizes that use of its gas system must change over time and describes herein the programs it is implementing as a result. At the same time, Con Edison must continue to keep its system safe. The overwhelming majority of the Company's gas system investments are to enhance the safety of its system. This entails programs to replace and/or upgrade its piping, equipment, and facilities. As shown in Exhibit ___ (GIOSP-1), the major drivers for the increase in gas capital expenditures in RY1 include the Leak Prone Main and Service Replacement Programs and Transmission Projects. These and other projects and programs are described below within the five program areas, *i.e.,* distribution, transmission, customer connections, technical operations and information technology.

A. DISTRIBUTION SYSTEM IMPROVEMENT PROGRAMS

1. Distribution Integrity

Q. Describe the Company's DIMP.

A. The purpose of DIMP is to enhance public and employee safety by identifying gas distribution pipeline integrity risks and implementing mitigating measures to address them. Some of these risks include distribution system leaks, excavation damages, and human error. The Company uses DIMP to enhance safety and create capital programs to improve safety.

Q. How does DIMP assess risk?

A. DIMP enhances safety by identifying and reducing distribution pipeline integrity risks through system analysis and by monitoring potential threats identified by internal subject matter experts ("SMEs"), regulators, gas associations and peers. Risk analysis is an ongoing process of understanding what factors affect the degree of risk posed by threats. To further enhance this process, starting in 2018, the Company moved from an evaluation process that considered risks separately under DIMP and the MRP Model, respectively, to a single consolidated risk model. The Company reviews top gas safety projects for changes and considers further actions such as reprioritizing our current replacement schedule and creating new programs for mitigating or eliminating emergent risks.

Q. How does DIMP drive capital investments?

A. By properly collecting, documenting, and analyzing information and data about our distribution system, DIMP informs the Company’s decisions on how to reduce risk through capital investments. One example is DIMP has identified leaks on small-diameter cast iron, wrought iron, and steel mains to be a threat, which is addressed through our Main Replacement Program, described further below.

Q. What is the Company’s strategy for the Main Replacement Program?

A. The Company uses a risk-based approach to prioritize elimination of its inventory of 12-inch and smaller cast iron, wrought iron, and unprotected steel mains. Work falls into two categories: Planned and Emergent.

1. Planned – The Company uses the DIMP risk model to assess risk and select main replacement projects. Planned projects mainly consist of highly ranked segments and flood prone pipe. The program will support decarbonization of the gas system by targeting simplification opportunities that will decrease the footprint of the distribution gas system, as well as focusing on the abandonment of cast iron

and wrought iron pipe.

2. Emergent – The Company identifies circumstances where leak-prone main replacement is required for reasons other than the risk model selection. These types of projects are outside of the Planned work, as described above, but support overall risk reduction efforts and can lead to cost savings. For example, the Company looks to proactively replace all 12-inch and smaller cast iron, wrought iron, and unprotected steel on a street prior to its scheduled paving date to reduce cost and prevent the need to excavate a newly paved street, should a leak occur. Some other examples of emergent conditions are leaks that cannot be repaired, cast iron encroachments, and public improvement projects.

Q. How does the Company try to achieve efficiencies in its main replacement program?

A. The Company proactively seeks opportunities to improve the reliability of our gas system and address other planned work streams in conjunction with this program. Such work includes winter load relief, customer connections, isolation valve installation, regulator station installations, and other pipework done in association with these projects. This allows us to integrate schedules so that all work streams can be efficiently planned and completed concurrently. This enhanced coordination reduces the impact to customers of repeated excavations and gas work.

Q. What are the proposed goals for each Rate Year?

A. We propose to replace 85 miles of main in each of the three rate years. For each rate year, we will replace 80 miles of planned work and five miles of conjunctional work, such as municipal infrastructure work that eliminates leak prone pipe. These goals are in line with our 20-year replacement strategy to be completed by 2040.

Q. Why has the Company reduced its annual main replacement target from the 90-mile annual target in effect for the last gas rate plan?

A. We believe this modest reduction improves safety while accounting for expected decreases in system use as electrification increases. We believe it is imperative to continue to replace high-risk pipe at a rigorous pace. At the same time, we recognize that we must prepare for electrification and look for opportunities to reduce risk by retiring rather than replacing pipe. Moreover, slightly modifying our targets in this filing mitigates overall customer costs without compromising our ability to complete the MRP by 2040. Specifically, our proposal reduces the requested gas revenue requirement by approximately $23.2 million per rate year.

Q. Is the Company adjusting its main replacement program strategy to focus more on emissions reductions?

A. Yes. We are adjusting our strategy to maintain our focus on safety while emphasizing reducing methane leaks. Going forward, the Company will preferentially select cast iron/wrought iron replacement, over bare steel, when risk factors are equivalent. This shift could result in the Company reducing more methane emissions because the emissions factor for cast iron is greater than that of bare steel.

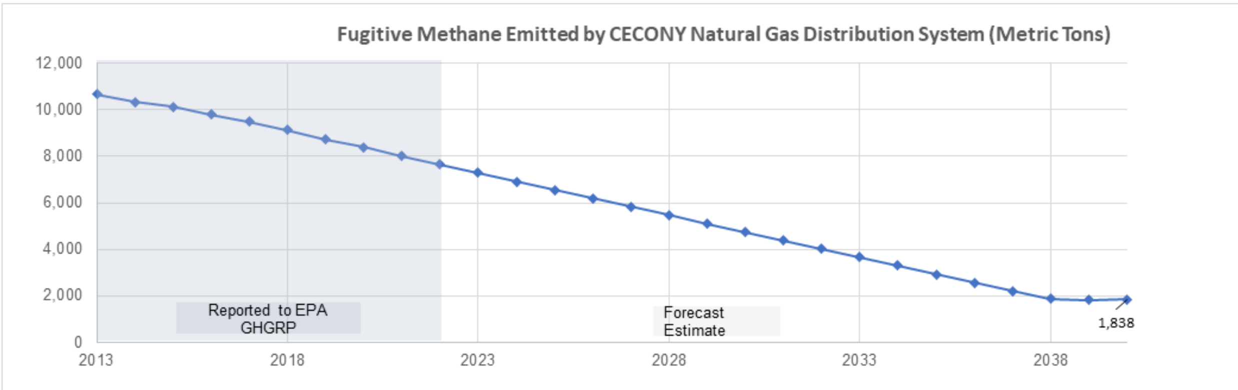
Q. Is the Company taking other steps to reduce emissions through its main replacement program?

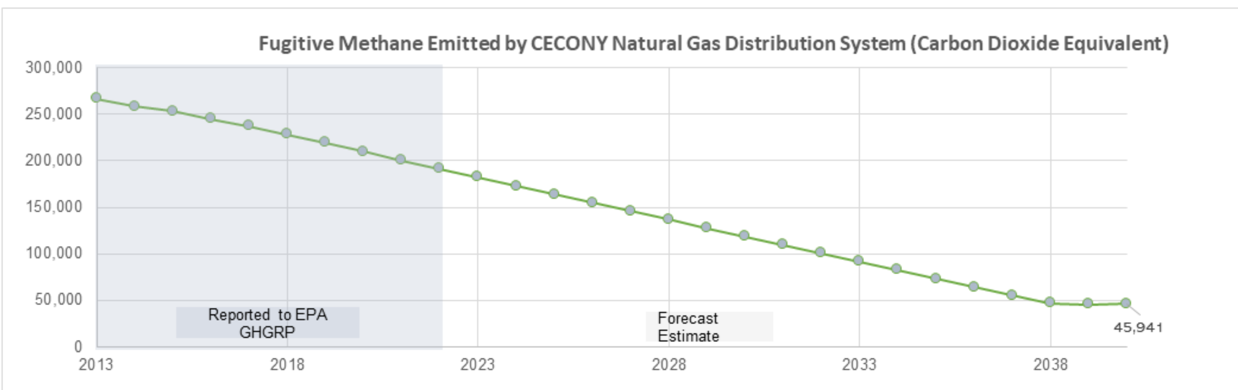
A. Yes. We are increasing our efforts to simplify the gas distribution system, which will serve to accelerate our methane emissions reduction. Simplification projects allow us to abandon leak-prone assets that will not be required in the long-term, given our expectations of lower system demand as a result of electrification to meet the State's CLCPA requirements.

Q. Can you quantify the emissions reductions from the MRP?

A. Yes. The reduction in emissions associated with these programs is quantifiable through the use of Title 40 – CFR 98. Subpart W. The projected annual reduction is shown in the charts below:

Table 1: Projected Fugitive Methane Emissions-CECONY





Q. What are the projected costs of the Main Replacement Program for each rate year?

A. The Company is projecting the following expenditures for this program: $404.8 million in RY1, $425.2 million in RY2, and $442.2 million in RY3, as set forth in Exhibit (GIOSP-1), which accounts for 45% in RY1, 46% in RY2 and 50% in RY3 of the total gas capital investment, excluding Municipal Infrastructure projects.

Q. Does the Company have any other proposals related to its

Main Replacement Program?

A. Yes, the Company proposes to capitalize all main installations, regardless of length. Currently, segments that are less than 25 feet are expensed as O&M.

Q. Has the Commission approved a similar proposal as part of any other NYS gas utility rate plan?

A. Yes, the Commission recently approved a similar proposal in National Grid's gas rate plan (Case 19-G-0309, *et. al*).

Q. Does the Company propose any additional investments that will reduce methane emissions?

A. Yes. The Company is introducing a new Methane Capture Technology program, which will procure and deploy Zero Emissions Vacuum ("ZEVAC") units to construction crews. Currently, certain construction activities release natural gas to the atmosphere. The ZEVAC unit can be used to mitigate methane emissions on larger volume pipe replacements for pipes operating at greater than or equal to medium pressure (15 psig MAOP). The ZEVAC units pump the gas out of the isolated pipe segment being replaced and into the portion of pipe remaining in service. The Company plans for full deployment by the end of 2026. The Company is projecting the following expenditure for this program: $1 million in each of RY1, RY2 and RY3.

Q. Is the Company proposing to continue the Safety and Reliability Surcharge Mechanism ("SRSM") to recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of main above the targets established for the Main Replacement Program?

A. Yes, the Company proposes to continue the SRSM for the Main Replacement Program.

Q. Are there additional costs not accounted for in this expenditure?

A. Yes. On January 12, 2022, the Company was informed that Urbint, the company that provides our current MRP modeling software, has made the strategic decision to no longer provide maintenance and support services for their Optimain products. Maintenance and support services will be discontinued on March 31, 2023. As a result of this announcement, the Company must seek an alternative software application to fill our MRP risk modelling needs. The cost of procuring an alternative software application is currently unknown and not accounted for in the costs presented for the Main Replacement Program. Therefore, the Company plans to determine the costs associated with this new project and present this information during the update phase of the proceeding.

2. System Reliability

Q. Are you planning any other programs that will address risk on the distribution system?

A. Yes. We plan to continue our gas system reliability improvement programs, which are described in the Company submitted White Papers. Some key programs include the Gas Reliability Improvement Program and Winter Load Relief. Currently our design criteria for regulator stations includes installation of components to prevent over pressurization of our gas distribution system. We also plan on initiating a program to install additional equipment to provide redundancy to the existing over pressure protection ("OPP") components, which is discussed later in this testimony. The benefits of the Company's proposed gas system reliability programs are described in more detail below.

Improve safety/reduce risk: The Gas Distribution System Over Pressure Protection improvement program will improve public safety and continue to reduce the risk of an over pressurization event by employing secondary OPP technology on our gas distribution system. Where regulator stations employ primary and monitor regulator design, this program will seek to eliminate common mode of failure by providing added protection, as outlined in the Protecting Our Infrastructure of Pipelines and Enhancing Safety ("PIPES")

Act, Section 206.[2] An over pressurization downstream of the regulator stations may create leaks on the system or, in the worst case, put life and property in imminent danger. This program increases public safety, and at the same time provides environmental benefits by minimizing methane emissions.

Operational excellence: Supply mains facilitate the delivery of natural gas to every customer on the Con Edison gas system. Improvements to these facilities are needed to enable the Company to continue to deliver reliable gas service to all our customers on the coldest winter days. This will be accomplished largely by planned capital programs, including the Winter Load Relief and the Gas Reliability Improvement Programs.

Customer experience: Programs such as Winter Load Relief and the Regulator Station Revamp Programs are designed for the natural gas system to be able to accommodate required gas pressures for existing customers as well as provide reliable service with minimal interruption, thus enhancing the customer experience.

Q. Please describe the planned work for each of the above-listed programs, the costs projected in RY1, RY2 and RY3,

[2] PIPES Act of 2020, S. 2299, 116th Cong. (2019)

as well as additional details regarding the benefits of this work.

A. <u>1. Winter Load Relief</u> – To maintain system reliability, Con Edison needs to reinforce our systems to achieve the minimum pressures required to serve customers. We must also reinforce our system to maintain minimum inlet pressures to our low and medium-pressure regulator stations. Using our annual network analysis model validation process, we project anticipated system loads and system performance for the following winter season. Where marginal pressures are anticipated, areas are identified for additional reinforcement and can be addressed through specific recommended projects under the Winter Load Relief program. These projects typically consist of installing new mains to make ties or replacing smaller mains with larger diameter mains to eliminate area constraints. The Company is projecting the following expenditures for Winter Load Relief related projects: $13.4 million for RY1, $14.0 million for RY2 and $14.3 million for RY3, as set forth in Exhibit ___ (GIOSP-1).

<u>2. Gas Reliability Improvement Program</u> – Our priority is to avoid large-scale outages on our system during peak demand periods. To address this potentially devastating and costly risk, system reinforcements such as main ties,

or regulator station upsizing are needed, specifically targeting vulnerable segments, more described in the whitepaper. The Company is projecting the following expenditures for the Gas Reliability Improvement Program: $10.1 million for RY1, $10.7 million for RY2 and $10.7 million for RY3, as set forth in Exhibit ___ (GIOSP-1).

B. TRANSMISSION PROGRAMS AND PROJECTS

Q. Please describe Con Edison’s gas facilities, which operate above 125 psig.

A. Con Edison has 97 miles of 6-inch to 36-inch diameter mains in Manhattan, Queens, the Bronx, and Westchester County, that operate above 125 psig. For purposes of this testimony, these pipelines will be referred to as transmission. These mains, most of which were installed between 1947 and 1973, have a maximum allowable operating pressure of either 245 psig or 350 psig. The transmission facilities are supplied by seven gate stations from four pipeline companies. In addition, most of these facilities are part of a larger regional network called the New York Facilities (“NYF”) System, which is jointly owned and used by Con Edison and National Grid. Con Edison’s system is connected to National Grid’s system at two bi-directional metering stations, as well as five metered take-off locations in Queens.

Q. Please describe the capital investment that is planned for the gas transmission facilities.

A. As presented in Exhibit__(GIOSP-1), the following expenditures are related to transmission programs and projects: $115.3 million in RY1, $133.8 million in RY2 and $112.8 million in RY3. These investments are required to comply with the new state and federal Transmission MAOP Reconfirmation Rule (MAOP Rule, part 1).

1. Transmission Risk Reduction and Reliability

Q. Please describe each of the gas transmission capital programs and projects that are planned for the 2023-2025 period and how they address safety and reliability.

A. The gas transmission capital programs are as follows:

1. Installation of Remotely Operating Valves (“ROVs”) - This program provides for rapid isolation of a compromised section of the transmission facilities; rapid isolation of transmission facilities at river and tunnel crossings and at the outlet of gate stations; and rapid separation of intersecting transmission mains at tee or branch locations. The ROV program consists of converting existing transmission valves or installing new ROVs to meet the future ROV design criteria, specifically targeting those transmission mains that are not slated for pipeline

replacement. Once the program is complete, the closure of any two consecutive ROVs will not negatively impact supply mains or the distribution system on an average winter day. Five total ROVs are required to meet System Design Criteria, as part of this program. All will be installed by the end of RY3. The Company projects the following expenditures for this program: $ 3.1 million in RY1; $3.3 million in RY2; and $3.3 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

2. The Newtown Creek Metering Station - This is a capital project that addresses a facility constructed in 1951 that contains older piping configurations and obsolete metering equipment that is maintenance intensive. One of those pieces of new equipment is the addition of a new control valve that would allow Con Edison to control the flow rate to National Grid. Our ability to control flow to National Grid would allow us to regulate the Con Edison portion of the gas transmission system and protect the Con Edison portion of the gas transmission system from abnormal operating conditions and maintain flow to the maximums permitted under the New York Facilities agreement. The Company forecasts the following expenditures for this project: $15.6 million in RY2; and $14.5 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

3. Transco Gate Station Over Pressure Protection – This project addresses the installation of Con Edison owned OPP at the following Transco facilities: Transco's Upper Manhattan Gate Station located in Manhattan and Transco's Central Manhattan gate station located in New Jersey. The Con Edison OPP will provide for the safe operation of the gas transmission system if Transco's OPP device at any of the two gate stations fails and the pipeline's operating pressure cannot be controlled. This project will also include installing new piping from the Transco-Con Edison demarcation point up to the outlet of the ROV with piping for the same MAOP as the Transco station inlet piping. The Company forecasts the following expenditures for these projects: $10 million in RY1; and $10.0 million in RY2, as set forth in Exhibit ___ (GIOSP-1).

4. Knollwood Overpressure Protection Project - This project addresses the installation of Con Edison owned OPP at the Tennessee Knollwood Gate Station. Upgrades at the Knollwood station are to be completed in 2022, after which, this OPP project can commence. The Con Edison OPP will provide for the safe operation of the gas transmission system in the event that the pipeline's OPP device fails and the pipeline's operating pressure cannot be controlled. This project will also include the installation of new

piping from the Tennessee-Con Edison demarcation point up to the outlet of the ROV, as set forth in Exhibit ___ (GIOSP-1).

5-9. MAOP Rule Replacement – The Company has five projects required for compliance with federal and state law. These projects will replace transmission infrastructure installed using legacy construction practices, for which traceable, verifiable and complete records related to the pipeline's MAOP show that the pipeline was not pressure tested to the new federal and state requirements.

Pursuant to federal and state regulations, "transmission lines" are defined as pipelines that operate at a hoop stress of 20 percent or more of Specified Minimum Yield Strength ("SMYS") (*see* 49 CFR 192.3). The Company plans to replace vintage federally defined transmission pipelines with new facilities that will improve safety and reliability by operating at less than 20 percent SMYS. Loss of supply from these facilities would otherwise cause widespread customer outages.

In addition to complying with federal and state law, these projects will improve safety through the retirement of certain high-risk assets, including: a compressor station, certain regulators and a super monitor.

The Company forecasts $99.8 million in RY1; $108.4 million in RY2; and $88.4 million in RY3 for these initiatives, as set forth in Exhibit ___ (GIOSP-1).

2. Gate Station Work

Q. Please describe the two broad categories of gate station work that the Company typically undertakes.

A. The first category is capital work at Company-owned gate station facilities. The second category is work on pipeline-owned facilities that primarily benefits the Company and its customers. Costs associated with this second category are usually recovered as a surcharge through the monthly rate adjustment ("MRA") for projects approved by the Commission, as set forth in the Company's Gas Tariff.

Q. Is the Company proposing any gate station projects during RY1-RY3 that fall under the first category (*i.e.*, work on Company-owned facilities)?

A. Yes, the Company plans to refurbish the Algonquin Cortlandt gate station. This work is scheduled to occur in 2022 and 2023. The cost associated with this project is $11 million in RY1, as set forth in Exhibit ___ (GIOSP-1). The need for this project is discussed in the whitepaper.

Q. Is the Company proposing any gate station projects during RY1-RY3 that fall under the second category (*i.e.*, work on pipeline-owned facilities that primarily benefit the Company and its customers)?

A. The Company is not proposing any new projects in this second category. But the Company is updating the cost estimate for the Tennessee White Plains gate station project, which was approved under the current Gas Rate Plan (Case 19-G-0066). The work at the gate station has been completed.

Q. What are the Company's final costs related to the White Plains gate station?

The final costs associated with the White Plains gate station work have not been provided to the Company as of the date of this rate filing. To the extent available, the Company will provide any additional information it obtains during the update phase of this proceeding. In the event that final cost information is not available by the update phase of this proceeding, the Company proposes to defer any costs in excess of the $11 million approved in Case 19-G-0066, for recovery in the Company's next base rate filing.

3. Renewable Natural Gas – Mount Vernon Interconnection

Q. Please describe the Mount Vernon RNG interconnection facility investment.

A. The Mount Vernon RNG interconnection facility is part of the Company's Smart Solutions initiatives. One of the

Smart Solutions for gas customers is to solicit the energy market for cost effective alternatives to pipeline capacity though non-pipeline alternatives ("NPAs"). In response to a request for proposals ("RFP"), a vendor has proposed a facility that will produce RNG from food waste within Con Edison's service territory. Con Edison will install equipment to support the interconnection to this RNG facility, which will consist of metering, gas quality measurement, odorant measurement and remote shutdown. The Company forecasts the following expenditures for these projects: $1.5 million in RY1, as set forth in Exhibit ___ (GIOSP-1).

Q. How does this investment align with the Company's clean energy commitments?

A. This RNG facility provides the ability for waste-related methane to be captured and used, in lieu of being released into the environment.

This interconnection is the first of its kind supplying the Con Edison system and opens the door for other similar interconnections in the future.

4. Pressure Control

Q. Please describe the functions performed by the Pressure Control Department.

A. The Pressure Control Department is primarily responsible for the maintenance and operation of the Company's gas pressure reduction equipment. This equipment ranges from major transmission gate station assets to the many components that make up the high and low-pressure district regulator stations located throughout the Company’s service territory. Most of this equipment is located within below-grade manhole structures underneath roadways and sidewalk areas. This equipment includes 337 regulator stations. The Pressure Control Department validates each station’s operating condition annually, as well as conducting monthly site inspections.

Q. Please summarize the capital expenditures projected for the Pressure Control Department during the 2023-2025 period.

A. The Pressure Control Department sponsors three capital programs that are planned for the rate years. The Company estimates capital expenditures of $20.3 million in RY1; $20.2 million in RY2; and $20.2 million in RY3, as set forth in Exhibit ___ (GIOSP-1). These investments are needed for safe and reliable service, because they keep essential pressure control equipment operational and give the Company new monitoring and control capabilities, which reduce the possibility of an overpressure event or loss of service continuity.

Q. Please describe the capital programs planned to be completed by the Pressure Control Department.

A. The capital programs planned to be completed by the Pressure Control Department are: Regulator Automation, Regulator Station Improvements, and Station Gas Detector & Fire Detection/Alarm Systems. All are described in more detail in the applicable White Papers.

The largest project of this category is Regulator Automation. The purpose of this program is to install automated control equipment at regulator stations throughout the gas system to enable remote operation while providing real time visibility. Also included is the installation of enhanced OPP equipment on the low-pressure gas system to provide additional levels of protection to prevent pressure exceedances. Where applicable, these installations will also include the replacement of regulator station piping that contains bypasses which connect different MAOP systems, the replacement of distribution mains that connect to pressure division valves, or the relocation of regulator station sensing, control, and overpressure protection monitoring lines within the boundaries of regulator stations to improve station operation and overpressure protection. The Company forecasts the following expenditures for this program: $19.1 million in each of RY1, RY2, and RY3, as set forth in

Exhibit ___ (GIOSP-1).

C. NATURAL GAS DETECTORS

Q. What is the purpose of NGDs?

A. NGDs are safety devices installed indoors near the gas point-of-entry ("POE") and head of service valve intended to provide continuous monitoring of atmospheres for a concentration of methane that result in an alarm. When a NGD alarms (10% lower explosion limit), this alarm information is transmitted through the AMI network to the Gas Emergency Response Center ("GERC"). The GERC will then notify the local fire department and dispatch a Gas Distribution Services ("GDS") mechanic to respond to the potential gas leak using normal leak response protocols.

Q. What benefits do NGDs provide to customers?

A. The accumulation of natural gas in a building can occur from a leak on the buried gas distribution infrastructure located outside of the building. Gas migrates through the soil or through a utility service POE and into the building. Buildings are typically constructed where the majority of utility POEs (water service, sewer pipe, buried electric service) are normally in close proximity to the gas POE. Locating the NGD on service line pipe near POE provides detection capability for this type of occurrence.

It will also detect leaks on nearby customer piping or equipment.

The development of methane sensor technology in combination with the Company's AMI communication network presents a first-of-a-kind and unique opportunity to pair remote methane detection with the AMI communication infrastructure that will enable a direct alarm to the Company's GERC that could prevent a gas incident in the future, improving public safety.

Using NGD technology will improve public and employee safety by identifying potential leaks much earlier than relying on odor calls, allowing GDS crews more time to identify potential gas leaks, make the location safe and evacuate the public if necessary.

Q. What investments are required to install and maintain NGDs?

A. Con Edison started mass deployment and monitoring of AMI enabled NGDs in 2020 after successful completion of the pilot phase of NGD deployment in 2019. To date, the Company has installed approximately 90,000 AMI NGDs and is estimated to install a total of 150,000 through the end of 2022. As of December 31, 2021, the Company has received and responded to over 900 NGD alarms.

NGD installations for rate case years 2023-2025 are estimated to be: 65,700 in RY1, 73,300 in RY2, and 67,800 in RY3. To reduce the cost of installations and decrease the number of visits to customers' homes and buildings, when possible, NGD installations will be completed with other work including service line/meter inspections. In total, we currently anticipate the following capital expenditures to install and support NGD's during the upcoming 2023-2025 period: $33.3 million in RY1, $37.6 million in RY2, and $35.2 million in RY3 as shown in Exhibit ___ (GIOSP-1).

D. PROPOSALS TO INCREASE CUSTOMER INTEREST IN GAS ALTERNATIVES

Q. How does the Company propose to make alternative energy solution options more attractive for new customers and support non-fossil technology adoption?

A. In line with the Company's clean energy commitment, we are proposing to eliminate certain tariff provisions that facilitate natural gas use but exceed statutory requirements. The Company is also enhancing the information it provides to customers, with the goal of discouraging customers from using or expanding their use of natural gas.

Q. Please describe the Company's proposed tariff modifications.

A. First, the Company is proposing to eliminate language in its gas tariff that allows multiple customers seeking to connect to the Company's gas distribution system to pool their installations and avoid connection costs. Eliminating the "concurrent connections" tariff language will preclude sharing of benefits between customers who otherwise would exceed their individual allotment of main, but for the fact that other customers connected at the same time and did not use their full allotment. As an example, a customer who needed 120 feet of main while the next building only needed 80 feet could "use" the current tariff allowance and would not incur any additional cost. This language is a legacy of the gas expansion period in the Company's history and is no longer part of our forward-looking clean energy vision.

Second, customers who pay for the main extension currently benefit from connections made along that length of main by subsequent customers connecting within a five-year window. Going forward the Company proposes that reimbursement (in part or in full) for costs to customers who chose to pay for their main extension be eliminated. Third, the Company is proposing to eliminate the "revenue test" for all customers, thus requiring every foot beyond the 100-foot allotment under law be paid for by the customer in full prior to the commencement of the work. Customers can currently avoid such charges if they can demonstrate that their gas usage will generate revenues above a specified threshold.

Finally, the Company proposes that no customer will receive a service determination (also referred to as a "ruling") for natural gas service of any size or for any purpose without first acknowledging in written form that they have been provided information on non-fossil alternatives and that they are aware of climate protection laws and regulations.

Q. What is the "100-foot rule"?

A. The obligation to provide customers a total of 100-feet of main and/or service without cost is codified in Public Service Law § 31. Section 230.2 of the Commission's regulations goes beyond the Public Service Law, based on the type of customer requesting service and usage. Specifically, for a residential heating customer, Section 230.2 requires New York State local distribution companies ("LDCs") to provide 100 feet of main *and* 100 feet of service, while for Residential non-heating customers and nonresidential customers Section 230.2 requires a *total* of 100 feet of main and/or service, plus the length of service line necessary to reach the edge of the public right-of-way.

Q. What is the Company proposing with respect to the "100-foot rule"?

A. The Company is not proposing any deviation from the requirements of the Public Service Law. But we are requesting a waiver from the requirements of 16 NYCRR §230.2 that provides additional piping to residential heating customers. Instead, the Company is proposing to provide all customers (regardless of customer type or usage) with a combined total of 100 feet of main and/or service, plus the length of service line necessary to reach the edge of the public right-of-way.

Q. Why are you requesting a waiver?

A. Some of the tariff modifications described above are not consistent with current Commission regulations and therefore require a waiver for implementation. Specifically, a waiver is required for the Company's proposals: to eliminate the revenue test for all customers; to eliminate reimbursements to customers who chose to pay for their main extensions due to subsequent customer connections; and to combine the 100-foot allotment of main and service, irrespective of the customers' service classification or usage. The Company's waiver request will apply to new customer connections only. These proposed measures will bring greater price parity between natural gas service and alternatives for many customers, while still allowing customers to make connections to existing infrastructure in accordance with our statutory obligations. These changes, however, require a waiver of 16 NYCRR §§230.2 and 230.3.

Q. What is the Company's justification for such a waiver?

A. As explained throughout our testimony, the Company fully supports the State's clean energy policy and efforts to achieve CLCPA requirements. While we recognize that important work related to the CLCPA is ongoing and final decisions in many key areas are still pending, we view the requirements in 16 NYCRR §§230.2 and 230.3 as incongruent with the CLCPA and highly unlikely to continue in their current form. Therefore, we believe a waiver is justified in anticipation of expected changes to the Commission's regulations and to advance important, state-wide policy goals.

E. CUSTOMER CONNECTIONS

Q. How has the Company advanced its goals through Customer Connections?

A. As described in more detail below, the Company's Customer Connections investments have offered the opportunity to enhance both customer engagement and operational performance. The Company is obligated by the Public

Service Law to provide gas service to new customers (even if we have educated them on the alternatives and they decline) and requests to increase gas demand for existing customers. In accordance with this obligation, we will continue to provide safe, reliable service to our customers in a cost-effective manner. However, as stated above, we encourage all potential natural gas customers to consider alternative (*i.e.*, non-fossil) energy solution options. Additionally, as outlined above, the Company's proposed tariff changes should have an impact on Customer Connections, as those changes are put into effect. The Company is forecasting a reduction in the number of customer connections during RY1-RY3, with even more significant reductions anticipated in the future.

Q. Are the Company's proposed tariff changes reflected in the forecast for customer connections?

A. No, considering we have no experience regarding the impact these proposed changes would have, it would be premature to reflect them in the Company's forecast. However, the Company notes that, under the downward-only capital reconciliation it is proposing, any capital underspending would be returned to customers.

Q. What are the projected overall costs associated with the Customer Connections Program?

A. As presented in Exhibit ___ (GIOSP-1), the Company projects the following expenditures for this program: $73.1 million in RY1; $74.6 million in RY2; and $76.7 million in RY3. The overall costs are for the installation and replacement of gas services and main associated with facilitating customer connection requests.

Q. Does the Company's request reflect an overall lower growth rate, including the impact of this industry change?

A. Yes. The current request assumes a significant reduction from historical service installations and associated main installation.

Q. Do you expect the Westchester moratorium to continue during the potential 2023-25 rate plan period?

A. No. We anticipate being able to lift the moratorium at the end of in RY1, as further described below in the Gas Supply portion of this testimony.

Q. Have you considered the New York City legislation or other state CLCPA initiatives when planning the Customer Connections program?

A. Yes. As discussed above, the number of customer connections anticipated is decreasing, but this will have a limited impact in the RY1-RY3 period. We expect to see more dramatic reductions in future rate cases.

Q. Why is the Company anticipating a limited impact in the RY1-RY3 period?

A. The New York City legislation will only begin to go into effect during this rate case, with certain building sectors having until 2027 to comply.

Q. Beyond the construction cost to install gas services and gas main to support growth, are there additional associated expenses the Company will incur?

A. Yes. We have a dedicated program to purchase and install gas meters. As explained in Exhibit ___ (GIOSP-1), Meter Purchases and the Meter Installation programs support the mandated replacement of existing meters for new connections and conversions programs. The following Section F.3 discusses this topic further.

F. TECHNICAL OPERATIONS

Q. Please summarize and briefly explain the purpose of this Technical Operations testimony.

A. Consistent with core Company principles this Section will discuss the importance of, and overall need for, infrastructure, operations, and technology investments to reduce risk, enhance safety across the system, and enhance system operational performance, for specific Company assets. Included is the Liquified Natural Gas (“LNG”)

Plant, Tunnels, Meters, Natural Gas Detectors, and Gas Information Technology.

1. LNG Plant

Q. How does the Company’s LNG facility benefit customers?

A. Con Edison uses its liquefied natural gas facility to maintain adequate supply during gas peak operations. The LNG Plant serves as a cost-effective alternative to more expensive firm peaking supplies and as a contingency resource, in the event of any incident impacting our external supply sources.

The LNG Plant is the only source of in-city natural gas supplying Con Edison’s customers in the event of an interstate pipeline interruption or other emergency condition affecting external gas supply. The LNG Plant continues to serve as a supply and hourly balancing source during very cold days, as its capacity is needed during design peak day conditions to meet the needs of our firm customers. The LNG Plant also serves firm gas customers by potentially mitigating short term price volatility.

Q. Why are the LNG Plant’s planned programs necessary?

A. The proposed capital programs and projects are important to continue safe plant operations and maintain plant reliability for the following plant systems: withdrawal (vaporizers), tank management, and injection (liquefaction) process plant. In addition, these projects are important measures to harden the LNG Plant.

Critical components of the plant are obsolete, with the original equipment manufacturer(s) unavailable to provide parts and services. Mechanical integrity of equipment is important for employee and public safety. The current liquefaction nitrogen refrigeration cycle is inefficient and does not fill the LNG tank in six months, consistent with its original design. To bring the plant up to standard, we plan to invest over $70.4 million in plant infrastructure over the next five years, starting in RY1. This will allow for the Company to continue to deliver affordable natural gas to our customers when they need it the most and continue to provide reliable services for gas peaking, unplanned upstream gas system contingency and to mitigate gas price volatility.

Q. What investments are required in the Company's LNG facility?

A. As shown in Exhibit ___ (GIOSP-1), the investments are described in five areas:

1) Instrumentation upgrade program:

- Plant Controls Instrumentation Upgrade Program: $12 million in RY1 and $2 million in RY2.

2) Nitrogen Refrigeration Cycle Replacement:

- Nitrogen Refrigeration Cycle Replacement: $10 million in RY1 and $10 million in RY2.

3) Electrical equipment upgrades and relocation:

- Motor Control Center: $2.8 million in RY1 and $500,000 in RY2.
- Electrical Distribution System Upgrade: $1.9 million in RY1.

4) Equipment integrity projects:

- Plant Boil-Off Compressor Replacement: $2 million in RY1 and $400,000 in RY2.
- Security Upgrade Program: $2.87 million in RY1.

5) Reliability Remediation Program:

- Various reliability projects including relocation of the LNG Meter Station, and the Independent Flare Gas Supply: $7 million in RY1, $8.25 million in RY2 and $4.75 million in RY3.

These programs reflect a $68 million capital improvement investment at the LNG Plant during this coming rate period. This amount is broken down as follows: $38.6 million in RY1, $21.15 million in RY2, and $4.75 million in RY3, as set forth in Exhibit ___ (GIOSP-1), with some projects extending past this proposed rate period.

Q. Please explain further the work that is planned for the LNG facility.

A. The new Instrument Upgrades Program contains real-time monitoring, data acquisition and analysis tools. The new Nitrogen Refrigeration Cycle Replacement will replace the original obsolete equipment. The nitrogen refrigeration cycle will have a new, more efficient turbine that will produce less CO_2 air emissions per million cubic feet of LNG produced. With recent local supply constraints and the LNG plant having the ability to withdraw and provide 15% daily supply to the transmission system, the ability to quickly, efficiently, safely fill the tank with new modern reliable nitrogen refrigeration cycle allows the LNG Plant to be a reliable supply source for gas system resiliency.

The new Electrical equipment upgrades and relocation will provide both a new motor control center and a new high tension vault substation relocated away from the existing natural gas transmission main and both projects will improve employee safety and plant reliability. The new equipment will meet current arc flashing, newer national electric code requirements, and replace original (50-year old equipment upon replacing) and obsolete equipment. This upgrade and relocation will modernize, make electrical power more reliable, and increase the plant's safety. LNG projects consist of multiple system reliability requirements for safety, system reliability and to enable continued safe operation as shown in Exhibit ___ (GIOSP-1).

2. Tunnels

Q. Briefly describe the Company's tunnel facilities and their importance in delivering safe and reliable energy services to the Company's electric, gas and steam customers.

A. There are eight utility tunnels on the Company's system. These tunnels house critical electric, gas, and steam facilities, as well as a fuel oil line and telecommunications systems. They are critical pathways for service lines under bodies of water, except for one, which was needed for our steam transmission infrastructure after the retirement of the Waterside Steam Generating Plant and does not cross under a body of water. Tunnel infrastructure is significantly impacted by atmospheric corrosion, water infiltration and salt deposits. The original infrastructure (*e.g.*, cast steel liner, steel beams), feeder cables, lighting and electrical outlets, and gas main rollers are exposed to heavy salt and water infiltration. In addition, safety components such as the fire and gas monitoring systems have become obsolete. If this infrastructure is not replaced there is an increased risk of a catastrophic failure jeopardizing the reliability of the electric, gas and steam transmission and distribution systems.

Q. Why are the proposed projects necessary for the tunnels?

A. These projects are required for system reliability, employee safety, and to enable continued access to critical infrastructure. This includes the gas main rollers, feeder cables, elevators, cast steel liner, structural concrete, ladders and landings, electric and ancillary equipment such as sump pumps, lighting, and remote monitoring capability. All of these are subject to corrosion and deterioration due to ground water intrusion and exposure to extreme moisture, salt, humidity, and heat, especially in the tunnels that carry steam mains.

Q. What are the critical projects related to tunnel system safety, customer experience, operational excellence or clean energy?

A. As shown in Exhibit ___ (GIOSP-1), and described further in the associated white papers, the tunnels projects are:

- Fire and Gas Monitoring Replacement: $1.5 million in RY1 and $1.5 million in RY2.

- Ravenswood Gas Main Rollers: $1.7 million in RY1 and $1.8 million in RY2.
- Ravenswood Concrete Restoration: $225,000 in RY1.
- Conduit Bulkhead Replacement: $1.0 million in RY1.
- Astoria Cast Steel Liner Replacement: $1.0 million in RY1.
- Lighting Improvement Program: $1.0 million in RY1; $1.0 million in RY2; and $1.0 million in RY3.
- Carbon Fiber Wrap Program: $701,000 in RY1; $744,000 in RY2; and $765,000 in RY3.
- Replacement Feeder Rollers: $1.7 million in RY2.
- Steel Replacement Program: $877,000 in RY1; $930,000 in RY2; and $957,000 in RY3
- Astoria Elevator Modernization: $600,000 in RY1.
- Annual Sump Pump Program: $100,000 in RY1; $100,000 in RY2; and $100,000 in RY3.

In total, the capital expenditures to support these tunnel projects during the upcoming 2023-2025 period are $8.7 million in RY1; $7.8 million in RY2; and $2.8 million in RY3.

Q. Is the Company considering moving responsibility for the tunnels to another organization?

A. Yes. We are considering moving the Tunnel Maintenance organization from Gas Operations to Central Operations.

Q. Please explain why this move is under consideration?

A. There are several reasons. These are multi-commodity tunnels that carry electric transmission feeders, steam mains, as well as gas mains. However, Gas Operations has historically had the responsibility for the maintenance of the tunnels, and the capital expenditures associated with improvement projects have fallen under Gas Operations and therefore paid for by gas customers. Additionally, most O&M expense for maintenance of the tunnels is also paid by gas customers. As we consider future rate mitigation opportunities given the foreseeable drop in demand for gas, we are evaluating whether the tunnels would be more appropriately paid for by electric customers. As such, we are exploring a re-organization to place the Tunnel Maintenance group under Central Operations and thereby shift the capital and O&M expenditures to electric customers. An update of the Company's analysis and plans will be provided in the update testimony.

3. Meters

Q. How will the Company's proposed meter purchase and meter installation programs foster better customer engagement?

A. These programs allow the Company to provide safe and reliable gas service to our customers. In addition, these programs also support the Company’s mandated meter replacement programs. We discuss below the need for this program and how its related to the Company’s AMI program.

Q. What meter investments are required by Technical Operations?

A. Technical Operations purchases gas meters and related devices for all our customers. When possible, we refurbish meters and when necessary we replace them. Our investment in this area takes into account historic replacement and refurbishment. Currently, 34 percent of the meters purchased and installed are related to mandated meter replacement programs and required replacements, while 66 percent of the meters purchased and installed are associated with customer connections or replacements of existing customer meters who are increasing their existing gas demand. While customer connection projects have decreased, we have experienced an increased need to replace undersized meters, which have been identified as a result of new AMI information. For this reason, the estimates used below remain level with historical numbers, for the short-term forecasting related to this rate case.

Installations are estimated at approximately $17 million annually, while purchases are estimated at approximately $11 million annually. Annual costs for purchases and installations are based on historical and projected usage. These capital expenditures include funding for the purchase of meters and related devices (*e.g.*, interruptible customer monitors (Metscans), service regulators, and electronic correctors); outsourced meter-related services for mandated meter programs required by 16 NYCRR 226; and for repair/replacement of defective meters (*e.g.*, customer complaints, broken meters, tampering) in accordance with Commission regulations. As shown in Exhibit ___ (GIOSP-1), these programs are listed as:

- Meter Purchases - Customer Connections and Meter Replacement Programs ($12 million in RY1, $12 million in RY2, and $12 million in RY3); and
- Meter Installations – Customer Connections and Meter Replacement Programs ($19.4 million in RY1, $20.9 million in RY2, and $20.9 million in RY3).

Q. How do the meter investments discussed above take into account AMI deployment?

A. Metering costs and savings associated with AMI are independent of the meter investments discussed above because there will still be a need for meter installations and replacements independent of AMI deployment. Approximately 250,000 gas meters have been replaced with new meters equipped with AMI modules, that were required by the PSC to be remediated by 2021. The remaining 950,000 or so gas meters were retrofitted with AMI gas modules. Although there are many benefits to these AMI replacements, once in service, these meters will have the same operations and maintenance requirements as any other meter. Additionally, a large population of older meter classes will require remediation during this coming rate case.

G. GAS INFORMATION TECHNOLOGY

Q. What Information Technology ("IT") improvements are planned for Gas Operations?

A. Gas Operations is presenting IT investments in the following two categories: Gas Control Center and Outage Management. Further details for each can be found in the associated white papers, with a few of the larger capital investments highlighted below. There are also gas-related IT programs, including the Work Management Program, that are separately being addressed by the Company's IT Panel.

1. Gas Control Center Improvements

Q. What improvements are planned for the Gas Control Center?

A. Gas Control is presenting three items for this Rate Case. They are Operator Training System ("OTS") Simulator Project, End of Life ("EOL") Equipment Replacement Program, and Gas Control Center ("GCC") Improvements Projects. Further details for each item can be found in the associated white papers.

The GCC Improvements is the largest capital investment in this category and consists of three improvement projects for the GCC. The first is the relocation of the Alternate GCC from Manhattan to Westchester, the second is the Gas Operations Supervisory System ("GOSS") and Gas Day Operations ("GDO") Application Upgrades, and the final project is the furnishment for the relocation of the Primary GCC. The expenditures associated with this project are $2.7 million in RY1; $3.0 million in RY2; and $3.95 million in RY3, as shown in Exhibit ___ (GIOSP-1). This project also has an O&M component which is further detailed below.

Q. What are the benefits to Gas Operations that are anticipated from the GCC Improvements?

A. The proposed GCC Improvement projects will provide numerous safety and reliability benefits for our gas customers and the public. The relocation of the Alternate GCC from Manhattan to Westchester will significantly reduce response time under a forced relocation from the primary site, while developing the site using industry and international standards will help address Pandemic lessons-learned and the expansion of the Gas Control Department since the original facility's construction. The GOSS and GDO Application upgrade will maintain Gas Operations critical remote monitoring and control applications on supported software and mitigate potential cybersecurity threats to the Gas HVN. Finally, the new GCC will allow Gas Operations to leverage best-in-class Control Center strategies to provide Gas Control Operators the tools to rapidly address abnormal operating conditions while facilitating Gas Operations organizational response to significant events, all while remaining compliant with Control Room Management compliance requirements.

Q. Have plans for the new GCC changed since the last rate case filing?

A. Yes, due to lessons learned from the pandemic, business user requirements, and projected schedules for the original location's Re-Development Project, the location of the new GCC has changed to a location within an existing facility in Westchester.

Q. What changes were made?

A. Additional user requirements were incorporated, which was not possible at the original location. The schedule was also deferred to later years, due to the pandemic, which temporarily halted progress. Due to these challenges, the new GCC will now be completed within this rate case.

Q. What investments are being requested for this Rate Case, related to the new GCC?

A. As described above and further in the associated white paper, the furnishment portion of the GCC Improvements Projects, as presented by the GIOSP. Other additional funding included as part of the relocation and new location's re-development project is being put forth by Facilities, under the Shared Services panel.

2. Gas Outage Management System

Q. What is the Company proposing related to a gas outage management system ("OMS")?

A. The Company is proposing an investment in the development and deployment of a gas OMS. The Company does not currently have such a system, so initial IT software development will be required for this project. The projected expenditures associated with this project are $9 million in RY1 and $8.8 million in RY2, as shown in Exhibit ___ (GIOSP-1), with associated O&M costs to be seen in RY3 and discussed further below.

Q. What are the current challenges in managing gas outages?

A. Without an OMS, identifying gas outages is done through direct communications with customers and tracking outage impacts is done by manually researching several systems, then using field verification to confirm. This is an administrative burden that requires extensive resources from several departments.

Q. In what scenarios would the Company use the OMS?

A. Generally speaking, the Company would leverage an OMS during larger outages, of 50 or more services or when larger buildings with 200 or more customers are affected. However, we believe even the management of smaller scale outages can benefit from an OMS.

Q. Please provide an example of a situation when such a large outage might be expected to occur.

A. While the gas system is extremely reliable, when outages do occur, they can be extensive. The most common occurrence is a result of water intrusion or damage, such as an event like Hurricane Ida. Gas outages can take considerably longer to restore service than an electrical outage; therefore, the implementation of an OMS system could be very beneficial to the affected customers and facilitate a better response.

Q. What are the benefits of having an OMS?

A. Having an OMS would help identify outages quicker via instant detection when faced with extreme weather or system related issues that compromise supplying service to customers. Having the ability to track outages with advanced technology as opposed to a manual process will provide an administrative advantage. One such example is: through system integrations (with systems such as AMI), the OMS can receive the electric meter count data for master metered buildings, providing quick and accurate customer outage information. The OMS would also serve as a repository to record outages throughout our system.

Q. How would an OMS impact communication?

A. Field, control center, and administrative employees will be able to view status information for outages. Dashboards will be shared that include locations, resources, and real-time status information. This will enhance communication between the control center and the field. Dashboards that include outage progress and additional tracking information will also be available.

Q. How does the Company plan to use an OMS to improve outage restoration?

A. An OMS should provide quick visibility into the number of customers affected by an event. Large outage areas can then be divided into several outage status areas, to increase visibility on customers pending restoration and to focus resources accordingly. Additionally, when implemented, we expect this new system will provide timely and accurate information to customers when they need it most.

IV. OPERATION & MAINTENANCE PROGRAM CHANGES

Q. What O&M Program Changes are the Company putting forward?

A. The Company is requesting O&M Program changes for the following programs: Service Line Inspections, Bridge Inspections, High Emissions Surveillance, and various software needs related to capital projects, with the Service Line Inspections being the largest O&M change request. Similar to the Company's capital expenditures, the majority of projected O&M expenses are focused on safety-related programs. The following testimony describes these program changes in further detail:

A. Service Line Inspections

Q. Please explain how the definition of "service line" has changed in recent years.

A. On April 2, 2015 in Case No. 14-G-0357, the Commission revised the definition of "service line" in 16 NYCRR 255.3(a)(29) to align with federal law. As a result of the new definition, New York State gas utilities were required to perform leakage surveys and corrosion inspections on piping that was previously not considered to be a "service line" under the Commission's rules. Specifically, under the prior definition, a service line associated with a gas meter inside a building ended at the first fitting inside the building. Under the revised definition, a service line extends further into the building and ends at the meter's outlet.

Q. Please describe the Company's experience inspecting the piping that was newly designated as Commission-jurisdictional service lines.

A. In accordance with the Commission's order in Case 15-G-0244, the Company initiated "baseline" inspections in 2017 to evaluate the newly jurisdictional pipe for the first time. These inspections targeted more than 300,000 service lines and nearly 1 million inside gas meters, of which approximately 200,000 are inside building sets in apartments (room sets).

Pursuant to State executive orders to address COVID-19, Con Edison suspended the inspections in March 2020. The Company resumed inspections in July 2020, when New York City entered Phase III of the reopening plan. At that time, the Company had 150,000 services and 400,000 gas meters left to inspect. Con Edison and other local distribution companies petitioned the Commission for an extension to complete the inspections until August 1, 2020, and the Commission granted the request.

Q. What efforts had the Company taken to complete the inspections prior to July 2020?

A. The Company notified customers of the required inspections and their obligation to provide access to our equipment. The Company communicated with customers through emails, letters, social media, a dedicated webpage, drop cards, phone calls, meetings with building management associations, and a robust appointment-scheduling process employed by our contractor. The Company made at least two attempts per premises (as required) to gain access for the inspections.

Q. Did the Company complete the inspections by August 1, 2020?

A. No.

Q. What was the primary reason that the Company was not able to complete the inspections?

A. Inability to gain access to the inside of buildings to perform the inspections, despite several attempts, exacerbated by customer reluctance to provide access because of COVID-19.

Q. What are some of the actions the Company took to gain access?

A. In addition to the efforts we already described, after resuming inspections in July 2020, the Company initiated an email campaign for customers who have email addresses on file and modified its letters and drop cards to include enhancements to appointment scheduling and information about the Company's COVID-19 safety precautions. The Company also created a notice that is placed directly on customers' bills when a fee is assessed. On December 22, 2020, the New York State Department of Public Service Chief of Pipeline Safety and Reliability provided a letter ("DPS Letter") emphasizing the importance of these inspections and the need for customers to provide access to allow utilities to perform these inspections. The Company began sending the DPS Letter to No-Access customers shortly after it became available. Con Edison also used no access fees to encourage customers to provide access for inspections.

Q. Did the Company take any further actions to complete inspections at these no access locations?

A. Yes. The Company increased the number of dedicated technicians performing additional cold call attempts, which resulted in a significant number of scheduled appointments through these communication efforts. In addition, the Company increased efforts to perform additional service line inspections when it was able to access a building for other work reasons (*e.g.*, turn-ons, inside leaks, meter exchanges, NGD installations, second cycle business district re-inspections). Despite these efforts, these opportunistic inspections resulted in only modest reductions in the Company's remaining backlog.

Q. Did Staff direct the Company to further revise its procedures for complying with the new gas service line rules?

A. Yes. On December 31, 2020, to comply with Staff's directive, the Company filed a compliance plan in Case 15-G-0244 (Petition to Establish an Additional Compliance Method for Gas Service Line Leakage Surveys/Corrosion Inspections for Premises with Access Issues) ("Service Line Compliance Plan"). The Commission has not issued an order on the petition, but Staff has made it clear that the Company must comply with the revised plan that it filed.

Q. What has the Company done under the Service Line Compliance Plan and what have been the results?

A. As outlined in the Service Line Compliance Plan, the Company has continued to conduct baseline gas service line inspections and intensified its efforts to notify customers of the inspection requirements in writing, assess fines where appropriate, and place customers that continued to refuse access under the threat of termination. Since the inception of the program, the Company has sent out: 1.1 million letters, over 110,000 e-mails, over 170,000 fee warning letters (a net of over 60,000 accounts were assessed fees) over 110,000 turn off warning letters, and over 77,000 final and reoccurring termination warning letters.

Q. How is the Company handling the remaining "No-Access" customers?

A. After all efforts were exhausted, Con Edison placed these customers into a separate service termination process. As of December 31, 2021, there were approximately 26,000 services and approximately 52,000 gas meters remaining to be inspected. The Company continues to attempt to gain access to complete these inspections to avoid terminating the customers' gas service. The remaining customers will continue to receive communications warning them about the possibility of service termination until the customer either grants the Company access to complete the inspection, the Company cuts and caps the existing gas service or, where appropriate and for buildings where the Company has been able to inspect some but not all meters, the Company replevins the relevant gas meter. We intend to resume potential service terminations after the heating season has concluded in March 2022.

Q. What are the inspection requirements after the baseline inspections?

A. The general periodic inspection requirement is once per year (not to exceed 15 months) for business district services and once every three years (not to exceed 39 months) for non-business districts. In Case 15-G-0244, the Commission authorized a pilot program for Con Edison designed to test whether extended inspection intervals for all service lines of once every five years (not to exceed 63 months), combined with conditions such as the installation of AMI-enabled methane detectors at each inspected meter, meets or exceeds existing safety standards.

Q. Have there been any other significant regulatory developments as they relate to inspection intervals for gas service lines?

A. Yes, on March 21, 2021, PHMSA modified 192.481 to extend onshore service line atmospheric corrosion control inspections to once every five calendar years, not to exceed 63 months. Then on October 25, 2021 in case 19-G-0736 the Commission proposed to modify 255.481 reflecting the PHMSA code modifications. Once the proposed 255.481 changes are adopted, all non-business district service line inspections can be extended to once every five-years, not to exceed 63 months.

Q. Based on the foregoing, what is the inspection interval that is assumed for purposes of the Company's forecast?

A. The Company's forecast assumes the extension of the inspection cycles for all services to a five-year cycle, not to exceed 63 months starting January 1, 2023.

Q. Please describe the Company's Service Line Program O&M request.

A. We propose a program change increase of $39.2 million in RY1, with reductions of $0.9 million in RY2 and $1.2 million in RY3. This proposed change reflects only a change in the cost recovery mechanism (from surcharge to base rates) and a significant reduction compared to the Company's recent costs for the service line inspection program.

Q. What were the Company's historic costs for this program during the current Gas Rate Plan?

A. The Company's actual costs under this program were $29.3 million in 2020 and $68.6 million in 2021 when it began following its revised compliance plan at Staff's direction.

Q. Why does the Company believe it can reduce the costs of this program so significantly in RY1?

A. We believe we can achieve these reductions through the anticipated completion of the baseline inspections and the expected corresponding decrease in repairs associated with baseline inspections. The Company also had high rates of access refusal due to customer concerns related to COVID-19.

Q. How does the Company recover the costs for this program under the current Gas Rate Plan?

A. The current Gas Rate Plan included a relatively small amount in base rates (approximately $7.0 million in 2020 and $700,000 in each of the subsequent two rate years) for this program. The Plan authorized an MRA surcharge mechanism, which was capped at approximately $99 million for the term of the three-year Gas Rate Plan.

Q. Has the Company gained sufficient experience with this program since its last rate filing to develop a projection of its future costs?

A. Yes. As we have explained, the Company has undertaken extensive and comprehensive measures to comply with the Commission’s and Staff’s additional directives relating to service line inspections and repairs.

Q. What is the basis for the Company’s estimated expenditures for this program?

A. The Company has approximately 1 million inside building sets, of which an estimated 200,000 inside building sets are in apartments (room sets) or other remote locations that are less readily accessible. As described above, the Company made significant efforts and is continuing to complete the remaining baseline inspections pursuant to its revised compliance plan. Because of the new five-year inspection cycle, inspections will be spread out more evenly throughout the five-year period. We will also attempt to bundle this work with installation of AMI natural gas detectors where feasible. Projected expenditures include all costs associated with the emergency response when a leak is detected, the repair to Company piping from the point of entry to the outlet of the gas meter, labor to perform the inspections and support the customer communication and scheduling. The expenditures enable a minimum of two cold call field attempts, plus additional attempts that may result from customer letters warning of fines and subsequent termination of service.

Q. What is the breakdown of the program forecast?

A. The $39.7 million annual forecast for this safety program is divided into the following functions:

1. $18 million annually for field inspections;

2. $4.2 million annually for non-field support, which includes customer support, scheduling, training and equipment;

3. $6.9 million annually for corrosion repairs and all necessary follow-up surveillance and rechecks after repair inspections;

4. $2.7 million annually for emergency response associated with any leaks identified during the service line inspection; and

5. $7.9 million annually for operating and maintenance costs associated with cutting and capping and/or replevin when a customer fails to provide access after the required attempts, and notifications fail to result in a completed inspection.

Q. Is the Company proposing any tariff changes related to the Service Line Inspection program?

A. Yes. The Company is proposing to modify the fee structure for customers or access controllers who deny the Company access to the premise to perform the inspection. The proposed change will modify the fee from one-time billed, to a fee assessed in every billing period, until access is provided. The customer will also be responsible for all costs associated with meter seizure/forced access if refusals continue.

Additionally, when customers refuse an outdoor meter location while Con Edison is performing work on their service, it perpetuates the need for inside service line inspections. Therefore, the Company is also proposing that the meter relocation refusal fee be increased to cover inside inspection costs that would have otherwise been avoided.

Q. Are there any other costs not included in this request?

A. Yes. The costs for additional vehicles and associated maintenance are not included. These costs are approximately $600,000, which we may include as part of our update filing.

B. Bridge Inspections

Q. Please describe the Company’s next O&M program change.

A. The Company is proposing a reallocation of funding for its Bridge Inspection program. Looking ahead to 2026, we see a much higher number of bridge inspections coming due in a single year than normal. Gas mains at bridges receive a visual inspection every three years and a more costly, detailed inspection (including preventative maintenance) every 21 years. The inspection workload varies, with inspections at 257 locations coming due on a cyclical basis. However, 137 inspections (about 62% above the normal amount) are due in 2026. Planning ahead, we expect that this increase in workload will challenge our ability in 2026 to complete these inspections. Therefore, the Company is proposing to preemptively move 30 detailed inspections, due in 2026, to the rate case years and spread them evenly across 2023, 2024, and 2025.

A total of $1,104,750 for the three years cumulatively needs to be reallocated to cover additional pipe inspection and preventative maintenance proposed for 2023, 2024, and 2025. The amount will be evenly distributed across the three years. Further details of this program change can be found in the associated white paper.

C. High Emissions Survey

Q. Please describe the next O&M change.

A. The Company has designed a program to identify and target the highest emitting natural gas leaks, which are currently defined as leaks emitting greater than 10 standard cubic feet per hour. To conduct the survey, we attach advanced leak detection technology to a passenger vehicle and drive multiple passes over the course of two to three nights down the same street, according to the manufacturer's recommendation. Currently, the Company is utilizing the Picarro Surveyor device for this survey. Once all passes are completed, data is downloaded and analyzed. This survey complements our current leak survey programs by covering one-third of the of the distribution system that has not recently been covered by the walking compliance survey.

Q. Once identified, how will the Company eliminate fugitive emissions?

A. The Company has a performance metric to repair gas leaks within 60 days, 85% of the time. On average, all leak types are repaired within 30 days or less, far exceeding code requirements. Once a high emitter is identified, the Company will maintain these high standards by repairing the known leak and eliminating the emissions.

Q. What benefits does this program provide?

A. By targeting leaks with the highest emissions and running the program as a complement to other existing leak survey programs, we are able to focus on eliminating fugitive methane emissions efficiently. Due to its propriety algorithms, the advanced leak detection system can detect methane leaks farther from the source, and it is the only leak detection equipment able to quantify the emissions rating. This program also supports the future rulemakings PHMSA will implement as required by the PIPES Act. The PIPES Act calls for rules to be promulgated for the use of advanced leak detection technologies on new and existing gas distribution pipeline facilities. In a recent industry presentation, PHMSA announced that it anticipates a notice of proposed rulemaking on this subject in 2022.

Q. Please provide the projected expenditures, and how the Company developed its projection.

A. We currently anticipate the following O&M expenditures for this new program: $499,000 per year, in each of RY1, RY2 and RY3. This cost was estimated based on the mileage per year needed to be surveyed, number of required passes per manufacturer's recommendation, and experience utilizing the equipment to know how many miles could be covered each day. Labor rates were then used to determine staffing increases.

D. Capital Projects Software Changes

Q. What is the final O&M change being proposed?

A. The Company, as described in more detail throughout this testimony and in the associated White Papers, is making capital investments, which includes the development and/or implementation of software technology. Licensing fees associated with software usage have an O&M expense and are therefore presented here.

Q. Which capital investments include such O&M expenses?

A. The following investments include an O&M component:

- The Gas Outage Management System: As described further in the associated white paper, this brand-new software solution will require ongoing licensing fee O&M expenses of $140,000 per year, starting in RY3.

- The Gas Control Operator Training System Simulator: As described further in the associated white paper, this new software solution will require ongoing licensing fee O&M expenses of $60,000 per year, starting in RY2.

V. DEFERRAL ACCOUNTING/SURCHARGES

A. Pipeline Safety Act

Q. Please describe the Pipeline Safety Act of 2011 ("PSA") and its requirements.

A. The PSA was signed into law in January 2012. The PSA authorizes and directs the United States Department of Transportation ("DOT") to perform studies and adopt rules intended to enhance gas pipeline safety.

Q. Please explain the status of PSA implementation.

A. To date, PHMSA has completed 40 of the 42 mandates and a number of non-mandated actions, leaving certain significant issues still pending. These pending issues include rules on the use of automatic and remote-controlled shutoff valves and expansion of the transmission integrity management program requirements.

Q. Please identify the continuing uncertainties associated with PSA requirements.

A. Although PHMSA has published Notice of Proposed Rulemakings ("NPRM") on certain aspects of the PSA, those were met with a large amount of public comment. Additionally, the Gas Pipeline Advisory Committee ("GPAC") has also modified and voted on these proposed rules. As a result, there are a number of uncertainties regarding the pending PSA regulations that could have a significant impact on the Company's costs. These include the following related to transmission mains: expansion of the existing integrity management requirements; new material verification requirements; new risk modeling requirements; and the required use of automatic or remote-controlled shut-off valves. As such, the Company proposes to continue the reconciliation for any costs related to compliance through a surcharge. As further explained below, the costs to comply remain uncertain.

Q. Has PHMSA taken any action to complete the remaining mandates?

A. To date, TIMP requirements and MAOP verification have been proposed by PHMSA through the NPRM "Pipeline Safety: Safety of Gas Transmission and Gathering Lines", Docket PHMSA-2011-5 0023. The NPRM was released in 2016, and GPAC meeting concluded in 2017, yet all parts of the final rule(s) have yet to be published. To date, only part one has been released, leaving two parts outstanding. It remains uncertain whether PHMSA will address the industry/public comments that they received and how they will modify the rulemaking, based on the GPAC comments and voting.

Q. Why is it reasonable to reconcile costs related to compliance with the PSA through a surcharge?

A. As described above, there are a number of uncertainties associated with pending DOT regulations enacted in response to the mandates in the PSA. Some of the uncertainties are directly related to the requirements that DOT may include in these new regulations, which are unknown at this time. Other uncertainties (and their related costs) are dependent on the regulations the DOT ultimately adopts.

Q. Can the Company provide an estimate of the costs of these pending regulations?

A. No, the Company does not have a basis to include an estimate. The uncertainties of these pending regulations, including the timeframe of enactment, make it too difficult to develop a cost estimate for the Rate Years.

Q. Why is the Company proposing a surcharge?

A. The Company believes it makes more sense to use a surcharge to avoid a potential large deferral build-up prior to the next rate case filing. The surcharge mechanics are described in the Gas Rates Panel testimony.

B. PIPES Act

Q. Please describe the new regulations that may be enacted by the United States DOT in response to the PIPES Act of 2020?

A. The PIPES Act of 2020 authorizes and directs the DOT to perform studies and adopt rules intended to enhance gas pipeline safety, as well as ties environmental safety to pipeline and public safety.

Q. What, if any, uncertainty exists with respect to the regulations that may be promulgated under the PIPES Act and their impact on Company operations?

A. As this Act is relatively recent, PHMSA has yet to propose any rulemakings to implement its directives. Without seeing the proposed rulemakings, significant uncertainty exists as to whether such new or modified rulemakings will have an impact on the Company's operations or investments.

Q. What is the anticipated timing of the PHMSA rulemaking associated with the PIPES Act?

A. Although no notices of proposed rulemaking have been released, the PIPES Act provides timeframes for each directive to PHMSA. These timeframes vary based on the topic within the Act; however, it is reasonable to expect that some associated rulemakings will be enacted during the rate years. During a recent industry presentation, PHMSA forecasted that Notice of Proposed Rulemakings ("NPRMs") should be expected as follows:

- Leak Detection NPRM in 2022
- Safety of Gas Distribution NPRM in 2022
- Pipeline Operational Status NPRM in 2023

Q. Why is it reasonable to reconcile the costs related to compliance with the PIPES Act through a surcharge?

A. As described above, there currently is uncertainty associated with pending DOT regulations enacted in response to the mandates in the PIPES Act. Some of the uncertainties are directly related to the requirements that DOT may include in these new regulations, which are unknown at this time. Other uncertainties (and their related costs) are dependent on the regulations the DOT ultimately adopts.

Q. Can the Company provide an estimate of the costs of these pending regulations?

A. No, the Company does not have a basis to include an estimate. The uncertainties of these pending regulations, including the timeframe of enactment, make it too difficult to develop a cost estimate for the Rate Years.

Q. Why is the Company proposing a surcharge?

A. The Company believes it makes more sense to use a surcharge to avoid a potential large deferral build-up prior to the next rate case filing. The surcharge mechanics are described in the Gas Rates Panel testimony.

C. NY Operator Qualification Rulemaking

Q. Why does uncertainty exist with respect to new regulations that may be enacted by the Commission related to the Operator Qualification ("OQ") notice of proposed rulemaking?

A. On December 17, 2021, the Company and other utilities and industry groups provided comments on the proposed OQ rule. Many of Con Edison's comments sought clarity from the Commission on regulatory language, which may affect the new investments necessary to comply with a final rule. Until the final rule is adopted, the Company cannot anticipate what investments will be necessary to present for recovery.

Q. What sections of the proposed regulation has the Company identified as areas with potential cost implications for the Company's operations?

A. The following topics within the proposed rule may result in the need for further investment, depending on the final rule:

- Time restrictions prior to evaluations;
- Span of control records;

- Training records associated with qualification records;
- Automatic failure from abnormal operating condition questions; and
- Program effectiveness.

Q. What is the anticipated timing of the OQ final rule?

A. As comments have already been submitted, Con Edison anticipates a final rule to be released sometime in mid-2022; therefore, any associated investments may not able to be included in this case.

Q. Why is reconciliation through a surcharge reasonable for such costs?

A. As described above, there currently is uncertainty associated with the pending OQ rule. Some of the uncertainties are directly related to the requirements that the Commission may include in these new regulations, which are unknown at this time. Other uncertainties (and their related costs) are dependent on the regulations the Commission ultimately adopts.

Q. Can the Company provide an estimate of the costs of these pending regulations?

A. No, the Company does not have a basis to include an estimate. The uncertainties of these pending regulations, including the timeframe of enactment, make it too difficult to develop a cost estimate for the Rate Years, at this time.

Q Why is the Company proposing a surcharge?

A. The Company believes it makes more sense to use a surcharge to avoid a potential large deferral build-up prior to the next rate case filing. The surcharge mechanics are described in the Gas Rates Panel testimony.

VI. PERFORMANCE MEASURES

A. Gas Performance Measures

Q. Is the Company proposing any changes to the existing Gas Performance Measures, which are set forth in Appendix 17 of the Joint Proposal adopted by the Commission in its January 16, 2020 rate order?

A. The Company proposes to continue most of the major elements associated with current Gas Performance Measures. We are proposing modifications to some of the targets and negative revenue adjustments, as discussed in more detail below.

Q. Are any of the Company's proposed changes similar to changes that have been approved in other Commission-approved utility rate plans or rate plans that are pending approval?

A. Yes, many of the changes the Company is proposing are consistent with recent trends of increased positive incentives in other utility rate plans that have been approved or are pending approval. However, the Company recognizes that each utility rate plan should be viewed in total and that individual elements of an overall settlement agreement should not be evaluated in isolation.

Q. How should NRAs be applied?

A. The Company proposes that any NRAs it incurs should be applied to fund incremental gas safety programs to be developed at the Company’s direction, in consultation with Staff.

Q. Which specific Gas Performance Measures does the Company propose to modify?

A. The Company is proposing to modify the following performance measures, established under its current Gas Rate Plan: Gas Main Replacement, Leak Management, and Gas Regulations Performance Measure.

1. Gas Main Replacement

Q. Please describe the Company’s proposed changes to the Gas Main Replacement Program Safety Performance Measure.

A. As discussed earlier under the Main Replacement Program, the Company is proposing a slight reduction from the prior rate case main replacement target of 90 miles to 85 miles per year for each rate year, for a total of 255 miles of leak prone pipe over the three-year period 2023 through 2025.

2. Leak Management

Q. What is the Company's proposed change to the Leak Management Performance Measure?

A. As set forth in the current Gas Rate Plan, the Company receives a positive revenue adjustment, up to an annual maximum of four basis points, for reducing the leak backlog below the associated annual targets. The Company would maintain the 2022 year-end total leak backlog target of 200, for each rate year. However, the Company is proposing an increase to the positive revenue adjustment basis points.

Q. What positive revenue adjustment changes are the Company proposing?

A. The positive revenue adjustment would be awarded as follows:

Total Leak Backlog:	Prior Rate Case Positive Basis Points:	Proposed Positive Basis Point:
76-100	1 BP	2 BP
26-75	2 BP	4 BP
<=25	4 BP	6 BP

Q. Why does the Company believe such positive revenue adjustment increases are appropriate?

A. In order to achieve such low total leak backlog targets, the Company must expend a significant level of resources. The cost of deploying such resources currently exceeds the value of the positive revenue adjustment ("PRA"). Therefore, the Company is proposing a PRA structure that is more in line with the costs associated with achieving such goals.

Q. Are there benefits to customers and other stakeholders associated with the gas main replacement and leak management positive incentives?

A. Yes. Eliminating 12-inch and smaller cast iron, wrought iron, and unprotected steel above the established targets will enhance safety and reduce emissions.

Q. Is the Company proposing any modifications to the current Joint Proposal language regarding the calculation of the final leak backlog count?

A. Yes. The Company believes additional clarity is needed regarding leaks being added back into the final leak backlog.

Q. Why is the Company proposing additional language around leaks being added back into the final leak backlog?

A. In 2021, there was a disagreement regarding the meaning of "successful elimination" of leaks and how type 3 leaks are successfully eliminated.

Q. What is Con Edison’s position on how a type 3 leak is successfully eliminated?

A. Type 3 leaks do not require follow up inspections by State code or Company specification and, therefore, the successful elimination of a type 3 leak is the action of repairing said leak and confirming (at the time of the repair) that there are no gas readings.

Q. What additional language is needed to clarify what is meant by “successful elimination?”

A. The language in any potential joint proposal or rate plan in this proceeding should be specific that successfully eliminated leaks are defined as both: 1.) leaks that have been repaired that do not require follow up by code or Company specification; and 2.) leaks that do require follow up by code and specification which have successfully passed the follow-up inspection.

Q. Is the Company proposing to continue the SRSM to recover incremental O&M expenses associated with lowering the Company’s leak backlog below the target established for the Leak Backlog performance measure?

A. Yes, the Company proposes to continue the SRSM for the Leak Backlog performance measure.

3. Emergency Response

Q. What modifications does the Company propose with respect to the Emergency Response Safety Performance Measure?

A. The Company is not proposing any changes to the Emergency Response Safety Performance Measure. The response time percentages set in the prior rate case (and associated negative and positive revenue adjustments) should remain, as is, for the next three years.

Q. Is the Company proposing any additional modifications to the Emergency Response Safety Performance Measure?

A. Yes, the Company proposes to clarify the exclusion under the Emergency Response Measure in the current Joint Proposal. The exclusion in the current Joint Proposal allows the Company to seek Staff's approval to exclude gas leak and odor calls resulting from circumstances that are beyond the Company's control, such as mass area odor complaints, major weather-related occurrences, and major equipment failure (unrelated to Company action/inaction or infrastructure).

Q. Why is the Company proposing to clarify this particular exclusion?

A. The rationale for including an exclusion for this performance measure is to address rare but expected situations when an inordinate number of odor calls are received for reasons beyond the Company’s control. There is a general recognition that, under such circumstances, it would be unreasonable to expect the Company to meet the targets that apply under normal conditions. Put another way, the Company should not be punished for failing to meet targets that are unrealistic due to rare and extreme conditions that arise for reasons beyond the Company’s control. This general understanding of the purpose of the exclusion should inform how it is implemented.

As a result of Hurricane Ida, the Company sought to invoke this exemption for odor calls and leaks that arose due to the hurricane and which were beyond the Company’s control. The Company experienced an increase in odor call volumes of over 400%. There was a disagreement regarding whether this exclusion should apply only to leaks that could directly be attributable to the storm (an identification and attribution process which would be impossible to validate). The Company believes this exemption applies to all odor calls that occurred during the hurricane, since the entire weather-event was out of the Company’s control.

Q. How is the Company proposing to modify the exclusion language?

A. The Company proposes the following:

“The Company may seek the following exclusion to operating performance under this measure: All odor calls associated with mass area odor complaints, major weather-related occurrences, and major equipment failure. Con Edison shall provide notification…"

4. Gas Regulations Performance Measure

Q. What modifications is the Company proposing to the Gas Regulations Performance Measure?

A. The Company is proposing the following modifications to this metric:

- Change in the NRA calculation;
- Establish audit protocols;
- Eliminate NRA for violations that were previously identified in a quality control/assessment process and rectified prior to an audit; and
- Eliminate NRA for violations that were self-reported and not subject to reporting requirements.

Q. Please describe the Company's first modification.

A. The Company is proposing to change the NRA calculation for violations identified in Records and Field Audits.

Q. How does the Company propose to calculate the NRAs for Records and Field Audit Violations?

A. Records Audit Operations

High Risk: 6-20 (1/2 BP); 21+ (1BP)

Other Risk: >15 (1/4 BP)

Records Audit Central

High Risk: 10-25 (1/2 BP); 26+ (1BP)

Other Risk: >15 (1/4 BP)

Field Audit

High Risk: 6-20 (1/2 BP); 21+ (1BP)

Other Risk: >15 (1/4 BP)

Q. What is the basis for separating the Central category and excluding that categories' first 10 audit high risk items and 15 other risk items in the records audit?

A. During the 2021 PSC Records Audit of 2020 Records, Staff changed the audit protocols for Central Records by sampling by borough, instead of the Central group as a whole, which resulted in quadruple the number of records and field inspections than had been historically sampled, in the Central categories. Con Edison has a Central Operations organization which singularly performs this work, and therefore, DPS Staff's historical practice of treating this group similar to an operational borough (*i.e.*, sampling protocols in place prior to 2021) was appropriate. Additionally, these changes were not negotiated for Rate Years 2020-2022 nor were they established in the current Gas Rate Plan. If this is the audit protocol going forward, the Company is requesting a separation of this category with the proposed dead band, in order to establish appropriate targets that reflect the audit protocol changes. Con Edison has shown a consistent downward trend in our Records and Field audit violations since this metric was put into place, and we will strive to continue this decline in violations.

Q. What is the basis for proposing a dead band for Field Audit findings?

A. Since the current rate case's negotiations, DPS Staff has greatly increased its field presence overall, and therefore, increased the number of field audits in the process.

Additionally, and as discussed above, in 2021 DPS Staff modified its sampling practices related to the Central group. This change occurred in the field audit as well, which resulted in quadruple the number of field inspections than had been historically sampled, in the Central categories. These changes were not negotiated for Rate Years 2020-2022 nor were they established in the Gas Rate Plan. Therefore, the Company is requesting a dead band of 5 high risk and 15 other risk Field Audit findings, in order to establish appropriate targets that reflect the audit protocol changes.

Q. Please describe the Company's next proposed modification to the Gas Regulations Performance Measure.

A. The next proposed modification would establish more consistency around audit sampling. In the context of annual field and record audits, where violations carry significant NRA implications and are reported in the annual Performance Measurement Report, it is imperative that consistent sampling and audit protocols be established. There is currently no documented methodology or protocols explaining how Staff develops samples and/or audits a LDC's records. As stated in the prior two answers, Staff has modified sampling protocols outside of rate case negotiations, which has greatly increased the number of audited items for both the Records and Field audit. To address this issue, the Company is requesting that the Commission direct Staff, in consultation with New York State LDCs, to establish a documented sampling and audit protocol to promote greater consistency.

Q. What is the Company's next proposed modification related to the Gas Regulations Performance Measure?

A. The Company is proposing the elimination of NRA for violations resulting from self-reported events not subject to reporting requirements, as long as the Company takes immediate corrective action to resolve said issue. To promote transparency and cooperation, the Company has self-reported issues or incidents to Staff, which do not meet current regulatory reporting requirements. These self-reported events should not be subject to NRA, because the Company should not be penalized for going above and beyond its reporting requirements.

Q. What is the Company's next proposed modification related to the Gas Regulations Performance Measure?

A. The Company is proposing the elimination of any NRA penalties associated with violations that were previously identified by internal quality control processes and rectified prior to identification in a PSC audit. The Company puts considerable effort into identifying and rectifying compliance or quality issues; therefore, it not reasonable for the rate plan to establish disincentive for a violation that has already been identified and rectified by the Company. Indeed, it is contrary to governmental policy regarding compliance, which is to encourage disclosure and correction.

VII. GAS SUPPLY

A. Capacity and Supply Portfolio

Q. Please describe the nature of the Companies' gas supply portfolio.

A. The Company manages a joint gas supply and capacity portfolio ("joint portfolio") with (Orange and Rockland Utilities, Inc. ("O&R") that allows for the joint utilization of both Companies' gas supply and interstate pipeline capacity contracts, including storage. The joint portfolio is operated for the benefit of the firm gas customers of both Con Edison and O&R (the "Companies"). The contracts that the Companies' have entered into are listed in Schedules 1, 2, 3, and 4 of Exhibit___(GIOSP-3).

Q. Please describe the objective of the Companies' long-term gas supply plan.

A. The Company evaluates supply and capacity requirements over a ten-year planning horizon and integrates and extends this over a 20-year planning horizon to determine the plan to meet the needs of its firm gas customers. While the Company plans only for its firm customers, it is cognizant of needs of its non-firm customers and of electric customers. The Companies have also adopted the objective of decreasing the emissions associated with the gas flowing through the system, through the purchase of certified gas and the interconnection of RNG facilities.

Q. Please describe the objective of the Companies' gas purchasing and hedging programs.

A. The Company's objective is to obtain reliable, diverse, lower emission, and reasonably-priced gas supply in order to: (i) meet the design winter requirements of its firm gas customers, (ii) minimize costs to its firm customers, (iii) reduce price volatility, (iv) react to changing weather conditions, (v) to the extent possible, maintain service during a contingency event affecting a major pipeline or supply basin and (vi) reduce the emissions associated with the gas it purchases.

Q. How do the Companies seek to maintain reliability of supply?

A. One of the cornerstones of a reliable gas portfolio is diversity. The Companies' joint gas supply and capacity portfolio includes contracted supplies from the Marcellus Shale in the Northeast, the Gulf Coast, and Canada, from suppliers on multiple pipelines, as set forth in Exhibit___(GIOSP-3), Schedule 1, Gas Supply Contracts. The Companies also have firm pipeline capacity contracts with various interstate pipeline transportation companies, as set forth in Exhibit___(GIOSP-3), Schedule 2, Pipeline Transportation Contracts, which provide access to diverse sources of supply. In addition, the Companies have a number of contracts for underground storage, which are listed in Exhibit___(GIOSP-3), Schedule 3, Storage Contracts, an LNG peaking facility, whose deliverability is set forth on Exhibit___(GIOSP-3), Schedule 4, baseload and peaking delivered service, as set forth in Exhibit (GIOSP-3), Schedule 2, and has contracted for CNG peaking deliveries, whose deliverability is set forth on Exhibit___(GIOSP-3), Schedule 4.

Q. What are design weather conditions?

A. The peak day demand represents the quantity of gas that firm customers would require in a twenty-four hour period of a gas day, which starts at 10:00 am, at a Temperature Variable of zero degrees Fahrenheit. The Temperature Variable is defined as the sum of 70 percent of the projected gas day average temperature plus 30 percent of the prior gas day average temperature, which provides the best correlation with firm customer demand. Exhibit___(GIOSP-3), Schedule 5, Forecasted Requirements – Peak Day, shows the forecast of Con Edison's and O&R's firm customers' peak day demand for each winter period (*i.e.*, November through March) beginning with the winter of 2019/2020 through winter 2021/2022. The Companies also calculate the gas requirements for meeting demand over the course of a winter under severe weather conditions (a "design winter") in order to establish storage and Delivered Services amounts needed to meet potential customer demand.

Q. Please explain how the Companies' contracts enable them to meet these design weather conditions.

A. The Companies meet peak day demand in four ways. First, the Companies rely on the delivery of firm supply through their firm interstate pipeline transportation and firm storage contracts, which are listed in Exhibit___(GIOSP-3), Schedules 2 and 3. Second, the Companies maintain contracts for Delivered Services. Historically, these have primarily been firm peaking supplies that give the option to purchase gas for a pre-determined number of days during the winter (typically 15, 30, or 60 days) and pay the daily citygate index price for the gas on those days. The Companies' also have base delivered supply contracts in addition to peaking supplies. Base delivered supplies are a commitment to procure gas at the citygate for a set winter term (typically December through February or November through March) and are priced at a NYMEX index price plus a fixed basis. These contracts for Delivered Services, which are listed in Exhibit___(GIOSP-3), Schedule 2, contribute to the Companies' ability to meet peak load. Third, Con Edison vaporizes gas from its LNG facility to meet peak day demand. Fourth, Con Edison can call upon its contracted CNG facility to meet peak day demand.

Q. What do you mean by "Delivered Services?"

A. Delivered Services are gas supplies procured at the citygate from third party suppliers that have primary firm capacity to the citygate.

Q. What risks does a high level of Delivered Services introduce to the Gas Supply portfolio?

A. The Company has identified three risks: re-contracting, availability, and price volatility.

Q. Please explain these risks.

A. Unlike the Company's contractual rights for pipeline capacity, there is no regulatory renewal right for Delivered Services and, therefore, no certainty that the Company can continue to rely on the same Delivered Service supply contract year-to-year, to reliably meet customer heating needs.

Second, with the pipeline capacity coming into the Con Edison service territory being fully contracted and new pipeline projects facing increased difficulty in securing necessary permits, the future availability of Delivered Services required to meet our forecasted peak demand is uncertain because shippers who hold this capacity can market it to persons outside of the service territory.

Third, the increased reliance on Delivered Services in the portfolio results in higher gas price volatility and potentially increased costs for our customers. Instead of buying gas at low price volatility production area receipt points and transporting it on pipeline capacity to our service territories, the Companies must purchase at New York area citygates where prices are subject to significant volatility during high demand periods.

Q. What actions have the Companies taken to reduce their reliance on Delivered Services?

A. The Companies actively seek to acquire firm transportation capacity to the New York area citygates as it becomes available from other shippers through permanent capacity release transactions or by contracting directly with pipelines once the capacity has been turned back by the existing shipper. The Companies have also acquired capacity released through Asset Management Agreements ("AMA") with third party capacity holders in addition to traditional capacity release agreements. The Companies will pay a fee in exchange for capacity with a supply component from the third party.

Q. Have there been changes to the Companies' supply and capacity portfolio over the last three years?

A. Yes. The Companies have recently entered into new agreements and elected not to renew certain agreements.

Q. Please describe the recent agreements the Companies have entered.

A. As discussed in further detail below, the Companies are diversifying their Delivered Services portfolio. The Companies have entered Delivered Services contracts with up to two or three-year durations to meet firm gas customers' current and future peak day requirements. These contracts give the Companies the right to call upon the supplier and purchase daily-priced gas for a maximum of 30 or 60 days during the winter season. As previously discussed, these Delivered Services contracts provide needed supply to our gas system to supplement pipeline capacity under contract by our suppliers.

The Companies have new contracts for additional deliverability to our citygates: four with Texas Eastern for 147,500 Dt/ of pipeline capacity which delivers to Lower Manhattan.

Beginning in 2020, the Companies have also subscribed to pipeline capacity through Asset Management Arrangements, specifically a total of 80,000 Dt/d delivery on Transco Pipeline to Manhattan and 15,500 (increases to 40,000 Dt/d in November 2023) on Tennessee pipeline to Westchester.

Q. How do the Companies evaluate whether to renew an expiring contract?

A. The Companies evaluate the capacity portfolio. If an expiring contract is still required to serve firm customers or manage system operations, the Companies assess the market to determine if there are more economic alternatives available that provide at least the same degree of reliability and flexibility. If not, the Companies will renew the contracts by exercising their rights pursuant to existing interstate pipeline tariff Right of First Refusal (“ROFR”) provisions or other applicable contract provisions.

Q. Have the Companies elected not to renew certain expiring contracts?

A. Over the past three years, the Companies elected not to renew some of their firm transportation contracts with National Fuel.

Q. Why did the Company elect not to renew these contracts?

A. The increase in supply available from the Northeast Marcellus and Utica shale regions has affected how the Companies evaluate certain contracts. Historically, the Companies seek to access receipt points where gas can be purchased from multiple sellers, which are often referred to as a “liquid supply points.” To accomplish this, the Company has historically entered contracts that formed paths accessing the Gulf, Canada, or a storage field. Some of these paths include multiple contracts such as one upstream pipeline with access to a liquid supply point, connected with one downstream pipeline with access to NYC.

With the increased gas available in the Northeast, liquid supply points that previously did not exist have formed on the downstream pipelines.

The firm transportation contracts with National Fuel were upstream transportation contracts that were needed to reach a liquid supply point. Since liquid supply points are now available on their downstream counterpart along the same path, the Companies no longer need to purchase firm transportation rights on this upstream pipeline.

Q. Do you anticipate any future changes to the capacity portfolio?

A. Yes. As described in our testimony in Case 19-G-0066, the Companies have subscribed to pipeline capacity on Mountain Valley Pipeline ("MVP") which is scheduled to be in service as early as 2022. The Companies have also subscribed to pipeline capacity on Iroquois pipeline for 62,500 Dt/d of capacity for deliveries from Waddington, NY to New York City, NY and on Tennessee pipeline for 115,000 Dt/d of capacity for deliveries from Pennsylvania to Westchester, NY. The estimated in-service date of the Iroquois pipeline is winter 2023 and while Tennessee pipeline has indicated an estimated in-service date of winter 2022, due to the high risk associated with that aggressive schedule, the Companies continue to plan for an in-service of winter

2023.

Q. What is the current/updated status of the anticipated future pipeline projects?

A. MVP was originally planned to be in service in 2018 and has now been delayed such that the earliest it will be in service is November 2022. In Case 19-G-0066, the Companies had also described a project, Penn East Pipeline, for 100,000 Dt/d. The pipeline company has permanently terminated that project.

The estimated in-service date of the project on Iroquois Pipeline has not changed since inception. The estimated in-service date of the project on Tennessee Pipeline has also not changed. The Tennessee project will allow Con Edison to lift its moratorium in Westchester, but we continue to plan for an in-service date of no earlier than winter 2023.

Q. Have there been any changes to the Companies' supply portfolio?

A. Yes. As illustrated in Exhibit__(GIOSP-3), certain of the Companies' gas supply contracts expire each year. Existing contracts may be renegotiated or replaced through competitive bidding or RFPs.

In the past, the gas supply contracts required to fill open firm transportation capacity typically had one, three, or five-year terms. The Companies' purchasing strategy has changed in recent years. Upstream supplies have generally been limited to one year or less, whereas for Delivered Services or peaking supplies, the Company will look to procure up to three years or more based on availability. The Companies have entered multi-year upstream supply purchase deals for a small portion of their supply in order to capture some of the current market differentials and will continue to do so when market conditions support it. The Companies re-evaluate their purchasing strategy and make changes as circumstances dictate. Exhibit___(GIOSP-3), Schedule 1, lists all gas supply contracts effective winter 2021/22.

B. Price Volatility Reduction

Q. What efforts have the Companies undertaken to reduce the volatility of delivered services?

A. To address the price volatility risk, the Companies have begun diversifying the type of Delivered Services procured by adding base delivered services to the portfolio. These products are priced at a fixed basis for the term plus the NYMEX settle for the month and are intended to reduce the impact of citygate commodity-priced peaking supplies on the total portfolio during periods of high volatility. On

October 22, 2018, the Commission approved the Company's request to include the costs of the new base delivered services as part of its DDS program (Case 18-G-0393).

Q. Please describe the procurement strategies the Companies employ in the wholesale market to minimize gas costs.

A. The Companies use many procurement strategies to minimize gas costs. For procurement of supply in liquid markets, such as production area receipt points, we use a competitive bidding process through Requests for Proposals ("RFPs") and by participating in on-line reverse auctions. In illiquid markets, such as Delivered Services procured at certain of our service area citygates, the Companies will at times engage in direct negotiation with the third parties capable of meeting the supply requirement.

Q. Please describe the Companies' gas hedging program.

A. The Companies' hedging program is designed to reduce gas price volatility. One of the hedging program's components is the Monthly Plan, which dictates the use of various financial instruments to hedge natural gas prices for part of the gas supply necessary to meet the monthly requirements of firm sales customers. The program provides for the Companies to hedge a predetermined quantity of their forecasted sales using financial price hedges for the winter period.

Q. Are there other efforts to reduce costs?

A. Yes. The dynamic nature of the wholesale gas market, since the advent of shale-based production, has created new opportunities for the Companies to purchase more economic natural gas at alternative receipt points along the path of its interstate pipeline capacity. As new production and upstream pipeline capacity go into service the Companies are frequently assessing and modifying their purchasing strategy for the resulting changes in pricing dynamics. In addition, the Companies seek to optimize their joint portfolio primarily through capacity releases, AMAs, and off-system bundled sales.

Q. Please provide an illustration of the historical benefits from the Companies' portfolio optimization efforts.

A. Exhibit___(GIOSP-3), Schedule 6, Non-Traditional Revenues, illustrates annual benefits received over the past five years from the Companies' portfolio optimization efforts to minimize overall costs to their firm gas customers.

Q. How are portfolio optimization benefits derived?

A. The expected benefits are derived when available capacity, not used to serve the Companies' customer requirements or balancing needs, is offered to the market through capacity releases, off-system sales, or AMAs that together are referred to as "discretionary capacity releases."

Q. What changes do you see for revenue from discretionary capacity releases?

A. We expect the revenue from discretionary capacity releases to decrease. First, because more existing capacity will be needed to serve firm customers more often, projected near term load growth, and therefore will be unavailable for release during times of higher market value. Second, the market value of some capacity has decreased because of recent pipeline buildouts from the Marcellus region (*e.g.*, Atlantic Sunrise, Rover) that have increased the capacity price in that region. This price increase decreases pricing differentials with other regions and decreases the value of released capacity.

C. Marginal Cost Study

Q. Please address the marginal cost study with respect to gas supply costs.

A. Supply-side marginal costs are the costs of procuring and transporting an additional unit of gas to the Companies' distribution systems. Fixed costs of existing resources are not considered because they do not vary with additional usage and because the Companies cannot avoid paying them. The marginal costs projected for the 2022-2025 period average $4.06/dt for the year, $6.95/dt for the winter period and $13.46/dt for a peak day.

Q. Please define the marginal commodity cost.

A. Marginal commodity cost is the cost of an incremental purchase of gas required to meet system demand that exceeds committed supply sources and planned supply additions.

Q. Please explain the development of the marginal commodity cost.

A. Exhibit___(GIOSP-3), Schedule 8, Summer Season Supply/Demand Balance and Schedule 9, Winter Season Supply/Demand Balance, compare the Companies' firm transportation and supply capability to serve gas demand for firm sales customers on a summer season and for a normal winter season. Exhibit___(GIOSP-3), Schedule 10, Peak Day Supply/Demand Balance compares the Companies' firm transportation and supply capability to serve all firm customers on a peak-day. The Companies' firm transportation and supply capability includes all firm transportation deliverability and accompanying purchased firm supplies. As shown by these Schedules, the highest cost of supply was assumed for purposes of the marginal cost study, combined with the projected firm demand, are less than the Supply Capability of the Companies except on a design day. The need to add capacity to serve firm customer requirements is driven by the Companies' requirements on a design day. As such the marginal cost for commodity on a design day reflects the purchase of gas through a peaking contract at a Con Edison citygate. The Companies often secure peaking supplies to supplement baseload, storage and other supplies to meet our peak demand on a design day.

Q. Please explain the calculation of the marginal commodity cost.

A. The marginal commodity cost is measured by using an optimization model to dispatch load profiles under normal and design weather and taking the resulting highest cost of supply.

Q. What is the forecast period used in your marginal cost study?

A. The forecast period for the marginal cost study is the three-year period from November 2022 through October 2025. Exhibit___(GIOSP-3), Schedule 11, Natural Gas Monthly Marginal Commodity Costs, displays the monthly forecasted marginal commodity costs for the three years of the study. Exhibit___(GIOSP-3), Schedule 12, Marginal Commodity Costs, summarizes these costs to show the impact of the incremental increase on an average annual, summer season, winter season, and design day basis.

D. Capital and O&M Investments

Q. Are there presently Gas Supply IT systems requiring capital enhancements?

A. Yes, there are presently two systems that require enhancements. The first is for the Transportation Customer Information System ("TCIS") with a capital cost of $1.08 million over the rate period; the white paper is called "Utilizing AMI Data for Interruptible Gas Marketer Forecasting and Retail Choice Information System ("RCIS") Migration." The second project is for the Gas Transaction System ("GTS") with a capital cost of $1.9 million in 2025 and is called "FIS GTS Enhancements and Upgrade." The white papers for these two projects are included in the exhibits of the Company's IT Panel.

Q. Starting with the first System Enhancement, Utilizing AMI Data for Firm and Interruptible Gas Marketer Forecasting and RCIS Migration, please describe the project's purpose.

A. TCIS is a software used by marketers to communicate gas operational information to Con Edison. TCIS has many functions, including the ability to communicate gas scheduling information, control access security, generate reports, post messages to the internet, store rates, create invoices and vouchers, and track enrollments/de-enrollments. In 2021, Con Edison enhanced TCIS to include the implementation of capacity release, implementation of rebill adjustments, and include a display of AMI meter reading data. The project proposed in this rate filing will expand TCIS' capability to leverage AMI data for forecasting as well as enable the Company to migrate current functionality from RCIS to TCIS. Currently, the system uses monthly data to create a linear forecasting equation that intakes forecasted temperature to determine the projected usage of firm transportation customers. AMI data will allow the Company to use daily information for daily forecasts, thus improving the accuracy of its forecasts. The movement of marketer related functionality from RCIS to TCIS will allow for the retirement of RCIS and combine all marketer related functionality into one system.

Q. Please describe the purpose of the second project, FIS GTS Enhancements and Upgrade.

A. GTS acts as the operational and accounting system of record, used by commodity operations to record and schedule deliveries of natural gas purchases to the Companies' service territory. In addition, it identifies, assembles, analyzes and reports the organization's transactions for accrual purposes, accounts for the related assets and liabilities and allocates the various costs of natural gas purchases to the various end uses. This purpose of this project is to upgrade the FIS GTS application to is latest version, modernize the system application to the cloud, and automate select processes, notifications, and business activities.

Q. Are there projected additional O&M expenses associated with these projects?

A. Yes, there are. The additional O&M expense is $690,000 over the rate period.

Q. What are the drivers for the projected increases in O&M?

A. The O&M expenses are associated with maintaining and supporting the TCIS system on a real-time basis. TCIS is a system used for daily operations, specifically to calculate the daily gas delivery requirements of the more than eighty gas marketers serving firm and interruptible customers in our service territory. TCIS also acts as the electronic bulletin board for accepting gas schedules from the gas marketers in accordance with both day ahead and intra-day scheduling deadlines. Those schedules are then sent through systems to Gas Control every fifteen minutes. These deliveries represent 50% of all nominations for firm gas customers on our system. This information is critical to Gas Control's confirming of gas supplies at the various pipeline citygates in order to maintain system reliability. This system is currently being supported by the capital team working on the current TCIS upgrades. However, the complexity of this in-house developed product combined with a recent uptick in system performance issues are driving the need for more internal IT support to supplement those of the third-party vendor. Due to the operational nature of the system, system performance issues are urgent and need to be resolved quickly, which is why the Company uses the capital team to resolve these issues. The O&M request is to provide funding to internally support TCIS starting in late 2023, after the proposed capital project ends.

Q. Was the document titled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. – GIOSP Gas Distribution Peak Forecasting Model O&M" prepared under this Panel's direction and supervision?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-4).

Q. Please describe this exhibit.

A. This exhibit outlines the O&M program change called Gas Distribution Peak Forecasting Model.

Q. Please briefly describe its benefits and justification.

A. Given the Company's commitment to a clean energy future and the interests of its stakeholders, optimization and accurate planning for the gas distribution system is necessary. The effectiveness of the Company's plans for its gas distribution system has a direct impact on its gas customers. If the gas distribution system is not planned for properly, there is the risk of shedding gas load in certain areas. Identifying distinct areas of load growth will assist with pinpointing non-pipe solutions instead of the need for system reinforcements. Current gas policy is moving towards less development of gas supply. As such, the margins on the system will become tighter thus prompting the need for a more granular and longer term forecasting model for the distribution system.

The Company is seeking to develop a firm gas distribution forecasting model that predicts firm gas peak day demand at design weather conditions. This new model will predict the peak-day and peak-hour firm gas demand for newly established districts within the gas distribution system in the Company's gas service territory out 20-years, which will be developed by an expert forecasting vendor and the Company's forecast development team. The Company's forecast development team will be comprised of subject matter experts from Gas & Steam Forecasting, Policy Integration Forecasting, Forecasting Services, Gas Engineering, and Gas Control – all working incrementally on this effort.

The total cost of this project is projected to be $2.05 million, which will result in:

- The development of an Excel based firm gas distribution peak day forecasting model.
- A proven methodology and algorithms for transposing the firm gas transmission system and regulator peak day forecasts to distribution level district forecasts.
- Mapping or the gas service territory to distribution districts.

Accordingly, the cost request here is for forecast vendor professional services and incremental Company labor costs. The nature of this work is considered O&M and three additional Full Time Equivalents("FTE") are required for Rate Year 1. In Rate Years 2 and 3, ongoing operations, maintenance, and calibration of the model/methodology/mapping will occur to sustain accuracy, totaling $190,000 per year for 1 FTE and associated overheads for the Gas & Steam Forecasting Section.

As such, projected incremental O&M costs total $1.67 million in Rate Year 1 (2023), $0.19 million in Rate Year 2 (2024) and $0.19 million in Rate Year 3 (2025). Please note that the total of these values is about $1 million less than what is included in the associated program change form and will be revised on update. The Company expects the completion of the forecast tool to occur early in RY2.

E. Lost and Unaccounted for Gas

Q. Please explain the current methodology for calculating lost and unaccounted for ("LAUF") gas.

A. In accordance with the current Gas Rate Plan, the Company uses a throughput method that calculates unaccounted for gas by subtracting metered deliveries to customers from metered supplies to the system. An adjustment is made for Generators who contribute 0.5% of their metered deliveries to the unaccounted for gas as well as the Delivering Party to the Receiving Party among the New York Facilities companies. Beginning September 2020 and going forward, gas loss due to inactive accounts are no longer part of the net gas loss calculation. The remaining LAUF gas is compared against a rolling five-year average. The calculation of the current average is shown on Exhibit___(GIOSP-3), Schedule 13.

Q. Are you proposing any changes to Con Edison's LAUF calculations for the period commencing January 1, 2023?

A. No.

F. Renewable Natural Gas and Retail Access

Q. Is RNG currently included in the retail access program?

A. Yes. In the event the Company purchases RNG on behalf of customers, Retail Access customers would receive a portion through Tier 3.

Q. Are you proposing any changes to RNG and the Retail Access program?

A. Yes. The Company is looking to incorporate the option for Retail Access marketers to directly procure RNG injected directly into our distribution system themselves. This would not change any current allocations for baseload or any of the tiers. Deliveries from RNG would be included in the marketers' daily delivery requirement and those volumes would be subject to the same imbalance and cashout procedures as all other volumes delivered to Con Edison.

Q. Why are allocations for baseload or any of the tiers not being changed if a Retail Access marketer subscribes to RNG?

A. The Company is responsible for ensuring sufficient capacity for all firm customers. The Company will continue to procure sufficient capacity for all firm customers to ensure that in the event a marketer turns its customers back to the Company, there will be adequate capacity to account for their peak day usage. If the Company were to reduce the amount of capacity procured by the annual amount of RNG, it may be unable to provide service down to the peak day in the event that customers return to the utility from a marketer.

G. Certified Natural Gas

Q. Is the Company proposing any procurement of certified natural gas?

A. Yes. The Company is proposing a pilot program designed to allow for the procurement of certified gas, during the rate period, limited to an annual cost above traditional supplies of $800,000 per year.

Q. What is certified natural gas?

A. Certified natural gas is natural gas originating from producing sites that have undergone third-party certification to verify that the operator has met high environmental standards and best practices for methane emissions reduction in their operations.

Q. Does the procurement of certified gas align with the goals of CLCPA?

A. Yes, per CLCPA, the 1990 net emissions baseline includes not only all statewide sources of greenhouse gas emissions but also those associated with imported electricity and fossil fuels.

Q. Why is the Company proposing a pilot program only?

A. The Company is proposing a pilot program given the market for certified natural gas is still evolving and many certification processes exist, rather than an industry standard. The experience from the pilot coupled with the reporting requirements of the pilot will allow the program to be ramped up or down as appropriate.

Q. What reporting requirements is the Company proposing as part of the pilot?

A. The Company will file an annual report each May, describing progress of the pilot to date and meet with DPS Staff each June to review the report and recommend next steps, which could include filing with the Commission for modification of the program.

H. Gas Supply Constraints and Temporary Moratorium

Q. Are there any updates to the status of the moratorium?

A. Yes, existing gas supply constraints in this part of our service territory still limit our ability to meet customer demand there.

Q. Is there an expectation of when the temporary moratorium will be lifted?

A. The temporary moratorium is expected to be lifted when the Company's subscribed Tennessee compression-only project is in service. The Company contracted with Tennessee Gas Pipeline to increase firm transportation capacity to our Westchester citygates utilizing increases in compression only. Tennessee has applied for permits for this project and those requests are currently pending before the Federal Energy Regulatory Commission and various state agencies.

While Tennessee continues to work toward an in-service date of November 1, 2022, the Companies are planning for an estimated in-service date of November 1, 2023.

Q. Are there other considerations that would allow the temporary moratorium to be lifted?

A. Yes, if the demand in the area decreases to a level where gas supply constraints no longer exist, but our current forecast does not show demand decreasing to that degree.

Q. What changes has the Company undertaken to its supply portfolio while the moratorium remains in effect?

A. In order to meet the increase in demand associated with the acceleration of customer applications received in the sixty days between moratorium announcement and implementation, the Company entered into an agreement with a trucked CNG vendor. As a result, a trucked CNG facility capable of providing 25,000 dt per day of supply is now in-service in Westchester County. This facility is temporary and will be retired once the Tennessee Pipeline project enters service or demand is reduced such that the CNG facility is no longer necessary and the moratorium is lifted.

Q. Has the Company provided any assistance to customers during the moratorium?

A. Yes. The Company provides information on non-fossil alternatives and has worked with potential customers prior to the purchase or lease of a property to find alternative solutions that will meet their energy needs.

I. Regulatory Activities

Q. Do the Companies undertake any regulatory efforts to maintain the reasonableness of their gas costs and the reliability of their supply?

A. Yes. The Companies participate in FERC proceedings involving: (i) their interstate pipeline transportation and storage providers ("service providers") and (ii) generic issues that impact the cost and quality of the gas service received by the Companies from FERC-regulated entities. The Companies review all significant FERC filings made by the interstate pipelines and storage companies from which they receive service. Since January 2017, the Companies have participated in numerous FERC proceedings and, when circumstances dictate, have filed detailed comments or objections. Exhibit___(GIOSP-3), Schedule 7, lists the FERC dockets in which Con Edison has filed detailed comments since January 2017.

The Companies are also active participants in the AGA FERC Regulatory Committee, which takes an active role in a range of federal regulatory issues relating to gas. The Companies closely follow FERC proceedings that impact rates and terms and conditions of service of their interstate pipeline service providers and actively participate in litigation as well as settlement negotiations. In addition to the FERC proceedings listed in Exhibit___(GIOSP-3) Schedule 7, the Company is participating in several federal appellate court cases where we advocate in favor of reasonable prices and adequate supply for our customers. The Companies have also actively participated in the FERC’s inquiries into gas-electric coordination and, more recently, impacts to pipeline rates due to the Tax Cuts and Jobs Act. The Companies are also actively engaged on several pipeline rate cases, both ongoing and expected, to negotiate reasonable rates for our customers. When appropriate, the Companies also participate in collaborative discussions among pipelines and their customers, the North American Energy Standards Board (“NAESB”) and the Natural Gas Council (“NGC”), either directly or through their membership in the AGA.GSP-

Q. Please provide examples of the Companies’ active participation in the rate proceedings of their interstate pipeline suppliers.

A. As examples, the Companies participated and are actively participating in rate settlements with Texas Eastern (RP21-1001 and RP21-1188), Eastern Gas (RP21-144 and RP21-1187), National Fuel (RP19-1426) and Transcontinental Gas

Pipeline’s ongoing market-based rate proceeding (RP21-1143). The Companies are actively participating in Texas Eastern’s (RP21-1001 and RP21-1188), Eastern Gas’ (RP21-1187), and Transcontinental Gas Pipeline’s (RP21-1143) ongoing FERC proceedings with LDC customer groups and is leading the LDC customer groups in Texas Eastern’s and Transcontinental Gas Pipeline’s proceedings, the Texas Eastern Customer Group and the WSS Customer Group, respectively.

Other FERC proceedings the Companies are following relate to interstate pipeline cost allocation issues involving, for example, fuel retention and electric power compression charges. In a recent case, the Companies negotiated a favorable settlement agreement related to Algonquin’s fuel rates (RP18-75), protecting a substantial one-time refund and preventing unreasonable cost shifting to our customers. In 2016 and 2017, the Companies were involved in settlement discussions regarding costs Texas Eastern had incurred and will incur as a result of its PCB Environmental Remediation Program. The Companies were participants in a shipper group that successfully negotiated a settlement agreement with Texas Eastern, and this agreement was ultimately approved by FERC in Docket Nos. 17-964 and 17-967.

The Companies also closely monitor proposed tariff changes by service providers that modify their terms and conditions of service, including matters related to rights of first refusal, gas quality, lost and unaccounted for gas, bidding rules, shipping priority, service provider credit policies, and tariff and negotiated agreement filings that could affect the quality of pipeline service to the Companies. The Companies also closely monitor new incremental services being offered by the Companies' current service providers so that the rates of those new incremental services are not subsidized by existing customers, such as the Companies. For example, in 2017, the Companies protested two National Fuel proceedings that would have resulted in the subsidization of fuel costs for the new Northern Access 2015 ("NA2015") expansion by system shippers, including the Companies. FERC ultimately sided with the Companies and required separate accounting for NA2015 fuel costs in Docket Nos. CP14-100 and RP17-407.

Q. What other regulatory efforts have the Companies taken to maintain the reliability of their supply?

A. The Companies have focused on preventing increasing electric system reliance on natural gas as a fuel from adversely affecting gas system reliability. In particular, the Companies advocated vigorously for the NYISO to prohibit electric generators from recovering penalties they incur as a result of violating Operational Flow Orders. Related rules changes were approved by the NYISO's stakeholder committees and FERC in 2016. In addition, the Companies continue to advocate for coordination of electric and gas system reliability and resilience through market rule changes, such as expanding dual-fuel requirements in New York State to outside of our service territory. The Companies are currently working closely with the NYISO on a Fuel Security Study, which, among other things, will identify possible system needs to be addressed.

Q. Are the Companies a member of any groups addressing gas reliability issues in New York State?

A. Yes. The Companies have been an active participant in the Natural Gas Reliability Advisory Group ("NGRAG") from its initiation. The NGRAG was formed to consider the evolving gas capacity markets and how they affect reliability, and to inform the Commission about issues that need to be addressed to protect reliability. The NGRAG has focused discussion on the NYISO gas/electric workgroup to address gas supply and transportation issues, updates of an ongoing LDC collaborative addressing Gas Marketer Transportation and Balancing Programs, and operational updates provided by gas industry LDCs, pipelines, marketers, customer groups, NYSERDA and NYMEX representatives.

Q. Please describe the Companies' efforts in connection with NAESB.

A. We have been a member of NAESB and its predecessor organization, the Gas Industry Standards Board ("GISB"), since the latter's inception in 1994. The Companies continue to monitor the development of new business standards and, as appropriate, participate in periodic revisions to the NAESB Base Contract, a form agreement frequently used in the industry for the purchase and sale of natural gas.

Q. Please describe the Companies' efforts in connection with the NGA.

A. The Companies participate on NGA's New York State Gas Utility Planning Committee ("NYPLAN"). NYPLAN is comprised of planning, supply, and regulatory personnel from New York's investor-owned natural gas utilities. Its mission is to provide a forum for New York State gas companies to address the broad spectrum of issues relating to the natural gas supply, transportation, storage, peak shaving, and demand planning process. This includes, but is not limited to, such responsibilities as responding to regulatory mandates, discussion/follow-up on key regulatory/ legislative issues, and working in collaboration with NYSEARCH, a collaborative Research, Development & Demonstration organization that serves its gas utility member companies, on R&D projects.

The Companies are members of the NGA Gas Supply Task Force ("Task Force"). The Task Force includes representation from all the interstate transmission companies serving the region, LNG importers and trucking companies, and the largest of the northeast region's LDCs. Recent members include several of the larger power generation owners who use natural gas as a major part of their fuel supply. The Task Force meets prior to the winter heating season to confirm communication protocols and to provide updates on the status of member company transmission and storage systems. The Task Force is convened during the winter to monitor supply and deliverability issues. The region's state regulators and the electric grid operators are notified of Task Force meetings and are provided meeting summaries.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2023-2025 OPERATIONS AND MAINTENANCE (O&M)

GAS OPERATIONS - O&M CHANGES BY CATEGORY	Total Dollars ($000)*		
	RY1	RY2	RY3
Service Line Definition	$ 39,190	$ (871)	$ (1,248)
High Emissions Survey	$ 499	$ -	$
Additional Bridge Inspection Work	$ 368	$ -	$ -
Capital Projects Software Changes**	$ -	$ 60	$ 140
Grand Total	**$ 40,057**	**$ (811)**	**$ (1,108)**

*dollars represented as incremental over historic year
**details associated with this increase can be found in the Outage Management System and GCC Operator Training System Simulator capital white papers

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	Capital
X	O&M

Gas Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Service Line Inspection Program	
Project/Program Manager: **Thomas Riviello/ Alexia Reno**	**Project/Program Number (Level 1):** NA
Status: ☐ **Initiation** ☐ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: on-going	**Estimated Date In Service: on-going**
A. Total Funding Request ($000) **Capital:** **O&M: $197.2 Mil**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M: n/a** **Capital: n/a**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

This program is to fund leak surveys and corrosion inspections of the inside gas piping from the point of entry (POE) of the building to the outlet of every gas meter. There are ~1 million gas meters on over 300,000 gas services located inside the customer's premise. This program supports the revision of the "service line" definition. This request includes the inspection of the gas piping on a five-year cycle. The inspection cycle is based on the extension of inspection cycles to five years for all inside service inspections, from a prior cycle of once a year annually for business district and once every three years for non-business district.

This program includes the funding for 2023-2025 inspection costs associated with inspector labor to support the physical inspection as well as the back-office labor to support customer communication and education, scheduling, routing and other efforts to coordinate work streams between natural gas detector (NGD) installation and service line inspections. During this period, the funding request also includes costs associated for repairs, emergency response, surveillance, and the need to raise customer awareness of this program. This also includes the mandated number of minimum attempts required before escalating communication, fee warning, fine assessment, termination notification and the associated inspection requests that may result from the multiple attempts made to complete the inspections.

Justification Summary:

On April 20, 2017 the Commission issued an Order in Case 15-G-0244 that immediately implemented the expanded leak survey and corrosion inspection requirements. In accordance with this Order, Con Edison was required to complete baseline natural gas leakage surveys. The Commission issued several Orders modifying the completion date due to COVID and New York State local gas distribution companies (LDCs) all experiencing access issues. On December 31, 2020 Con Edison filed a Petition to Establish an Additional Compliance Method for Gas Service Line Leakage Surveys/Corrosion Inspections for Premises with Access Issues in Case 15-G-0244. In the Petition, Con Edison provided it's compliance plan and committed to the completion of the baseline program, which required the inspections to be completed or the gas meter was placed into a termination eligible status by September 15, 2021. This target was achieved.

The Company has approximately 1.1 million inside meter sets, with over 900K inside building sets, located in more readily accessible building areas (*e.g.,* basements), and about 200K inside building sets in apartments ("room sets") or other remote locations. The expenditure level assumes an inside leak survey and corrosion inspection program for the inside piping associated with the 900,000 inside meters that are readily accessible, and the 200,000 room sets, as well as any necessary repairs.

We estimated the cost based on the assumption that a portion of these inspections will be completed during the normal course of business. (responding to leaks or performing other inspections). However, the majority of these inspections must be completed during dedicated visits. Furthermore, some locations will require multiple attempts due to inability to access the building. The most challenging locations generally are the buildings that have apartment meters, which requires individual apartment customers to provide access within a building.

We initiate communication to the customer to inform them that the inspection is required and providing several ways to make a scheduled appointment. If the customer elects not to schedule an appointment, we proactively make a minimum of two cold call attempts to gain access. If the attempts are not successful, we send additional communication that informs the customer of a fee that will be assessed for failing to get their inspection done and with information on how to make an appointment. If that also goes unanswered, the customer will be assessed a fine and then a termination notification process will be initiated. Prior to termination of service, the customer may elect to make a scheduled appointment to comply and avoid termination. Therefore, for each individual gas meter, we may make as many as 3-4 attempts prior to completion. In addition, when in a building with apartment meters, we may pre-emptively make additional cold calls to customer as our goal is to ensure safety, compliance and avoid service termination.

To minimize the number of appointments, we are attempting, where feasible, to complete inspections while installing and replacing AMI enables NGDs. In addition, when other inside compliance work is being performed, we are proactively completing an opportunistic service line inspection. In some cases, this may result in inspections being completed more than the minimum required per a 5-year cycle. The significant challenge remains the apartment meter inspections which can't generally be bundled with other opportunistic visits.

The projected number of service line completions per year are listed below:

	2022	2023	2024	2025	2026
Inspections	121,130	107,630	114,470	104,023	100,447

Based on the results of the baseline, we anticipate finding (in the next inspection cycle):
~ 8.25% of the completed inspections result in a leak being discovered, which requires an emergency response and associated leak repair. The majority of which are anticipated to be associated with minor leaks on fittings, and not due to corrosion.
~ 1% of the completed inspections result in a corrosion repair being required

In order to reduce the percentage of no access we also included programmatic funding to raise customer awareness of and education on these inspections.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)
Con Edison recognizes the significant costs associated with complying with the mandated gas safety inspection program. We are taking every opportunity when in a customer's premise and have access, to perform the inspection. This can help increase compliance, reduce repeat visits and minimize the

costs associated with this program, thus enhancing the customers' experience. Most importantly, we are bundling the NGD installations with a service line inspection. In this manner, we can align the inspection cycles with the NGD install/replacement schedules. As the NGD device battery life and technology progresses towards a 10-year battery life, we would seek to increase the service line inspection cycles from a 5-year plan to a 10-year cycle plan to minimize the on-going O&M associated with such inspections.

2. Supplemental Information

Alternatives
Alternative 1:

Alternative 2:

Alternative 3:

Risk of No Action
The Company will be in violation of the state and federal gas safety codes.

Non-Financial Benefits
Company will be in compliance with the state and federal gas safety codes and as a result improve public and employee safety.

Summary of Financial Benefits and Cost
This program does not yield any financial benefit.

Project Risks and Mitigation Plan
N/A

Technical Evaluation / Analysis

		2022	2023	2024	2025	2026
SLI Leak Repairs Type 1 Leaks		398	354	376	342	330
SLI Emergency Response		9,994	8,880	9,444	8,582	8,287
Corroded Sleeves Repairs		1,211	861	572	520	502

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M				5,842	552	297
Regulatory Asset	4,077	15,753	22,139	29,259		69,719

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*		$ 39,742	$ 38,871	$ 37,623	
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor					
M&S					
Contract Services					
Other					
Overheads					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

	Capital
X	O&M

Gas Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: High Emissions Survey	
Project/Program Manager: **Lindsey Fitzgerald**	**Project/Program Number (Level 1):** NA
Status: ☐ **Initiation** ☒ **Planning** ☐ **Execution** ☐ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: 1/1/2023	**Estimated Date In Service: on-going**
C. Total Funding Request ($000) **Capital:** **O&M: $2,493**	**D.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M: n/a** **Capital: n/a**
E. 5-Year Ongoing Maintenance Expense ($000) **O&M: $2,493** **Capital:**	**F. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

This program is designed to reduce methane emissions by identifying the highest emitting natural gas leaks and prioritizing them for repair. This is designed to be complimentary to our current leak survey programs by utilizing advanced leak detection technology to survey areas of the distribution system not covered by the walking compliance survey in a given year. Resulting data is then gathered and analyzed for indications. All high emitting indications are then investigated utilizing approved leak detection technology in a timely manner. The survey is designed to cover areas of the system not covered by other existing programs, with the entire system covered by advanced leak detection within a three year period.

The use of advanced mobile leak survey provides additional tools to quantify emissions and prioritize locations for repair not available through other existing leak survey programs. This includes being able to drive an area and quantify the size of a methane indication. Doing so will provide another layer of emissions data to prioritize emissions reduction. To conduct the survey, the technology is attached to a passenger vehicle and a dedicated driver must drive at night. The driving protocol requires multiple passes over the course of two to three nights. Once all passes are completed, the data is downloaded and analyzed. Based on field trial data, we can expect 69% of the indications found to result in a natural gas leak with other indications being false positive or non-natural gas methane indications (such as sewer gas). The costs under this program include the annual cost for the advanced leak detection equipment, labor, supervision, and leak investigations.

Justification Summary:

Natural gas contains methane, a potent greenhouse gas, that once emitted into the air is 80 times more potent than carbon dioxide. To identify methane emissions in gas leaks and reduce emissions, Con Edison currently has several leak survey programs which meet or exceed code requirements, including a monthly mobile survey of all distribution main, multiple transmission leak surveys, walking leak surveys of business and non-business district services, and various special surveys. Once identified, leaks are repaired on average within a few weeks and far ahead of code requirements. Con Edison has also been the first to deploy Natural Gas Detectors (NGDs) across the territory to immediately notify the Gas Emergency Response Center (GERC) of natural gas leaks inside buildings. This comprehensive approach to leak identification and repair allows the Company to reduce fugitive methane emissions across the territory. The High Emissions Leak Survey Program will supplement these programs, target the highest emitting gas leaks, and further reduce emissions. Overall, this new program is designed to complement the other programs and add an additional layer of emissions reduction.

In addition to the environmental and operational benefits to this program, the U.S. Congress passed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act) which directed the Pipeline and Hazardous Materials Safety Administration (PHMSA) to promulgate rules for the use of advanced leak detection technologies on new and existing gas distribution pipeline facilities. This program will support the PIPES Act, and associated future regulations, through periodic surveys with advanced leak detection equipment mounted on a mobile vehicle.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)
This program also supports Con Edison's Clean Energy Commitment and New York State's Climate Leadership and Community Protection Act to achieve a reduction in greenhouse gas emissions.

2. Supplemental Information

Alternatives
Alternative 1: Maintain emissions reduction through existing programs.

Alternative 2: Increase the frequency of current mobile leak detection, which would come at a much higher cost.

Risk of No Action
No action would result in less emissions data and reduction

Non-Financial Benefits
The benefits for this program primarily come from the benefits to the environment. By limiting the volume of greenhouse gasses emitting into the atmosphere we slow climate change. Non-Financial benefits include emissions reduction and quantification through widespread use of advanced leak detection. Targeting the highest emitting leaks will make the fastest impact on emissions reduction. This program also identifies leaks potentially faster than if such a survey was not conducted; therefore, enhancing pipeline and public safety as well.

Summary of Financial Benefits and Cost

Costs	O&M	Description
Advanced Mobile Leak Detection	$237,800	Cost for technology, software payments go to clearing
Supervision	$66,231	$60 per hour, 168 days to complete the survey, management Employees go to clearing
Driver	$173,914	$129 per hour, 168 days to complete survey, weekly employees charge direct to O&M
Leak Investigations	$20,691	Investigate 100% of the LISAs, ~1 per 100 miles driven

$498,636

Project Risks and Mitigation Plan

Risk – The advanced mobile leak detection technology may not function properly.

Mitigation Plan – Proper maintenance and ongoing discussions with the manufacturer will mitigate any downtime for both the vehicle or data that must be downloaded from the cloud.

Risk – Adverse weather could limit driving.

Mitigation Plan – The technology cannot be used during periods of heavy precipitation. Planning ahead to anticipate poor weather will ensure driving time is maximized.

Technical Evaluation / Analysis

During the course of 2021, Leak Survey completed a field trial of this program. A vehicle equipped with advanced mobile leak detection drove over 1,700 miles. During that time, 16 high emitting indications were flagged by the software. All indications were investigated by qualified personnel with approved instrumentation; 11 of the indications (69%) were natural gas, the remaining indications were non-natural gas atmospheric readings with traces of methane such as sewer gas. On average, each indication had an emissions rating of 19 scfh. All indications were repaired in a timeframe ranging from 5 to 22 days, eliminating any additional methane from emitting into the air.

The 11 indications confirmed to be natural gas included the following leak types:

Type 1's	2
Type 2's	3
Type 3's	6
Total	11

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	$0	$0	$0	$0	$0	$0
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0	$0

Total Request ($000): $1,497,000

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*		$499	$499	$499	$499
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor					
M&S					
Contract Services					
Other					
Overheads					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

	Capital
X	O&M

Gas Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☐ Capital ☒ O&M ☐ Regulatory Asset**
Work Plan Category: ☒ Regulatory Mandated ☐ Operationally Required ☐ Strategic	
Project/Program Title: Inspection and Maintenance of Aboveground Gas Mains at Bridges	
Project/Program Manager: M. Cifelli	**Project/Program Number (Level 1): n/a**
Status: ☐ Initiation ☐ Planning ☐ Execution ☒ On-going ☐ ☐ Other: Submit Rate Case	
Estimated Start Date: On-Going	**Estimated Date In Service: not applicable**
E. Total Funding Request ($000) **Capital:** **O&M: $2,338**	**F.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
G. 5-Year Ongoing Maintenance Expense ($000) **O&M: $2,338** **Capital:**	**H. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This existing, annual bridge inspection program entails inspection and maintenance of natural gas piping at expansion joints, bridges, and stations as per Con Edison Specification G-11815 and State regulations covering aboveground gas pipelines throughout the CECONY service territory, pursuant to 16NYCRR Part 255, Sections 161, 317, 323, 479, 481, and 487. Pipeline inspections at submarine (waterway) crossings and expansion joints are also regulated mandates under this Program. On average, aboveground gas mains at 85 bridges are visually inspected each year with approximately 13 of these locations receiving detailed inspection and repair. Looking ahead to 2026, we see a large increase in the number of bridge inspections coming due on a cyclical basis. In fact, 137 inspections (62% above the norm) are scheduled to be inspected in 2026. This future, sharp increase in workload threatens to overrun the O&M budget and strain manpower resources. To avoid a sudden drain on Program resources, Con Edison proposes to preemptively move 30 inspections due in 2026 to be distributed over rate case years 2023, 2024, and 2025.
Redistributing these periodic inspections from 2026 will require reallocation of O&M funding into upcoming rate case years 2023 through 2025. This funding request of $1,104,750 represents the additional, reallocated funds necessary to complete 30 detailed bridge inspections earlier than 2026. The reallocated funds will supplement regular, ongoing O&M spending on this Bridge Inspection and Maintenance Program.
This request for reallocation of O&M funding is not made in response to a PSC audit.

Justification Summary:
Each gas pipeline that is exposed to the atmosphere, including those on bridges, is inspected at least once every three calendar years with intervals not exceeding 39 months as per Code of Federal Regulations CFR Title 49 192.481. Every 21 years, in addition to the regular 3-year visual inspections, Con Edison performs a detailed inspection and maintenance regimen for each bridge asset. Of the 137

total inspections coming due in 2026, 42 are detailed inspections (due on a 21-year inspection frequency) that may also involve routine maintenance work like coating and hanger repairs. The cost of inspecting and maintaining gas mains on bridges is escalating, especially for inspections at the 21-year mark due in large part to extrinsic factors beyond our control. High traffic control costs and limitations to working hours on highly congested roadways contribute to the rising costs. Aging facilities and bridge structures, together with the growing impact of climate change, have also placed an added financial burden on caring for gas mains at bridge crossings. The additional, reallocated O&M funding (described in this request) will ultimately serve to offset future O&M expenses while avoiding some of the higher cost of future main replacement.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Normally exposed gas mains, especially on heavily traveled bridges above major highways and at railroad crossings, are among the most inaccessible and vulnerable facilities that require extra levels of care and attention. Loss of a gas supply main, due to inadequate inspection/maintenance, at a bridge crossing will likely cause major service interruptions along with the potential for having a harmful impact on public safety. Long range budget planning (at least 5-year) is necessary to ensure adequate funding and manpower is available to meet the scheduled workload. With an unusually large number of inspections coming due in 2026, reallocation of O&M funds for 2023 through 2025 is strongly advised to lower the risks of scheduling too much inspection work in a single year. Higher O&M spending in rate case years 2023, 2024, and 2025, made possible with reallocated funding above historical levels, is necessary as a countermeasure to these corporate risks.

2. Supplemental Information

Alternatives

*Briefly describe reasonable alternatives and reason for rejection (e.g., costs, timing, etc.). **At least one is required.***

<u>Alternative 1 description and reason for rejection</u>

Inspection and maintenance of aboveground piping at bridges and stations is currently managed as a stand-alone, regulatory mandated program. If O&M funding continues over the next five years within historical spending limits, some inspections would have to be postponed or money/staffing diverted from other equally important programs to pay for a heavy inspection workload. Therefore, continuing forward on the current fiscal path challenges our ability to comply with mandatory inspection commitments, especially for 2026. For these reasons, keeping funding at existing levels was not selected.

<u>Alternative 2 description and reason for rejection</u>

<u>Alternative 3 description and reason for rejection</u>

Risk of No Action

Give the consequences, including enterprise risks that might arise by not doing the project/ program. Quantify the risks, if applicable.

<u>Risk 1</u>

If Con Edison's bridge inspection schedule is not adjusted to provide a more even distribution of the future workload and funds are not accordingly reallocated, pipeline safety could be compromised because available funding and manpower for inspection and maintenance of bridge piping in 2026 will not cover all 137 inspections. No action may lead to major delays in addressing maintenance issues.

Risk 2
No action could mean O&M funding for 2026 is diverted from other sources, forcing other programs to lower standards.

Risk 3
The Bridge Program remains underfunded and at-risk ultimately leading to a significant increase in future maintenance or main replacement costs.

Non-Financial Benefits

- Enhancing pipeline safety benefits a reputation of reliability and resilience.
- Ensuring 100% regulatory compliance is a solid corporate commitment.

Summary of Financial Benefits and Costs
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost
Over the next 5 years, O&M spending on the Bridge Inspection & Maintenance Program is projected to rise $2,406,203 above the $2,337,767 spent during the previous 5-year period. Based on the number of periodic inspections coming due, the 5-year O&M cost (2022-2026) for the Program is estimated to be $4,744,000. Reallocation of $368,250 per year for 2023, 2024, and 2025 is requested. The total reallocation is $1,104,750.
.
4. Basis for estimate

Cost estimates for projected O&M spending are based on priced items for inspection and maintenance from the existing bridge inspection & maintenance contract for NYC and Westchester County. Other variables used in cost calculations include the number of linear feet to be inspected as well as the number and type of bridge inspections coming due in each year, as determined from the 3-year and 21-year inspection schedules.

5. Conclusion
Since this Program is mandated by Federal and State regulations, continued funding is necessary. Additional O&M funding above historical levels is strongly advised, primarily because an overload of costly 21-year inspections coming due in 2026. A portion of these inspections can be done earlier. Reallocation of O&M funds is the prudent approach to lowering future cost pressures.

Project Risks and Mitigation Plan

Risk 1 Mitigation plan
The plan to prevent O&M cost overruns (above the 5-year spending plan contained herein) is to issue a new inspection and maintenance contract by March 31, 2022, with unit costs for inspection and maintenance maintained at or below present levels.

Risk 2 Mitigation plan
Work locations are widely dispersed across different operating areas. Starting in 2022, the Bridge Inspection and Maintenance Program will be managed by a central authority- Corrosion Control will ensure completion of all Program work throughout NY City and Westchester.

Technical Evaluation / Analysis

Detailed inspection reports and analysis for bridge assets, archived for the past 15 years, are documented in our Gas Information System GIS. These reports give a clear picture of the condition of bridge assets and inspection deadlines, as required for directing resources on a priority basis.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M	$19,793	$213,852	$704,875	$699,247	NA	$700,000
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*		$368 K	$368 K	$368 K	$368 K
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2021	2022	2023	2024	2025
Labor					
M&S					
Contract Services					
Other					
Overheads					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M	$700K	$700K	$1,127K	$907K	$1,288K
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. – GIOSP
Gas Distribution Peak Forecasting Model O&M

2022

1. Project / Program Summary

Type: ☒ Project ☐ Program	**Category: ☐ Capital ☒ O&M ☐ Regulatory Asset**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: Gas Distribution Peak Forecasting Model	
Project/Program Manager: Ildi Telegrafi	**Project/Program Number (Level 1):**
Status: ☐ Initiation ☐ Planning ☐ Execution ☐ On-going ☐ ☐ Other: ___________	
Estimated Start Date: 2023	**Estimated Date In Service: 2024**
A. Total Funding Request ($000) **Capital: 0** **O&M: $2,054 (2023-2026)**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

The Company is seeking to develop a firm gas distribution forecasting model that predicts firm gas peak day demand at design weather conditions. This new firm gas distribution forecast model will predict the peak day and peak hour firm gas demand for newly established districts within the gas distribution system in the Company's gas service territory. Using this new model, the Company will be able to project firm gas peak day demand at the neighborhood/district level as well as for any specific location of interest for the gas distribution system out 20 years.

This forecast will consider new business, new construction, demand response, steam-to-gas customers, energy efficiency (EE), distributed generation, oil to gas conversions, electrification of heating (EoH), and electrification of gas appliances.

The Company currently uses the Gas System and High Pressure (HP)/Transmission Regulator Forecasts to manage the gas transmission system, and these existing forecasts will be used along with other analytical tools to determine the boundaries for the firm gas peak distribution forecasting model at design weather conditions.

The new forecasting model will balance and reconcile with the System and HP/Transmission Regulator Forecasts to factor line loss into its predictions. The model will bridge these boundary forecasts with the existing daily forecast model and with assessments made by using the Synergi Distribution Hydraulic Model (Stoner). The existing Marquette Daily Gas Forecasting Model will be utilized to assist in the development. Connecting the existing models to the new model would allow the Company to balance output and forecasted demands by distribution location and to consider future changes to distribution and transmission piping. Such will enable enhanced planning and strategic pinpointing for non-pipe solutions.

This effort will result in:

- The development of a granular Excel based firm gas distribution peak day forecasting model
- A proven methodology and algorithms for transposing the firm gas transmission system and regulator peak day forecasts to distribution level district forecasts
- Mapping of the gas service territory to distribution districts

Con Edison Subject Matter Experts (SMEs) from the Gas Forecasting, Policy Integration Forecasting, Forecasting Services, Gas Engineering, and Gas Control Sections will team up with a vendor to develop the model, methodology, and mapping.

Justification Summary:

Given the Company's commitment to a clean energy future and the interests of its stakeholders, optimization and accurate planning for the gas distribution system is necessary. The effectiveness of the Company's plans for its gas distribution system has a direct impact on its gas customers. In addition, if the gas distribution system is not planned for properly, there is the risk of shedding gas load in certain areas. Identifying distinct areas of load growth will assist with pinpointing non-pipe solutions instead of the need for system reinforcements. Current gas policy is moving towards less development of gas supply. As such, the margins on the gas system will become tighter thus prompting the need for a more granular and longer-term forecasting model for the distribution system.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

This project would provide information vital in forming long-range goals and will address future changes to the gas distribution system over the next 20 years. Planning around accurate forecasts for firm gas peak day demand at the distribution district/neighborhood level reduces many risks.

Currently, the Company is assessing its plans for the gas system because of implications from climate policy. Legislation like the CLCPA and Local Law 97 advocate moving toward renewable energy sources and electrification. This project will enable enhanced planning and strategic pinpointing for non-pipe solutions, which aligns with these regulations/policies, and will be instrumental in the Company's strategic planning towards assisting energy customers achieve a green energy future.

2. Supplemental Information

Alternatives

The only alternative is to continue the current gas distribution forecasting process, which does not provide a long-range projection and does not entirely bridge the technical information between the existing long-term system and transmission regulator forecasts and short-term distribution forecasts.

Risk of No Action

Identifying distinct areas of load growth will assist with pinpointing non-pipe solutions instead of the need for system reinforcements. The risk of no action is that the Company may miss the opportunity to pursue Non-Pipe Alternatives on behalf of its customers.

Under the current policy landscape, not having a locational district and granular distribution long-term peak day forecasting model could lead to reduced reliability of the gas system over time. If the gas distribution system is not planned for with accuracy, there is the risk of shedding gas load in certain areas.

Non-Financial Benefits

Non-financial benefits of this project include the ability to predict peak demand at the distribution district level well into the future hence, the potential to leverage that information to develop distribution management strategies, the potential to improve the reliability of the system by optimizing engineering strategies, and the enhanced ability to achieve and comply with the New York City and State's long-term climate goals and regulations.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

This project will indirectly result in financial benefits, as mentioned below. Improved precision of gas distribution system modeling through a) statistical and other methodologies and b) inclusion of climate change driven policy will improve short- and long-term planning for system infrastructure that will lead to optimized operation and maintenance of the overall system. An optimized system maintains safety and reliability, leading to overall cost savings.

2. Major financial benefits

This new tool will optimize predicting firm gas peak demand in specific areas of the gas distribution system over a 20-year period. This improved and long-term gas distribution system forecast will lead to:

- Improved pinpointing and planning of Non-Pipe Solutions
- Maintaining normal planning for an increasingly dynamic distribution system consumption that is inclusive of the direction within climate change driven policy (i.e., CLCPA, Local Law 97, etc.)
- Avoided cost of building additional distribution system infrastructure
- Optimized planning of regulator operations to better maintain system pressure within operational requirements
- Improved planning towards optimal areas of critical investment in decreasing opportunities for leaks by operating at lower pressures

3. Total cost

The total cost of this project is $2.054 million, which will result in:

- The development of an Excel based firm gas distribution peak day forecasting model
- A proven methodology and algorithms for transposing the firm gas transmission system and regulator peak day forecasts to distribution level district forecast
- Mapping or the gas service territory to distribution districts

The primary cost components are forecast vendor professional services and incremental internal labor. This work is O&M and 3 additional Full Time Equivalents (FTE) are required in Rate Year 1. An estimated cost breakdown for Rate Year 1 is as follows:

- Consultant Professional Services: $1,166,000

- 3 FTE: $388,000
- Overheads: $120,000

In Rate Years 2 and 3, ongoing operations and maintenance on the model/methodology/mapping will occur, totaling $190,000 per year. This includes 1 FTE and associated overheads for the Gas & Steam Forecasting Section; and is anticipated for adjustments and calibrations required annually to update the mapping, to operate and maintain model, and to sustain accuracy.

4. Basis for estimate

Vendor quote and Company estimates.

5. Conclusion

This tool must be developed in order to continue to increase the accuracy, time horizon, and the granularity of the firm gas peak day distribution system forecast. The final product will facilitate more prudent planning and will help Gas Operations effectively adapt to emerging energy policy and regulations.

Project Risks and Mitigation Plan

See Technical Evaluation / Analysis below.

Technical Evaluation / Analysis

The Company has held several detailed discussions, internally and with a gas forecasting expert vendor, that have reviewed and assessed the scope and approach towards achieving an accurate firm gas peak demand distribution forecast model.

Project Relationships (if applicable)

N/A.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*		1,674	190	190	

Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor					
M&S					
Contract Services					
Other					
Overheads					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M		1,674	190	190	
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program