# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>I. INTRODUCTION</td>
<td>2</td>
</tr>
<tr>
<td>II. CAPITAL EXPENDITURES</td>
<td>20</td>
</tr>
<tr>
<td>A. Oil-To-Gas Conversion Program</td>
<td>35</td>
</tr>
<tr>
<td>B. Annual Capital Programs</td>
<td>55</td>
</tr>
<tr>
<td>C. Distribution Supply Main Projects</td>
<td>100</td>
</tr>
<tr>
<td>D. Transmission Programs and Projects</td>
<td>105</td>
</tr>
<tr>
<td>E. Storm Hardening Projects</td>
<td>122</td>
</tr>
<tr>
<td>F. Information Technology Projects</td>
<td>139</td>
</tr>
<tr>
<td>III. O&amp;M EXPENDITURES</td>
<td>156</td>
</tr>
<tr>
<td>IV. DEFERRAL ACCOUNTING/RECONCILIATIONS</td>
<td>159</td>
</tr>
<tr>
<td>A. Pipeline Safety Act</td>
<td>161</td>
</tr>
<tr>
<td>V. PERFORMANCE MEASURES</td>
<td>166</td>
</tr>
</tbody>
</table>
GAS INFRASTRUCTURE AND OPERATIONS PANEL - GAS

I. INTRODUCTION

Q. Would the members of the Gas Infrastructure and Operations Panel please state your names and business addresses?

A. Our names are Anthony Mancino, Cheryl Payne, Nick Inga, Jyotin Thaker, and Scott Kalberer. Our business addresses are 750 East 16th Street, New York, New York 10009 (for Mancino), 1615 Bronxdale Avenue, Bronx, New York 10462 (for Payne, and Kalberer), 4 Irving Place, New York, New York 10003 (for Inga), and 315 Saw Mill River Road, Valhalla, New York 10595 (for Thaker).

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 “Company”).

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

(Payne) I am the Chief Gas Transmission Engineer.

(Inga) I am the Director of the Gas Conversion Group.

(Thaker) I am the General Manager of Westchester Gas Operations.
I am the Section Manager of the Gas Work Management Group.

Please state your educational background.

A. I hold a Bachelor’s Degree in Engineering and a Master of Business Administration (“MBA”) Degree in Finance from Manhattan College.

I hold a Bachelor’s Degree in Chemical Engineering from the State University of New York at Buffalo, and an MBA in Finance from the University of Pennsylvania’s Wharton School. I have also completed Power Technology Institute’s (“PTI”) Power Technology Transmission Systems program.

I hold a Bachelor of Science Degree in Mechanical Engineering from Polytechnic University, and an MBA in Corporate Finance from Fordham University. I have also completed PTI’s Power Technology Distribution Systems program, and a Project Management certificate course through the Company’s program with Stony Brook University.

I hold a Bachelor of Science Degree in Electrical Engineering from Manhattan College. I have
also completed PTI’s Power Technology Distribution Systems program, and the Gas Technology Institute’s (“GTI”) Registered Gas Distribution Professional (”RGDP”) program.

(Kalberer) I hold a Bachelor of Science degree in Organizational Management from Manhattan College.

Q. Please describe your work experience.

A. (Mancino) I have been employed by Con Edison since 1991. From 1991 to 2004, I held positions of increasing responsibility in various groups within the Gas Engineering and Gas Operations departments. In 2004, I was promoted to Section Manager of the Gas Distribution Planning & System Reliability department, and in 2009 I became the Section Manager of Bronx Gas District Construction and in 2012 I was promoted to General Manager of Bronx Gas Operations. In 2013, I was moved to my current position as General Manager of Manhattan Gas Operations.

(Payne) I have been with Con Edison for 24 years, during which time I have held various management positions of increasing responsibility in Central
Operations, Central Engineering, Environment, Health & Safety ("EH&S"), Human Resources, and Gas Operations. From 1988 to 2000, I worked in Fossil Power Technical Operations, Fossil Power EH&S, and Corporate EH&S. From 2000 to 2004, I worked as the Section Manager of Steam Distribution Engineering in Civil/Mechanical Engineering. In 2004, I was promoted to Director of Con Edison’s Corporate EH&S Remediation department, where I worked until 2007, at which time I became Director of Human Resources Talent Management. In 2010, I moved to my current position where I serve as the Chief Gas Transmission Engineer. (Inga) I have been with Con Edison for 20 years. In 1992, I joined the Company’s Corporate Intern Program and have since held various positions of increasing responsibility, including Engineer of Gas Distribution Services, Gas Engineering; Operating General Supervisor of Manhattan Gas Operations Distribution Services; Section Manager of Treasury, Disbursements and Operations Support; Section Manager of Queens Gas Operations Distribution Services; Section Manager of
Bronx Gas Construction; and Section Manager of Enterprise Shared Services, Shared Services Administration. 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 my current position as Director of the Gas Conversion Group.

(Thaker) My service at Con Edison spans 34 years. During this time, I have held various management positions of increasing responsibility in Electric Distribution Engineering, Electric Construction, and Gas Operations. These positions include General Manager of Bronx/Westchester Electric Operations, Chief Electric Distribution Engineer, and my current position as General Manager of Westchester Gas Operations.

(Kalberer) I have been employed by Con Edison for 31 years. I joined the Company in 1980 as an Engineering Technician in Gas Operations. In 1988, I was promoted into management and have since held several positions
of increasing responsibility in Technical Operations, Gas Engineering, Gas Field Support, and the Gas Work Management Group, where I am currently the Section Manager.

Q. Please describe your current responsibilities.

A. (Mancino) In my current position as General Manager of Manhattan Gas Operations, I am responsible for construction, maintenance, and operation of the Company’s gas distribution system in New York County.

(Payne) In my current position as Chief Gas Transmission Engineer, I am responsible for transmission planning, system reliability, and contingency planning; transmission pipeline integrity; pressure control; gas control; and major project design and engineering.

(Inga) In my current position as Director of the Gas Conversion Group, I am responsible for leading, managing, and coordinating the Company’s program to connect new customers who choose to convert from other fuels, such as #4 and #6 fuel oils, to natural gas. As such, I am responsible for the marketing,
engineering, operations planning, project management, and customer liaison activities related to these types of conversions, which have recently seen a significant increase.

(Thaker) In my current position as General Manager of Westchester Gas Operations, I am responsible for construction, maintenance, and operation of the Company’s gas distribution system in Westchester County.

(Kalberer) In my current position as Section Manager of the Gas Work Management Group, I am responsible for evaluating Gas Operations’ present work practices and assessing the viability of managing future work using fully integrated systems and state-of-the-art work management software.

Q. Do you belong to any professional organizations?

A. (Mancino) Yes, I am currently a member of the Society of Gas Operators (“SOGO”), and a former member of various Northeast Gas Association committees.
Yes, I am currently a member of the American Gas Association’s ("AGA") Transmission Pipeline Operations Committee.

Yes, I am currently a member of SOGO, and a former member of various Northeast Gas Association committees as well as the Gas Utilization Advisory Group.

Yes, I am currently a member of the AGA’s Growth Task Force, and I am also a RGDP with GTI.

Yes, I am currently a member and former Director of the Northeast Gas Distribution Council.

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

Yes, I testified before the Commission in the previous gas rate case proceeding (i.e., Case 09-G-0795). None of us have previously testified before the Commission.

What is the purpose of the Gas Operations Panel’s testimony in this proceeding?
A. In order to continue providing the same high level of safety, service, and reliability to our natural gas customers, while also maintaining the ability to adequately and efficiently meet the growing demand for natural gas, the Company must continue to invest in its gas system. This testimony provides the basis for the Company’s planned gas-related capital expenditures and forecasted O&M expenses, as well as its proposals related to deferral accounting/reconciliations and performance measures, all of which are organized into the following major categories:

1. Capital Expenditures;
   A. Oil-to-Gas Conversion Program;
   B. Annual Capital Programs;
   C. Distribution Supply Main Projects;
   D. Transmission Programs and Projects;
   E. Information Technology Projects;

2. O&M Expenditures;

3. Deferral Accounting/Reconciliations; and


Q. Please summarize your testimony.
A. Our testimony will:

- Highlight the Company’s infrastructure replacement objectives, and discuss its long-term strategy and vision for Gas Operations, particularly with respect to Oil-to-Gas Conversions and the growing demand for natural gas;

- Identify major capital programs/projects to be conducted during the upcoming five-year period from 2013 through 2017, and introduce the associated “White Papers” that describe the scope of work, cost, schedule, and justification for each of these programs/projects. These programs/projects are grouped into the major categories listed in the answer to the previous question. It should be noted briefly here that the Company does anticipate having other gas-related capital expenditures as part of Public Improvement/Interference work during the term of the rate plan. These Public Improvement/Interference expenditures are not
addressed in this testimony by the Gas Infrastructure and Operations Panel. These expenditures instead are addressed in separate testimony provided by the Company’s Municipal Infrastructure Panel.

- Identify and describe the Company’s Storm Hardening initiatives and projects to mitigate the effects of coastal flooding.
- Describe the Company’s projected O&M expenses for the rate year ending December 31, 2014 ("Rate Year" or "RY1");
- Explain how several pending regulatory requirements pertaining to transmission pipeline integrity management and the Pipeline Safety Act of 2011, the full effects of which are unknown at this time, may affect the Company’s capital and O&M budgets;
- Propose a deferral accounting/reconciliation mechanism for capital expenditures, which also recognizes the potential for additional costs
associated with the Company’s efforts to comply with the Pipeline Safety Act of 2011;

- Propose a discrete accounting deferral/reconciliation mechanism for O&M expenses associated with the Company’s efforts to comply with the Pipeline Safety Act of 2011; and

- Recommend that there be no changes to the performance measure metrics established in Case 09-G-0795.

Q. How does the Company’s capital and O&M expenditure forecast compare to the Company’s historical expenditures?

A. Based on its current expenditure forecast, the Company is seeking:

- The same projected level of spending for most of the Company’s Annual Capital Programs and Distribution Supply Main Projects;

- Targeted spending to support:

  o the Oil-to-Gas Conversion Program;
o several elements of the Company’s Transmission Program, including costs needed for transmission pipeline integrity management; and
o several storm hardening initiatives; and
o several Information Technology projects, including the planned development of an integrated Work Management System; and
• A projected increase in O&M expenses from $88.2 million in the historic year to $90.4 million in the Rate Year generally attributable to:
o normalization of a non-recurring credit of $1.4 million received by the Company during the historic year from the New York City Department of Water Resources; and
o a projected increase of $800,000 to support new mandated in-line testing of gas transmission pipelines.

Q. Please describe Con Edison’s Gas Long Range Plan (“GLRP”).

A. Con Edison’s mission is to deliver gas to our customers safely and reliably, to demonstrate respect
for the environment, and to create a culture that encourages safety and develops our employees. This mission entails building and maintaining the gas infrastructure necessary for the transmission and distribution of gas, and providing meter reading, billing, and other services to our customers. The GLRP’s strategy to meet our mission focuses on improving cost-effectiveness while meeting safety and reliability objectives. Con Edison will minimize rate increases for our customers by efficiently managing our assets and investments and by pursuing cost-effective growth.

Q. Please provide an overview of the GLRP.

A. Con Edison’s long-term strategic objectives are to:

- Meet our customers’ expectations for safe and reliable gas service;
- Manage cost to keep rates affordable;
- Pursue incremental growth opportunities that are economically beneficial to our gas customers;
- Provide competitively-priced gas supply to our city-gates from diversified sources;
• Be stewards of investors’ economic interests through responsible financial management;
• Provide a safe and professionally satisfying environment for our workforce; and
• Support the environmental and economic development policy goals and betterment of New York and the communities we serve.

New pipeline and environmental regulations, coupled with favorable natural gas prices forecasted for the next 20 years will increase peak-hour demand system wide and require significant investment in capital infrastructure. We expect to invest $7.2 billion in equivalent 2011 dollars, equating to an average of $358 million per year, including investments to support gas customer demand growth. Even though #2 fuel oil users comply with the new environmental regulations, we have also seen a number of them convert to natural gas. A customer’s decision is important to Con Edison as it impacts our infrastructure planning and capital requirements.
Since we are seeing many fuel oil users convert to natural gas, we are faced with the challenge of meeting natural gas demand and infrastructure needs. We also need to ensure that we have adequate supply and pipeline capacity to reliably operate our natural gas system. Furthermore, we face the logistical challenges that come with managing a significant number of natural gas service requests and effectively coordinating the work. We must complete the work in a way that minimizes disruptions to the community, is cost effective, and does not contribute to higher customer bill rates for existing customers. To meet these challenges, we have growth strategies and marketing campaigns to bring customers onto the system as efficiently as possible. In addition, we support projects, such as the Spectra pipeline, that give us access to new sources of low-cost natural gas supply and bring needed diversity of deliveries to Manhattan in furtherance of our reliability objectives. To save on our own project costs and avoid street disruption, we plan to coordinate and integrate our street work...
with concurrent Con Edison or City projects. We have also created a new department to dedicate resources towards natural gas conversion efforts.

We will continue to seek new opportunities to reduce our customers’ gas energy costs. Our projections of customer bill impacts indicate a lower rate of increase than our recent historical trajectory. This will be accomplished by better project designs, more efficient management of assets, increased system usage, lower gas commodity costs and leveraging of technology. We will continue our efforts to achieve additional regulatory reforms with emphasis on lowering the tax component of customer bills. We will continue to address safety, system integrity, service reliability, regulatory requirements, and cost impact to maintain the critical gas infrastructure that supports the economic viability and security of New York City and Westchester County.

We understand that our product is vital for an energy efficient “green” future and, as such, we will use technology and the resources of our stakeholders to
meet the goals of customers, the system, the
environment, and the economy. It is in these ways
that we expect to successfully carry out our
objectives and implement our long range gas plan.

Q. How has the Company’s response to the cultural
barriers identified in the most recent Management
Audit affected the way you conduct your operations?

A. Gas Operations’ contributions to the Company’s efforts
to implement cultural imperatives are demonstrated in
many different ways, including the following examples:

- Open Communication – From daily job briefings, to
  monthly safety meetings and town hall meetings,
  Gas Operations communicates openly across all
  levels;

- Enhance Customer and Other External Relationships
  – The Oil-to-Gas Conversion program is designed
to make the conversion process more efficient and
less disruptive to customers; and

- Cost Management Consciousness – Our testimony
addresses efforts by Gas Operations to mitigate
costs and operate more efficiently.
II. CAPITAL EXPENDITURES

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

A. Con Edison manages a large, complex underground natural gas transmission and distribution system. This system consists of 4,360 total miles of gas main – i.e., 88 miles of mains operating at pressures greater than 125 psig (transmission mains) and 4,272 miles of mains operating at pressures less than 100 psig (distribution mains). Of the 4,272 miles of distribution mains, 650 miles are large-diameter Supply Mains that connect the transmission system to 3,622 miles of smaller-diameter distribution mains which deliver natural gas to our customers at a variety of pressures, as detailed below:

- 32% is high-pressure;
- 9% is medium-pressure;
- Less than 1% is intermediate-pressure; and
- 59% is low-pressure.
Q. Is the Company seeking an increase in its capital expenditures?

A. Yes. As discussed in our testimony, the Company has made significant efforts to mitigate its capital expenditures. To this end, the Company is proposing to maintain capital expenditures at current levels for many of its Annual Capital Programs and Distribution Supply Main Projects. The Company is, however, seeking targeted expenditure increases in support of several of its key capital programs and projects.

Q. What are the primary drivers behind these targeted capital expenditure increases?

A. The primary drivers behind the Company’s targeted capital expenditure increases are:

- Infrastructure expenditures needed to support the Oil-to-Gas Conversion Program;
- Expenditures needed to support certain elements of the Transmission Program, including regulatory requirements relating to transmission pipeline integrity management; and
Expenditures needed to support certain Information Technology Projects, including Gas Operations’ planned development of an integrated Work Management System.

Q. Why is it necessary for the Company to maintain its present level of capital expenditures for many of its Annual Capital Programs and Distribution Supply Main projects?

A. A gas distributor since 1823, Con Edison currently provides natural gas service to more than one million customers in Manhattan, the Bronx, Queens, and Westchester County. The Company’s system comprises over 4,300 miles of gas mains and over 383,000 service pipes that transport more than 200 million dekatherms of natural gas each year. Con Edison’s gas system is a vital part of the energy infrastructure in the areas it serves and, for this reason, is crucial to the economic well-being of the City of New York, Westchester County, and New York State at large. As is the case with other critical pieces of infrastructure - such as roads, bridges, and water
mains – Con Edison’s gas distribution system must be continually maintained and upgraded in order for it to remain capable of providing the safe and reliable gas service that its customers have come to expect. In particular, the Company’s residential and commercial customers rely on the vitality of the gas delivery system to provide the necessary fuel for their space heating, water heating, cooking, processing, air conditioning, and other needs. In addition, major gas customers, including hospitals, public housing authorities, and schools, all play a critical role in serving the needs of the public throughout New York City and Westchester County. In addition, by providing the infrastructure needed to deliver the millions of dekatherms of natural gas that are relied upon by the many in-City electric generating plants and other steam/steam-electric production facilities, Con Edison’s gas system is a necessary part of the region’s electric and steam systems. As such, the Company’s gas delivery system provides the fuel for the electric and steam energy
that heats, lights, and powers the area’s residences, businesses, high-rise elevators, and mass transit system.

Moreover, as the primary alternative to fuel oil, the Company’s natural gas delivery infrastructure offers residents throughout its service territory significant environmental benefits by allowing customers to avoid the higher level of harmful emissions that would result if adequate supplies of natural gas were not readily available.

For these reasons, the Company needs to maintain its present level of capital expenditures for many of its Annual Capital Programs and Distribution Supply Main Projects. The Company’s plans to replace and/or upgrade its piping identified for replacement, equipment, and facilities, as outlined in this filing, are necessary for it to be able to continue providing the safe, reliable, and clean-burning gas service that Con Edison’s customers depend on.

Q. Please summarize your projected annual capital spending for the period of 2013 through 2017.
A. The Company’s projected annual capital spending for the period of 2013 through 2017 is as follows: $436.9 million in 2013; $459.6 million in 2014; $513.7 million in 2015; $517.4 million in 2016; and $449.1 million in 2017. Later in this testimony we will describe the purpose of each capital program/project and introduce detailed “White Papers” that explain the scope, cost, and schedule of each program/project.

Overall, the Company has prioritized its capital work in a manner that is designed to maintain current levels of safety, service, and reliability. Accordingly, Con Edison will continue programs to replace 50 miles annually of gas pipe prioritized-for-replacement ("PPR"), and to complete all mandated safety inspections and resulting repairs/replacements. Finally, in the area of Oil-to-Gas Conversions, the Company is proposing a level of annual capital spending that will allow for the installation of new gas mains, services, and district regulator stations, all of which are necessary to meet the significant
expansion of natural gas use that is currently anticipated.

Q. Please describe the Company’s gas infrastructure replacement objectives and how these objectives relate to the Company’s long-term strategy for Gas Operations.

A. The Company’s gas system is a “zero contingency” system, meaning that a single point of failure can result in the loss of at least some customers. In order to minimize potential customer loss at all times, the Company has developed written Gas Specifications identifying the Company’s gas infrastructure replacement objectives, which are as follows:

- To maintain the reliability of the gas Transmission and Distribution systems;
- To maintain the reliability of Distribution Supply Mains in the event of an outage to a gate station or critical regulating station; and
- To reduce the potential of incoming gas leaks each year, and to maintain the system at optimal
operating pressures while satisfying applicable
design basis conditions.

We adhere to these objectives in designing our system
and in making infrastructure replacement decisions.
As such, these objectives have become a central
feature of our daily tasks and the Company’s long-term
strategy for Gas Operations.

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
systems to meet the requirements of 16 NYCRR Part 255
and the load requirements of all firm customers 365
days per year, 24 hours per day, assuming conditions
at or above the design day temperature criteria of 0°F
Fahrenheit and a low temperature of -10 °F (i.e.,
design hour).

Q. Please summarize the guidelines used by the Company
for replacement of distribution mains and services.

A. We utilize the following design criteria for
replacement of distribution mains and services:
• Small-diameter bare steel and unprotected coated steel mains are replaced each year in quantities that are sufficient to achieve a long-term planned reduction of incoming leaks;

• Cast iron distribution mains are replaced whenever:
  o Criteria for interference (i.e., criteria for undermining and angle of repose – see 16 NYCRR 255.756) are met in accordance with Company Gas Specifications; and
  o Criteria for replacement/retirement are met in accordance with Company Gas Specifications

• Intermediate-pressure cast iron distribution mains that are 8” or smaller are replaced or downgraded to low-pressure, whenever possible;

• Replacements of existing Supply Mains and installation of new Supply Mains must be able to supply local distribution mains in the event of a loss of one source of supply, including either a gate station or major regulating station; and
Low-pressure distribution mains are reinforced prior to their extremity points reaching 4” of water column during a design hour.

Q. What are the design criteria used by the Company for selecting replacement of Distribution Supply Mains?

A. Con Edison’s gas distribution system consists of more than 4,300 miles of mains in Manhattan, the Bronx, Queens, and Westchester. Within this total are key gas mains and distribution regulator stations that represent approximately 650 miles of critical facilities known as “Distribution Supply Mains” or simply “Supply Mains.” These mains are the “backbone” pipes that transport gas to major load pockets and/or other regulator stations that feed lower-pressure areas. In many cases, these Supply Mains represent single sources of supply into distribution areas that have no backup contingency in the event of a damage or leak that requires the full shutdown of the Supply Main and which could result in customer outages. Most of these Distribution Supply Mains are large-diameter (i.e., 8” through 30”) and are located under
major roadways. Because of the significant time and expense associated with replacing these facilities, we segregate these projects from smaller-diameter distribution main replacements and then prioritize them in a manner that results in the maximum cost-benefit possible in terms of safety and system reliability. For example, in 2012 we replaced a 1,000-foot section of 8” steel main with 12” polyethylene main on Bedford Road in Westchester County. This section of Supply Main, which connects the Hawthorne and Yorktown high-pressure systems, was identified because it met several replacement criteria – i.e., it eliminated existing leaks and increased the capacity of a critical Supply Main. By replacing this section and eliminating the existing leaks, we were able to mitigate possible safety issues, avoid future costs associated with emergency response and leak repair, and incrementally increase system capacity to allow that section of Supply Main to operate at lower-pressures, which improves our ability to supply firm gas customers in the event of an interruption.
Q. Are there other guidelines or factors relied upon by the Company in selecting capital improvements?

A. Besides the infrastructure replacement objectives highlighted above, the Company is guided by federal, state, and local regulations, and also by Gas Operations’ long-term objectives of maintaining reliable service to its customers and improving safety by reducing incoming gas leaks. Finally, the Company is guided by its plans to continue replacing 50 miles per year of PPR. This level of replacement is in line with an independent study indicating that the replacement of 50 miles of PPR per year is optimal for lowering incoming leaks and repairs over the next 25 years. The optimal level is the point at which the incremental replacement footage no longer yields an increasing benefit in terms of reduced incoming leaks and associated repairs.

Q. In addition to the programs that involve the replacement of leaking gas main and PPR, does the Company have other annual distribution capital
programs that are projected for the upcoming five-year period?

A. Yes. These programs include capital expenditures associated with the replacement of leaking services and other capital improvements proposed for the Company’s LNG Plant, Tunnels, and Pressure Control assets. All of these capital expenditures are discussed in the Annual Capital Programs portion of this testimony and are also presented in Exhibit ___ GOP-1, page 1.

Q. Was the document entitled “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2013-2017 GAS CAPITAL PROGRAMS,” prepared under the Gas Operations Panel’s direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (GOP-1)

Q. Please describe this exhibit.

A. This exhibit summarizes Gas Operations’ 5-year capital expenditure estimates for the years 2013 through 2017. These capital expenditure estimates are organized into the functional areas shown on the exhibit. As can be
seen, the Company will continue its annual and multi-year capital programs to improve the infrastructure of its gas system. As part of these efforts, the Company is concentrating on prioritized asset replacement and reinforcement to maintain its levels of service, reliability, and safety. We are also planning capital expenditures to support our Oil-to-Gas Conversion Program and several elements of our Transmission and Information Technology Programs, including Gas Operations’ planned development of an integrated Work Management System.

Q. What measures does the Company use to complete its programs and projects at the lowest reasonable cost?

A. The Company utilizes several controls for the efficient and cost-effective implementation of its capital and O&M work. These measures include the use of competitive bidding, project management techniques, cost management oversight tools, and innovative technologies. For example, on larger system reinforcement projects, such as the installation of a new regulator station, a Company project manager is
assigned to oversee the project from design through completion. This is done so that best practices are used, schedules are developed and met, and any and all delays are resolved as expeditiously as practicable.

In addition, prior to construction, these larger projects are assigned to a contractor after a multi-party competitive bidding process that includes the use of bid-check estimates to verify that the lowest-price is in line with historical costs.

On smaller main replacement projects, “area contractors” work jobs under pre-awarded unit price contracts that allow the Company to closely control and manage installation costs. Engineers are also assigned to each operating area to prioritize main replacement projects and identify opportunities to repair – rather than replace – the mains involved, as well as incorporate cost-efficient innovative technologies, where appropriate. One such innovative approach is the use of various methods of “trenchless technology” to reduce excavation and restoration costs during main replacement.
A. Oil-To-Gas Conversion Program

Q. What choices do Con Edison’s customers have to meet their heating needs?

A. Con Edison’s customers have a number of choices to meet their heating needs. Within our service territory, our customers primarily choose among three options: heating oil; natural gas; and/or steam, which is available only in Manhattan south of 96th Street. Electric heating is also a choice but is generally not a prevalent heating method in the Company’s service territory.

Q. Please summarize the Company’s recent experience regarding customer interest in natural gas.

A. As a result of cost savings due to falling natural gas prices, together with New York City’s recently-enacted PlaNYC Clean Heat regulations (see 15 RCNY § 2-15), a significant number of fuel oil users have contacted the Company to convert to natural gas service or to find out more information regarding the conversion process.
Q. Please provide additional background regarding the PlaNYC Clean Heat regulations.

A. In 2007, New York City’s Mayor Michael Bloomberg launched PlaNYC 2030. The purpose of this plan was to “…prepare the city for one million more residents, strengthen our economy, combat climate change, and enhance the quality of life for all New Yorkers.”

According to Mayor Bloomberg, the 1% of buildings in New York City (approximately 10,000 in total) that rely on #4/#6 fuel oil (“heavy fuel oil”) have been responsible for producing approximately 86% of the City’s soot pollution, an amount that exceeds the total soot emitted from all cars and trucks in the City combined.

In April 2011, after two years of stakeholder engagement, Mayor Bloomberg announced that the City had adopted new PlaNYC Clean Heat regulations to improve air quality (see 15 RCNY § 2-15). The new regulations, which specifically target heavy fuel oil usage, established the following limitations:
Effective immediately, no new boiler or burner installations will be permitted to use #4 or #6 fuel oil, and instead must use one of the cleanest fuels (i.e., ultra-low sulfur #2 fuel oil, biodiesel, natural gas, or steam);

Beginning July 1, 2012, existing buildings that use #6 fuel oil must convert to a cleaner fuel (i.e., low-sulfur #4 fuel oil or cleaner) before their 3-year certificate of operation expires. This will result in a full phaseout of #6 fuel oil by mid-2015; and

By 2030 or upon boiler or burner replacement, whichever is sooner, all buildings must convert to one of the cleanest fuels (i.e., ultra-low sulfur #2 fuel oil, biodiesel, natural gas, or steam).

The significant increase in customer requests to convert from fuel oil to natural gas began after New York City announced these new Clean Heat regulations in April 2011.
Q. Approximately how many buildings within Con Edison’s service territory that are currently burning heavy fuel oil could potentially convert to natural gas?

A. There are approximately 7,000 buildings in Con Edison’s New York City natural gas service territory that currently burn heavy fuel oil, with the greatest density of these buildings being in Manhattan and the west Bronx. The other 3,000 buildings are located in National Grid’s natural gas service territory in Staten Island, Brooklyn, and part of Queens. Approximately 4,000 out of the 7,000 buildings that are within Con Edison’s natural gas service territory are located in Manhattan, where our natural gas and steam service territories overlap.

Q. How many #4/#6 fuel oil users have submitted oil-to-gas service conversion requests since New York City’s new Clean Heat regulations went into effect?

A. From May 2011 to June 2012, nearly 2,100 oil-to-gas service conversion requests were received by the Company. These requests were specifically from customers looking to convert from #4/#6 fuel oil to
natural gas. Of these 2,100 requests, approximately 1,500 were from customers using #6 fuel oil and approximately 600 were from customers using #4 fuel oil.

Q. What challenges does the Company face with meeting the significant increase in customers who are interested in converting to natural gas?

A. The Company faces three primary challenges with meeting the significant increase in customers who are interested in converting to natural gas. First, the Company must endeavor to make an adequate supply of natural gas readily available to meet the increasing customer demand. This involves arranging and maintaining adequate gas supply and interstate pipeline transmission capacity to deliver the gas to Con Edison’s distribution system. The Company’s efforts in this area are addressed in separate testimony provided by Company witness Carnavos (Gas Supply).

Second, the Company must complete the gas infrastructure improvements that are needed to both...
deliver the gas to newly converted customers and to reinforce the overall gas system so that it can handle the increased load.

Finally, the Company faces logistical challenges with managing the significant number of gas service conversion requests and coordinating the associated infrastructure work. These logistical challenges arise, at least in part, because the necessary infrastructure work must be completed in a safe, timely, and cost-effective manner that minimizes potential impact to the public.

Q. What is being done to meet the above-described challenges?

A. The Company has developed a comprehensive business plan and marketing campaign designed to make the Oil-to-Gas Conversion process as smooth and efficient as possible. In addition, the Company is strongly supporting projects that will bring additional natural gas supply into our service territory (e.g., the Lower Manhattan Interconnection Project). Furthermore, wherever possible, the Company is working to
coordinate and combine its oil-to-gas infrastructure work with other Con Edison- and New York City-related infrastructure work so as to minimize cost and potential impact to the public. To facilitate these efforts, the Company has created the “Gas Customer Conversion Group,” a new department dedicated solely to coordinating natural gas conversion activities.

Q. How many #4/#6 fuel oil-to-gas service conversions did the Company complete in calendar year 2011?

A. In 2011, the Company completed 243 #4/#6 fuel oil-to-gas service conversions.

Q. How many #4/#6 fuel oil-to-gas service conversions has the Company completed so far in 2012?

A. Through September 30, 2012, the Company has completed 291 #4/#6 fuel oil-to-gas service conversions.

Q. How does the Company reinforce its system to meet increasing customer demand?

A. There are three techniques Con Edison uses to reinforce its system to meet increasing customer demand. These techniques are as follows:
• Install distribution regulator stations, where possible. In areas with nearby high-pressure gas mains, we can install regulator stations and associated main ties/extensions to provide additional supply points into the low-pressure distribution system;

• Replace smaller-diameter distribution mains with larger-diameter mains to provide additional capacity; and

• Install new distribution mains to supply new customers.

Q. What purpose do gas regulator stations serve?
A. Regulator stations are gas distribution system assets that are strategically located to provide an additional source of supply and which also allow us to utilize existing mains instead of having to open up large trenches and replace or install significant portions of gas main.

Q. How much does the Company project it will spend in capital dollars during the upcoming five-year period
to reinforce its natural gas distribution system to meet the increasing customer demand?

A. As presented in Exhibit __ GOP-1, page 1, we currently anticipate the following capital expenditures to support oil-to-gas system reinforcement efforts during the upcoming five-year period: $107.7 million in 2013; $90 million in 2014; $98.9 million in 2015; $84.9 million in 2016; and $47.6 million in 2017. These system reinforcement efforts will involve installing new regulator stations, replacing existing mains, installing new mains, connecting new services, and installing new meters to converted customers. In all cases, we will pursue the lowest-cost infrastructure solutions that provide the required levels of safety and reliability. This work is explained in detail in our “White Papers,” which are included in Exhibit __ GOP-2, pages 3 through 5, 16 and 17, and 30 and 31.

Q. Please describe the comprehensive business plan that Con Edison has designed for meeting the anticipated increase in customer demand?
A. Con Edison’s objective is to convert as many fuel oil users as possible to natural gas. Our comprehensive business plan for meeting the anticipated increase in customer demand is to do this in a manner that is efficient and cost-effective for both the Company and its other firm customers. To achieve this, we need to maximize the efficiency of our work by finding synergies with other construction projects around our service territory, and by capturing economies of scale by creating “clusters” that allow us to maximize the number of “zero-cost” (cost to customer) connections. We plan to expand the use of “clustering” – an approach that involves extending or expanding existing common mains to meet new or increased customer needs – to geographic areas where multiple main extensions and expansions can promote area growth. Doing so will enable us to manage the gas expansion process more effectively by leveraging both capital costs and converting customer revenue on the basis of larger geographical areas, rather than on the basis of individual customers. Consistent with our plan, we
will work to minimize “external” capital construction costs (i.e., costs for Company facilities) for new customers in accordance with our “zero-cost” (cost to customer) target. We are taking this approach because we recognize that “external” capital construction costs are one of the two financial factors involved in a customer’s decision to switch to natural gas, the other financial factor being the customer’s “internal” conversion costs (i.e., costs to convert internal customer equipment), which can be significant. We will also be seeking some tariff modifications in a separate filing to address area clustering.

Q. Please continue.

A. Our plan estimates the conversion of 50% of the heavy fuel oil users in our service area by 2019. This provides for a phased build-out of the infrastructure extensions and reinforcements that are necessary to accommodate these new customers. We have designed this phased build-out so that it makes engineering and business sense. We will build higher-density areas sooner; build infrastructure in the order that is most
cost effective; and, whenever possible, we will minimize construction disruptions to the community. Over this period of time, we plan to make significant capital investments in 32 geographic areas/90 geographic sub-areas in Manhattan, the Bronx, and Queens, all of which have been strategically selected. The plan and schedule that we have developed for this capital construction work will guide our phased build-out activities over the upcoming five-year period, and necessary adjustments will be made based on changes in anticipated customer demand.

Q. Why are area growth and clustering important strategies for meeting increased customer demand?

A. Area growth and clustering are important strategies because they allow overall per-customer connection costs to be lowered, while enabling the Company to increase construction efficiency and minimize community disruption. These strategies also provide the Company with opportunities to analyze aggregated customer revenue and capital connection cost data in
an effort to identify additional ways of lowering customer connection costs.

Q. Why do some customers receive high connection costs in order to convert to natural gas?

A. Conversion costs can be broken into two categories: internal costs and external costs. Customers are responsible to determine and pay for all the internal conversion costs within their property line (e.g., gas piping, equipment and chimney liner costs), and may also be responsible for some or all of the external costs, which include the capital infrastructure costs needed for Con Edison to provide and install gas facilities to the building's property line. Based on information provided in each service conversion request, Con Edison provides a cost estimate for the external costs that are the customer's responsibility. External connection costs are based on several factors: (1) proximity to a capacity-adequate gas distribution main; (2) entitlements based on service type selected (i.e., firm or interruptible); and (3) revenue generated from service.
Q. Please describe how capital and O&M expenditures and revenues associated with customers who convert from #4/#6 fuel oil to natural gas are treated under the current Gas Rate Plan.

A. Expenditures (both capital and O&M) and revenues related to #4/#6 oil-to-gas conversions are being deferred pursuant to the mechanism established in the current Gas Rate Plan.

Q. Please describe how the Company proposes to treat revenues from customers who convert from #4/#6 fuel oil to natural gas during the Rate Year.

A. The Company proposes to treat these revenues through the current revenue decoupling mechanism ("RDM") process that is being used for all customers. As discussed by the Company’s Gas Forecasting Panel, projected revenues from customers to be added as a result of oil-to-gas conversions will be included in establishing new revenue-per-customer ("RPC") targets.

Q. How does the Company propose to treat the deferrals (costs and revenues) accrued under the current Gas Rate Plan associated with #4 and #6 fuel oil-to-gas
conversions?

A. The treatment of deferrals for revenue and capital and O&M expenditures under the current Gas Rate Plan will be addressed in the Company’s Gas Accounting Panel Testimony.

Q. What ongoing outreach initiatives are in place to educate potential natural gas customers?

A. We are advising customers that the Gas Conversion Group can be reached at 1-800-643-1289, and that information can be obtained at www.coned.com/gasconversions. This website includes listings of buildings that can convert to gas heating without any external costs on the customer. There are also several frequently asked questions (FAQs) available at www.coned.com/gasconversions/faq.asp to assist customers through the conversion process. Con Edison has also made other conversion information publicly available on its website (www.coned.com), and customers can always call 1-800-75-CONED (1-800-752-6633) to request information. The Company’s website explains how potential customers can obtain natural
gas service, and also contains the necessary conversion application, and Company contact information. It also contains the Gas Blue Book which explains what the Company will provide depending on the customer’s distance to existing infrastructure.

Q. In light of the City’s new Clean Heat regulations phasing out the use of #4 and #6 fuel oils, is the Company terminating its oil-to-gas conversion incentive program (“Conversion Incentive Program”)?

A. No. The Company proposes to continue the Conversion Incentive Program at the same level of funding provided under the Company’s current Gas Rate Plan (i.e., up to $1.465 million annually). The Company is also seeking to continue recovering the incentives payments through the monthly rate adjustment (“MRA”).

Q. Please describe the Conversion Incentive Program.

A. The Conversion Incentive Program is set forth in detail in Appendix B of the Company’s Gas Sales and Transportation Operating Procedures (“GTOP”). In general, under the Conversion Incentive Program, the Company provides financial incentives to residential
and commercial customers to encourage their conversion from oil use to gas heating use. The incentives, typically in the form of a cash rebate, are intended to defray a portion of an applicant’s conversion or installation costs. The $1.465 million annual funding for the program is the maximum amount that the Company may collect through the MRA. If the Company provides incentives in excess of the $1.465 million, the Company absorbs the excess. If the Company spends less than $1.465 million, then only that lesser amount is collected from customers through the MRA.

Q. Why is it appropriate, given the stimulation of oil-to-gas-conversions by the City’s new Clean Heat regulations and the favorable current price of gas in relation to oil that you have indicated, to continue the Conversion Incentive Program?

A. Continuing the Conversion Incentive Program is appropriate in these circumstances because: (1) the City’s Clean Heat regulation, which requires the phasing out of #6 fuel oil by 2015 and #4 fuel oil by 2030, does not impact the majority of the Conversion
Incentive Program participants who are in the 1-4 family dwelling market segment and heat with #2 fuel oil; (2) the current favorable price of gas in relation to the price of oil, a relationship that may change in the future, is only one of several factors that bear on the decision of whether to convert from oil to gas; (3) the City’s regulation does not preclude compliance by a conversion from either #6 or #4 fuel oil to #2 fuel oil instead of gas; (4) the City’s regulation has no effect outside of the City, while the Conversion Incentive Program is applicable throughout the Company’s entire service territory, with approximately 40% of the program participants coming from Westchester County; and (5) customers receiving an incentive for an oil-to-gas conversion are required to purchase high efficiency equipment, thus the conversion incentive contributes to the State’s environmental policy goal of reducing carbon emissions.
Q. Other than the favorable price of gas in relation to the price of oil, what other factors bear on the decision of whether to convert from oil to gas?

A. Although the environmental benefits of the use of gas rather than oil might be valued by a customer, the Company has found the upfront cost of the conversion to be the most significant barrier to a customer proceeding with a conversion. Based on information gathered from participants in the Conversion Incentive Programs, the average cost of an oil-to-gas conversion in the Con Edison service territory for a service that is adequate for a 1-4 family dwelling is approximately $9,000, which is the full responsibility of the customer. This cost is substantially higher than simply upgrading to more efficient equipment, as it involves not only replacing the heating equipment, but also the supporting internal infrastructure (i.e., piping).

Q. To what extent may the cost of conversion be mitigated by sources of funding such as the New York State
Energy Research and Development Authority ("NYSERDA")
or tax credits?

A. NYSERDA administers its fully-encumbered Multifamily Carbon Emissions Program, funded with Regional Greenhouse Gas Initiative ("RGGI") dollars, with eligibility limited to buildings that heat with #6 fuel oil and that convert to #2 fuel oil or natural gas. NYSERDA may provide some incentives, through its Energy Efficiency Portfolio Standard ("EEPS") programs, as well, to install certain high-efficiency gas equipment above the standard code requirements. Certain tax credits may be available and the Company encourages customers to inquire with their accountant or check on applicable state and federal websites for tax credit availability.

Q. Does the Conversion Incentive Program Impact the Operation of the Company’s EEPS Programs?

A. Yes. The Company requires that customers receiving incentives through the Conversion Incentive Program install high-efficiency equipment when they convert, since otherwise customers might install standard
efficiency equipment, which would likely be an energy efficiency “lost opportunity” for the life of the equipment. The Conversion Incentive Program effectively acts as an entry point for conversion customers to the Company’s EEPS programs, particularly the 1-4 family residential programs.

B. Annual Capital Programs

Q. Please describe the Annual Capital Programs category of capital expenditures.

A. The Company’s Annual Capital Programs include infrastructure replacement to address leaks and other known equipment issues; to upgrade undersized piping, which otherwise must be operated at higher-than-preferred pressures; and to replace PPR in an effort to further reduce incoming leaks and avoid future gas emissions. In accordance with these objectives, the Company pursues programs under the following categories of Annual Capital Programs:

* Gas Distribution-1 (“GD-1”) - This program involves the annual installation or replacement
of mains, services, meters, and regulators, for both traditional new business (i.e., other than #4/#6 conversions) and gas system reinforcement purposes, and also the emergency replacement of cast iron low-pressure mains;

- Gas Distribution-3 (“GD-3”) - This program involves the annual replacement of corroded and leaking services;

- Gas Distribution-4 (“GD-4”) - This program involves the annual replacement of corroded steel mains;

- Gas Distribution-5 (“GD-5”) - This program involves the annual identification of coated unprotected steel mains and services, and the installation of cathodic protection to extend the useful life of such pipe;

- Gas Distribution-11 (“GD-11”) - This program involves the annual replacement of small-diameter (i.e., 4”, 6”, and 8”) low-pressure cast iron mains; and
Gas Distribution 29 ("GD-29") – This program involves the annual replacement of 2" high-pressure steel mains where mechanical couplings have the potential for leakage.

Q. Please describe the specific Annual Capital Programs that the Company is proposing to continue.

A. The Annual Capital Programs that the Company is proposing to continue are as follows:

- **Traditional New Business** – This includes mains and services for all new construction, and all new fuel oil-to-gas conversions, excluding #4 and #6 fuel oil-to-gas conversions in New York City;

- **System Reinforcement** – This includes winter load relief and service replacements due to main replacements;

- **Replacement of Prioritized Pipe** – This involves replacement of small-diameter (8" or less) cast iron and unprotected steel main under the GD-1, GD-4, GD-11, and GD-29 programs described above;
Replacement of Gas Services – These replacements fall into the GD-1 and GD-3 programs described above;

Meter Installations – These installations fall into the GD-1 program described above;

Cathodic Protection of Steel Mains – These activities fall into the GD-5 program described above; and

#4/#6 Fuel Oil-to-Gas Conversions – These conversions are being tracked separately from the #2 fuel oil-to-gas conversions that are included as part of the GD-1 program described above.

Additional information is presented in separate “White Papers” that describe the scope of work, cost, schedule, and justification for each of these programs.

Q. Have you prepared an exhibit containing the “White Papers” described above?
A. Yes, we have.

Q. Were the “White Papers” in this exhibit prepared under the Gas Operations Panel’s direction and supervision?
A. Yes, they were.

Q. Please provide more details concerning the Company’s New Business Program.

A. As explained in Exhibit ___ GOP-2, pages 1 and 2, the New Business Program provides new facilities (i.e., gas mains and services) in response to customer requests for new gas service or increased gas usage. This program includes #2 fuel oil-to-gas conversions. As presented in Exhibit ___ GOP-1, page 1, we currently anticipate the following capital expenditures to support the New Business Program during the upcoming five-year period: $42.3 million in 2013; $42.6 million in 2014; $44.1 million in 2015; $44.1 million in 2016; and $45.7 million in 2017. Our projected expenditures for this program do not include increases to support #4/#6 fuel oil-to-gas conversions, which are being addressed separately.

Q. Please explain the increase in projected New Business Program expenditures between 2013 and 2017.
A. Although we have seen a reduction in the number of new business services installed annually – from historical levels of approximately 3,000 per year – we currently project a steady increase in the number of #2 fuel oil-to-gas service conversions that will be completed during the upcoming five-year period. This increase is attributable to the low commodity cost of natural gas compared to the price of oil.

Q. Have there been changes in residential space-heating equipment that have an impact on the facilities that the Company must provide without charge to an applicant?

A. Yes. The Company has received several service requests from developers of planned residential complexes to include multiple buildings with multiple apartments in each building or groups of attached townhouses. The developers did not propose a central heating plant for the complex or for each building. Instead, each apartment or townhouse would be provided with its own gas-fired space-heating equipment, for which the gas service would be metered to the
resident. These smaller package heating units have only recently come into widespread use.

Q. Why is this type of service request a matter of concern for the Company?

A. An example will illuminate the source of the Company’s concern. In one development, 147 townhouses, in groups of two to six units, are to be constructed along a private road. Connection to the Company’s gas system requires an approximate 6,000-foot main extension in the public right-of-way and nearly 14,000 feet of service line within the subdivision. Edison’s construction costs for this work are estimated at approximately $10 million. The Company understands that each unit should be treated as a “residential applicant – heating” under the Commission’s main and service line extension regulations. Under this interpretation of the regulation and the Company’s implementing tariff, the Company’s responsibility for service to each such unit is the cost of up to 100 feet of main extension and up to 100 feet of service line. Because of the number of
units in this development, the foregoing
interpretation of the regulation requires that the
Company provide all main and service line facilities
without charge to the developer or any resident.
However, the adjusted gas revenues from the entire
subdivision are estimated at less than $200,000 per
year. Accordingly, under this situation, the
Company’s cost responsibility for the main extension
and service lines to be provided without charge would
unreasonably burden other ratepayers.

Q. Do the Commission’s regulations and the Company’s
tariff that implements those regulations anticipate
this type of gas use?

A. No. The Commission’s main and service line extension
regulations were adopted more than 25 years ago and
assumed that in a multiple-dwelling building central
heating would be provided by the owner. Where central
heating is provided to a building with new gas space-
heating load, the regulations only entitle the
applicant and require the utility to provide, without
charge, up to 100 feet of main extension to the
building and a service line only to the edge of the public right of way; the balance of the main extension and any service line outside the public right-of-way is at the applicant’s cost. The regulations and tariffs provisions to which we are referring are 16 NYCRR §§230.2(e) and 230.3; and P.S.C. No. 9 - Gas, General Rule III-3.(B)(4) (Leaf 31).

Q. How does the requirement for facilities necessary to serve a single-family home compare to this new multiple dwelling scenario?

A. An applicant for heating gas service for a single-family home that is 2,000 feet from the Company’s gas main would be responsible for the cost of a substantial portion of the main extension costs according to the Commission’s regulations and the Company’s tariff. Although the Company’s installation costs for a multiple dwelling with individual heating accounts that is 2,000 feet from a main will be little more than the costs to serve the single-family home, the Company must bear all the costs initially if each apartment is assumed to be entitled to its own main
extension without charge. And, as indicated above, although the multiple dwelling may contribute more revenue to the Company, in many circumstances, the revenue may be substantially less than the amount needed to avoid unduly burdening other customers.

Q. Is the Company proposing any tariff modifications to moderate the Company’s cost responsibilities related to the installation of mains and services to multiple dwellings where space heating will be provided through individual apartment gas-fired space-heating appliances?

A. Yes. The Gas Rate Panel is proposing tariff changes that would limit the Company’s cost responsibilities for main extensions to multiple dwellings with individually metered apartments to up to 100 feet of main multiplied by the average number of dwelling units per floor and one service line per building. This division of cost responsibility with respect to service for apartments in multiple dwellings would be analogous to the Commission’s line extension rule for underground electric service to multiple dwellings, 16
NYCRR §98.2(e), and reflected in the Company’s
electric rate schedule, P.S.C. No. 10 – Electricity,
General Rule 5.5.2.6 (Leaf 48).

Q. Is the Panel proposing any changes to the treatment of
customers with dual-fuel equipment that take firm gas
service?

A. Yes. We are proposing that a minimum charge apply to
all dual-fuel firm customers taking service under firm
sales classifications (“SC”), SC 2 and SC 3. This
proposal is reflected in tariff changes sponsored by
the Gas Rate Panel.

Q. Does SC 2 and SC 3 currently have a minimum charge for
dual-fuel firm customers?.

A. Yes. However, the minimum charge is currently
applicable only to customers with annual allocations
at or above 100,000 therms.

Q. Please describe the changes you are proposing.

A. First, the minimum charge would be applicable to all
dual-fuel firm customers regardless of their annual
allocation.
Second, the minimum bill will be equal to two-thirds of the customer’s annual allocation, with one exception.

Q. Please explain the one exception.

A. Currently, the minimum charge for customers with annual allocations at or above 100,000 therms is capped at two-thirds of 100,000 therms or 67,000 therms. Effective January 1, 2014, the Company proposes that the minimum charge for customers with allocations above the 100,000 therm threshold that submitted to the Company an application for gas service on or after January 1, 2014, not be subject to the 67,000 therm cap. For example, a new customer with an annual allocation of 200,000 therms would have a minimum charge based on 134,000 therms. All dual-fuel firm customers with annual allocations at or above 100,000 therms who are on, or who request, firm gas service as of December 31, 2013, will continue to be subject to the minimum charge cap of 67,000 therms.
Q. Please describe the formula for calculating the minimum charge applicable to dual-fuel firm customers.

A. The formula is:

\[
\frac{\frac{2}{3} \text{annual allocation}}{365} \times n \times R = M
\]

where \( n \) is the number of days in the billing cycle, \( R \) represents the applicable rates and charges under the customer’s service classification, and \( M \) is the resulting minimum charge.

Q. Why are you proposing this change?

A. Based on the increased level of gas service requests, there is significant interest in natural gas throughout our service territory. Much of this interest can be attributed to the potential commodity savings of gas compared to the three primary fuel oils (#2, #4 and #6 fuels), as well as the environmental benefits of natural gas. In addition, New York City customers are further motivated to consider natural gas because of City regulations phasing out the use of heavy fuel oils (#4 and #6 fuel). While many are interested in realizing significant operating savings,
and are aware of the favorable forecasts of gas availability and pricing, they have expressed a strong desire to retain their oil-burning capability (burners being sold today generally have the capability of handling both natural gas and fuel oil).

Interruptible service is not an attractive dual-fuel option to them because of the upfront costs associated with that service class and the interruptible nature of the service. In addition, the Company is proposing in this case to limit the availability of interruptible gas service prospectively to customers with annual allocations at or above 100,000 therms.

As a dual fuel firm customer, the customer can demand gas service but can suspend gas usage at its discretion. Accordingly, in the event fuel oil prices align more closely with gas prices and customers choose not to burn gas, the Company will realize lower delivery revenue to the detriment of other firm customers.
Q. Do you project any incremental revenues to be derived from the application of minimum charges to these new customers?
A. No. At present, with the price of gas very low in comparison with the price of fuel oils, we do not project the minimum bill changes to generate any additional revenues.
Q. Will the annual reconciliation mechanism be applicable to the minimum charges imposed on these customers?
A. Yes.
Q. Please provide more details concerning the Company’s System Reinforcement Program.
A. The System Reinforcement Program includes the following categories of work:
- Winter load relief, which involves main enlargements, extensions, replacements, and retirements, as detailed below and in Exhibit __ GOP-2, pages 6 and 7; and
- Gas service replacements, as detailed below and in Exhibit ___ GOP-2, pages 8 through 11.
As presented in Exhibit ___ GOP-1, page 1, we currently anticipate annual capital expenditures of $42.5 million to support the System Reinforcement Program during the upcoming five-year period from 2013 through 2017. These estimates were developed from historic capital expenditures.

Q. Please describe the categories of work under the System Reinforcement program.

A. Winter load relief is the annual process during which we compile large amounts of data pertaining to actual system conditions during the winter, the extent of new business loads, and any system modifications that have been made as part of gas main replacements and installations. Once obtained, this data is entered into a Stoner computer model, which calculates resulting gas pressures and flow rates. Based on the results of this Stoner modeling, we then upsize certain smaller-diameter pipes so that adequate pressure is provided to all customers. Historically, we have replaced 2 to 3 miles per year as part of this winter load relief effort.
The other major item of work under the System Reinforcement Program is the replacement of gas services, which are categorized as follows:

- Steel services that are replaced in conjunction with various main replacement programs; and
- Services that are replaced because they do not have an outdoor shut-off valve.

Q. Please provide more details concerning the Company’s program to replace prioritized pipe (i.e., cast iron PPR and steel PPR).

A. The replacement of cast iron PPR is grouped into the following two budget categories:

- GD-1, which includes the emergency replacement of cast iron mains (Exhibit ___ GOP-2, pages 12 and 13); and
- GD-11, which includes the replacement of small-diameter cast iron mains (Exhibit ___ GOP-2, pages 24 and 25).

As of the end of 2011, Con Edison’s gas distribution system was comprised of approximately 4,360 miles of main. Of this total, approximately 30 percent (1,305
miles) is made from cast iron and 27 percent (1,190 miles) is made from unprotected steel.

Emergency low-pressure cast iron main replacement is only a small portion of the much larger GD-1 program. In fact, this emergency low-pressure cast iron main replacement program only includes the emergency replacement of cracked 10” and larger cast iron mains to mitigate immediate risk to public safety. As presented in Exhibit ____ GOP-1, page 1, we currently anticipate annual capital expenditures of $2.5 million to support emergency low-pressure cast iron main replacements during the upcoming five-year period from 2013 through 2017.

The GD-11 program is an annual program to replace small-diameter low-pressure cast iron gas mains. We have more than 1,300 miles of cast iron gas mains throughout our system, and we currently plan to replace 80,000 feet per year of cast iron PPR during each of the next five years. As presented in Exhibit ____ GOP-1, page 1, we currently anticipate the following capital expenditures to support the GD-11 program.
program during the upcoming five-year period: $49.3 million in 2013; $41.8 million in 2014; $43.1 million in 2015; $42.9 million in 2016; and $43.0 million in 2017. The GD-11 program is a critical component of the Company’s larger program to replace PPR because it effectively addresses and mitigates the significant safety risks that cast iron main cracks, breaks, and leaks pose to employees and members of the public.

Q. Please provide more details concerning the Company’s program to replace steel PPR.

A. The replacement of steel PPR is grouped into the following two budget categories:

- GD-4, which includes the replacement of corroded steel gas mains (Exhibit ___ GOP-2, pages 20 and 21); and
- GD-29, which includes the replacement of 2” high-pressure steel mains with existing or anticipated coupling leaks (Exhibit ___ GOP-2, pages 26 and 27).

The GD-4 program is an annual program to replace approximately 70,000 feet of corroded and leaking
steel gas mains. Con Edison has over 1,100 miles of
unprotected steel gas main throughout its system. As
presented in Exhibit ___ GOP-1, page 1, we currently
anticipate the following capital expenditures to
support the GD-4 program during the upcoming five-year
period: $18.6 million in 2013; $33.1 million in 2014;
$33.1 million in 2015; $34.9 million in 2016; and
$34.0 million in 2017. This level of spending is
necessary because it will provide Con Edison with the
ability to continue improving its gas infrastructure
while mitigating safety risk to employees and the
public. This will also enable Con Edison to continue
reducing its greenhouse gas emissions associated with
methane leaks.

To mitigate the risk of 2” high-pressure coupling
leaks in Queens and Westchester, a budget category
called “GD-29” was established in 2009. This is an
accelerated program to replace targeted sections of 2”
steel gas main in Queens and Westchester that have
potential integrity problems associated with high-
pressure couplings. We are currently planning to
replace approximately 30,000 feet of 2” high-pressure steel gas main during each of the next five years under the GD-29 program. As presented in Exhibit __, page 1, we currently anticipate the following capital expenditures to support the GD-29 program during the upcoming five-year period: $5.9 million in 2013; and $6.8 million per year in 2014, 2015, 2016, and 2017.

Q. Please explain the increase in projected GD-4 steel gas main replacement expenditures from $18.6 million in 2013 to $33.2 million, $33.1 million, and $34.9 million in 2014, 2015, and 2016, respectively.

A. Under the terms of the current Gas Rate Plan, the Company is required to replace a minimum of 150 miles of PPR. In 2011 and 2012, the Company accelerated its plan and, by the end of calendar year 2012, the Company will have replaced approximately 110 miles of PPR. Therefore, we are currently planning to replace less steel PPR footage in 2013, as compared to 2011 and 2012. Despite this reduction in 2013, the Company will still achieve the minimum replacement footage of
150 miles required under the current Gas Rate Plan. This reduction in PPR footage in 2013 will also partially mitigate the funding needed to support significant capital expenditure increases associated with oil-to-gas conversions and gas interference work.

Q. Please provide more details concerning the Company’s program to replace gas services.

A. The replacement of gas services is grouped into the following budget categories:

- GD-1, which includes:
  - Installation of new business services; and
  - Replacement of services completed in conjunction with other capital main work (Exhibit ___ GOP-2, pages 8 and 9);

- Replacements of services that are found to be missing curb valves, which are required by New York City Building Code; and

- GD-3, which includes emergency replacement of leaking gas services (Exhibit ___ GOP-2, pages 18 and 19).
As of the end of 2011, Con Edison’s gas distribution system was comprised of 387,881 services, as detailed below:

- 225,936 services (58.2%) made of plastic;
- 117,767 services (30.4%) made of unprotected steel;
- 24,093 services (6.2%) made of copper;
- 19,198 services (4.9%) made of protected steel; and
- 887 services (0.2%) made of other combinations of materials.

Q. Please provide more details concerning the Company’s program to replace gas services during other capital main replacement work.

A. When Con Edison replaces PPR, it also typically replaces any steel gas services connected to such mains. This is done because future gas leaks on these steel services would require us to re-excavate in order to make repairs, resulting in greater potential for customer impact and increased roadway restoration costs. As presented in Exhibit ___ GOP-1, page 1, we
currently anticipate the following capital expenditures to support the replacement of services associated with other capital main replacement work during the upcoming five-year period: $21.8 million in 2013; and $27.5 million per year in 2014, 2015, 2016, and 2017. This program is funded under System Reinforcement.

Q. Please provide more details concerning the Company’s program to replace gas services that are missing outside curb shutoff valves.

A. The replacement of gas services that do not have a curb valve is an on-going multi-year program. The New York City Building Code requires outside curb shutoff valves on each and every gas service. In 1998, the Company conducted a field survey of existing gas services in New York City and found 5,526 services without outside curb shutoff valves. Based on these findings, a program was initiated to replace all gas services missing outside curb shutoff valves by 2020. As of the end of 2011, a total of 1,067 of these services remained to be replaced. We currently plan
to continue replacing these services at a rate of 140 per year until 2020. As presented in Exhibit ___ GOP-2, pages 10 and 11, we currently anticipate annual capital expenditures of $1.1 million to support the replacement of services without curb valves during the upcoming five-year period from 2013 through 2017. This program is funded under System Reinforcement.

Q. Please provide more detail concerning the Company’s program to replace leaking services.

A. The GD-3 program is an annual program for the replacement of leaking gas services that are found as part of our leak survey program or in response to incoming leak calls. Based on our current projections, we expect to replace over 1,500 leaking services each year during the next five years under the GD-3 program. As presented in Exhibit ___ GOP-1, page 1, we currently anticipate the following capital expenditures to support the GD-3 program during the upcoming five-year period: $26.5 million in 2013; $25.6 million in 2014; and $25.0 million per year in 2015, 2016, and 2017.
Q. Please provide more details concerning the Company’s gas meter installation program.

A. The Company’s gas meter installation program is an annual program to install or replace gas meters as part of new business service installations and other required gas meter replacement programs. As presented in Exhibit ___ GOP-1, page 1, we currently anticipate the following capital expenditures to support the meter installation program during the upcoming five-year period: $16.4 million in 2013; $17.0 million in 2014; $16.9 million in 2015; $16.8 million in 2016; and $12.5 million in 2017.

Q. Please explain the Company’s cathodic protection program.

A. The GD-5 program is the capital portion of the work associated with the installation of test stations and anodes utilized to cathodically protect unprotected steel gas mains. This cathodic protection extends the useful life of these steel gas mains by helping to prevent corrosion. As presented in Exhibit ___ GOP-2, pages 22 and 23, we currently anticipate the following
capital expenditures to support the GD-5 program
during the upcoming five-year period: $393,000 in
2013; $396,000 in 2014; $397,000 in 2015; $396,000 in
2016; and $375,000 in 2017.

Q. Does the Company anticipate other capital expenditures
for programs and projects that are not discussed above
but which also fall under the GD-1 category?

A. Yes. The capital expenditures discussed above falling
under the annual GD-1 program represent those
categories of expenditures that have historically been
made by the Company. However, there are additional
GD-1 capital expenditures that the Company has not
incurred in the past that it expects to incur during
the upcoming five-year period. These expenditures are
for capital work associated with #4/#6 fuel oil-to-gas
conversions.

Q. Do you have any planned capital programs for your
Technical Operations department involving the
Liquefied Natural Gas (“LNG”) Plant, Gas Measurement,
and Tunnel Maintenance?

A. Yes, we do.
Q. Please provide a brief overview of the LNG Plant.

A. Con Edison’s LNG Plant is located in Astoria, Queens, and has been in service since 1974. The LNG tank at the Plant has a storage capacity of 1,050,000 dekatherms of natural gas. When needed, the LNG stored at the Plant can be vaporized and re-injected into Con Edison’s gas transmission system at an hourly rate of deliverability of up to 10,500 dekatherms based on 1,050 Btus and four vaporizers operating.

Q. What benefits does the LNG Plant currently provide to Con Edison’s customers?

A. The LNG Plant serves a critical reliability/contingency function as the only source of in-City natural gas with which Con Edison’s customers can be supplied in the event of an interstate pipeline interruption or other emergency condition severely affecting its external gas supply. The LNG Plant also serves as a supply and hourly balancing source during very cold days, while its entire capacity is needed during design peak day conditions to meet the needs of our firm gas customers.
Q. When does the Company typically liquefy gas and vaporize LNG?

A. We typically liquefy gas two seasons each year; once in the Spring and again in the Fall. It takes approximately 300 days to fill the LNG tank from empty. When required, we vaporize LNG for peak shaving purposes, and also for contingencies and operational needs.

Q. Please explain the LNG Plant’s vaporization process.

A. Vaporization at the LNG Plant involves warming the LNG to a gaseous state for re-injection into the gas transmission system. Vaporization is accomplished by pumping the LNG from the tank using submerged pumps. The LNG is then warmed through water bath heat exchangers called vaporizers. The LNG Plant has five submerged combustion vaporizers, each equipped with four burners. The exhaust gas from the burners heats the water, which heats the LNG and converts it back into a gaseous state. The gas is then odorized and sent out into the gas transmission system.
Q. Please summarize the capital expenditures projected by the Company for the LNG Plant during the period 2013 through 2017.

A. The Company plans to spend approximately $14.7 million in capital improvements at the LNG Plant during the period 2013 through 2017. This amount is divided into the following: $1.9 million in 2013; $2.8 million in 2014; $2.85 million in 2015; $2.3 million in 2016; and $4.8 million in 2017.

Q. Please describe the major projects at the LNG Plant that comprise these proposed capital expenditures.

A. There are two main projects. The first is the purchase and replacement of vaporizer Units 2 and 3. The second is the installation of equipment that will allow the Plant to liquefy year-round.

Q. Please explain the basis for the proposed capital expenditures to upgrade the LNG Plant vaporizers.

A. The LNG Plant was constructed in 1974 with five vaporizers, of which vaporizer Units 4 and 5 have already been replaced. The remaining original vaporizers (i.e., Units 1, 2, and 3) are still in
operation and are nearing the end of their useful
service lives. As such, many of their original
components, equipment, and instrumentation have become
obsolete, and replacement parts are either no longer
available or are very difficult to obtain. Also,
vaporizer inspections have shown deterioration of the
carbon steel structural elements. For these reasons,
the Company plans to replace two of the remaining
three original vaporizer units (i.e., Units 2 and 3)
during the upcoming five-year period. The remaining
original unit (i.e., Unit 1) will be replaced at a
future time. In terms of project schedule, we plan to
procure one of these replacement units in 2013 and
then install it in 2014. The second replacement unit
will be procured in 2015 and installed in 2016. As
presented in Exhibit ___ GOP-2, pages 53 and 54, and
59 and 60, we currently anticipate the following
capital expenditures to support these vaporizer
replacement projects at the LNG Plant during the
upcoming five-year period: $1.05 million in 2013; $1.4
million in 2014; $1.75 million in 2015; and $2.3
million in 2016.

Q. Please explain the basis for the proposed capital expenditures to upgrade the LNG Plant liquefier so that it can operate year-round.

A. The LNG Plant’s liquefaction system utilizes cooling water to remove waste heat from the equipment used to make LNG. This cooling water system currently limits the timeframe during which the plant can liquefy to only those days when sustained weather is above freezing. Attempting liquefaction on days when temperatures are below freezing will cause the cooling water to freeze and damage the system. This proposed project will upgrade the liquefaction system from water coolers to air coolers, which are not subject to the effects of freezing temperatures. This upgrade will enable the liquefaction system to operate 365 days per year and allow the LNG Plant to make LNG during the winter. Having the ability to operate the liquefaction system in this manner will enable the plant to replace LNG consumed within the winter period, which will increase the availability of LNG
for reliability purposes. As presented in Exhibit GOP-2, page 49 and 50, we currently anticipate the following capital expenditures to support this liquefaction system upgrade at the LNG Plant during the upcoming five-year period: $1.4 million in 2014; and $1.1 million in 2015.

Q. Is there additional information concerning these vaporizer and liquefaction system projects at the LNG Plant?

A. Yes, the Company has prepared detailed “White Papers” that provide additional information concerning the scope of work, projected cost, timeframe, and justification for each of these projects at the LNG Plant.

Q. Please explain the basis for the projected annual capital expenditures to support meter purchases during the upcoming five-year period.

A. The Company currently anticipates the following capital expenditures to support meter purchases during the upcoming five-year period: $5.8 million in 2013; and $7.1 million per year in 2014, 2015, 2016, and
2017 (see Exhibit ___ GOP-2, pages 28 and 29). The basis for these projected capital expenditures is to fund: the purchase of meters and related devices (e.g., 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, etc.) in accordance with Commission regulations. These projected annual expenditures include the cost of new business meters, and the funding needed to support the retirement and remediation of poorly performing meters.

Q. Please provide a brief overview of the Company’s utility tunnels.

A. Con Edison has a total of eight utility tunnels in its system; three running underneath the East River, one running underneath the Harlem River, the Bronx River, the Flushing River, and Newtown Creek, and another running underneath First Avenue in Manhattan from 20th Street to 36th Street. The oldest tunnel (i.e., the
Ravenswood Tunnel) went into service in 1895 and the newest (i.e., the Harlem River Tunnel) went into service in 2012. These tunnels house critical electric, gas, and steam facilities, as well as fuel oil lines and telecommunications systems. They provide our facilities with necessary pathways underneath the region’s water bodies, and our First Avenue Tunnel provides an essential conduit underneath the east side of Manhattan for the transfer of our steam transmission infrastructure, which was needed after our Waterside Steam Generating Plant was retired. All of our tunnels have walking passages with elevators and/or ladders that are used as the primary means of entry and egress. The tunnels are kept dewatered by fixed pumps, and contain electric and communications systems used for their maintenance. The tunnels also have remote monitoring capability via the Company’s supervisory control and data acquisition system (“SCADA”). The tunnels have vertical shafts at each end, ranging from 56 feet to 261 feet in depth, and from 18 feet to
34 feet in diameter. The length of the tunnels (measured from the centerline of each shaft) varies from 540 feet to 4,662 feet. Due to their size, depth, and subsurface configuration, they are subject to continual groundwater intrusion.

Q. What is the impact of the groundwater intrusion?

A. As a result of the groundwater intrusion, the steel used in the tunnels to construct the utility supports, elevators, ladders, and landings are constantly subject to corrosion and deterioration. The tunnels also contain ancillary support equipment, such as ventilation fans, sump pumps, oil/water separators, and electrical and telecommunications equipment, all of which is similarly subject to corrosion and deterioration as a result of the groundwater intrusion.

Q. Please explain the functions performed by the Company’s Tunnel Maintenance section.

A. The Tunnel Maintenance section operates and maintains the support equipment and performs regular inspections.
of the tunnel facilities and the utilities traversing the tunnels.

Q. Please explain the basis for the capital expenditures that the Company is proposing for its tunnels.

A. Exhibit __ GOP-2, pages 32 through 46, describes the projected capital expenditures for the Company’s tunnels. These capital expenditures are operationally required in order to maintain the safety and reliability of these facilities. As described above, the tunnel infrastructure, which includes electrical, structural, and mechanical equipment, is constantly exposed to extreme moisture, salt, humidity, and heat, especially in the tunnels that carry steam mains. This harsh environment causes corrosion that can compromise the structural integrity of our infrastructure. As such, the infrastructure, equipment, and facilities inside of our tunnels must be periodically replaced and/or upgraded so as to maintain the reliability and safety of our system for our customers and employees. Maintaining our tunnels in this manner also helps protect the environment.
Q. Please describe the major programs that make up the capital expenditures that are projected for the tunnels.

A. Our major capital programs for the tunnels will address corrosion of tunnel infrastructure and equipment caused by water intrusion and salt. For instance, in the Ravenswood Tunnel, we will implement a program to replace the corroded steel that supports our high-voltage electrical transmission feeders. Additionally, all of the pipe and feeder support rollers in the Ravenswood Tunnel will be changed out during this project. Electrical service and corroded junction boxes will also be upgraded during this work. As part of our efforts to maintain a safe work environment for our employees, we are planning to complete projects to address the emergency egress ladder and landing system in the Hellgate shaft of the Astoria Tunnel. This project is necessary because the existing ladder and landing egress structure does not meet current safety standards (i.e., it is missing necessary landings). In addition, a project is
planned for the replacement of the deteriorated floor of the Patterson Avenue Headhouse of the Bronx River Tunnel.

Q. Please summarize the cost of these planned projects.

A. As presented in Exhibit ___ GOP-1, page 1, we currently anticipate the following capital expenditures to support these tunnel projects during the upcoming five-year period: $2.3 million per year in 2013, 2014, 2015, and 2016; and $1.7 million in 2017. These annual expenditures also include various smaller-scale projects (ranging from $50,000-$200,000 each), such as the installation of a hoisting device in the Bronx River Tunnel; the replacement of the roof at the 11th Street Conduit Headhouse; the renewing of a cracked and bowed wall in the breezeway at the Manhattan-side headhouse of the Hudson Avenue Tunnel; and the purchase of replacement sump pumps.

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 low-pressure district regulator stations located throughout the Company’s service territory. Some of this equipment is situated above-grade; however, most is located within below-grade manhole structures underneath roadways and sidewalk areas. This equipment includes 284 regulator stations, all of which are inspected on an annual basis by the Pressure Control department as part of the Company’s efforts to maintain system integrity and proper gas pressures.

Q. Please summarize the capital expenditures projected for the Pressure Control department during the upcoming five-year period.

A. The Pressure Control department is planning to complete eight capital programs during the upcoming five-year period. As presented in Exhibit ___ GOP-1, page 1, we currently anticipate annual capital expenditures of $2.8 million to support these Pressure
Control programs during the upcoming five-year period from 2013 through 2017.

Q. Please describe the eight capital programs planned to be completed by the Pressure Control department during the upcoming five-year period.

A. The eight capital programs planned to be completed by the Pressure Control department during the upcoming five-year period involve various scopes of work ranging from equipment replacement and piping refurbishment to remote electronics monitoring and control system upgrades. Detailed information concerning these programs is presented in associated “White Papers” found in Exhibit __ GOP-2, pages 73 through 88. Brief summaries of these capital programs are provided below.

The first three Pressure Control capital programs are asset improvement programs (see Exhibit __ GOP-2, pages 73 through 78) which include: Waterproofing Manhole Structures; Replacing 2” and Larger Equipment; and Replacing Unserviceable Equipment. Due to the enclosed and below-grade nature of most gas regulator
stations, their piping and equipment are inherently exposed to ground water infiltration, salt from roadway runoff, and corrosion. These first three capital programs were developed to address these corrosion concerns. As part of these programs, regulator stations will continue to be inspected on an annual basis and identified, as needed, for subsequent manhole waterproofing, select component replacement, and/or complete equipment refurbishment. These programs will result in continued asset improvement and increased system reliability. As presented in Exhibit ___ GOP-2, pages 73 through 78, we currently anticipate annual capital expenditures of $1.3 million to support these three Pressure Control asset improvement programs during the upcoming five-year period from 2013 through 2017.

The fourth Pressure Control capital program involves Regulator Vent System Refurbishment (see Exhibit ___ GOP-2, pages 79 and 80). In order to comply with Code requirements, regulator stations contained in underground manhole structures must have venting
systems, which provide fresh air exchange and atmospheric balance for regulator pilots. Many of the Company’s early regulator station vent systems were installed with steel components. As such, these older vent systems are subject to corrosion, which can lead to water infiltration and resulting interference with equipment and atmospheric pressure balancing. As part of this program, regulator vent systems will continue to be inspected on an annual basis and refurbished, as needed. As presented in Exhibit ___ GOP-2, pages 79 and 80, we currently anticipate annual capital expenditures of $400,000 to support the Regulator Vent System Refurbishment program during the upcoming five-year period from 2013-2017. The fifth and sixth Pressure Control capital programs involve the Replacement of Leaking Buried Pipe (i.e., uncoated inter-stage piping and corroded gauge lines) found during mandated annual inspections or periodic leak patrols, or as part of gas leaks that are reported by the public (see Exhibit ___ GOP-2, pages 81 through 84). These two programs cover the
replacement of leaking pipe that is buried outside of regulator station manholes. As part of this program, necessary repairs will be completed immediately following the discovery of any leaks. This type of prompt repair will allow for the proper functioning of such regulating stations. As presented in Exhibit __ GOP-2, pages 81 through 84, we currently anticipate annual capital expenditures of $400,000 to support this Replacement of Leaking Buried Pipe program during the upcoming five-year period from 2013 through 2017.

The seventh Pressure Control capital program involves the Installation of Remote Monitoring/Telemetrics Equipment at Regulator Stations (see Exhibit __ GOP-2, pages 85 and 86). As part of this program, various equipment, including electronic pressure sensors, power supplies, and communications equipment, will be installed at certain regulator stations. This equipment will allow for the transmittal of pressure readings, alarm signals, and equipment status information directly to our Gas Control Center, where our trained system operators continuously monitor the
Con Edison gas system. These installations are part of the Company’s effort to establish a robust design standard that supports the integration of natural gas-fueled "Thermal Electric Generator" power supplies that will provide uninterrupted communications capabilities with the Company’s Gas Control Center. This robust platform is expected to not only provide greater communications, but will also improve real-time regulator station alarm functionality for water intrusion, security breaches, and combustible gas detection. As presented in Exhibit ___ GOP-2, pages 85 and 86, we currently anticipate the following capital expenditures to support the Installation of Regulator Station Remote Monitoring/Telemetrics Equipment program during the upcoming five-year period: $356,000 in 2013; $390,000 in 2014; $406,000 in 2015; and $403,000 in 2016 and 2017. The eighth and final Pressure Control capital program involves the Installation of Regulator Station Remote Control/Gridboss Adaptive Controls (see Exhibit ___ GOP-2, pages 87 and 88). As part of this program,
remote and local control devices will be installed at regulator stations. Where installed, these control devices will respond to real-time system demand data to automatically adjust regulator station set points and flow values. This type of "smart" equipment minimizes the need to dispatch mechanics to a location for seasonal pressure adjustments and, therefore, virtually automates the distribution facilities to which they are connected. As presented in Exhibit ___ GOP-2, pages 87 and 88, we currently anticipate annual capital expenditures of $300,000 to support the Installation of Regulator Station Remote Controls/Gridboss Adaptive Controls program during the upcoming five-year period from 2013 through 2017.

C. Distribution Supply Main Projects

Q. What are “Distribution Supply Mains”?

A. “Distribution Supply Mains” or simply “Supply Mains” are part of the “backbone” distribution network that supplies gas between the transmission system and the distribution piping that delivers gas to customers.
We generally do not replace large portions of this “backbone” network, but rather install and replace select portions for project- and system-specific reasons.

Q. Please describe the Distribution Supply Main Projects that are projected for the upcoming five-year period.

A. The Company is planning a number of Distribution Supply Main Projects for the upcoming five-year period. Detailed “White Papers” discussing the scope, cost, schedule, and justification for each of these Supply Main Project are presented in Exhibit __ GOP-2, pages 89 through 171. As presented in Exhibit __ GOP-1, pages 1 and 2, we currently anticipate the following capital expenditures to support these Supply Main projects during the upcoming five-year period: $11.1 million in 2013; $22.4 million in 2014; $58.4 million in 2015; $88.9 million in 2016; and $43.9 million in 2017.

Q. Please explain the increase in projected capital expenditures to support Supply Main projects between 2013 and 2017.
A. Capital expenditures to support Supply Main projects are expected to increase between 2013 and 2017 because several of these projects, which were originally scheduled for completion between 2010 and 2013, were postponed to accommodate increased capital expenditures related to oil-to-gas service conversions. These projects, which include replacement and upsizing of our critical backbone Supply Mains, will allow us to avoid having to increase operating pressures beyond those pressures currently stipulated in our winter operating guidelines. These Supply Main projects will also eliminate radial and medium pressure cast iron mains, accommodate future load growth (including interruptible customers converting to firm service), and upgrade existing regulator stations.

Q. Please explain why Con Edison replaces and installs select portions of its Distribution Supply Main system.
A. We replace and install select portions of Supply Mains for the following reasons, all of which help reinforce our system:

- To maintain minimum required operating pressures
  - As demand for natural gas increases, we need to reinforce our low-, medium- and high-pressure systems in order to maintain the minimum pressures we deliver to each customer’s head-of-service (i.e., 4” of water column). As demand increases, we must also reinforce our system to maintain minimum operating pressures to our low- and medium-pressure regulator stations (i.e., 5 psig and 25 psig, respectively).

- System Integrity – Many of our Supply Mains are pre-1900 cast iron or bare steel initially installed in the 1920’s. As the cast iron and steel portions of these Supply Mains experience the effects of breakage and corrosion, they are identified and prioritized for replacement based on an evaluation of their leak history together with the results of statistical computer modeling.
performed by a gas mains replacement prioritization program that assesses risk, corrosion probability, and economic criteria. Replacing these sections of pipe reduces the risk of significant customer outages during the coldest winter days. For example, over the past several years, existing 6” and 8” portions of steel gas main installed between the 1920’s and the 1960’s along the Hawthorne-to-Peekskill Supply Main have been replaced. This critical Supply Main feeds the low-pressure distribution system through seven low-pressure, one medium-pressure, and two intermediate-pressure regulator stations as well as 13,000 individual high-pressure customers. There is a multi-year Supply Main program currently under way, with an end-state design to replace approximately 25 miles of this main with 12” PE to eliminate corroding bare steel and improve the capacity for source regulators at Peekskill and Hawthorne to backup each other on the coldest winter days.
• **Reduce Operating Pressures** - By replacing existing Supply Mains with larger-diameter pipe, regulator station operating pressures can be reduced, thereby minimizing gas leaks. Selective Supply Main replacements will also allow for system operating pressures to be significantly reduced throughout the high-pressure gas distribution system. Lowering operating pressures helps reduce leaks, provides a safer environment for our workers, increases public safety, and also helps minimize methane emissions, which are potent greenhouse gases.

Each Supply Main has its own set of unique issues, and the existing conditions and exposures for each proposed project are explained in Exhibit ____ GOP-2, pages 89 through 171.

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**D. Transmission Programs and Projects**

Q. Please describe Con Edison’s gas transmission system and the philosophy of the capital improvements being made to the system.
A. Con Edison’s gas transmission system is comprised of 88 miles of 6”- to 36”-diameter mains in Manhattan, Queens, the Bronx, and Westchester County. These mains, most of which were installed between 1947 and 1973, operate at pressures ranging from 245 psig to 350 psig. The transmission system is supplied by six gate stations from three pipeline companies. In addition, most of this system is part of a larger regional network called the New York Facilities (“NYF”) System, which is jointly operated by Con Edison and National Grid. Con Edison’s system is connected to National Grid’s system at two bi-directional metering stations (i.e., the Newtown Creek Metering Station in Long Island City and the Lake Success Metering Station in Nassau County).

The Company’s primary objective is to provide safe and reliable gas service to its customers at reasonable rates. To support this objective, the Company plans to:

- Employ a risk-based approach to identify and replace segments of the gas transmission system
that operate at greater than 20 percent of the Specified Minimum Yield Strength ("SMYS") (approximately 50 miles in total), and which are constructed of a lower ductility pipe than what is currently used by the Company to construct new transmission mains.

• Meet the Company’s future design criterion such that the gas system can withstand the loss of any one of the six gate stations that supply the transmission system without causing customer outages.

Q. Please explain the significance of SMYS.

A. For a pipe manufactured in accordance with a listed specification, the term SMYS refers to the minimum stress that a pipe may experience before permanent deformation occurs. The percent SMYS represents a pipe’s operating stress level (based on operating pressure, pipe diameter, and wall thickness) expressed as a percent of the yield strength of the pipe; the lower the percent of SMYS, the higher the safety factor. According to federal regulations,
“transmission lines” are defined as pipelines “that operate at a...stress of 20 percent or more of SMYS” (see 49 CFR 192.3).

Q. Please identify the gas transmission system capital programs and projects that are planned for the upcoming five-year period.

A. All of the gas transmission system capital programs and projects described below are presented in Exhibit __ GOP-2, pages 172 through 186. These programs and projects include the following:

- Lower Manhattan Interconnection Project;
- St. Ann’s Tee to Hunts Point Downgrade Project;
- Transmission Pipeline Integrity Program;
- Westchester/Bronx Border to White Plains Project;
- Hunts Point Regulator Refurbishment Project;
- Greenburgh Yard Refurbishment Project;
- Remotely Operating Valves Program; and
- Critical Components – Hunts Point to Bronx Border Project.
Q. How much does the Company project to spend in capital dollars during the upcoming five-year period to support its Transmission Programs and Projects?

A. As presented in Exhibit ___ GOP-1, page 2, we currently anticipate the following capital expenditures to support Transmission Programs and Projects during the upcoming five-year period: $23.1 million in 2013; $39.2 million in 2014; $34.3 million in 2015; $33.5 million in 2016; and $56.5 million in 2017.

Q. Please describe the Lower Manhattan Interconnection Project.

A. The Lower Manhattan Interconnection Project is a new project that will link Con Edison’s gas transmission system to Texas Eastern’s new delivery point on the lower west side of Manhattan. This interconnection, which is being done as part of the larger NJ-NY Expansion Project, requires the installation of approximately 1,500 feet of 30”-diameter steel piping, over-pressure protection equipment, and a remotely operated valve. The project is scheduled to be
completed in 2013. The total estimated capital expenditure for this project is $11 million. Gas Supply’s testimony discusses the benefits of the NJ-NY Expansion Project.

Q. Please describe the St. Ann’s Tee to Hunts Point Downgrade Project.

A. The St. Ann’s Tee to Hunts Point Downgrade Project is a new multi-year project to mitigate transmission system risk through the downgrade of a 2.7-mile section of our gas transmission system that operates at 32 percent of SMYS to less than 20 percent of SMYS. This 2.7-mile section of pipe (i.e., the section running from St. Ann’s to Hunts Point) will be downgraded from transmission pressure – having a maximum allowable operating pressure (“MAOP”) of 350 psig – to distribution pressure with a MAOP of 99 psig. This project includes the installation of two new regulator stations that will supply the high-pressure distribution system from transmission pressure. One of these regulator stations will be located at St.
Ann’s Tee and the other will be located at Hunts Point. As a result, four “transmission-to-high-pressure” regulator stations (i.e., GR-190, GR-160, GR-183, and GR-116) will be retired and replaced with polyethylene pipe. In addition, three “transmission-to-low-pressure” regulator stations will be modified and converted into “high-to-low-pressure” stations (i.e., GR-184, GR-128 and GR-118). As presented in Exhibit ___ GOP-2, pages 176 and 177, we currently anticipate the following capital expenditures to support this project: $600,000 in 2013; and $3.0 million in 2014. This project is scheduled to be completed in 2014.

Q. Please describe the Transmission Pipeline Integrity Main Replacement Program.

A. The Transmission Pipeline Integrity Main Replacement Program is an ongoing multi-year effort to replace or repair sections of defective transmission main and appurtenances that are identified through: pipeline integrity assessments administered in accordance with the Integrity Management Plan (which guides our
inspection of the transmission system for existing external and internal corrosion or damage in compliance with federal and state regulatory requirements; transmission main leak surveys; in-line inspections; and hydrostatic pressure testing. As presented in Exhibit ___ GOP-2, pages 185 and 186, we currently anticipate annual capital expenditures of $1.0 million to support this program during the upcoming five-year period from 2013 through 2017. This projected level of spending matches historical levels for this program. As explained in more detail below in the “Deferral Accounting/Reconciliations” section, actual expenditures to support this program could be much higher if the final regulatory requirements promulgated under the Pipeline Safety Act of 2011 are more stringent than anticipated.

Q. Please describe the Westchester/Bronx Border to White Plains Project.

A. The Westchester/Bronx Border to White Plains Project is a new multi-year project to install approximately 54,000 feet of new 36” steel transmission main
replacing the existing 24” steel transmission main
from the Westchester/Bronx border to the Tennessee
White Plains Gate Station outlet.
The 245-psig system consists of two mains – i.e., a
24” main operating at 26 percent of SMYS (1940s
vintage) that connects the Hunts Point Yard to the
Tennessee White Plains gate station, and a 20” main
operating at 16 percent of SMYS (1970s vintage) that
loops the 24” main from the Hunts Point yard to the
Westchester/Bronx line. There are approximately
315,000 customers supplied by the Hunts Point – White
Plains 245 PSIG system. Supplying the system from the
south is the Hunts Point Regulator Station (i.e., GR-
199) that reduces pressure from the 350-psig system
and is supplied from Transco and the Iroquois Gate
Station. Supplying the system from the north is the
Tennessee White Plains Gate Station. Installing the
proposed main will create a continuous parallel system
from the Bronx/Westchester border to the White Plains
Gate station in Westchester, and enable the Company to
meet a future design criterion such that it could
withstand the loss of the White Plains Gate Station or Hunts Point Regulator Station GR-199.

In addition, the 24” transmission main is the oldest on our system, and is constructed of lower-strength steel joined with mechanical couplings, approximately 2,000 of which are not reinforced. There are also 66 drip pots on the 24” main, and these provide potential points of failure. This reinforcement will allow the Company to systematically downgrade the existing 24” main and operate at stress levels of less than 20 percent of SMYS. The new main will replace the lower ductility pipe with transmission pipe that is made of steel that is stronger and more resilient. This will allow for safer operation and minimize the possibility of a main rupture. As presented in Exhibit ____ GOP-2, pages 182 through 184, we currently anticipate the following capital expenditures to support this project during the upcoming five-year period: $6 million in 2013; $25 million in 2014, 2015, and 2016; and $35 million in 2017. The anticipated completion date for
Q. Please describe the Hunts Point Regulator Station Project.

A. The Hunts Point Regulator Station Project is a new project consisting of the replacement of spiral-wound piping, regulators, regulator components, vintage transmission isolation valves, pneumatic supervisory controls, and the upgrade of overpressure protection at the Hunts Point Regulator Station GR-199. As presented in Exhibit ___ GOP-2, pages 180 and 181, we currently anticipate the following capital expenditures to support this project during the upcoming five-year period: $500,000 in 2013; and $2.5 million in 2014. This project is expected to be completed in 2014.

Q. What is the justification for this project?

A. Regulator Station GR-199 is a critical regulator station that is supplied by the Transco and Iroquois Gate Stations. This station reduces pressure from 350-psig to 245-psig, and provides transmission
pressure to the Bronx and Westchester County 245-psig backbone system. In 1995, this station’s supervisory control equipment was upgraded to support pneumatic primary (with nitrogen backup) supervisory control schemes from Gas Control. The station piping throughout its 50 years of service has gone through numerous configuration changes, and has now reached the end of its viable service cycle. Thus, this piping is in need of complete replacement in order for continued safe and reliable operation of the station and the Bronx/Westchester gas transmission and distribution systems.

Station inlet and outlet piping has been recommended for replacement because it is made of less ductile pipe. In addition, the inlet and outlet isolation valves do not provide a tight isolation/shutoff, making it difficult to perform station maintenance. Moreover, the overpressure protection relies on a single super monitor and, therefore, should be upgraded to a more robust control system with redundancies for testing and maintenance purposes.
Also, the station’s pressure control valves utilize compressed air as the primary means of valve actuation. This air is transported from the Hunts Point Control Building, which is located across the yard from GR-199, via underground pneumatic control lines. During the winter months, the station has experienced frozen supply lines and malfunctioning compressor equipment. Natural gas is used for supervisory control actuation for many regulator and gate stations throughout the system. To mitigate future risk, natural gas should be utilized as the primary means of supervisory control actuation. Additionally, the current station design is a high-noise area when the station is flowing at high throughputs. A complete redesign will be implemented to maintain velocity parameters at the appropriate levels.

Q. Please describe the Greenburgh Yard Refurbishment Project.

A. The Greenburgh Refurbishment Project is a new project involving the replacement of a field-fabricated
second-stage regulator, and the removal of all pre-1972 buried piping, including bare steel and cast iron piping, flange end gate valves, plug valves, 1940’s vintage transmission piping, leaking buried by-pass piping, and radial main elements which are no longer required. As presented in Exhibit ___ GOP-2, pages 172 and 173, we currently anticipate the following capital expenditures to support this project during the upcoming five-year period: $200,000 in 2014; and $800,000 in 2015. This project is expected to be completed in 2015.

Q. Please explain the Remotely Operated Valve ("ROV") Program.

A. The ROV Program is an ongoing effort that consists of converting existing transmission valves, or installing new ROVs, to meet the ROV design criteria, such that the closure of any two consecutive ROVs will not negatively impact the gas distribution system on an average winter day (i.e., where the temperature is 20°F). In order to protect the gas transmission and distribution systems, maintain supply to firm gas
customers, and protect the public, a number of ROVs have been installed at various locations on the gas transmission system. Prioritization of new ROV installations is based on the total number of customers that would be negatively impacted within the existing ROV configuration. ROVs are also installed to achieve the following objectives:

- Rapidly isolate a compromised section of the transmission system to minimize affected areas;
- Rapidly isolate the transmission system at river and tunnel crossings and at the outlet of gate stations; and
- Rapidly separate intersecting transmission or Supply Mains at tee or branch locations, thereby minimizing affected areas.

The ROV Program includes the installation of one retrofit or new ROV per year. As presented in Exhibit GOP-2, pages 178 and 179, we currently anticipate the following capital expenditures to support this program during the upcoming five-year period: $1.0

Q. Please explain why the Company is requesting additional funding over historical levels for the ROV Program?

A. As noted above, the Company established a prioritization schedule for new ROV installations based on the number of customer outages that would be mitigated with each new installation. The first five ROV locations, two of which are in Manhattan, are in locations that are expected to carry a higher cost due to the surrounding dense network of underground utilities.

Q. Please describe the Critical Components – Hunts Point to Bronx Border Project.

A. The Critical Components – Hunts Point to Bronx Border Project is a multi-year project to replace sections of transmission main that are identified as containing fabricated mitered welds, drip pots, and/or couplings. The 7.6 miles of 24” transmission main traverses the Bronx from the Bronx River Tunnel to the Bronx –
Westchester Border in Mount Vernon. The main operates at an MAOP of 245 psig and approximately 26 percent of SMYS. The project calls for the removal, examination, and replacement of several pipe segments each year in order to perform a risk-based, fitness-for-service assessment of mitered welds on this portion of the transmission system. A total of 34 individual segments have been identified covering approximately 3,900 feet of transmission main. As presented in Exhibit ___ GOP-2, pages 174 and 175, we currently anticipate the following capital expenditures to support this project during the upcoming five-year period: $3 million in 2013; and $6 million per year in 2014, 2015, 2016, and 2017.

Q. Please identify some of the considerations affecting the selection and/or prioritization of the individual pipe segments involved in the Critical Components – Hunts Point to Bronx Border Project.

A. Some of the factors impacting the selection and/or prioritization of the individual pipe segments include:
The degree of certain mitered welds – i.e., operating stresses tend to increase proportionally with the degree of a mitered weld; multiple mitered welds in close proximity to one another; system/operating constraints; proximity of couplings, drips and/or other appurtenances; and construction constraints (e.g., mitered welds in close proximity to railroad/highway crossings).

E. Storm Hardening Projects

Q. Given the impacts of Superstorm Sandy, are there any new initiatives underway designed to reduce the impact of future storms?

A. Yes. A corporate System Design Task Force was established to develop and recommend both short- and long-term storm hardening initiatives and system design changes that would mitigate the impacts of future weather-related damage, such as the damage
sustained from the flooding and high winds experienced during Superstorm Sandy.

Q. Please describe the efforts and objectives of this task force.

A. We have new initiatives underway in a number of areas and are exploring a number of others. We are working on ways to mitigate the effects of flooding and other storm-related issues on the gas system. A cross functional team has been assembled to address effective and efficient cost and capability plans for both short-term and long-term solutions. The team will develop a prioritized listing of potential design changes, operational strategies, procedural modifications and hardening initiatives to mitigate the impact of coastal flooding. Their analysis will include potentially impacted Company facilities, such as utility tunnels, the LNG Plant, transmission and distribution facilities, regulating stations, and associated communications systems that support Gas’ SCADA System.
Q. Has the Company made any preliminary decisions regarding projects and/or programs to enhance and/or reinforce its gas system as a result of its experience with Superstorm Sandy?

A. Yes. As we will explain, the Company has preliminary plans to invest approximately $100 million in storm hardening of its gas facilities during the period 2013 through 2016. We also describe additional storm hardening projects and programs still under evaluation.

Q. Please describe the Company’s plans for 2013.

A. In 2013, the Company will complete two projects that will reduce the risk of possible over-pressurization to customers served by high pressure distribution in flood prone areas, and address flooding that occurred at the First Avenue Tunnel facility.

Q. Please describe these projects.

A. To address the increased risk of possible over-pressurization to customers in flood prone areas that have high pressure gas services, the Company will install float check valves at regulator vents for
approximately 9,000 customers. This will prevent water from infiltrating into service regulators, a condition that can lead to over-pressurization of customer piping and equipment. The Company will begin installing these check valves in 2013.

The Company will also address flooding experienced at the First Avenue Tunnel during Superstorm Sandy. While most of the water that infiltrated a number of Company tunnels during the storm was quickly removed, the First Avenue Tunnel experienced an area power outage, and because there was no local capability for backup electric power generation, the pumps could not be utilized. In 2013, the Company will design and fabricate vent cover plates that will restrict flood waters from entering the tunnel through vent shafts, and which will also incorporate a design for the temporary connection of a remote backup generator that would not be affected by a tidal surge. These vent covers and remote emergency generators will be installed as a precaution during a coastal storm flood watch. This will allow the tunnel pumps to have
continuous power for de-watering during a major storm.

Additional information concerning these projects is presented in associated “White Papers” found in Exhibit ___ GOP-2, pages 224 through 228.

Q. What is the projected costs for these two initiatives.

A. As presented in Exhibit ___ GOP-1, page 2, we currently anticipate a combined capital expenditure of approximately $2.1 million to support both of these projects in 2013.

The float check valves are projected to cost approximately $1.6 million. The design and fabrication of the vent cover plates and connection work to allow for the operation of a remote backup generator are projected to cost approximately $500,000.

We note that the Company plans to perform this work within the capital budget established for Gas for 2013 by deferring certain planned projects.

Q. Have you identified the programs and/or projects you plan to defer?
A. At this time, we plan to defer the Vision/Netmap Implementation/Upgrade and the Scarsdale High Pressure Supply Main Projects.

Q. Do you have any specific storm hardening projects planned for 2014?

A. Yes. In 2014, the Company will complete the installation of customer high pressure regulator vent float check valves in flood prone areas started in 2013. As presented in Exhibit ___ GOP-1, page 2, we currently anticipate a capital expenditure of approximately $4.8 million in 2014 to complete this project. This projected expenditure is in addition to the 2013 capital budget for Gas that was used to develop the revenue requirement for the Rate Year. As discussed by the Company’s Accounting Panel, the costs for this initiative were not developed in time to be reflected in the revenue requirement and will be reflected in the Company’s update in this proceeding. Additional information concerning this project is presented in an associated “White Paper” found in Exhibit ___ GOP-2, pages 226 through 228.
Q. Is the Company considering any longer-term system design changes based on the effects of Superstorm Sandy?

A. Yes. Preliminarily, in addition to the projects identified for 2013 and 2014, there are two initiatives planned for 2015 and 2016. They are:

a) An incremental main replacement program that targets bare steel and cast iron low pressure pipe within coastal flood zones.

b) To design and construct long-term storm hardening for tunnel facilities.

Q. Please describe the incremental main replacement program.

A. Low pressure distribution mains allow water to infiltrate into the system if facilities have undetected leaks or if facilities are damaged during coastal flooding. In addition to water infiltration mitigation, replacement of bare steel and cast iron pipe is desirable because it reduces the number of potentially hazardous natural gas leaks. The National Transportation Safety Board and the United States
Department of Transportation Pipeline and Hazardous Materials Safety Administration encourage replacement of such pipe. This replacement program will target replacement of cast iron and bare steel pipe above the main replacement program already reflected in our capital forecasts for 2015 and 2016. As presented in Exhibit ___ GOP-1, page 2, we currently anticipate the following capital expenditures to support these incremental pipe replacements: $16.6 million in 2015; and $16.7 million in 2016. Additional information concerning this program is presented in an associated “White Paper” found in Exhibit ___ GOP-2, pages 226 through 228.

Q. Please describe the Company’s plans to design and construct long-term storm hardening for tunnel facilities.

A. In addition to the First Avenue Tunnel, the Hudson Avenue, Ravenswood, and Astoria Tunnels experienced flooding to some degree during Superstorm Sandy. These tunnels will be targeted for enhancements as
part of a continuing evaluation of tunnel storm hardening projects.

Q. Please describe the impact of Superstorm Sandy on these tunnels.

A. As a result of Superstorm Sandy, flood waters entered facilities in the Ravenswood Tunnel, Astoria Tunnel, First Avenue Tunnel and Hudson Avenue Tunnel, all of which contain steam mains, gas mains, and/or high-voltage electrical feeders. All of these tunnels have “head house” entrances in close proximity to bodies of water. Currently, these head houses are prefabricated sheet metal or masonry structures that are not designed to withstand major flood waters. To protect the tunnels against future storms, hardened and reinforced concrete structures can be installed in place of the current head houses. These new head houses will be designed with flood doors to minimize/prevent water intrusion from storm surges. There will also be a long-term initiative to install a permanent emergency generator and transfer switch.
generator capable of feeding the First Avenue Tunnel during a loss of normal power event.

Q. What is the projected cost of these long-term tunnel hardening efforts?

A. As presented in Exhibit ___ GOP-1, page 2, we currently anticipate the following capital expenditures to support these long-term tunnel hardening efforts during the upcoming five-year period: $19.5 million in 2015; and $40 million in 2016.

Q. Do the Company’s projected revenue requirements for 2015 and 2016, which Company witness Muccilo provides for illustrative purposes as a basis for exploring a multi-year rate plan through settlement discussions, reflect the preliminary storm projects you have described?

A. Yes, they do.

Q. Is the Company considering any additional hardening initiatives?
A. Yes. In addition to the above projects, the Company is currently evaluating the following long-term storm hardening initiatives:

a) Installation of high pressure distribution facilities.

b) Hardening of GOSS/SCADA and Remote Operated Valve (ROV) communications.

c) Hardening Remote Operated Transmission Valves within coastal flood zones.

d) Evaluating the feasibility of a water infiltration mitigation device.

e) Evaluating methods to harden and/or mitigate the impact of flooding to 62 distribution system district regulator stations within coastal flood zones.

f) Evaluating and assessing methods to structurally harden the Company’s LNG facility.

Q. Please describe the effort to evaluate and implement a program to determine the proper balance between low
pressure isolation valves and upgraded high pressure
distribution facilities within coastal flood zones.

A. The purpose of this effort is to mitigate/prevent the
infiltration of water into the low pressure
distribution system resulting from damaged and
undermined gas facilities caused by failures of
seawalls and bulkheads.

Although the Gas system sustained little direct damage
during Superstorm Sandy, there exists a potential risk
to the gas system resulting from damage/breaks on low
pressure gas mains. These breaks can lead to water
entering the low pressure gas mains and spreading
throughout the system due to limited valving. This
would result in significant outages, both in terms of
number of customers affected and outage duration.

Replacement of low pressure cast iron facilities with
new high pressure steel or plastic mains will reduce
the risk of breakage caused by undermining. The high
pressure would also prevent the infiltration of water
into the system caused by damaged facilities. The
installation of additional low pressure valves would
limit the spread of water infiltration and expedite the restoration of affected customers. This evaluation will also consider possible use of water detection equipment in low pressure piping systems located in flood zones to determine possible water entry and the possible use of remote operated valves (ROVs) for isolation to minimize the number of associated customer outages.

Q. Please describe the initiative to harden GOSS/SCADA and ROV communications.

A. The Gas Operations Supervisory System (“GOSS”) is Con Edison Gas Operation’s SCADA system that monitors and controls gas regulating stations, ROVs, gate stations, tunnels and various pressure points on the gas delivery system. As a result of flooding and loss of power to various Verizon facilities, communication to approximately 45% of our SCADA locations failed during Superstorm Sandy. These communications provide critical system data and functionality to the Gas Control Center where system pressures and flows are monitored and controlled. As a result, the Company
needed to have employees visit field locations to periodically phone in gas pressure readings from a number of sites to Gas Control Operators so that they could continue to monitor the safe and reliable operation of the gas system.

Q. Please explain the initiative to harden Remote Operated Transmission Valves within coastal flood zones.

A. After Superstorm Sandy, a periodic 30% closure test on ROV 4169 resulted in a malfunction, causing lower than normal pressures at our East River Plant. The cause was a corroded pin connection device on the controls of the valve actuator caused by flood water. The Company will evaluate all ROV locations in flood zones and determine required communication and electric power supply hardening.

Q. Please describe the initiative to evaluate the feasibility of a water infiltration mitigation device that would minimize the impact of customer’s flooded basements and damaged equipment on the Company’s low pressure distribution systems.
Following Superstorm Sandy, water was found in parts of the low pressure gas distribution mains in flood zones that was believed to be the result of water entering these mains from compromised customer facilities in flooded customer buildings. Water in mains can then result in customer outages. A device to prevent water from entering low pressure mains from flooded customer basements would avoid customer outages caused by this issue.

Please describe the options the Company is considering to harden and/or mitigate the impact of flooding to distribution system district regulator stations within coastal flood zones.

Options include hardening district regulator station vent lines to prevent possible water entry and upgrading facilities to high pressure to allow for the retirement of affected stations. Currently Gas’s storm preparedness procedure requires the isolation of gas distribution regulators in flood zones projected to be affected by a pending storm. This is done to prevent possible over-presurization caused by water...
entering the vent lines of the regulators. For Category 2 and 3 flooding, the number of regulators that would need to be isolated could result in customer outages depending on the time of year and gas demands during the storm. Options of a hardened vent piping or upgrading facilities to high pressure will be evaluated.

Q. Please describe the initiative to harden the LNG facility.

A. The Company is evaluating and assessing methods to structurally harden the Company’s LNG facility from coastal flooding and hurricane force wind damage that would occur during a storm event coincident with high tides levels at Astoria. This evaluation will include a determination of the flood issues that would have been encountered at the LNG facility had the flood surge of Superstorm Sandy coincided with high tides at Astoria.

Q. Does the Company have specific project or program details in support of the initiatives planned and/or being considered for 2015 and 2016 and beyond?
A. Not at this time. Specific plans for effectuating these concepts were not complete at the time of the rate filing. The Company will update the rate filing with additional details for these projects and programs during the course of this rate proceeding, as appropriate.

Q. Do the foregoing efforts represent final plans for storm hardening as a result of Sandy?

A. No, they do not. As indicated above, evaluation of storm hardening alternatives is an ongoing effort. The projects and programs identified in this testimony reflect the Company’s best thinking as a result of diligent efforts to focus on storm hardening requirements immediately following the storm. Accordingly, these projects and programs will continue to evolve and may be modified, accelerated or deferred and/or replaced by other programs deemed more beneficial to customers and the service territory in general.

Q. Does the Company have a proposal for addressing costs and cost recovery of storm hardening projects and
programs that cannot be timely considered for inclusion in rates that are established in this rate proceeding?

A. Yes. Company witness Muccilo proposes a framework for addressing the recovery of such costs through a surcharge mechanism.

F. Information Technology Projects

Q. Please summarize the Gas-related Information Technology projects currently planned to be completed during the upcoming five-year period.

A. The Company is planning to complete seven Gas-related Information Technology projects during the upcoming five-year period. Five of these projects are being completed exclusively for Gas Operations, while the remaining two projects are initiatives that affect at least one other service (i.e., electric and/or steam).

Q. Please list and describe the Gas-related Information Technology projects currently planned to be completed exclusively for Gas Operations during the upcoming five-year period.
A. Gas Operations is planning to have the following five Gas-related Information Technology projects completed during the upcoming five-year period:

- Data Warehouse Project;
- Upgrading Gas Inspection System/Computer Dispatch System;
- Gas Outage Management System;
- Viryanet G4 Migration; and
- Work Management System.

Q. How much does the Company project to spend in capital dollars during the upcoming five-year period to support its Gas-related Information Technology projects?

A. As presented in Exhibit ___ GOP-1, page 2, we currently anticipate the following capital expenditures to support Gas-related Information Technology projects during the upcoming five-year period: $4.7 million in 2013; $7.1 million in 2014; $19.4 million in 2015; $18.3 million in 2016; and $21.1 million in 2017.

Q. Please describe the Data Warehouse Project.
A. The first Gas Operations project is the Data Warehouse project, which began in 2011. The purpose of this project is to consolidate the Company’s gas asset data from several systems into a single data source that will allow for self-service custom business reporting in a user-friendly manner, and will also improve the overall consistency and integrity of the Company’s gas asset and inspection data. This project was initiated to address the limitations of our current systems, which have made the preparation of custom business reports difficult and time-consuming. As a result, only skilled and dedicated programming contractors have been able to prepare these custom business reports. Once complete, the new Data Warehouse System will allow Company employees to produce custom business reports with a user-friendly self-service tool that requires no programming skills or in-depth knowledge of database structures. The new Data Warehouse System is being constructed in planned asset increments following a “building block” approach. This new system already includes data
associated with gas main valve assets, outside gas
leak and associated repair information, financial
exception reports, gas dispatcher and mechanic
efficiency information, and emergency response time
rates. The new Data Warehouse also includes a summary
dashboard showing information related to key metrics,
such as the Company’s outside gas leak year-end
target. During 2012, asset data for vaulted areas and
high-pressure regulators is being added to the new
Data Warehouse. In 2013, data for meters and
corrosion programs will be added for reporting,
scheduling, and regulatory compliance purposes. The
final phase of this project will be completed in 2014,
during which time all data and reports will be
migrated from the existing systems into the new Gas
Data Warehouse. This final migration phase must be
completed by the end of 2014 because the existing
Windows XP platform for the current gas asset data
systems will no longer be supported by Microsoft
beyond 2014. As presented in Exhibit ___ GOP-2, pages
203 through 205, we currently anticipate the following
capital expenditures to support the Gas Data Warehouse project during the upcoming five-year period: $480,000 in 2013; and $750,000 in 2014.

Q. Please describe the Upgrading Gas Inspection System/Computer Dispatch System program.

A. The second Gas Operations project involves upgrading the Gas Inspection System (“GIS”) and Gas Computer Dispatch (“CD”) System. As part of these upgrades, both of which will be completed in 2013, the GIS and Gas CD System will be expanded to include work and inspection tracking functionality for transmission drips and encroachment assets. Inspection and maintenance work for these assets are currently tracked in the Emergency Control System (“ECS”) and on separate spreadsheets. Adding these assets to the GIS and Gas CD System will provide increased scheduling and dispatching capabilities. As presented in Exhibit ___ GOP-2, pages 206 through 208, we currently anticipate a capital expenditure of $200,000 in 2013 to support the GIS and Gas CD System upgrades project.
Q. Please describe the Gas Outage Management System project.

A. The third Gas Operations project is the Gas Outage Management System Phase 0. This project involves an effort to define the scope of a comprehensive Outage Management System that can be used as a functional resource by Gas Operations in the planning and management of gas system outages. This type of system will significantly improve the Company’s ability to understand customer impact and associated restoration times, and will also improve the overall efficiency with which the Company responds to gas system outages. During this Phase 0, the Company will identify the base requirements of a Gas Outage Management solution, research best-of-breed solutions within the industry, and finally recommend a solution (i.e., single application or suite of applications) based on several factors, including: functionalities offered; reliability; cost-effectiveness; technical stability; performance; security; supportability; and compliance with our information technology standards. As
presented in Exhibit ___ GOP-2, pages 197 and 198, we currently anticipate the following capital expenditures to support the Gas Outage Management System Phase 0 during the upcoming five-year period: $250,000 in 2015; and $250,000 in 2016.

Q. Please describe the Viryanet G4 Migration project.

A. The fourth Gas Operations project is the Viryanet G4 Migration, which involves the upgrade of the current Gas CD software package to Viryanet’s G4 platform. This project is necessary because the current system is reaching the end of its technical life and, therefore, needs to be migrated to the new G4 software package. As part of this migration, all work templates, processes, and functionalities developed specifically for the Company will be rebuilt and/or rewritten using Viryanet’s G4 tools. Hardware and software will also be upgraded based on the requirements of the G4 package. As presented in Exhibit ___ GOP-2, pages 201 and 202, we currently anticipate a capital expenditure of $345,000 in 2014 to support the Viryanet G4 Migration project.
Q. Please describe the Work Management System project.

A. The fifth Gas Operations project involves the planned development of an integrated Work Management System. In January 2012, Gas Operations assembled a team of internal and external subject matter experts to conduct a Phase 0 assessment of its workflow and business processes. This Phase 0 lasted 6 months. During this time, it was determined that Gas Operations could significantly improve its ability to plan and manage its workload with an integrated work management system. The project team also developed a business plan for the implementation of a standard work management system for Gas Operations. The standard system identified by the project team utilizes the Logica Asset and Resource Management (“ARM”) Suite of applications, which provides a fully integrated work management solution encompassing all aspects of work initiation, scheduling, dispatch, and completion. Gas Operations selected the Logica ARM Suite, at least in part, because the Company’s Electric Operations Business Unit also recently
implemented the Logica ARM Suite in support of its
efforts to improve work management processes.
Enabling both Gas Operations and Electric Operations
to manage their short- and long-term work via a single
integrated platform is a high priority for the Company
because it increases the potential for cross-commodity
work planning and the natural synergies and
efficiencies that will follow.
Q. Please continue.
A. As a result of this comprehensive Phase 0 assessment,
Gas Operations is planning to deploy the Logica ARM
Suite to all of its departments and sections over a
three-year period beginning in late 2014. The only
exception, however, is for the LNG Plant, which will
continue to use its MAXIMO work system.
A variety of applications do presently support the
core work management processes within the various
departments and sections of Gas Operations. Although
some of these applications remain operable and
technically supportable, they do not provide the
levels of real-time visibility, integration, and
coordination that are needed to significantly improve work management processes throughout Gas Operations. Implementation of the Logica ARM Suite, however, will provide Gas Operations with a single integrated repository for all planned maintenance and inspection work. This system will significantly improve work management in Gas Operations. Other benefits include the following: work requirements and tasks will be mapped to worker skills; detailed workforce productivity data will be transparent and available at all levels; the system can be easily integrated with mobile technologies, thereby allowing for real-time transfer of data to and from the field; and the system will have the ability to interface with already existing features of the Company’s Finance, Supply Chain, and HR systems.

As presented in Exhibit ___ GOP-2, pages 194 through 196, we currently anticipate the following capital expenditures to support the Gas Work Management System during the upcoming five-year period: $0 in 2013; $2.6 million in 2014; $17.6 million in 2015; $18.0 million
in 2016; and $10.6 million in 2017. Upon full implementation of the Logica ARM Suite, Gas Operations expects to realize an annual benefit of $13.3 million. This amount represents cost savings from efficiency and productivity gains in both process and technology improvements.

Q. Please describe any other Gas-related corporate Information Technology initiatives currently planned to be completed by the Company during the upcoming five-year period.

A. The Company plans to complete the following two Gas-related corporate Information Technology initiatives during the upcoming five-year period:

- Mapping System; and
- Replacement of ADAMS.

Q. Please describe the Mapping System project.

A. The first corporate initiative is the Mapping System, which is a Company-wide effort to define and implement a solution to consolidate six core mapping systems and thirty-two other ancillary applications over a five-year period. The systems to be replaced are between
fifteen and twenty-nine years old. From a technology perspective, the VISION system (i.e., the system used by the Company’s engineering departments to maintain the maps and records of gas mains and secondary electric lines), together with the Netmap and Maps applications (i.e., the applications used by the Company to visualize maps for end-users of electric, gas, and steam maps), are facing the highest risks for obsolescence. These applications need to be replaced because they are currently running on software that cannot be upgraded. If these applications are not upgraded, the Company will be forced to choose in July 2015 between running on an unsupported operating system (i.e., Server 2003) or paying $1.6 million to Microsoft for annual technical support. These technical support costs are estimated to double annually to $3.2 million in 2016 and $6.4 million in 2017.

From a business perspective, the existing platform does not fully meet the Company’s current business
needs. Implementation of a consolidated mapping platform, however, will offer the following benefits:

- Consolidating data on a standard integrated platform will simplify and reduce the time required to record new assets on the maps and issue design work;

- Implementing a common, real-world coordinate system will make it easier to overlay and share data across commodities and with external stakeholders (e.g., municipal agencies, OEM, etc.);

- Establishing standards for mapping processes that results in efficiencies by leveraging common work processes and software;

- Leveraging investment in work management with integration to the Logica ARM Suite; and

- Providing self-service tools for ad-hoc reporting and visualization.

As presented in Exhibit ___ GOP-2, pages 187 through 190, we currently anticipate the following capital expenditures to support Gas Operations’ share of the
Company-wide Mapping System initiative during the upcoming five-year period: $3.0 million in 2014; and $1.5 million in 2015.

Q. Please describe the replacement of ADAMS program.

A. The second corporate initiative involves the replacement of ADAMS, which is the application used across the Company to track and manage meters and meter exchanges. The new ADAMS application will be developed with current technologies that offer meter inventory management and extensive reporting capabilities for meter trending and performance tracking. This project is necessary because meter assets must be managed and tracked in order to ensure they are both adequately booked and performing properly. Despite past efforts to address its deficiencies, ADAMS remains an inflexible system that cannot be modified to fully meet the Company’s current needs. As a result, it is becoming increasingly difficult for the Company to meet changing requirements related to meters. For instance, even though the Company is currently engaged in a large
automatic meter reading ("AMR") deployment, ADAMS can only capture serial numbers of each device installed together with a limited association to a meter – i.e., there is no manner in which to capture installation history, purchasing or retirement history, maintenance history, or device transfer history. The ADAMS application, which was originally developed in 1989, also has limitations with generating new required reports, performing queries, and identifying meters and metering devices by type, service dates, and other criteria. In addition, the prefix system currently used for tracking the functionality of meters in ADAMS cannot support new meters that have the ability to change functionality through reprogramming. As such, the annual reconciliation of ADAMS and the Company’s Customer Service System is a major programming effort, particularly since the programming language for ADAMS is considered obsolete. For these reasons, the Company’s investment in a system to replace ADAMS will allow Gas Operations to more effectively manage its meter population in the foreseeable future. As
presented in Exhibit ___ GOP-2, pages 191 through 193, we currently anticipate a capital expenditure of $2.5 million in 2017 to support Gas Operations’ share of the Company-wide ADAMS replacement initiative during the upcoming five-year period. Preliminary estimates indicate Company-wide annual savings of approximately $1.5 million from this project. These savings estimates will be validated during an upcoming Phase 0 assessment that will be conducted in 2013.

Q. Please describe how the Company handles cyber security for its Gas systems environment.

A. Cyber security has been identified as one of the Company’s top corporate risks. For this reason, cyber security is designed and factored into all aspects of the Company’s Gas Control systems. Each year additional security measures, technologies, and policies are incorporated into this environment. The Company’s Gas Operations and Information Resources departments work closely to implement industry best practices together with other necessary security measures, technologies, and policies.
Q. Please describe the cyber security initiatives the Company is planning for its Gas systems environment during the upcoming five-year period.

A. The Company currently plans to complete two cyber security initiatives during the upcoming five-year period. The first initiative involves the implementation of new intrusion prevention systems into its primary Gas Control Center. The second initiative involves network reliability improvements in the Company’s backup Gas Control Center.

Q. What is the purpose of the backup Gas Control Center?

A. The backup Gas Control Center provides a means for continuous monitoring and control of the Company’s gas transmission and distribution systems in the event that the primary Gas Control Center and/or its systems become unavailable or inoperable due to computer hardware/software failure and/or physical destruction.

Q. What network reliability improvements are being planned for the backup Gas Control Center?

A. The backup Gas Control Room and associated control network computer hardware will be moved to a more
desirable location within the same building as part of other planned facility upgrades that are not associated with the backup Gas Control Room. The scope of work includes improvements to both the physical and cyber security of the control network and Control Center.

Q. What is the projected cost and completion date for this project?

A. This project is included in the Corporate Facilities capital budget. The projected cost is $1.3 million and the projected completion date is December 2013.

III. O&M EXPENDITURES

Q. What were the Company’s Gas O&M expenditures for the test year?

A. The Company had $88.2 million in O&M expenditures in the historic year.

Q. What level of O&M expenditures is the Company projecting for the Rate Year?
A. The Company is projecting $90.4 million in O&M expenditures in the Rate Year, or an increase of $2.2 million over historic year expenditures.

Q. Has the Company included forecasted financial information for periods beyond the Rate Year?

A. Yes. The Company has included financial information for two annual periods beyond the Rate Year (i.e., the 12-month periods ending December 31, 2015 and December 31, 2016, which we will refer to as RY2 and RY3, respectively, for ease of reference). The Company is forecasting O&M expenditures of $90.9 million in RY2 and $92.3 million in RY3.

Q. Have you prepared an exhibit entitled “GAS OPERATIONS – O&M EXPENDITURES BY CATEGORY?”

A. Yes, we have.

Q. Was this exhibit prepared under your supervision and direction?

A. Yes, it was.

Q. Please explain what is reflected in Exhibit ___ GOP-3.

A. This exhibit shows O&M expenditures in the test year and projected expenditures for the Rate Year. The
exhibit also provides projected O&M expenditures for RY2 and RY3.

Q. Please summarize your current O&M request.

A. Our current O&M request maintains historical levels of spending on existing programs while providing adequate funding to support new programs that are needed to meet emerging issues, all of which are being done in an effort to maintain system reliability and public safety.

Q. Please describe the drivers behind the $2.2 million O&M increase from the historic year.

A. The $2.2 million increase reflects two items. The first item is a normalization of a non-recurring credit of $1.4 million received by the Company in March 2012 from the New York City Department of Water Resources. This credit was for amounts expended by the Company in 1990 during its response to a water main break at East 18\textsuperscript{th} Street and 5\textsuperscript{th} Avenue in Manhattan. The second item is an increase of $800,000 to support new mandated in-line testing of gas transmission pipelines that operate at greater than
20% SMYS. The Company’s efforts to comply with these new in-line testing requirements are discussed in greater detail below in the “Deferral Accounting/Reconciliations” section.

IV. DEFERRAL ACCOUNTING/RECONCILIATIONS

Q. Does the Company’s current Gas Rate Plan provide for net plant reconciliation for capital expenditures and capital spending targets?

A. Yes.

Q. Is the Company proposing any modifications to these mechanisms?

A. Yes. The Company proposes to continue downward-only reconciliation of net plant, with certain changes to the mechanism currently in effect, and to allow the capital spending target mechanism to expire. The Company’s proposal is presented by Company witness Muccilo.

Q. Does the Company’s current Gas Rate Plan provide for periodic reporting regarding capital expenditures?
A. Yes. Under the current Gas Rate Plan, the Company must provide reports of its actual gas capital expenditures according to prescribed standards twice a year – once on a calendar year basis and once on a mid-year basis (i.e., for the first six months of a calendar year). For some special categories of expenditures, such as in connection with customer conversions from oil to gas use, the reports of expenditures are informational and without comparison to any forecast. The principal reporting requirement, however, is a project-by-project or category-by-category comparison of actual expenditures to those stated in the current rate plan with an explanation of the reason for any variance of 10% or more in a calendar year report and also in a mid-year report.

Q. Does the Company recommend any changes to this reporting requirement?

A. Yes, the mid-year reporting requirement should be eliminated. Our testimony supports capital expenditures on a full calendar year basis. Within the context of an annual period, month-to-month
operational planning and execution, including responding to unexpected circumstances, is the norm, not the exception. In fact, the rate plan recognizes and acknowledges the Company’s need for flexibility to reprioritize projects and even substitute one project for another. A six-month variation report could send a false signal(s) as to the Company’s performance in relation to the rate plan. For example, a project may be re-prioritized within the year but still completed on target by the end of the year. Accordingly, the Company believes that the semi-annual reporting requirement imposes an unnecessary administrative requirement that serves no valid purpose and should be eliminated. The Company proposes no changes to the annual reporting requirements.

A. Pipeline Safety Act

Q. Please describe the Pipeline Safety Act of 2011 and what it requires.

A. The Pipeline Safety Act of 2011 was introduced in Congress in September 2011 and signed into law in
January 2012, largely in response to a deadly gas
transmission explosion that occurred in September 2010
in San Bruno, California, on a 30” steel gas pipeline
owned by Pacific Gas and Electric. The Pipeline
Safety Act of 2011 authorizes and directs the U.S.
Department of Transportation ("DOT") to perform
studies and promulgate rules intended to enhance the
safety of the gas pipeline industry. Some of the
provisions of the Pipeline Safety Act of 2011 include:

- Increased civil penalties;
- Increased focus on damage prevention;
- Use of automatic and/or remote-controlled shut-
  off valves on transmission pipelines, where
economically, technically, and operationally
feasible;
- Expansion of transmission pipeline integrity
  management programs beyond high-consequence
  areas; and
- Requirements for operators to validate the MAOP
  of their transmission pipelines.
Q. Please explain more specifically the requirement for operators to validate the MAOP of their pipelines.

A. The Pipeline Safety Act of 2011 mandates DOT to require owners/operators to conduct a records search of their transmission pipelines to verify that their records accurately reflect the physical and operational characteristics of the pipelines, and confirm the established MAOP of the pipelines. For owners/operators of pipelines with records that are insufficient to establish the MAOP, the Pipeline Safety Act of 2011 requires DOT to issue regulations for conducting tests to confirm the material strength of pipelines that operate at greater than 30% SMYS. DOT must consider pressure testing and alternative methods, including in-line inspections ("ILI"), which may be determined by DOT to be of equal or greater effectiveness.

Q. When are the regulations under the Pipeline Safety Act of 2011 expected to become effective?

A. Most of the regulatory requirements are expected to become effective from 18 to 24 months after passage of
the Pipeline Safety Act of 2011 (i.e., prior to December 2013).

Q. Please identify some of the uncertainties associated with the requirements of the Pipeline Safety Act of 2011?

A. With respect to MAOP verification for operators with insufficient transmission records, the Pipeline Safety Act of 2011 requires DOT to issue regulations for conducting tests to confirm the material strength of pipelines that operate at greater than 30% SMYS. The Company currently has approximately 8.5 miles of gas transmission pipe that operate above 30% SMYS. Upon completion of the St. Ann’s Tee to Hunts Point Downgrade Project, which involves the downgrade of approximately 2.7 miles of pipe from transmission pressure to high pressure, the Company will have approximately 5.8 miles of transmission pipe operating above 30% SMYS. Therefore, in 2013, the Company plans to begin conducting ILI over a five-year period of the 5.8 miles of gas transmission pipe that operate above 30% SMYS. The estimated annual cost for ILI is
The Company projects that by the end of the upcoming five-year period it will have completed ILI for approximately 3.8 miles of gas transmission pipe. However, there is significant risk that the regulations will be more stringent than anticipated. For example, DOT may not allow ILIs as an acceptable alternative to hydrostatic pressure tests. Additionally, ILI and/or hydrostatic pressure testing of the pipe may reveal anomalies that require significant capital expenditures to address. Moreover, DOT may extend its testing requirements to include all transmission pipe (i.e., greater than 20% SMYS); instead of limiting the testing requirement to transmission pipelines operating above 30% SMYS. Finally, DOT’s compliance schedule may be more aggressive than anticipated. Accordingly, because it is difficult to predict the full impact of the DOT regulations during the Rate Year, the Company is proposing that the Commission provide the Company the opportunity to defer O&M expenses in excess of $800,000, the Company’s current Rate Year projection
for costs related to compliance with the Pipeline Safety Act of 2011.

Company witness Muccilo discusses in his testimony a proposed deferral/reconciliation mechanism for net plant, including capital costs the Company may incur to comply with the Pipeline safety Act of 2011.

Mr. Muccilo notes Commission approval of a similar deferral mechanism in a prior Con Edison gas rate case associated with new regulatory requirements for distribution integrity and/or gas inspections promulgated by either federal or state regulatory agencies.

V. PERFORMANCE MEASURES

Q. Is the Company proposing any changes to the currently-effective Safety Performance Measures, which are set forth in section VI. A. of the Joint Proposal adopted by the Commission in its September 2010 rate order?

A. No. For the reasons explained in prior Con Edison rate proceedings, the Company does not believe that its safety or reliability performance would differ in
the absence of these specific performance measures. Nonetheless, the Company recognizes that the Commission has determined that safety performance measures continue as an element of gas utility rate plans.

The current mechanisms were considered and established two years ago. There are no new circumstances that warrant an adjustment to these mechanisms. The Company has met each of these targets during the current rate plan and expects to meet these targets in the future, should they be continued. Any adjustments to these targets that would make them more stringent would likely cause the Company to incur incremental costs that would unnecessarily increase rates, without a necessary or measurable increase in the safety or reliability of the Company’s gas service.

Q. Does this conclude the Gas Operations Panel’s initial testimony?

A. Yes, it does.