Liberty Utilities

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 20-105

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

DIRECT TESTIMONY

OF

BRIAN R. FROST,

ROBERT A. MOSTONE,

AND

HEATHER M. TEBBETTS

July 31, 2020

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TABLE OF CONTENTS

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I. INTRODUCTION AND BACKGROUND

Q. Mr. Frost, please state your full name, business address, and position.

A. My name is Brian R. Frost. My business address is 130 Elm Street, Manchester, New Hampshire. I am an Engineer IV for Liberty Utilities Service Corp. ("Liberty") in New Hampshire and provide engineering services to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or "the Company").

Q. Please describe your educational background and training.

A. In 2007, I received a Bachelor of Science degree in Mechanical Engineering from Rochester Institute of Technology. In the past I have attended the Appalachian Gas Measurement Short Course, the Northeast Gas Association ("NGA") Gas Operations School, and several in-person formal training classes provided by the manufacturer of the software the Company uses to make system planning decisions. On an ongoing basis, I regularly complete various self-study training programs on the mapping computer program the Company has utilized to manage its distribution system and prioritize replacement for gas mains under its Cast Iron and Bare Steel ("CIBS") program.

Q. Please describe your professional experience.

A. Since April 2016, I have been responsible for project identification and design related to the Company's CIBS program. I have also designed numerous gas distribution system growth and reinforcement projects. From 2019 to date, I have provided support to the Company's gas system planning efforts. From 2008 to 2016, I worked for New York State Electric & Gas Corporation as an engineer, mainly specializing in the writing and maintenance of gas construction standards and operating and maintenance procedures. In 2005 and 2006, I worked as a college intern at Rochester Gas and Electric Corporation in the Gas Engineering Department.

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes, I have testified on multiple occasions before the New Hampshire Public Utilities Commission ("Commission"), most recently in DG 20-049 in relation to EnergyNorth's 2020 CIBS program results.

Q. Mr. Mostone, please state your full name and business address.

A. My name is Robert A. Mostone and my business address is 130 Elm Street, Manchester, New Hampshire.

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

A. I am employed by Liberty as the Director of Gas Operations for EnergyNorth.

Q. Please state your professional experience and educational background.

A. I am a seasoned professional with more than 35 years of field experience with a solid understanding of Gas Field Operations and Construction & Maintenance. In July 2018, I assumed my current position of Director of Gas Operations where my responsibilities include managerial oversight of all gas operations and construction processes. From 2014 to 2018, I held the position of Customer Meter Services ("CMS") Manager, Gas Operations for EnergyNorth. My responsibilities as CMS Manager included business planning, strategy, and operations for CMS and managing over 50 employees across three gas divisions. From 2012 to 2014, I was the CMS Supervisor, Gas Operations, and selected as the lead to transition the Company and its employees through new system implementations by managing all aspects of the project. From 1992 through 2013, I worked for Colonial Gas Company, Eastern Enterprises, Keyspan, and National Grid in various supervisory roles. I have numerous certificates and licenses in the gas industry and years of leadership training and development obtained over my 35-year career.

Q. Have you previously testified before the Commission?

A. Yes. I testified before the Commission in DG 20-049 along with Mr. Frost.

Q. Ms. Tebbetts, please state your full name, business address, and position.

A. My name is Heather M. Tebbetts and my business address is 15 Buttrick Road, Londonderry, New Hampshire. I am Manager of Rates and Regulatory Affairs for Liberty and am responsible for providing rate-related services for EnergyNorth and Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Granite State").

Q. Please describe your educational background and training.

A. I graduated from Franklin Pierce University in 2004 with a Bachelor of Science degree in Finance. I received a Master of Business Administration from Southern New Hampshire University in 2007.

Q. Please describe your professional background.

A. I joined Liberty in October 2014. Prior to my employment at Liberty, I was employed by Public Service Company of New Hampshire ("PSNH") as a Senior Analyst in NH Revenue Requirements from 2010 to 2014. Prior to my position in NH Revenue

Requirements, I was a Staff Accountant in PSNH's Property Tax group from 2007 to 2010 and a Customer Service Representative III in PSNH's Customer Service Department from 2004 to 2007.

Q. Have you previously testified before the Commission?

A. Yes, I have testified on numerous occasions before the Commission, most recently in Docket No. DE 19-064, which was Granite State's most recent distribution rate case.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support the Company's cost recovery of plant additions placed in service since the Company's last rate case, as well as the request for step adjustments to recover the cost of non-growth plant additions in 2020, 2021, and 2022. Our testimony describes the factors driving the need for increased capital investment and outlines the Company's proposal to implement and fund an integrated capital improvement plan to maintain system safety and reliability and to address asset condition.

II. RATE CASE DRIVERS AND MAJOR CAPITAL PROJECTS

Q. How much capital has the Company invested in its distribution system since its last distribution rate case, Docket No. DG 17-048?

A. The Company's last rate case in Docket No. DG 17-048 was based on a 2016 test year and provided for a step increase to recover non-growth-related capital investments through December 31, 2017. The Company subsequently made capital investments for growth and non-growth capital in its distribution system of $49.9 million in 2018 and

$63.9 million in 2019, for a total of $113.8 million. Approximately $23.1 million of this total is currently included in rates.[1] The remaining balance of $90.7 million of the spending is not currently in rates and, of that amount, $84.4 million is for plant in service that is included in the Company's proposed revenue requirement.

Q. Please describe the factors driving the need for capital investment in the system.

A. In general, the Company's capital investments can be separated into two categories: (1) non-growth-related investment, which is associated with activities necessary to maintain system safety and address asset condition issues; and (2) growth-related investment, which is associated with new customers or increased load. Non-growth-related investment arises primarily from the replacement of leak prone pipe ("LPP") and other leak prone assets, from city and state requirements, and from public works projects. Growth-related investment, as stated above, is primarily due to the addition of new customers and increased load on the gas distribution system.

Q. For non-growth investments, please explain how EnergyNorth has historically recovered the cost of its investment to replace leak prone pipe.

A. The Company has historically recovered its investment to replace leak prone pipe through the CIBS program. The Commission established the CIBS program in 2007 to incentivize the replacement of cast iron and bare steel pipes, as those were most likely to leak or fail. To support the replacement of LPP, the Commission allowed for annual

[1] Of those capital investments, $23,077,461 has already been reflected in rate base through the CIBS program dockets for FY2019 (2018) and FY2020 (2019). Consequently, this amount is not included in the proposed revenue increase in this proceeding.

recovery of reasonably incurred costs through the CIBS program. The annual cost recovery was intended to ensure that aging infrastructure was replaced promptly while reducing regulatory lag and the expense of more frequent base rate cases.

In 2019, Commission Staff recommended that EnergyNorth's cast iron and bare steel replacement activities should continue as part of the Company's normal course of business, and not through the CIBS program, with capital spending on these replacements incurred after March 31, 2020, to be recovered through base rate cases. In Order No. 26,266, the Commission stated:

> By terminating the existing CIBS program, we are not precluding an alternative proposal in Liberty's next rate case. We continue to believe it is important to replace the cast iron bare steel infrastructure and would consider an alternative proposal from the parties during the anticipated rate case.[2]

Q. Did the Company make any other significant investments as part of the CIBS program that were not recovered in the CIBS rate dockets?

A. Yes. As part of the settlement agreement that established the CIBS program, meter set fittings (above-ground piping at customer meter sets) were not included for cost recovery in CIBS dockets. In 2018, the Company incurred costs of $1,427,488 in fitting work. In 2019, total spending related to CIBS meter fitting was $1,422,921. Because fitting costs

[2] Docket No. DG 19-054, Order No. 26,266 at 7 (June 28, 2019).

were not recovered through the CIBS program, the Company is requesting recovery of fitting costs in this proceeding.[3]

Q. Regarding the other broad category of non-growth investments, please describe city and state requirements and public works projects, and how they affect the Company?

A. The Company is responsible for the costs to install, relocate, and protect its gas facilities that are within the public right of way ("ROW"). This affects the Company in two major ways: (1) project coordination with state and municipal road projects; and (2) gas facility relocation to clear conflicts with public works jobs. For example, when a municipality is paving a roadway or performing sewer or water main replacements and LPP exists within the municipality's work area, the Company typically replaces the affected sections of LPP before paving in an attempt to avoid future excavation for leak repair maintenance. Additionally, if the location of the Company's existing gas facilities, such as gas mains or services, impedes or conflicts with municipal or state construction on roads, bridges, sewers, or drains, the Company is required to relocate those facilities so the municipality or state work can proceed.[4] Common examples of physical location conflicts occur when the Company's existing pipes are in the way of proposed bridge foundations, manholes, or gravity fed sewers and drains.

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[3] Fitting work for 2018 and 2019 LPP replacement was tracked under Projects 8840-1813 and 8840-1913, respectively.

[4] Two project numbers were used to track this work in 2018. Project 8840-1823 was used to capture all work related to gas mains and services installation. Project 8840-1825 captured all fitting work on aboveground pipe and meter sets.

Q. Is the annual volume of work for city/state requirements and public works projects easily predictable?

A. No. While the Company estimates the volume of work based on past trends, the actual amount in any given year is determined by what the municipalities and state decide to do in that year, over which the Company has no control. For example, in 2018 the City of Nashua introduced an accelerated five-year paving plan under which it increased its paving schedule by two to three times the normal volume. As a result, the Company completed two to three times the amount of work to replace cast iron and bare steel mains in the area that Nashua intended to pave, which avoided the significant costs of excavating newly paved streets for replacement projects in future construction seasons.

Overall in 2018, in coordination with city/state requirements and public works projects, the Company completed a total of 32 independent main replacement projects where approximately 2.9 miles of cast iron or bare steel and 0.5 miles of coated steel or plastic were replaced with plastic piping. As part of this work, the Company also replaced or transferred 236 services, 80 of which were bare steel that were replaced with plastic, and the remaining services being plastic or coated steel that were either transferred to the new main or replaced with plastic.

Even though the Company regularly meets with the municipalities in an attempt to refine the upcoming budget, the projects actually undertaken by the municipalities often differ from those originally identified as planned projects, thus affecting the Company’s budget. Such changes are, of course, outside the Company’s control. As a consequence, the

Company's total actual year-end spend in 2018 for replacement projects was $6,130,938 (compared to a budget of $5,310,000), with some of the variance driven by the increased volume of work due to municipal and state projects as described above.

In 2019, gas facility replacements in conjunction with municipal and state public works projects continued. The total spend for the main and service replacement work was $5,754,082. The Company also incurred costs of $241,623 for the associated fitting work,[5] *i.e.*, the above-ground work at the customers' meter sets. In completing this municipally driven work in 2019, the Company replaced approximately 1.7 miles of cast iron and bare steel mains and transferred 94 services, of which 31 were bare steel and were replaced with plastic. As noted in the Company's recent CIBS dockets, cast iron and bare steel gas facilities are often in the range of 100 years old and therefore it is imperative to replace them in conjunction with other public improvement projects.

Q. Please describe the growth-related capital investment since the last rate case.

A. The Company's customer base increases approximately two to three percent each year. To accommodate this growth, the Company installs new service lines off its existing mains, and builds main extension projects that include new service lines. The Company used four project numbers to track this work: (1) project number 8840-1847 was used to track all work associated with the installation of the gas mains installed to support growth; (2) project number 8840-1850 was used for gas services related to residential customers; (3) project number 8840-1851 tracked service work related to all other

[5] Fitting work for 2019 city state coordination projects was tracked under Project 8840-1925.

commercial and industrial customers; and (4) project number 8840-1849 collected costs related to the installation of above-ground piping from the new service lines and new meters, which was necessary prior to turning the gas on (meter fitting work related to new services).

In calendar year 2018, EnergyNorth completed 67 main extension projects totaling 14.5 miles of new plastic mains to support growth. The Company also installed 864 new service lines and a total of 1,461 new meters, of which 1,169 were residential meters and 292 were commercial meters. The total spending on growth projects in 2018, including all related project numbers, was $13,041,465.

For 2019, the Company utilized the following four project numbers to track work associated with growth of its customer base: 8840-1947 (new gas mains), 8840-1949 (meter fitting work related to new services), 8840-1950 (residential services), and 8840-1951 (commercial and industrial services). The Company installed approximately 12 miles of new gas mains along with 1,043 new service lines. The Company also installed 1,938 new meters of which 1,611 are residential meters and 327 are commercial meters. The total spending in 2019 for growth projects was $15,195,938.

Q. Please provide a summary of the Company's capital investments since the last rate case that are not currently recovered in rates.

A. Please see Attachment BF/RM/HT-1 for a list of capital investments that were placed in service as of December 31, 2019, but are not currently included in rates. A summary is also presented below in Table 1.

Total In Service Spend 2018 through 2019

Table 1

	2018	2019	Total
Non-Growth In Service	$23,921,009	$30,426,488	$54,347,497
Growth In Service	$13,079,184	$16,968,575	$30,047,759
Total	$37,000,193	$47,395,062	$84,395,256

III. PLANNED CAPITAL PROJECTS

Q. Does the Company have any significant capital projects planned for the next several years?

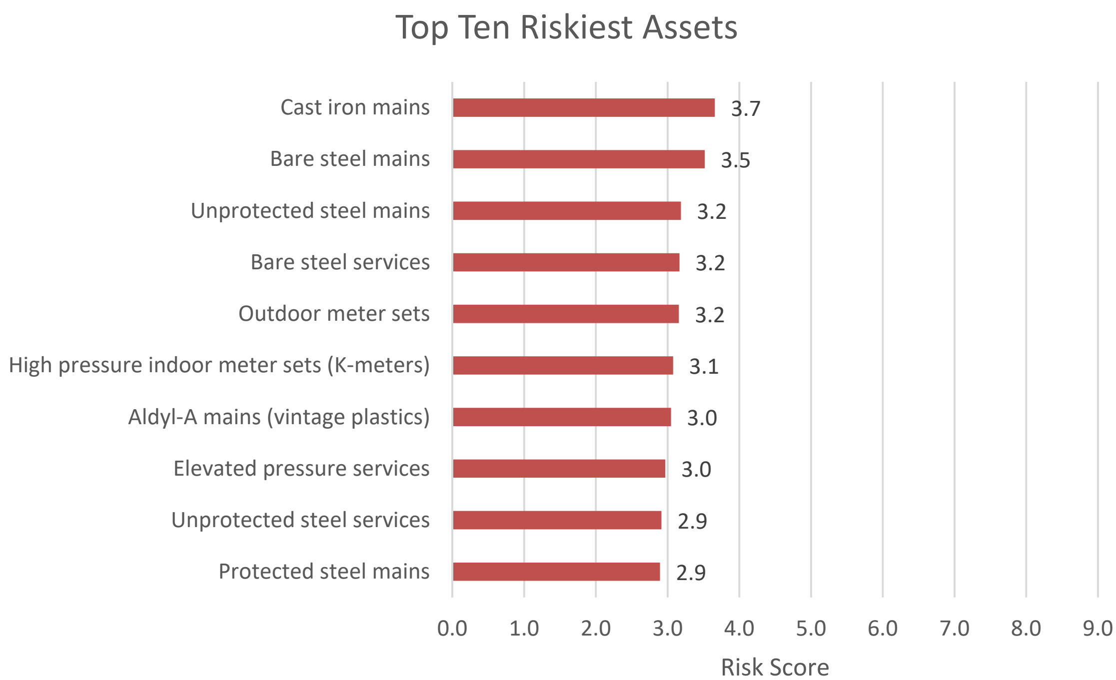
A. Yes, the Company has developed an integrated capital spending plan with defined projects and investments through 2023 as part of its 5-year plan related to pipeline safety projects. The Company also plans to address reliability and capacity on its distribution system, along with increasing upstream gas supply. The integrated capital spending plan for the years 2021, 2022, and 2023 is included with estimated costs as Attachment BF/RM/HT-2.

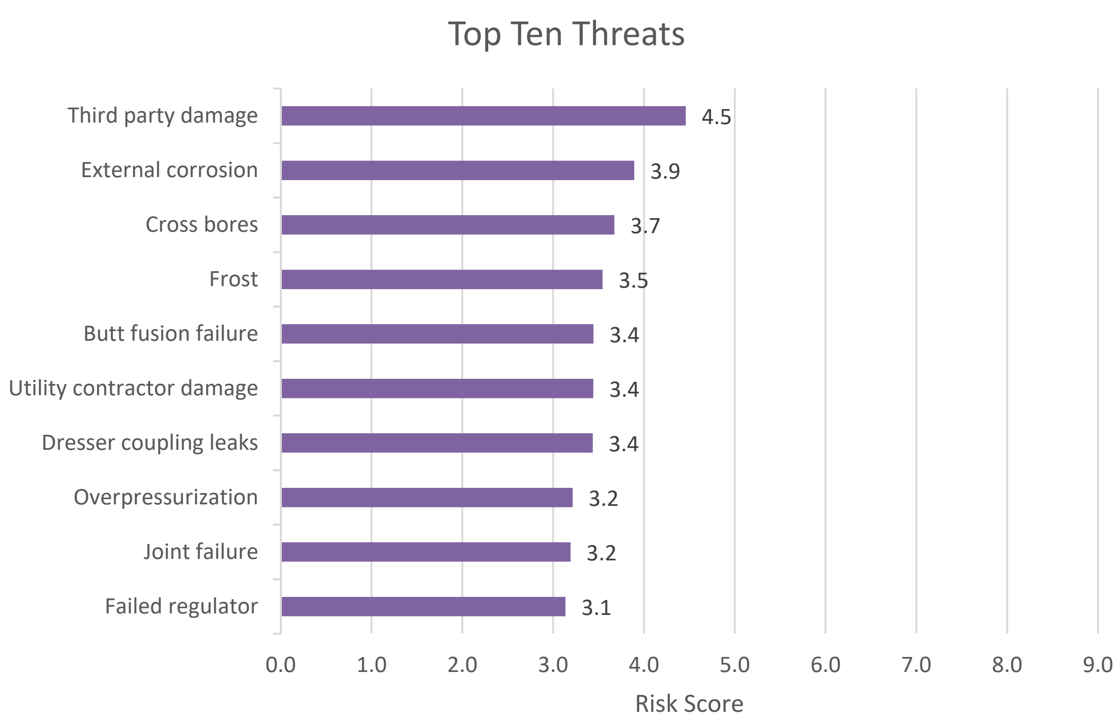
Q. What tools and input did the Company use to identify the types of projects in its capital plan?

A. Several tools and sources were used to identify the continued needs of the distribution system in a coordinated fashion. First, in Order No. 26,374 (the most recent CIBS docket), the Commission recommended an aggressive timeline for replacement of cast iron and bare steel pipe materials, which the Company intends to meet. Second, pipeline safety and asset condition related projects were identified primarily by using the Company's Distribution Integrity Management Program ("DIMP"), as that document identifies top threats and risk prone assets within the distribution system. Finally, a computer-based optimization tool was used during the analysis of gas system enhancement projects. The industry standard DNVGL Synergi Gas computer model was used to simulate EnergyNorth's distribution system and identify areas requiring reinforcement for reliability, along with modeling optimum solutions.

Q. What is DIMP and how did that methodology factor into project decisions?

A. DIMP was introduced into the federal pipeline safety regulations that govern construction and maintenance of the Company's gas system in 2009. This pipeline safety regulation improves overall pipeline safety by having distribution operators identify risks specific to their individual distribution system, rank those risks, and then implement risk reduction measures to provide greater pipeline safety improvement than is achieved through prescriptive regulations. In May 2020, the Company finished a complete revision of its DIMP plan. The two charts below describe the top issues identified, that the Company is now addressing.


Top Ten Riskiest Assets
Cast iron mains
3.7
Bare steel mains
3.5
Unprotected steel mains
3.2
Bare steel services
3.2
Outdoor meter sets
3.2
High pressure indoor meter sets (K-meters)
3.1
Aldyl-A mains (vintage plastics)
3.0
Elevated pressure services
3.0
Unprotected steel services
2.9
Protected steel mains
2.9
0.0 1.0 2.0 3.0 4.0 5.0 6.0 7.0 8.0 9.0
Risk Score


Top Ten Threats
Third party damage
4.5
External corrosion
3.9
Cross bores
3.7
Frost
3.5
Butt fusion failure
3.4
Utility contractor damage
3.4
Dresser coupling leaks
3.4
Overpressurization
3.2
Joint failure
3.2
Failed regulator
3.1
0.0 1.0 2.0 3.0 4.0 5.0 6.0 7.0 8.0 9.0
Risk Score

Q. How does the Company's capital plan address the risks of cast iron and bare steel leak prone pipe that were identified in DIMP?

A. For approximately 12 years, the CIBS program operated successfully by providing the Company with the financial resources to make steady progress replacing leak prone pipe. In 2019 the Commission made the decision to discontinue annual cost recovery through the CIBS program. Order No. 26,266 (June 28, 2019). And in 2020, in the last CIBS proceeding, the Commission directed the Company to replace or abandon all cast iron and bare steel pipes with a nominal diameter of 10 inches and smaller by the year 2025. Order No. 26,374 (June 30, 2020).

Cast iron and bare steel pipes are ranked as the two most risk prone assets in the Company's DIMP plan. The Company supports replacement of these assets and has determined the rate of replacement required to accomplish this goal by 2025. The majority of remaining affected pipe is located in Nashua, with the aforementioned paving program, and in Manchester, which is undertaking a multi-year sewer-drain separation project, with utility relocations starting in late 2020. The Company has identified that it is most efficient to closely coordinate and combine replacement of cast iron and bare steel pipe with those municipal projects.

The Company has developed a timeline of replacing a total of 10.8 miles of gas main per year, with approximately 9.75 miles per year directed at cast iron and bare steel pipe materials with a nominal diameter of 10 inches or smaller. The remaining 1.05 miles is an allowance for small amounts of other pipe materials replaced during the course of cast iron-bare steel projects and municipal projects affecting only coated steel or plastic pipe materials. The total projected cost for this core pipe replacement program through 2023 is approximately $76 million.

Q. Are there other deteriorating assets or safety related conditions identified in the DIMP that the Company is planning to address through its capital construction program?

A. Yes. The Company's plan includes work to ensure leak mitigation for several pipe materials identified in its DIMP program, and to address indoor high-pressure meter sets (K Meters) over the next five years. Pipe materials to be replaced include first generation plastic pipe, coated steel pipe in areas constructed with mechanical fittings, and unprotected coated steel pipe.

A K Meter is an integrated gas meter, pressure regulator, and safety relief valve manufactured by Sprague and installed by one of EnergyNorth's predecessor companies. (They are called "K Meters" because, at the time of installation, they were given meter serial numbers coded with the letter K.) There are approximately 2,300 K Meters currently installed within the system. Due to their integrated pressure regulator, these meters were installed within the Company's 60 psig distribution system, and virtually all were installed with indoor meter sets. Indoor installation of residential meters, especially those on 60 psig distribution systems, is not a current gas utility industry practice and the K Meters are therefore identified as a risk in DIMP. The Company is proposing to eliminate all remaining K Meters over the next five years by replacing 300 installations in

2021 and 500 installations from 2022 through 2025. The total cost to accomplish this work through 2023 is estimated at $7.8 million.

DuPont Aldyl-A plastic pipe was used in the Concord area from the early 1970s until the mid to late 1980s. Failures with this pipe material are observed at butt fusion joints where individual pieces of factory manufactured pipe were joined together in the field. The Company has documented 10 such failures in the past eight years and makes yearly reports to Commission Staff regarding failure history and replacement efforts. In order to continue addressing this deteriorating asset, the Company is projecting to spend approximately $2.9 million through 2023 to replace 0.5 miles of Aldyl-A pipe per year, with a focus on piping that has a designated leak history and that operates at 60 psig.

Mechanical fittings on coated steel pipe are the primary driver of leaks in the southern part of the Company's service territory. Dresser branded mechanical couplings were used to assemble pipe sections and connect valves for gas mains in this area in the 1960s and 1970s. Each year, Dresser couplings are the source of a significant number of leaks that the Company must repair, typically by removing the couplings and valves and welding new steel pipe as the replacement gas main. To accomplish this work the Company anticipates completing 86 repairs per year with a total cost of $5.3 million through 2023.

The Company also plans to maintain a program for capital replacement of gas mains with emergent leak history. This mostly affects coated steel pipes without corrosion protection and short lengths of bare steel mains. Both of these assets are recognized as top risks in the DIMP plan. The Company is proposing a reactive main replacement plan of 0.31 miles per year, consistent with historical averages. Based upon recent cost trends, total spend through 2023 for this program would be approximately $2 million.

Q. Is the Company proposing any reliability projects to reinforce the gas system over the next three years?

A. Yes, the Company is proposing several improvements to main feeder pipes in order to supply adequate pressure to its existing customers and to make the distribution system available to new customers. The Company used DNVGL Synergi Gas software to predict operating pressures in the system based on recent customer usage history. Based on a recent gas system model fully updated in the spring of 2020, the Company proposes between one and three reliability projects per year to maintain capacity within the distribution system in response to recent customer growth. There are a number of projects within system reliability to be completed over the next three years. Among those projects are the following:

- Reinforcement of the Concord low pressure distribution system due to low operating pressures caused by Concord Steam load growth;
- Increasing supply to the City of Laconia due to organic growth so that system operating pressure can be maintained;
- Reinforcing feeder pipes to south Nashua so there is available capacity for growth in Hudson and Nashua without negatively affecting pressure at the edge of the Company's service territory;

- Complete the rebuilding of the Concord-Tilton Hi-Line to provide adequate supply to customers north of Concord and reduce use of the Tilton LNG peaking plant; and

The Gas System Planning & Reliability line of Attachment BF/RM/HT-2 reflects costs of the projects above along with other projects to reinforce the distribution system.

Q. Is the Company proposing any enhancements to its system to accommodate its supply capacity contracts?

A. Yes. The Company's greatest single delivery point from the interstate pipeline system is currently its Hudson take station. This location is supplied by Tennessee Gas Pipeline ("TGP") via Windham on a pipeline that is at maximum capacity. To address long term gas supply need, the Company recently completed development of an updated model showing that 40,000 dekatherms per day of additional long-term capacity was needed in the Company's service territory, and recently signed a contract with TGP to provide that capacity to Londonderry. The Company in turn analyzed two scenarios to distribute this additional capacity, and selected the option that carries the least long-term cost to its customers. Details of that analysis are provided in the Second Supplemental Direct Testimony of Francisco C. DaFonte and William R. Killeen filed in Docket No. DG 17-198. Work the Company plans to undertake to implement that option from 2021 to 2023 includes:

- Completing design and permitting in 2021;

- Rebuilding the point of delivery from TGP in Manchester at Candia Road, building a new point of delivery into the distribution system from the Granite Ridge transmission pipeline, and then building a pipeline from the new point of delivery into the Manchester distribution system in 2022; and
- Uprating the pressure of the existing 130 psig sub-transmission feeder in Manchester, and building a river crossing from the new pipeline into the distribution system in in Merrimack in 2023.

The Gas System Supply Enhancements line of Attachment BF/RM/HT-2 reflects the projects above to increase supply.

Q. What are the estimated costs by year for each project?

A. The estimated costs for each project are shown in Attachment BF/RM/HT-2. The attachment shows the estimated capital expenditure in each year and the amount that is expected to be in-service and used and useful at the end of each year.

Q. In preparing for these projects, has the Company made any changes to its budget and planning process?

A. Yes. Given that field conditions have the potential to cause large variances from budget, the Company reassessed its process and determined that several changes were appropriate. Typically, the Company has applied a 10 percent contingency factor when estimating gas project costs. This is a relatively small contingency factor, but has been used in part in the interest of being cost conscious. However, the Company recognizes that certain areas that have not been excavated in 50–60 years often lack records, and there may be little or no information about environmental conditions or hazards that might be encountered and which could be used to inform and refine estimates.

Going forward, the Company's Gas Engineering Department will continue to develop initial budget estimates. As projects are designated to move forward, the Construction Department will work directly with Gas Engineering to refine the estimates for individual projects. The Construction Department will perform additional research on location history with respect to ledge, asbestos, and utility conflicts. The Company will also attempt to gather history on underground work in the area, not only by EnergyNorth, but by others. The Company will be looking to add additional internal resources to assist with these efforts.

Q. How will this additional coordination between the Gas Engineering and Construction Departments be reflected in budget estimates?

A. Absent test borings, the Company can only make a "best guess" of the environmental conditions it will encounter. However, going forward, the additional research and coordination will allow for more accurate estimates. The Company will also apply different contingency factors to its budget estimates based on its expectations with respect to ledge or asbestos. For example, where ledge is anticipated, the Company will use a contingency factor of 15 percent. Where asbestos is anticipated, the Company will use a contingency factor of 20 percent. In areas where utility infrastructure congestion can cause scope changes to project design that result in change orders and an existing conditions survey is conducted, the Company will employ that information. For all other projects, the Company will continue to employ a 10 percent contingency factor.

Q. Are there any other actions you are taking to improve the budget and planning process?

A. Yes, coordinating the Company's work with the municipalities in its service area has been a high priority for the Company because it mitigates the costs that are ultimately paid by customers, and minimizes the disruption to the communities where we strive to be good neighbors. As described earlier, the Company makes every effort to coordinate its work plan with its communities, but not all of the municipalities have regularly scheduled meetings to address public works. Going forward, the Company's Construction Department will more aggressively pursue meetings with the communities where large amounts of work are expected and regular meetings do not already occur.

IV. REQUEST FOR STEP ADJUSTMENTS

Q. Please describe the Company's request for step adjustments for capital projects placed in service after December 31, 2019.

A. EnergyNorth continues to invest in its infrastructure and is requesting a series of step adjustments to recover the cost of non-growth-related additions to the Company's net plant made after December 31, 2019, which is the end of the test year in this case. The step adjustments would apply to plant investments made in 2020, 2021, and 2022.

Q. How would the step adjustments be implemented?

A. For non-growth plant placed in service in calendar year 2020, the Company proposes a step increase to recover approximately $37.6 million of non-growth capital as provided in the revenue requirement model Schedule Step Increase – EnergyNorth, to be implemented in 2021. The Company will provide documentation during this case supporting the actual cost of these investments through the end of the 2020.

For future step increases (2021 and beyond), the Company proposes to file documentation demonstrating the change in its net plant between January 1 and December 31 of each year. The actual change would be compared to forecasted increases in plant in service derived from the Company's annual forecast. If the amount of the actual change is equal to or greater than the amount forecasted, the step increase will take effect on July 1 of each year, subject to prudency review. The amounts of the step increases would be those associated with 80 percent of the non-growth changes in net plant. If the Company's net plant additions are less than the forecasted amount, then the total net utility plant balance will be compared to the forecasted amount for a given year. If the plant balance meets the forecasted amount, the step increase would take effect as scheduled, subject to a prudency review.

For illustration, Attachment BF/RM/HT-3 provides a revenue requirement calculation showing that if the Company spends $40 million on capital projects during calendar year 2020, the step increase in rates that is projected for July 1, 2021, is $2,755,731. Under this proposal, if the change in Company's net utility plant between January 1 and

December 31, 2020, is at least $20 million (that is, if the increase in the Company's distribution plant for that period, after taking into account accumulated depreciation, is greater than or equal to $20 million) and the plant additions (following a finding by the Commission that the plant additions are prudent, used and useful, and providing service to customers), then the Company will be permitted to increase its revenues by $2,755,731, which represents the revenue requirement associated with 80 percent of that change in net plant. If the Company does not add $20 million in net plant assets, the lower net amount of the change will be used in calculating the revenue requirement for the adjustment. Should the Company add more in assets than was forecast, it will not receive a corresponding increase to the step adjustment.

Q. Is this methodology similar to step adjustments approved for other New Hampshire utilities in the past?

A. Yes. Step increases involving a similar methodology have been approved in the past for Eversource Energy in Docket No. DE 09-035 and Unitil Energy Services in Docket Nos. DE 10-055 and DE 16-384.

The Company's proposal is reasonable and should be approved because it is necessary to allow timely recovery of plant investments without driving a need for multiple rate cases, and is consistent with the step adjustment mechanisms that the Commission has previously approved for other New Hampshire utilities.

Q. Is the Company's proposal also necessary due to termination of cost recovery through the CIBS program?

A. Yes. Even though the CIBS accelerated recovery mechanism has been discontinued, as mentioned above the Company will continue to replace CIBS as part of its ongoing business operations and will seek to include those investments as part of the step adjustment mechanism described above.

V. CONCLUSION

Q. Please summarize your testimony.

A. Since the last general distribution rate proceeding, the Company has placed in service approximately $84.4 million of capital investments that are not currently in rates. This capital spending drives a significant portion of the proposed distribution rate increase requested in the Company's rate case filing.

The future projects described in this testimony will provide the needed asset replacement related to pipeline safety and capacity for growth in the area, and will form the basis for requests for cost recovery through future step adjustments to allow the Company timely recovery of the costs associated with safe and reliable service, thus reducing the pressure to file rate cases on a more frequent basis.

Q. Does this complete your testimony?

A. Yes, it does.