PRE-FILED DIRECT TESTIMONY

OF

SUSAN L. FLECK

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Susan L. Fleck. My business address is 52 Second Avenue, Waltham, MA 02451. I am Vice President of Engineering Standards and Policy for National Grid USA.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science in Civil Engineering from Carnegie-Mellon University in 1980. In 1989, I received a Masters of Business Administration in Finance from Boston College. From 1980 to 1981, I worked as an engineer for Columbia Gas Transmission Company in the Measurement and Regulation Department. I joined The Brooklyn Union Gas Company in 1981 as an Engineer. From 1982 to 1985, I worked for Consolidated Edison Company as an Associate Engineer in the Gas Operations Department. In 1985, I joined Boston Gas Company as a Measurement and Design Engineer. I remained with Boston Gas Company through the end of 2000, holding numerous positions including: Superintendent Distribution Administration; Director Distribution System Planning; Group Leader Distribution System Design; Construction Engineer; Vice President Engineering and Gas Control, and Vice President Engineering and Environmental Management. Following the acquisition of Boston Gas Company by KeySpan Corporation in 2000, I was named Vice President NY Gas

Operations. Following the acquisition of KeySpan Corporation by National Grid PLC in August 2007, I returned to New England and was named to my current position.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the American Gas Association and current chairperson of the Operations Managing Committee. I am also a member of the American Society of Civil Engineers.

Q. WOULD YOU BRIEFLY DESCRIBE YOUR CURRENT AREAS OF RESPONSIBILITY FOR NATIONAL GRID?

A. Yes. In my position as Vice President of Engineering Standards and Policy, I have several areas of responsibility. My areas of responsibility include: (1) ensuring the Company's regulatory compliance with applicable state and federal codes and standards relating to gas-pipeline safety, including reporting and communications with those agencies; (2) the development and periodic review of the Company's internal codes and standards relating to gas-pipeline safety; (3) the development of material specifications and analysis of material failures, and (4) oversight of the Company's research and development activities aimed at improving gas-pipeline safety.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents the Company's proposal to accelerate the bare steel and cast-iron main replacement programs historically maintained by the Company (as

Southern Union Company and its predecessor companies), as well as the Company's proposal to establish a new capital-replacement program targeted at the elimination of high-pressure, bare-steel services located inside customer premises. To that end, my testimony is organized as follows: Section II provides an overview of the Company's Rhode Island gas operations and outlines the Company's operating philosophy. Section II also discusses the post-acquisition review process conducted by the National Grid after the acquisition of operations from Southern Union Company ("Southern Union"), as well as the resulting conclusions. Section III describes two initiatives that the Company has identified as critical elements of a going-forward strategy to maintain and improve the safety and reliability of its Rhode Island gas operations for the benefit of customers and the communities that the Company serves.

II. IMPLEMENTATION OF THE NATIONAL GRID OPERATING PLATFORM

Q. WOULD YOU PLEASE PROVIDE A BRIEF DESCRIPTION OF THE CHARACTERISTICS OF THE RHODE ISLAND GAS OPERATION?

A. Yes. National Grid distributes natural gas to approximately 250,044 active residential and commercial and industrial ("C&I") customers in 39 cities and towns in Rhode Island. At end of calendar year 2007, the delivery infrastructure in place to serve these customers was comprised of the following:

Category	**Miles of Main**	**Number of Services**
Bare Steel – Unprotected	440	53,671
Coated Steel – Unprotected	240	12,802
Coated Steel – Protected	564	11,408
Plastic	941	106,500
Cast Iron	900	183
Ductile Iron	17	0
Copper	0	180
Other	1	1,547
Total	**3,102**	**186,291**

Like other natural gas local distribution companies, National Grid's fundamental obligation is to maintain its distribution infrastructure in a manner that is in compliance with applicable state and federal pipeline safety regulations and that will provide safe and reliable service to customers. As described below, National Grid takes this obligation very seriously and views its current size and organizational capability post-merger as positive for Rhode Island customers in terms of the expertise, investment capability and commitment that will be brought to bear on a going forward basis.

Q. WHAT ARE THE REGULATORY STANDARDS THAT MANDATE OR PROVIDE GUIDELINES FOR MAIN AND SERVICE REPLACEMENTS?

A. Regulations promulgated by the U.S. Department of Transportation ("USDOT") require the Company to maintain a safe and reliable system and establish minimum standards set forth at 49 C.F.R., Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. Although the regulations designate the Company as the "pipeline operator" with responsibility for maintaining the safety and reliability of the distribution system, the regulations do not mandate specific asset replacement cycles. Instead, the regulations obligate the pipeline operator to identify and evaluate main replacements based on site-specific determinations on criteria such as leak history, maintenance history, street reconstruction activities, and operating pressure, which are factors best assessed by the pipeline operator. The USDOT regulations delegate authority to the Division to ensure that the Company is meeting its obligations for safety and reliability.

Q. HOW DOES NATIONAL GRID PLAN TO FULFILL ITS OBLIGATIONS AS A NATURAL GAS PIPELINE OPERATOR?

A. In Rhode Island, National Grid has historically provided electric delivery services to customers on a statewide basis with the exception of Block Island and the Pascoag Fire District. In 2006, National Grid acquired the Rhode Island operations of New England Gas Company, along with responsibility for providing gas service to approximately 250,000 customers located in 39 cities and towns. In

August 2007, National Grid completed a merger with KeySpan Corporation, and now serves over 3 million natural gas customers using a delivery structure that spans four state jurisdictions. The delivery relied on to provide service to customer premises encompasses a broad range of system components of varying material, vintage and operation and maintenance ("O&M") histories. At this juncture, one of the Company's core challenges is to operate its Rhode Island gas distribution system to the level of safety and reliability that customers expect and deserve.

To that end, National Grid has worked to organize its gas operations to ensure a strong focus on safety, reliability and customer service. The Company's efforts are aimed at not only ensuring compliance with state and federal pipeline safety requirements, but also on the establishment of a corporate operating philosophy and service-territory presence that recognizes the unique responsibilities and privileges that are inherent in the delivery of natural gas service to customer homes and businesses. As Vice President of Engineering Standards and Policy, my responsibility is to ensure that the Company's operating philosophy and commitment is converted into action on a consistent basis through the Company's service territory.

Q. HOW WILL THE COMPANY ACHIEVE THIS OBJECTIVE FROM AN OVERALL PERSPECTIVE?

The Company will achieve this objective through its efforts to comply with applicable state and federal pipeline safety requirements, as well as through the development and application of internal standards that are designed to set optimal thresholds for asset integrity and system maintenance across all operating areas within the National Grid service territory. As discussed in more detail below, the Rhode Island gas operations will benefit greatly on a going forward basis from their inclusion in the National Grid framework because application of the Company's operating standards to the Rhode Island distribution system will represent a substantial improvement over the historical practices of the Company's predecessor owners. Through its consolidation of gas distribution operations throughout its service territory, National Grid is now in the position to bring a higher level of technical expertise, experience and resources to the Rhode Island gas operations.

Q. HOW DID THE COMPANY APPROACH IMPLEMENTATION OF ITS OPERATING APPROACH IN RHODE ISLAND?

A. Starting prior to, and continuing through, merger-integration activities in New York, Massachusetts and New Hampshire, the Company took steps to perform a baseline assessment of the Rhode Island gas operations. This baseline assessment was designed to give the Company a comprehensive view of the state of the Rhode Island distribution system and to facilitate the development of internal work and resource plans under the new organization. The baseline assessment was performed by the gas operations integration team, which was comprised of representatives from National Grid, KeySpan and New England Gas Company, including subject-matter experts in the areas of engineering, construction, maintenance and customer service. As part of this assessment, the integration team evaluated a series of factors including (1) organizational structure and division of responsibilities; (2) internal O&M work standards and practices; (3) historical records on system performance and construction, maintenance and replacement activities; (4) records regarding compliance or non-compliance with applicable pipeline safety requirements; (5) historical operating budgets and expenditures; (6) compliance statistics, and (7) relevant system maps and records.

The integration team was tasked to evaluate Rhode Island compliance with state and federal pipeline safety requirements and to reach a determination as to the competency of the system in terms of asset integrity and system maintenance. The Company views asset integrity and system maintenance as the two principal drivers of system reliability and has established internal thresholds for these factors to be applied on a consistent basis across its service territories. These thresholds are established to achieve optimal operating performance, balanced with considerations of load requirements and resource allocations. Therefore, the fundamental objective of the baseline assessment performed by integration team was to render a determination as to the steps to be taken by the new organization to ensure that the Rhode Island gas operations measure up to the system-wide threshold standards.

Q. WHAT WERE THE RESULTS OF THE BASELINE ASSESSMENT?

A. The integration team reached several conclusions as a result of its assessment of the Rhode Island gas operations indicating areas of strength and areas where challenges exist. The challenges of primary interest to the Company were the following:

- Cast iron pipe inventory (leak prone)
- Bare steel pipe inventory (leak prone)
- High pressure bare steel inside service inventory
- Cast iron encroachment backlog and strengths:

The areas of strength included:

- Emergency response
- Maps and records

All of these considerations were taken under advisement and are serving as an important guide in shaping and implementing future work plans.

Q. WHAT ARE THE SPECIFIC STEPS THAT THE COMPANY IS TAKING IN ITS WORK PLANS TO ADDRESS THE SHORTCOMINGS IDENTIFIED THROUGH THE BASELINE ASSESSMENT?

A. In the past several months, National Grid has implemented a series of changes aimed at improving efforts to construct, maintain and operate the Rhode Island gas delivery infrastructure. The efforts include, but are not limited to the following:

- Implementation of a new leak detection and repair process, adding a "Grade 2A" leak classification, increasing surveillance activities and expediting repairs for higher-risk leaks.
- Initiation of a new Gas Emergency Plan.
- Reducing cast-iron encroachment backlog.

Q. HAS THE COMPANY IDENTIFIED ANY AREAS AS REQUIRING SPECIFIC ATTENTION AND CONSIDERATION IN TERMS OF GOING FORWARD WORK PLANS?

A. Yes. There are two specific areas that will require particular attention by the Company on a going forward basis. These two areas are: (1) bare-steel and cast-iron main replacement, and (2) replacement of high-pressure, bare-steel services located inside customer premises. These two areas are critical in terms of improving the safety and reliability of the Rhode Island distribution system. For that reason, the Company is proposing in this case to establish the framework necessary for the Company to make increased progress on these issues for the benefit of customers and the communities that within which the Company serves.

III. INFRASTRUCTURE IMPROVEMENT PROPOSAL

Q. WHAT IS THE COMPANY'S PROPOSAL FOR INFRASTRUCTURE IMPROVEMENT IN THIS PROCEEDING?

A. As a result of the baseline assessment of the Rhode Island gas operations, the Company has concluded that capital spending must be increased substantially over historical levels in two areas in order to ensure that the Rhode Island system meets the Company's basic thresholds for operating integrity. As stated above, these areas are: (1) bare-steel and cast-iron main replacement, and (2) the replacement of high-pressure, bare-steel services located inside customer premises (hereinafter referred to as "HP/IS"). In this proceeding, the Company is proposing to commence an Accelerated Pipe Replacement Program ("APRP") to allow for the accelerated replacement of bare steel and cast-iron mains and to eliminate bare steel HP/IS over a five-year period. An outline of proposed program mechanics is provided as Attachment NG-SLF-1. To fund the APRP, the Company proposes to establish a capital-tracking mechanism that would allow for the recovery of the capital expended on an annual basis for bare steel and cast-iron main replacement and to eliminate bare steel HP/IS. An overview of the Company's proposal is discussed in detail below.

Q. WHY IS THE COMPANY PROPOSING TO ACCELERATE MAIN REPLACEMENTS AND TO ELIMINATE HP/IS WITHIN FIVE YEARS?

A. Put simply, the Company is proposing to accelerate main replacements and eliminate HP/IS in order to achieve a higher level of safety and reliability on the distribution system.

In that regard, the distribution system consists of many different types of piping, including a large amount of cast iron and unprotected bare-steel mains and services that are highly susceptible to corrosion and /or breakage. Cast-iron piping was installed in the early 1900s because it was strong and relatively easy to install. Over time, it became apparent that cast iron was susceptible to breakage from ground movement and encroachment, and because it was not easily joined, was leak-prone at its joints. Cast-iron main was also unsuitable for long-distance transportation of gas because of its inability to withstand high pressures. Therefore, the use of cast iron for gas-main installation was curtailed, with the last cast iron installed on the Rhode Island distribution system in 1970. Today, the Company's Rhode Island distribution system encompasses approximately 900 miles of cast-iron main (and 183 related cast-iron services), comprising approximately 29 percent of the Company's total Rhode Island distribution main.

During the post WWII construction boom, the Company's predecessors followed prevailing industry practice by installing a significant amount of bare-steel mains and services in the Rhode Island distribution system. Although deemed to be stronger than cast iron and able to withstand greater pressure, bare-steel piping installed at that time had no exterior coating and no cathodic protection, which are now viewed as critical elements in preventing pipe corrosion. As best as the Company can determine, unprotected bare steel was not installed in the Rhode Island distribution systems after 1966, and in 1970, the federal government prohibited any further use of bare steel for natural gas distribution infrastructure.

Q. WHAT STEPS WERE TAKEN BY THE INDUSTRY TO COMBAT CORROSION ON BARE STEEL MAINS?

A. All metals corrode as a result of the natural process of chemical interactions with their physical environment, but moisture and soil conditions are viewed as the most common culprits in the chemical process. In order to combat corrosion, gas companies began to install coated steel instead of unprotected bare steel. The coating was designed to electrically isolate the steel from electrolytes in the surrounding soil; however, over time unprotected coated steel corroded. Eventually, the Company began to install "cathodic protection," which is a procedure by which underground metal pipe is protected from corrosion and deterioration through the application of an electric current to the pipe. Cathodic protection reduces corrosion by making the surface of the pipe the "cathode" and another metal the "anode" of an electric mechanical cell. A primary function of the coating on a cathodically protected pipe is to reduce the surface area of exposed metal pipe on the pipeline. Cathodically protected steel has all the advantages of steel in terms of strength, but also is highly resistant to corrosion.

Today, the Company's Rhode Island system encompasses approximately 680 miles of unprotected, bare steel and coated-steel main (and 66,473 related services), comprising approximately 22 percent of the Company's total Rhode Island distribution main. The Company's Rhode Island system also encompasses 563 miles of cathodically protected bare-steel main (and 11,408 related services). However, it is the unprotected coated and uncoated bare-steel main that is of particular concern to the Company.

Q. WHAT IS THE PREVAILING INDUSTRY PRACTICE REGARDING MAIN REPLACEMENT AT THIS POINT?

A. Given the corrosion issues involved in the installation of bare-steel main, and the cost of installing cathodic protection to avoid that corrosion, the industry is currently relying heavily on the use of plastic pipe for distribution system main installations. Plastic pipe has proven to be the accepted industry standard for main installation given its strength, flexibility and relative immunity to the stress of ground movement. Plastic main is also less costly to purchase, and easier to join and install than steel pipe. Most importantly, plastic main does not corrode. Today, the Company's Rhode Island system encompasses approximately 941 miles of plastic main (and 106,500 related services), comprising approximately 30 percent of the Company's total Rhode Island distribution main.

Q. THE COMPANY HAS A LONGSTANDING MAIN REPLACEMENT PROGRAM. WHAT HAS CHANGED TO REQUIRE AN ACCELERATION OF THESE ACTIVITIES AT THIS POINT?

A. Since the early 1970s, the Company's predecessors have continuously replaced and retired cast iron and unprotected bare-steel mains based on historical leak rates and a number of internally defined risk criteria indicating the need for replacement. However, at this point, the Company's Rhode Island distribution system is comprised of approximately 900 miles of cast-iron main and 440 miles of unprotected bare-steel and coated-steel main, which together represent 43 percent of the Rhode Island distribution system. As part of its baseline assessment, the Company reviewed the historical level of main replacement under taken to eliminate bare-steel and cast-iron main, as well as the available leak and maintenance history for these facilities. National Grid determined that there is an unacceptable level of leaks in certain areas where cast iron and unprotected bare-steel piping is concentrated and the rate of occurrence of these leaks is increasing.

Specifically, the Rhode Island gas operation has averaged over 1,400 total leaks per year in its system since 2005, which is more than 50% higher than the leak rate of 900 leaks per year for the years 1991 through 2004, despite a significantly reduced inventory of bare and unprotected coated steel. This experience is a clear indication that damage and deterioration associated with corrosion is accelerating. Of the 680 miles of unprotected steel main existing on the Company's Rhode

Island system, approximately 440 miles are unprotected, uncoated bare-steel main, which is the oldest and most susceptible main in terms of a corrosion threat. Much of the remaining 240 miles of unprotected coated steel pipe is not suitable for cathodic protection. Through the existing main-replacement program, the predecessors of the Company have removed almost 120 miles of bare and unprotected coated steel mains from the system in the last 10 years, yet the total number of leaks has climbed from 651 in 1998 to 1414 in 2007. Moreover, the number of leaks per mile for bare and unprotected coated steel in Rhode Island exceeds the average number of leaks per mile for the bare and unprotected coated steel in other areas of the Company's system.

At the current replacement rate of 7.5 miles/year of bare steel and 5.5 miles/year of cast iron, National Grid estimates it would take approximately 60 years to replace the remaining bare steel and approximately 160 years to replace the remaining cast-iron main. As a result of the baseline assessment, National Grid has determined that continual system degradation due to unrelenting corrosion will inevitably undermine its ability to meet demand and operate the system safely and reliably, as required by federal pipeline regulations. Accordingly, the Company is proposing to implement an accelerated program of cast-iron and unprotected steel main replacement in order address the challenges presented by this type of distribution infrastructure.

Q. WHAT IS THE COMPANY'S PROPOSAL TO ACCELERATE MAIN REPLACEMENTS?

A. By comparison to historical replacement levels, the Company anticipates that a cost-effective ramp-up of main-replacement activities would result in the replacement of approximately 18 miles per year of bare-steel mains as compared to historical levels and up to 5 miles per year for small diameter, cast-iron mains, which have not been replaced on a systematic basis in the past. The details of the APRP are set forth in Attachment NG-SLF-1 and the related rate recovery is discussed in the testimony of Mr. Laflamme. Through the APRP program the Company would replace bare and unprotected coated steel mains, small-diameter, high-risk cast-iron mains and other related facilities based on the needs of the distribution system, in accordance with the basic terms of the APRP. Replacements would be prioritized by the condition and age of the pipe, geographical proximity, the capacity needs of the area, and expected growth in system demand requirements. The Company will undertake the program in a systematic, planned basis to maximize cost efficiency and program effectiveness in terms of reduced leak rates.

Q. WOULD YOU PROVIDE MORE SPECIFICITY REGARDING THE METHODOLOGY THAT THE COMPANY WOULD EMPLOY TO PRIRORITIZE MAIN REPLACEMENTS IF THE ACCELERATE PROGRAM IS IMPLEMENTED?

A. Yes. In short, the Company would seek to replace main on a risk-based prioritization basis, with consideration given to opportunities to coordinate replacement projects with state and local construction and street-paving schedules.

More specifically, the Company has an evaluation process in place that is designed to identify and plan for the replacement of mains and services necessary to ensure the safety and reliability of the distribution system. To achieve this objective, the Company (1) compiles data on the condition of mains and services; (2) reviews and evaluates mains and services for potential replacement; and (3) prioritizes and schedules replacements. Information regarding the condition of the Company's mains is gathered and documented through various field-maintenance activities and ongoing activities that review the distribution system. Historical data is compiled over time and also utilized in the process. The Company uses this data to evaluate the condition of the mains and services as follows:

- Review of System Leak History: The Company maintains a database of active and repaired leaks. The Company reviews the historic leaks, reasons for the leaks, the frequency of leaks along a pipe segment, and the type of leak and leak-repair needed. The Company reviews all outstanding leaks that are scheduled for repair.

- Review of Cast-Iron Bell Joint Leaks: This review is designed to analyze the number of leaking joints and resulting repair costs and compares the cost of repair to the cost of pipe replacement.
- Review of Maintenance Activities Other Than Leak Repair: This review is designed to analyze maintenance activities for conditions other than leaks, such as active corrosion on bare or coated steel mains. As with the leak-history analysis, the Company reviews the historic corrosion activity, frequency of corrosion-related repairs along a pipe segment, and the type of repair. This review identifies areas of the distribution system where active corrosion may exist. This analysis includes the evaluation of outstanding leaks that are scheduled for repair to ensure that all potential safety concerns are addressed.
- Observed Field Conditions: On-the-spot assessments of the condition of mains and services from field operations personnel.
- Review of Piping Material: The Company reviews the type, size and joining process for each piping material. This analysis takes into account the type of pipe (cast-iron, ductile iron, bare or coated steel, or plastic), the size of the existing pipe and whether size-for size upgrading is prudent, and the pipe-joint type (welded, threaded, bell and spigot joint, or mechanical joint).

- Review of Current and Future System Pressure and Capacity Review: This review analyzes the distribution system's current minimum pressure and compares it to established standards.
- Review of Customer Requests and/or Projected Growth: This review analyzes the distribution system's ability to serve new customers and to meet increased gas usage by existing customers.
- Proposed State or Municipal Construction and/or Paving Activity: Construction activities are reviewed and analyzed for the potential to create safety concerns or damage to the distribution system. In addition, replacement in conjunction with construction or paving contracts provides cost efficiencies for two reasons. First, the state or municipality will typically impose a moratorium on future excavation making it extremely difficult to undertake repairs should repairs become necessary in the short term (i.e., less than five years). Second, the cost of temporary and permanent pavement restoration is substantially mitigated. This results in a more cost effective replacement process and maximizes the total replacement footage with the available capital resources. Because State and municipal entities communicate information regarding planned construction and paving activities at various times during the year, the prioritization of replacement candidates may change as new information becomes available.

Following the evaluation of compiled data, the Company would identify and prioritize replacements for the program year.

Q. DOES THE COMPANY HAVE ANY SPECIFIC CONCERNS THAT WOULD BE ADDRESSED ON A PRIORITY BASIS WITHIN THE APRP?

A. There are two specific areas that would be prioritized through the implementation of the APRP, which are: (1) the acceleration of the existing bare-steel main replacement program, and (2) the commencement of replacement activities for small-diameter cast-iron mains and high-pressure, bare-steel inside services, where no systematic replacement was undertaken in the past. The Company has identified that the highest-priority infrastructure issues existing on the Rhode Island gas distribution system at this point is the quantity of bare-steel and cast-iron mains remaining on the system and the existence of approximately 8,261 high-pressure, bare-steel inside services.

In particular, high-pressure bare-steel inside services pose a unique risk to public safety because of the fact that these services are both high pressure <u>and</u> susceptible to corrosion. The Company has a limited ability to detect corrosion on these types of services because the inside location results in a situation where the Company's pipe crosses through the wall of the customer premises and is not readily accessible to corrosion inspection. As a result, failure of this pipe segment is detected only when a leak occurs. In the past, the Company's predecessors have replaced these services at the point that a leak is detected. However, the Company's experience indicates that a more proactive approach is necessary and warranted, which would involve the accelerated, systematic removal of these types of services at a rate of approximately 1,600 units per year (as compared to

500-600 per year historically). From the Company's perspective, the accelerated replacement of these types of customer services is vital.

Q. WHAT IS THE COMPANY'S PROPOSAL TO ELIMINATE HIGH-PRESSURE, BARE-STEEL INSIDE SERVICES?

A. As represented in Attachment NG-SLF-1, the Company would accomplish its objective of eliminating HP/IS as an incremental capital program encompassed within the APRP over a five-year period.

Q. ARE THERE ANY OTHER CONSIDERATIONS DRIVING THE NEED TO IMPLEMENT THESE TWO PROPOSALS AT THIS POINT IN TIME?

A. Yes. I am currently serving as the Chairperson of the American Gas Association Operations Management Committee. Through my participation in that group, I am aware that the USDOT is planning on issuing draft regulations in April 2008, which would impose new requirements on LDC pipeline operators. These regulations are designed to move away from a prescriptive framework establishing O&M codes and standards and mandating compliance with those standards. Under the new regulatory plan, pipeline operators like National Grid would be required to establish O&M work plans based on an "organic" assessment of system maintenance requirements and asset integrity. This new system would require the pipeline operator to conduct risk assessments of system-maintenance requirements and asset-integrity considerations and to bear responsibility for maintaining its system within acceptable risk tolerances. This shift in regulatory emphasis is important because the philosophical approach embodied therein is the same approach driving the Company's proposals in this proceeding. Specifically, the Company believes that it is absolutely critical that it has the funding necessary to move forward with an accelerated main replacement program and a plan to eliminate HP/IS within five years because the risk inherent in *not* moving ahead with these initiatives is inconsistent with the risk profile of the rest of its systems.

Q. HOW WOULD THE COMPANY'S PROGRESS ON THESE TWO INITIATIVES BE MEASURED, TRACKED OR REPORTED?

A. As stated in the APRP, the Company would institute a program work-plan, tracking and reporting process that would allow for coordination with Commission and Division staff throughout the construction year. The major aspects of this effort would include:

- The annual submission of a "DRAFT" Pipe Replacement Program Plan ("PRP Plan") to the Division and Commission staff for their review and comment;
- Technical sessions with Commission and Division staff to review, modify and agree on the PRP Plan;
- Filing with the Commission for review, approval and implementation of the Plan;
- Annual reconciliation of capital expenditures made in accordance with the PRP Plan and recovery through rates; and

- Filing of an annual compliance report on the prior fiscal year's activities.

Q. DOES THE COMPANY CURRENTLY CONDUCT SIMILAR PROGRAMS IN OTHER JURISDICTIONS?

A. Yes, the company is currently administering a similar APRP in New York and has recently begun a new program in New Hampshire as well. Both programs are currently being implemented and contain provisions that are consistent with the approach proposed for Rhode Island.

Q. WHAT IS THE RECOMMENDED AMOUNT OF INCREMENTAL CAPITAL SPENDING THAT WOULD BE NEEDED TO ACCELERATE THE REPLACEMENT OF BARE STEEL AND CAST-IRON MAINS AND HP/IS.

A. In Attachment NG-SLF-2, I have summarized the Company’s overall operations-related capital requirements, with specific detail on the recommended capital spending associated with the Company’s plan to accelerate the replacement of bare steel and cast-iron mains and HP/IS (entitled “Proactive Integrity Programs” on Attachment NG-SLF-2). As shown therein, the Company expended approximately $10.8 million in 2008 to replace bare steel mains and associated services. The replacement of HP/IS and small diameter cast-iron main was not undertaken in the past on a systematic basis, and therefore, minimal capital investment is associated with these activities on a historical basis. Any minimal spending that did occur in 2008 would be categorized within "Non-Growth" on Attachment NG-SLF-2.

Therefore, to accommodate the recommended level of acceleration, the Company would need to increase its investment in bare steel and cast-iron main replacement from $10.8 million in 2008 to approximately $21.5 million in 2009 and $26.7 million in the years 2010, 2011 and 2012.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Attachments of
Susan L. Fleck

Attachments

Attachment NG-SLF-1 - Accelerated Replacement Program

Attachment NG-SLF-2 – Direct Gas Business Unit Capital Budget

NG-SLF-1

Accelerated Replacement Program

(A) Preparation and Filing of Plans

(1) By no later than January 15 of each year, the Company will provide a draft copy of its Accelerated Replacement Program ("ARP") to the Division and Commission staff for their review and comment. The Company will meet with the Division and Commission staff in technical sessions to discuss the ARP, to obtain comments, and to answer any questions with a goal of arriving at a consensus plan to be implemented for the subsequent fiscal year ending March 31st[1]. After the Division and Commission staff review, the Company will file its final proposed ARP with the Commission no later than February 15. The review by the Division and Commission staff will not constitute an "approval" of the ARP and the Commission will have the right to take any position at Commission hearings after the ARP is filed.

(2) The ARP shall provide a description of the activities to be performed within the targeted amount of investments to be made during the following fiscal year. The ARP will itemize the proposed activities by general category.

(3) The Company's ARP shall be docketed by the Commission for review and approval by the Commission. The Commission retains the discretion to approve or reject any components of the ARP.

(4) After the Commission issues an order approving the ARP or components thereof, the Company will take all reasonable steps to carry out and implement the

[1] The first planning year is assumed to be the fiscal year ending March 31, 2010, with a draft ARP Plan due no later than January 15, 2009. The plan review and targeted spending levels for the fiscal year ending March 31, 2009, included in section C below is to be reviewed in the context of this proceeding.

approved components, consistent with the Commission's approval. It is recognized that the Company will not finalize its plans until after the winter frost patrol ends in early April. By May 1, the Company will finalize actual projects and provide a copy of the final plans to the Safety Division for confirmation that it is consistent with the approval granted by the Commission. In addition, the priority rankings for pipe replacement may change over the course of the year due to new information that may become available. In such case, if the Company believes it is prudent to change the rankings from the approved plan, it will notify the Division and Commission staff, stating the reasons for the change prior to construction. In either instance, if the Division and Commission staff do not believe that any particular components of the revised plans are consistent with the Commission's approval, the Division or staff may object and the matter may be referred to the Commission if not resolved between the Company and the Division and Commission staff.

(5) The Company will reconcile actual capital expenditures with the ARP's targets at the conclusion of the ARP period. Approval by the Commission of the ARP or components thereof is for the purpose of allowing rates to be adjusted in accordance with the ARP and the rate adjustment provisions of section (D) below and does not relieve the Company of its obligation to operate its business and maintain safe, reliable service through expenditures and other capital investments in the ordinary course of business that are not set forth in the ARP.

(B) Process to Develop ARP

The Company will engage in an evaluation and selection process to target investments to be proposed in the ARP, as follows:

(1) The Company will undertake an annual review of the performance of the Company's distribution system in Rhode Island as it relates to the integrity of its bare steel and cast-iron mains as well as high-risk inside set services. This review will provide a detailed analysis of high-risk inside set services and leak activity over the preceding 10 years on the bare steel and cast-iron mains and an evaluation of which main segments and services represent the highest priority for replacement. Consideration will be given to the age of the main(s) or service(s), the date the leak(s) occurred, leak classification, type of leak, number of clamps used in leak repair, condition of main when repaired, specific leak location, and building types in the area of the main segment.

(2) Adjustments in the priority of pipe replacement may be made due to planned paving projects, public relations or whether new main segments have been identified by operating personnel in the field that were not captured through the company's data systems.

(3) Categories of spending in this program will include the following:

   a. Inside set services

   b. Unprotected bare-steel main replacement,

c. Cast-iron main replacement, and

d. Main replacement candidates requested by operating personnel.

(4) Using the process identified above, the Company will rank and prioritize the mains and services to be replaced in the following year. The ranking will be provided to the Commission for approval of the ARP, subject to adjustment as provided in section (A)(4) above.

(C) ARP Target Amounts

There shall be established a target amount of capital expenditures for bare steel and, cast-iron mains and services replacement. The target level of incremental PRP spending anticipated for the plan's first three fiscal years ending March 31, 2009, 2010 and 2011 are as follows: $21,500,000 for the Fiscal Year ending March 31, 2009 and, $25,100,000 for the fiscal years ending March 31, 2010 and 2011

(D) Capital Investment Allowance

After the Commission approves the ARP for a given fiscal year, the Company shall track all capital investments made in accordance with the approved components of the ARP. By no later than May 15, the Company shall file a report ("ARP Report") detailing the actual amount of capital investments made in accordance with implementing the approved ARP during the prior fiscal year[2]. The report shall include a calculation of a revenue requirement for the actual ARP spending up to the targeted amount[3].. The

[2] The first ARP Reconciliation Report will be due no later than May 15, 2009 for the fiscal year ended March 31, 2009.

[3] The Company's cost of service for the Rate Year ending September 30, 2009 included in this proceeding include 100% of the ARP target for the Fiscal Year ended March 31, 2009 and 50% of the ARP target for the fiscal year ending March 31, 2010. Consequently, if the Company spends less than the total ARP target in fiscal year 2009 and/or less than 50% of the ARP target for fiscal year 2010, a customer credit for the

imputed capital structure and costs approved by the Commission in this proceeding will be used in calculating such revenue requirement. If the Company spends more than the annual ARP targeted amounts, it reserves its right to petition the Commission for incremental rate recovery but will bear the burden of proof that such over spending was prudent.

Provided that the investments were made in accordance with the approved ARP, the Company will be allowed permanent annual rate increase adjustment for the revenue requirement of the actual ARP spending amounts, including a permanent reconciliation credit or incremental surcharge for the reconciliation of PRP spending allowances in base rates for the fiscal year 2009 ("ARP Rate Adjustment"). This permanent ARP Rate Adjustment take effect for usage on and after July 1 and until such time as the Commission approves a subsequent Company cost of service. The first ARP Rate Adjustment, if any, will take effect for usage on and after July 1, 2009 and annually on July 1 thereafter.

(E) Annual Report and Plan Deviations

The Company will file an annual CIBS Report on the prior fiscal year's activities at the time it makes its rate adjustment filing on May 15. In implementing the ARP, the circumstances encountered during the year may require reasonable deviations from the approved Plan. In such cases, the Company would include an explanation of any deviations in the report. For cost recovery purposes, the Company has the burden to

amount of under-spending in each of those fiscal years calculated in accordance with this section will be implemented If different ARP targeted amounts are approved by the Commission in this proceeding, ARP Targets will be modified accordingly.

show that any deviations were due to circumstances out of its reasonable control or, if within its control, were reasonable and prudent.

NG-SLF-2

National Grid - RI Gas
Direct Gas Business Unit Capital Budget
Fiscal Year - 12-months ended March

Line No.		Forecasted Budget	Projected Capital Budgets			
1						
2		**2008**	**2009**	**2010**	**2011**	**2012**
3						
4	**Growth (New Main, Services & Meters)**	$ 8,021,470	$ 9,222,910	$ 9,222,470	$ 9,222,470	$ 9,222,470
5						
6	**Proactive Integrity Programs**					
7	Main Replacement Bare Steel	$ 5,646,362	$ 9,694,080	$ 9,694,080	$ 9,694,080	$ 9,694,080
8	Main Replacement Small Diameter Cast Iron - High Risk	$ -	$ 1,583,366	$ 3,958,416	$ 3,958,416	$ 3,958,416
9	Service Replacements for Bare-Steel Main Replacement	$ 5,174,769	$ 5,331,840	$ 6,131,616	$ 6,131,616	$ 6,131,616
10	Service Replacement Program - Bare Steel H.P. Inside Set	$ -	$ 4,875,000	$ 6,906,250	$ 6,906,250	$ 6,906,250
11	Subtotal	$ 10,821,131	$ 21,484,286	$ 26,690,362	$ 26,690,362	$ 26,690,362
12						
13	**Non-Growth (Leak, Public Works, Corrosion, Meters)**	$ 9,336,919	$ 13,112,334	$ 13,085,976	$ 13,085,977	$ 13,085,978
14						
15	**Reliability (LNG, Reinforcement, Regulators)**	$ 3,045,913	$ 3,546,637	$ 6,370,912	$ 7,439,557	$ 7,548,098
16						
17	**Automatic Meter Reading (AMR)**	$ -	$ -	$ 4,600,000	$ -	$ -
18						
19	**Total**	$ 31,225,433	$ 47,366,167	$ 59,969,719	$ 56,438,366	$ 56,546,908